ORIGINAL

IN THE SUPREME COURT OF OHIO

Columbus Southern Power Company	:	**Case No. 10-723**
	:	
Appellant,	:	
	:	**Appeal from Public**
v.	:	**Utilities Commission of Ohio**
	:	
The Public Utilities Commission of Ohio,	:	**Public Utilities**
	:	**Commission of Ohio**
Appellee.	:	**Case No. 09-516-EL-AEC**

APPELLANT APPENDIX OF COLUMBUS SOUTHERN POWER COMPANY

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1.42 Common, technical or particular terms.
Words and phrases shall be read in context and construed according to the rules of grammar and common usage. Words and phrases that have acquired a technical or particular meaning, whether by legislative definition or otherwise, shall be construed accordingly.
Effective Date: 01-03-1972

1.47 Presumptions in enactment of statutes.
In enacting a statute, it is presumed that:
(A) Compliance with the constitutions of the state and of the United States is intended;
(B) The entire statute is intended to be effective;
(C) A just and reasonable result is intended;
(D) A result feasible of execution is intended.
Effective Date: 01-03-1972

4903.13 Reversal of final order - notice of appeal.
A final order made by the public utilities commission shall be reversed, vacated, or modified by the supreme court on appeal, if, upon consideration of the record, such court is of the opinion that such order was unlawful or unreasonable. The proceeding to obtain such reversal, vacation, or modification shall be by notice of appeal, filed with the public utilities commission by any party to the proceeding before it, against the commission, setting forth the order appealed from and the errors complained of. The notice of appeal shall be served, unless waived, upon the chairman of the commission, or, in the event of his absence, upon any public utilities commissioner, or by leaving a copy at the office of the commission at Columbus. The court may permit any interested party to intervene by cross-appeal.
Effective Date: 10-01-1953

4905.31 Reasonable arrangements allowed - variable rate.
Chapters 4901., 4903., 4905., 4907., 4909., 4921., 4923., 4927., 4928., and 4929. of the Revised Code do not prohibit a public utility from filing a schedule or establishing or entering into any reasonable arrangement with another public utility or with one or more of its customers, consumers, or employees, and do not prohibit a mercantile customer of an electric distribution utility as those terms are defined in section 4928.01 of the Revised Code or a group of those customers from establishing a reasonable arrangement with that utility or another public utility electric light company, providing for any of the following:
(A) The division or distribution of its surplus profits;
(B) A sliding scale of charges, including variations in rates based upon stipulated variations in cost as provided in the schedule or arrangement.
(C) A minimum charge for service to be rendered unless such minimum charge is made or prohibited by the terms of the franchise, grant, or ordinance under which such public utility is operated;
(D) A classification of service based upon the quantity used, the time when used, the purpose for which used, the duration of use, and any other reasonable consideration;

(E) Any other financial device that may be practicable or advantageous to the parties interested. In the case of a schedule or arrangement concerning a public utility electric light company, such other financial device may include a device to recover costs incurred in conjunction with any economic development and job retention program of the utility within its certified territory, including recovery of revenue foregone as a result of any such program; any development and implementation of peak demand reduction and energy efficiency programs under section 4928.66 of the Revised Code; any acquisition and deployment of advanced metering, including the costs of any meters prematurely retired as a result of the advanced metering implementation; and compliance with any government mandate. No such schedule or arrangement is lawful unless it is filed with and approved by the commission pursuant to an application that is submitted by the public utility or the mercantile customer or group of mercantile customers of an electric distribution utility and is posted on the commission's docketing information system and is accessible through the internet. Every such public utility is required to conform its schedules of rates, tolls, and charges to such arrangement, sliding scale, classification, or other device, and where variable rates are provided for in any such schedule or arrangement, the cost data or factors upon which such rates are based and fixed shall be filed with the commission in such form and at such times as the commission directs. Every such schedule or reasonable arrangement shall be under the supervision and regulation of the commission, and is subject to change, alteration, or modification by the commission.
Effective Date: 10-29-1993; 2008 SB221 07-31-2008

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.

(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, 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 that it consumes electricity it so produces, sells that electricity for resale, or obtains electricity from a generating facility it hosts on its premises.
(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 has a certified territory and is engaged on a for-profit basis either 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 October 5, 1999, pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on October 4, 1999, 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, the home energy assistance program, the home weatherization assistance program, and the targeted energy efficiency and weatherization program.
(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 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) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users, including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" also includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.
(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 undepreciated 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)"Starting date of competitive retail electric service" means January 1, 2001.
(29)"Customer-generator" means a user of a net metering system.
(30) "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 that is fed back to the electric service provider.
(31) "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.
(32)"Self-generator" means an entity in this state that owns or hosts on its premises an electric generation facility that produces electricity primarily for the owner's consumption and that may provide any such excess electricity to another entity, whether the facility is installed or operated by the owner or by an agent under a contract.
(33) "Rate plan" means the standard service offer in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.
(34)"Advanced energy resource" means any of the following:
(a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;
(b) Any distributed generation system consisting of customer cogeneration of electricity and thermal output simultaneously, primarily to meet the energy needs of the customer's facilities;
(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion;
(d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;
(e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM).
(g) Demand-side management and any energy efficiency improvement; (h) Methane gas emitted from an operating or abandoned coal mine.
(35) "Renewable energy resource" means solar photovoltaic or solar thermal energy, wind energy, power produced by a hydroelectric facility, geothermal energy, fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion, biomass energy, biologically derived methane gas, or energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors. "Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; storage facility that will promote the better utilization of a renewable energy resource that primarily generates off peak; or distributed generation system used by a customer to generate electricity from any such energy. As used in division (A)(35) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:
(a) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined by the applicable licensing agency for the facility.
(b) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 1341, and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 1313.
(c) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromus fish.
(d) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.
(e) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 1531 to1544, as amended.
(f) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic preservation office, to the extent it has jurisdiction over the facility.

(g) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.
(h) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.
(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.
Amended by 128th General Assembly File No. 9, HB 1, § 101.01, eff. 10/16/2009.
Effective Date: 10-05-1999; 01-04-2007; 2008 SB221 07-31-2008

4928.02 State policy.
It is the policy of this state to do the following throughout this state :
(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 including, but not limited to, demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure;
(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 both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language;
(F) Ensure that an electric utility's transmission and distribution systems are available to a customer-generator or owner of distributed generation, so that the customer-generator or owner can market and deliver the electricity it produces;
(G) Recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment;
(H) 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, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates;

(I) Ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power;
(J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates;
(K) Encourage implementation of distributed generation across customer classes through regular review and updating of administrative rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering;
(L) Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource;
(M) Encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses;
(N) Facilitate the state's effectiveness in the global economy. In carrying out this policy, the commission shall consider rules as they apply to the costs of electric distribution infrastructure, including, but not limited to, line extensions, for the purpose of development in this state.
Effective Date: 10-05-1999; 2008 SB221 07-31-2008

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.
Effective Date: 10-05-1999

4928.06 Commission to ensure competitive retail electric service.
(A) Beginning on the starting date of competitive retail electric service, the public utilities commission shall ensure that the policy specified in section 4928.02 of the Revised Code is effectuated. To the extent necessary, the commission shall adopt rules to carry out this chapter. Initial rules necessary for the commencement of the competitive retail electric service under this chapter shall be adopted within one hundred eighty days after the effective date of this section. Except as otherwise provided in this chapter, the proceedings and orders of the commission under the chapter shall be subject to and governed by Chapter 4903. of the Revised Code.

(B) If the commission determines, on or after the starting date of competitive retail electric service, that there is a decline or loss of effective competition with respect to a competitive retail electric service of an electric utility, which service was declared competitive by commission order issued pursuant to division (A) of section 4928.04 of the Revised Code, the commission shall ensure that that service is provided at compensatory, fair, and nondiscriminatory prices and terms and conditions.
(C) In addition to its authority under section 4928.04 of the Revised Code and divisions (A) and (B) of this section, the commission, on an ongoing basis, shall monitor and evaluate the provision of retail electric service in this state for the purpose of discerning any noncompetitive retail electric service that should be available on a competitive basis on or after the starting date of competitive retail electric service pursuant to a declaration in the Revised Code, and for the purpose of discerning any competitive retail electric service that is no longer subject to effective competition on or after that date. Upon such evaluation, the commission periodically shall report its findings and any recommendations for legislation to the standing committees of both houses of the general assembly that have primary jurisdiction regarding public utility legislation. Until 2008, the commission and the consumer's counsel also shall provide biennial reports to those standing committees, regarding the effectiveness of competition in the supply of competitive retail electric services in this state. In addition, until the end of all market development periods as determined by the commission under section 4928.40 of the Revised Code, those standing committees shall meet at least biennially to consider the effect on this state of electric service restructuring and to receive reports from the commission, consumers' counsel, and director of development.
(D) In determining, for purposes of division (B) or (C) of this section, whether there is effective competition in the provision of a retail electric service or reasonably available alternatives for that service, the commission shall consider factors including, but not limited to, all of the following:
(1) The number and size of alternative providers of that service;
(2) The extent to which the service is available from alternative suppliers in the relevant market;
(3) The ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms, and conditions;
(4) Other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services. The burden of proof shall be on any entity requesting, under division (B) or (C) of this section, a determination by the commission of the existence of or a lack of effective competition or reasonably available alternatives.
(E)(1) Beginning on the starting date of competitive retail electric service, the commission has authority under Chapters 4901. to 4909. of the Revised Code, and shall exercise that authority, to resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service.
(2) In addition to the commission's authority under division (E)(1) of this section, the commission, beginning the first year after the market development period of a particular electric utility and after reasonable notice and opportunity for hearing, may take such measures within a transmission constrained area in the utility's certified territory as are necessary to ensure that retail electric generation service is provided at reasonable rates

within that area. The commission may exercise this authority only upon findings that an electric utility is or has engaged in the abuse of market power and that that abuse is not adequately mitigated by rules and practices of any independent transmission entity controlling the transmission facilities. Any such measure shall be taken only to the extent necessary to protect customers in the area from the particular abuse of market power and to the extent the commission's authority is not preempted by federal law. The measure shall remain the commission, after reasonable notice and opportunity for hearing, determines that the particular abuse of market power has been mitigated.

(F) An electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code shall provide the commission with such information, regarding a competitive retail electric service for which it is subject to certification, as the commission considers necessary to carry out this chapter. An electric utility shall provide the commission with such information as the commission considers necessary to carry out divisions (B) to (E) of this section. The commission shall take such measures as it considers necessary to protect the confidentiality of any such information. The commission shall require each electric utility to file with the commission on and after the starting date of competitive retail electric service an annual report of its intrastate gross receipts and sales of kilowatt hours of electricity, and shall require each electric services company, electric cooperative, and governmental aggregator subject to certification to file an annual report on and after that starting date of such receipts and sales from the provision of those retail electric services for which it is subject to certification. For the purpose of the reports, sales of kilowatt hours of electricity are deemed to occur at the meter of the retail customer.

Effective Date: 10-05-1999

4928.14 Failure of supplier to provide service.

The failure of a supplier to provide retail electric generation service to customers within the certified territory of an electric distribution utility shall result in the supplier's customers, after reasonable notice, defaulting to the utility's standard service offer under sections 4928.141, 4928.142, and 4928.143 of the Revised Code until the customer chooses an alternative supplier. A supplier is deemed under this section 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:

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

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

(C) 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.

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

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.141 Distribution utility to provide standard service offer.

(A) Beginning January 1, 2009, an electric distribution utility shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a 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. To that end, the electric distribution utility shall apply to the public utilities commission to establish the standard service offer in accordance with section 4928.142 or 4928.143 of the Revised Code and, at its discretion, may apply simultaneously under both sections, except that the utility's first standard service offer application at minimum shall include a filing under section 4928.143 of the Revised Code. Only a standard service offer authorized in accordance with section 4928.142 or 4928.143 of the Revised Code, shall serve as the utility's standard service offer for the purpose of compliance with this section; and that standard service offer shall serve as the utility's default standard service offer for the purpose of section 4928.14 of the Revised Code. Notwithstanding the foregoing provision, the rate plan of an electric distribution utility shall continue for the purpose of the utility's compliance with this division until a standard service offer is first authorized under section 4928.142 or 4928.143 of the Revised Code, and, as applicable, pursuant to division (D) of section 4928.143 of the Revised Code, any rate plan that extends beyond December 31, 2008, shall continue to be in effect for the subject electric distribution utility for the duration of the plan's term. A standard service offer under section 4928.142 or 4928.143 of the Revised Code shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan.
(B) The commission shall set the time for hearing of a filing under section 4928.142 or 4928.143 of the Revised Code, send written notice of the hearing to the electric distribution utility, and publish notice in a newspaper of general circulation in each county in the utility's certified territory. The commission shall adopt rules regarding filings under those sections.
Effective Date: 2008 SB221 07-31-2008

4928.142 Standard generation service offer price - competitive bidding.

(A) For the purpose of complying with section 4928.141 of the Revised Code and subject to division (D) of this section and, as applicable, subject to the rate plan requirement of division (A) of section 4928.141 of the Revised Code, an electric distribution utility may establish a standard service offer price for retail electric generation service that is delivered to the utility under a market-rate offer.
(1) The market-rate offer shall be determined through a competitive bidding process that provides for all of the following:
(a) Open, fair, and transparent competitive solicitation;
(b) Clear product definition;
(c) Standardized bid evaluation criteria;
(d) Oversight by an independent third party that shall design the solicitation, administer the bidding, and ensure that the criteria specified in division (A)(1)(a) to (c) of this section are met;

(e) Evaluation of the submitted bids prior to the selection of the least-cost bid winner or winners. No generation supplier shall be prohibited from participating in the bidding process.
(2) The public utilities commission shall modify rules, or adopt new rules as necessary, concerning the conduct of the competitive bidding process and the qualifications of bidders, which rules shall foster supplier participation in the bidding process and shall be consistent with the requirements of division (A)(1) of this section.
(B) Prior to initiating a competitive bidding process for a market-rate offer under division (A) of this section, the electric distribution utility shall file an application with the commission. An electric distribution utility may file its application with the commission prior to the effective date of the commission rules required under division (A)(2) of this section, and, as the commission determines necessary, the utility shall immediately conform its filing to the rules upon their taking effect. An application under this division shall detail the electric distribution utility's proposed compliance with the requirements of division (A)(1) of this section and with commission rules under division (A)(2) of this section and demonstrate that all of the following requirements are met:
(1) The electric distribution utility or its transmission service affiliate belongs to at least one regional transmission organization that has been approved by the federal energy regulatory commission; or there otherwise is comparable and nondiscriminatory access to the electric transmission grid.
(2) Any such regional transmission organization has a market-monitor function and the ability to take actions to identify and mitigate market power or the electric distribution utility's market conduct; or a similar market monitoring function exists with commensurate ability to identify and monitor market conditions and mitigate conduct associated with the exercise of market power.
(3) A published source of information is available publicly or through subscription that identifies pricing information for traded electricity on- and off-peak energy products that are contracts for delivery beginning at least two years from the date of the publication and is updated on a regular basis. The commission shall initiate a proceeding and, within ninety days after the application's filing date, shall determine by order whether the electric distribution utility and its market-rate offer meet all of the foregoing requirements. If the finding is positive, the electric distribution utility may initiate its competitive bidding process. If the finding is negative as to one or more requirements, the commission in the order shall direct the electric distribution utility regarding how any deficiency may be remedied in a timely manner to the commission's satisfaction; otherwise, the electric distribution utility shall withdraw the application. However, if such remedy is made and the subsequent finding is positive and also if the electric distribution utility made a simultaneous filing under this section and section 4928.143 of the Revised Code, the utility shall not initiate its competitive bid until at least one hundred fifty days after the filing date of those applications.
(C) Upon the completion of the competitive bidding process authorized by divisions (A) and (B) of this section, including for the purpose of division (D) of this section, the commission shall select the least-cost bid winner or winners of that process, and such selected bid or bids, as prescribed as retail rates by the commission, shall be the electric distribution utility's standard service offer unless the commission, by order issued before

the third calendar day following the conclusion of the competitive bidding process for the market rate offer, determines that one or more of the following criteria were not met:
(1) Each portion of the bidding process was oversubscribed, such that the amount of supply bid upon was greater than the amount of the load bid out.
(2) There were four or more bidders.
(3) At least twenty-five per cent of the load is bid upon by one or more persons other than the electric distribution utility. All costs incurred by the electric distribution utility as a result of or related to the competitive bidding process or to procuring generation service to provide the standard service offer, including the costs of energy and capacity and the costs of all other products and services procured as a result of the competitive bidding process, shall be timely recovered through the standard service offer price, and, for that purpose, the commission shall approve a reconciliation mechanism, other recovery mechanism, or a combination of such mechanisms for the utility.
(D) The first application filed under this section by an electric distribution utility that, as of July 31, 2008, directly owns, in whole or in part, operating electric generating facilities that had been used and useful in this state shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid under division (A) of this section as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year of years one through five. The standard service offer price for retail electric generation service under this first application shall be a proportionate blend of the bid price and the generation service price for the remaining standard service offer load, which latter price shall be equal to the electric distribution utility's most recent standard service offer price, adjusted upward or downward as the commission determines reasonable, relative to the jurisdictional portion of any known and measurable changes from the level of any one or more of the following costs as reflected in that most recent standard service offer price:
(1) The electric distribution utility's prudently incurred cost of fuel used to produce electricity;
(2) Its prudently incurred purchased power costs;
(3) Its prudently incurred costs of satisfying the supply and demand portfolio requirements of this state, including, but not limited to, renewable energy resource and energy efficiency requirements;
(4) Its costs prudently incurred to comply with environmental laws and regulations, with consideration of the derating of any facility associated with those costs. In making any adjustment to the most recent standard service offer price on the basis of costs described in division (D) of this section, the commission shall include the benefits that may become available to the electric distribution utility as a result of or in connection with the costs included in the adjustment, including, but not limited to, the utility's receipt of emissions credits or its receipt of tax benefits or of other benefits, and, accordingly, the commission may impose such conditions on the adjustment to ensure that any such benefits are properly aligned with the associated cost responsibility. The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The commission shall not apply its consideration of the return on common equity to reduce any adjustments

authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. Additionally, the commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure that the resulting revenue available to the utility for providing the standard service offer is not so inadequate as to result, directly or indirectly, in a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution. The electric distribution utility has the burden of demonstrating that any adjustment to its most recent standard service offer price is proper in accordance with this division.
(E) Beginning in the second year of a blended price under division (D) of this section and notwithstanding any other requirement of this section, the commission may alter prospectively the proportions specified in that division to mitigate any effect of an abrupt or significant change in the electric distribution utility's standard service offer price that would otherwise result in general or with respect to any rate group or rate schedule but for such alteration. Any such alteration shall be made not more often than annually, and the commission shall not, by altering those proportions and in any event, including because of the length of time, as authorized under division (C) of this section, taken to approve the market rate offer, cause the duration of the blending period to exceed ten years as counted from the effective date of the approved market rate offer. Additionally, any such alteration shall be limited to an alteration affecting the prospective proportions used during the blending period and shall not affect any blending proportion previously approved and applied by the commission under this division.
(F) An electric distribution utility that has received commission approval of its first application under division (C) of this section shall not, nor ever shall be authorized or required by the commission to, file an application under section 4928.143 of the Revised Code.
Effective Date: 2008 SB221 07-31-2008; 2008 HB562 09-22-2008

<u>4928.143 Application for approval of electric security plan - testing.</u>
(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.
(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:
(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to

test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code; and provisions for the recovery of the utility's cost of securitization.
(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;
(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.
(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.
(C)(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.
(2)(a) If the commission modifies and approves an application under division (C)(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division (C)(2)(a) of this section or if the commission disapproves an application under division (C)(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.
(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division (C) of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division (C) of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141, division (B) of section 4928.64, or division (A) of section 4928.66 of the Revised Code.
(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the

more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

Effective Date: 2008 SB221 07-31-2008

4928.31 Transition plan.

(A) Not later than ninety days after the effective date of this section, an electric utility supplying retail electric service in this state on that date shall file with the public utilities commission a plan for the utility's provision of retail electric service in this state during the market development period. This transition plan shall be in such form as the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code and shall include all of the following:

(1) A rate unbundling plan that specifies, consistent with divisions (A)(1) to (7) of section 4928.34 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code, the unbundles components for electric generation, transmission, and distribution service and such other unbundled service components as the commission requires, to be charged by the utility beginning on the starting date of competitive retail electric service and that includes information the commission requires to fix and determine those components;

(2) A corporate separation plan consistent with section 4928.17 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;

(3) Such plan or plans as the commission requires to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service consistent with any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code;
(4) An employee assistance plan for providing severance, retraining, early retirement, retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring under this chapter;
(5) A consumer education plan consistent with former section 4928.42 of the Revised Code and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. A transition plan under this section may include tariff terms and conditions to address reasonable requirements for changing suppliers, length of commitment by a customer for service, and such other matters as are necessary to accommodate electric restructuring. Additionally, a transition plan under this section may include an application for the opportunity to receive transition revenues as authorized under sections 4928.31 to 4928.40 of the Revised Code, which application shall be consistent with those sections and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The transition plan also may include a plan for the independent operation of the utility's transmission facilities consistent with section 4928.12 of the Revised Code, division (A)(13) of section 4928.34 of the Revised Code, and any rules adopted by the commission under division (A) of section 4928.06 of the Revised Code. The commission may reject and require refiling, in whole or in part, of any substantially inadequate transition plan.
(B) The electric utility shall provide public notice of its filing under division (A) of this section, in a form and manner that the commission shall prescribe by rule adopted under division (A) of section 4928.06 of the Revised Code. However, the adoption of rules regarding the public notice under this division, regarding the form of the transition plan under division (A) of this section, and regarding procedures for expedited discovery under division (A) of section 4928.32 of the Revised Code are not subject to division (D) of section 111.15 of the Revised Code.
Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.66 Implementing energy efficiency programs.
(A)(1)(a) Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one per cent in 2012, nine-tenths of one per cent in 2013, one per cent from 2014 to 2018, and two per cent each year thereafter, achieving a cumulative, annual energy savings in excess of twenty-two per cent by the end of 2025.
(b) Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through 2018. In 2018, the standing committees in the house of representatives and the senate

primarily dealing with energy issues shall make recommendations to the general assembly regarding future peak demand reduction targets.

(2) For the purposes of divisions (A)(1)(a) and (b) of this section:

(a) The baseline for energy savings under division (A)(1)(a) of this section shall be the average of the total kilowatt hours the electric distribution utility sold in the preceding three calendar years, and the baseline for a peak demand reduction under division (A)(1)(b) of this section shall be the average peak demand on the utility in the preceding three calendar years, except that the commission may reduce either baseline to adjust for new economic growth in the utility's certified territory.

(b) The commission may amend the benchmarks set forth in division (A)(1)(a) or (b) of this section if, after application by the electric distribution utility, the commission determines that the amendment is necessary because the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control.

(c) Compliance with divisions (A)(1)(a) and (b) of this section shall be measured by including the effects of all demand-response programs for mercantile customers of the subject electric distribution utility and all such mercantile customer-sited energy efficiency and peak demand reduction programs, adjusted upward by the appropriate loss factors. Any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customers to commit those capabilities to those programs. If a mercantile customer makes such existing or new demand-response, energy efficiency, or peak demand reduction capability available to an electric distribution utility pursuant to division (A)(2)(c) of this section, the electric utility's baseline under division (A)(2)(a) of this section shall be adjusted to exclude the effects of all such demand-response, energy efficiency, or peak demand reduction programs that may have existed during the period used to establish the baseline. The baseline also shall be normalized for changes in numbers of customers, sales, weather, peak demand, and other appropriate factors so that the compliance measurement is not unduly influenced by factors outside the control of the electric distribution utility.

(d) Programs implemented by a utility may include demand-response programs, customer-sited programs, and transmission and distribution infrastructure improvements that reduce line losses. Division (A)(2)(c) of this section shall be applied to include facilitating efforts by a mercantile customer or group of those customers to offer customer-sited demand-response, energy efficiency, or peak demand reduction capabilities to the electric distribution utility as part of a reasonable arrangement submitted to the commission pursuant to section 4905.31 of the Revised Code.

(e) No programs or improvements described in division (A)(2)(d) of this section shall conflict with any statewide building code adopted by the board of building standards.

(B) In accordance with rules it shall adopt, the public utilities commission shall produce and docket at the commission an annual report containing the results of its verification of the annual levels of energy efficiency and of peak demand reductions achieved by each

electric distribution utility pursuant to division (A) of this section. A copy of the report shall be provided to the consumers' counsel.
(C) If the commission determines, after notice and opportunity for hearing and based upon its report under division (B) of this section, that an electric distribution utility has failed to comply with an energy efficiency or peak demand reduction requirement of division (A) of this section, the commission shall assess a forfeiture on the utility as provided under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code, either in the amount, per day per undercompliance or noncompliance, relative to the period of the report, equal to that prescribed for noncompliances under section 4905.54 of the Revised Code, or in an amount equal to the then existing market value of one renewable energy credit per megawatt hour of undercompliance or noncompliance. Revenue from any forfeiture assessed under this division shall be deposited to the credit of the advanced energy fund created under section 4928.61 of the Revised Code.
(D) The commission may establish rules regarding the content of an application by an electric distribution utility for commission approval of a revenue decoupling mechanism under this division. Such an application shall not be considered an application to increase rates and may be included as part of a proposal to establish, continue, or expand energy efficiency or conservation programs. The commission by order may approve an application under this division if it determines both that the revenue decoupling mechanism provides for the recovery of revenue that otherwise may be foregone by the utility as a result of or in connection with the implementation by the electric distribution utility of any energy efficiency or energy conservation programs and reasonably aligns the interests of the utility and of its customers in favor of those programs.
(E) The commission additionally shall adopt rules that require an electric distribution utility to provide a customer upon request with two years' consumption data in an accessible form.
Effective Date: 2008 SB221 07-31-2008

OHIO ADMINISTRATIVE CODE

4901:1-38-03 Economic development arrangements.

(A) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for commission approval for an economic development arrangement between the electric utility and a new or expanding customer or group of customers. The application shall include a copy of the proposed arrangement and provide information on all associated incentives, estimated annual electric billings without incentives for the term of the incentives, and annual estimated delta revenues for the term of the incentives.
(1) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.
(2) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall, at a minimum, meet the following criteria, submit to the electric utility and the commission verifiable information detailing how the

criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) Eligible projects shall be for non-retail purposes.

(b) At least twenty-five new, full-time or full-time equivalent jobs shall be created within three years of initial operations.

(c) The average hourly base wage rate of the new, full-time or full-time equivalent jobs shall be at least one hundred fifty per cent of the federal minimum wage.

(d) The customer shall demonstrate financial viability.

(e) The customer shall identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.

(f) The customer shall identify potential secondary and tertiary benefits resulting from its project including, but not limited to, local/state tax dollars and related employment or business opportunities resulting from the location of the facility.

(g) The customer shall agree to maintain operations at the project site for the term of the incentives.

(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an economic development arrangement bears the burden of proof that the proposed arrangement is reasonable and does not violate the provisions of sections 4905.33 and 4905.35 of the Revised Code, and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(B) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for an economic development arrangement between the electric utility and its customer or group of customers for the retention of an existing customer(s) likely to cease, reduce, or relocate its operations out of state. The application shall include a copy of the proposed arrangement and provide information on all associated incentives, estimated annual electric billings without incentives for the term of the incentives, and annual estimated delta revenues for the term of the incentives.

(1) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(2) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall, at a minimum, meet the following criteria, submit to the electric utility verifiable information detailing how the criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) Eligible projects shall be for non-retail purposes.

(b) The number of full-time or full-time equivalent jobs to be retained shall be at least twenty-five.

(c) The average billing load (in kilowatts to be retained) shall be at least two hundred fifty kilowatts.

(d) The customer shall demonstrate that the cost of electricity is a major factor in its decision to cease, reduce, or relocate its operations to an out-of-state site. In-state relocations are not eligible. If the customer has the potential to relocate to an out-of-state site, the site(s) shall be identified, along with the expected costs of electricity at the site(s)

and the expected costs of other significant expenses including, but not limited to, labor and taxes.
(e) The customer shall identify any other local, state, or federal assistance sought and/or received in order to maintain its current operations.
(f) The customer shall agree to maintain its current operations for the term of the incentives.
(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an economic development arrangement bears the burden of proof that the proposed arrangement is reasonable and does not violate the provisions of sections 4905.33 and 4905.35 of the Revised Code, and shall submit to the commission verifiable information detailing the rationale for the arrangement.
(C) Upon the filing of an economic development application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.
(1) The economic development arrangement shall be subject to change, alteration, or modification by the commission.
(2) The staff shall have access to all customer and electric utility information related to service provided pursuant to the economic development arrangements.
(D) Customer information provided to demonstrate eligibility under paragraphs (A) and (B) of this rule shall be treated by the electric utility as confidential. The electric utility shall request confidential treatment of customer-specific information that is filed with the commission, with the exception of customer names and addresses.
(E) Affected parties may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.
Effective: 04/02/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4905.04, 4905.06
Rule Amplifies: 4905.31, 4928.02

4901:1-38-04 Energy efficiency arrangements.
(A) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for commission approval for an energy efficiency arrangement between the electric utility and its customer or group of customers that have new or expanded energy efficiency production facilities. The application shall include a copy of the proposed arrangement and provide information on all associated incentives, estimated annual electric billings without incentives for the term of the incentives, and annual estimated delta revenues for the term of the incentives.
(1) Each customer requesting to take service pursuant to an energy efficiency arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.
(2) Each customer requesting to take service pursuant to an energy efficiency arrangement with the electric utility shall meet the following criteria, submit to the electric utility verifiable information detailing how the criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) The customer shall be an energy efficiency production facility as defined in this chapter.
(b) At least ten new, full-time or full-time equivalent jobs shall be created within three years of initial operations.
(c) The average hourly base wage rate of the new, full-time, or full-time equivalent jobs shall be at least one hundred fifty per cent of federal minimum wage.
(d) The customer shall demonstrate financial viability.
(e) The customer shall identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.
(f) The customer shall agree to maintain operations at the project site for the term of the incentives.
(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an energy efficiency arrangement bears the burden of proof that the proposed arrangement is reasonable and does not violate the provisions of sections 4905.33 and 4905.35 of the Revised Code, and shall submit to the commission verifiable information detailing the rationale for the arrangement.
(B) Upon the filing of an energy efficiency application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.
(1) The energy efficiency arrangement shall be subject to change, alteration, or modification by the commission.
(2) The staff shall have access to all customer and electric utility information related to service provided pursuant to the energy efficiency arrangements.
(C) Customer information provided to demonstrate eligibility under paragraph (A) of this rule shall be treated by the electric utility as confidential. The electric utility shall request confidential treatment of customer-specific information that is filed with the commission, with the exception of customer names and addresses.
(D) Affected parties may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.
Effective: 04/02/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4905.04, 4905.06
Rule Amplifies: 4905.31, 4928.02

<u>4901:1-38-05 Unique arrangements.</u>
(A) Notwithstanding rules 4901:1-38-03 and 4901:1-38-04 of the Administrative Code, an electric utility may file an application pursuant to section 4905.31 of the Revised Code for commission approval of a unique arrangement with one or more of its customers, consumers, or employees.
(1) An electric utility filing an application for commission approval of a unique arrangement with one or more of its customers, consumers, or employees bears the burden of proof that the proposed arrangement is reasonable and does not violate the provisions of sections 4905.33 and 4905.35 of the Revised Code, and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(2) Upon the filing of an application for a unique arrangement, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.
(3) The unique arrangement shall be subject to change, alteration, or modification by the commission.
(B) A mercantile customer, or a group of mercantile customers, of an electric utility may apply to the commission for a unique arrangement with the electric utility.
(1) Each customer applying for a unique arrangement bears the burden of proof that the proposed arrangement is reasonable and does not violate the provisions of sections 4905.33 and 4905.35 of the Revised Code, and shall submit to the commission and the electric utility verifiable information detailing the rationale for the arrangement.
(2) The customer shall provide an affidavit from a company official as to the veracity of the information provided.
(3) Upon the filing of an application for a unique arrangement, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.
(4) The unique arrangement shall be subject to change, alteration, or modification by the commission.
(C) Each applicant applying for approval of a unique arrangement between an electric utility and one or more of its customers, consumers, or employees shall describe how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.
(D) Unique arrangements shall reflect terms and conditions for circumstances for which the electric utility's tariffs have not already provided.
(E) Customer information provided to the electric utility to obtain a unique arrangement shall be treated by the electric utility as confidential. The electric utility shall request confidential treatment of customer-specific information that is filed with the commission, with the exception of customer names and addresses.
(F) Affected parties may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.
Effective: 04/02/2009
R.C. 119.032 review dates: 09/30/2013
Promulgated Under: 111.15
Statutory Authority: 4905.04, 4905.06
Rule Amplifies: 4905.31, 4928.02

FILE

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IN THE SUPREME COURT OF OHIO

Columbus Southern Power Company	:	**Case No.** 10-0723
Appellant,	:	
v.	:	**Appeal from Public Utilities Commission of Ohio**
The Public Utilities Commission of Ohio,	:	**Public Utilities Commission of Ohio**
Appellee.	:	**Case No. 09-516-EL-AEC**

NOTICE OF APPEAL OF COLUMBUS SOUTHERN POWER COMPANY

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SUPREME COURT OF OHIO

NOTICE OF APPEAL OF
APPELLANT COLUMBUS SOUTHERN POWER COMPANY

Appellant, Columbus Southern Power Company ("CSP" or "Appellant"), hereby gives notice of its appeal, pursuant to R.C. 4903.11 and 4903.13, and Supreme Court Rule of Practice II, Section 3(B), to the Supreme Court of Ohio and Appellee, the Public Utilities Commission of Ohio ("Commission"), from an Opinion and Order entered on Ocotber 15, 2009 (Attachment A), a December 11, 2009 Entry on Rehearing granting CSP's (and other parties') rehearing applications so that the Commission could further consider the issues raised on rehearing (Attachment B), and an Entry on Rehearing entered on March 24, 2010 (Attachment C), in PUCO Case No. 09-516-EL-AEC. That case involved an application filed by Eramet Marietta, Inc. (Eramet) to establish a reasonable arrangement with CSP for electric service to Eramet's facility in Marietta, Ohio.

In its March 24, 2010 Entry on Rehearing, the Commission granted rehearing regarding an issue raised on rehearing by an intervenor in the proceeding below. CSP actively opposed that intervenor's rehearing request and the Commission's granting of that rehearing request harmed CSP's interests. The assignments of error listed below as (a)-(h) were raised in Appellants' Application for Rehearing filed in accordance with R.C. 4903.10. The assignment of error listed below as (i) arises from the Commission's granting rehearing on the issue raised on rehearing by the intervenor.

The Commission's Opinion and Order and Entries on Rehearing are unlawful and unreasonable in multiple respects.

(a) The Commission's finding that Eramet cannot shop through the period ending with the expiration of CSP's ESP is contrary to the evidence in the record and to the public policy codified in Ohio law.

(b) Basing the determination of whether Eramet can shop under the terms of a ten-year contract on only three of those ten years is unreasonable and unlawful.

(c) Basing the determination of whether Eramet can shop under the terms of a ten-year contract on the period time for which CSP's current POLR charge has been authorized is unreasonable and unlawful.

(d) Finding that there is not a risk that Eramet will be permitted, at some point during the term of the unique arrangement, to shop for competitive generation and then return to generation service under CSP's standard service offer is unreasonable and unlawful.

(e) Requiring CSP to reduce its recovery of delta revenues (i.e., revenue foregone) resulting from the contract with Eramet is unreasonable and unlawful.

(f) Requiring CSP to credit any POLR charges paid by Eramet under the CSP/Eramet contract to CSP's economic development rider is unreasonable and unlawful.

(g) Requiring CSP to enter into a contract with Eramet, which conforms to the Commission's order, is unreasonable and unlawful.

(h) *Requiring* CSP *to enter into a contract, which results in a reduction in* CSP's revenues, and not permitting CSP to recover the full amount of that reduction, is unreasonable and unlawful.

(i) Finding that CSP should credit the full amount of the POLR component of the tariff rate that would otherwise apply on a per MWh basis to CSP's Economic Development Rider, is unreasonable and unlawful.

WHEREFORE, Appellant respectfully submits that Appellee's October 15, 2009 Opinion and Order, and March 24, 2010 Entry on Rehearing are unlawful, unjust, and unreasonable and should be reversed. Commission Case No. 09-516-EL-AEC should be remanded to the Commission with instructions to correct the errors complained of herein.

Respectfully submitted,

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ATTACHMENT A

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application for Establishment of a Reasonable Arrangement Between Eramet Marietta, Inc. and Columbus Southern Power Company.	)	Case No. 09-516-EL-AEC

OPINION AND ORDER

The Commission, considering the above-entitled application, hereby issues its opinion and order in this matter.

APPEARANCES:

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo, Lisa G. McAlister and Thomas L. Froehle, 21 East State Street, Columbus, Ohio 43215, on behalf of Eramet Marietta, Inc.

Richard Cordray, Ohio Attorney General, by Duane W. Luckey, Section Chief, and Werner Margard and Thomas McNamee, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Marvin I. Resnik and Steven T. Nourse, American Electric Power Service Corporation, 1 Riverside Plaza, 29th Floor, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Gregory J. Poulos, and Maureen R. Grady, Assistant Consumers' Counsel, the Office of the Ohio Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215, on behalf of the residential consumers of Columbus Southern Power Company and Ohio Power Company.

Boehm, Kurtz & Lowry, by David F. Boehm, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

OPINION:

I. History of the Proceeding

On June 19, 2009, Eramet Marietta, Inc. (Eramet) filed an application pursuant to Section 4905.31, Revised Code, to establish a reasonable arrangement with Columbus Southern Power Company (CSP) for electric service to its manganese alloy-producing facility in Marietta, Ohio. In its application, Eramet requests that the Commission establish a reasonable arrangement for electric service with Columbus Southern Power Company (CSP) that will allow Eramet to secure a reliable supply of electricity with a reasonable, predictable price over a term that will allow the investment of approximately $40 million in capital investments to upgrade the Marietta facility.

CSP, Ohio Energy Group (OEG), and the Office of the Ohio Consumers' Counsel (OCC) each timely filed comments regarding Eramet's application.

Motions to intervene were also filed by CSP, OEG, and OCC. Those motions were granted by the attorney examiner by entry issued July 16, 2009.

Based upon the comments, the attorney examiner set this matter for hearing, which commenced on August 4, 2009, and concluded on August 14, 2009. At the hearing, Eramet presented three witnesses, OCC presented one witnesses, CSP presented one witness, and Commission staff (Staff) presented one witness. During the course of the hearing, on August 5, 2009, Eramet and Staff filed a Joint Stipulation and Recommendation (Joint Ex. 1, or Stipulation), which addresses several of the issues and concerns related to Eramet's Application. Briefs were filed on August 24, 2009, by Eramet, CSP, Staff, and jointly, by OEG and OCC. Reply briefs were filed on September 8, 2009.

II. Discussion and Conclusions

In support of the reasonable arrangement, as set forth in the Stipulation, Eramet argues that the reasonable arrangement is an important part of the plan it must present to Eramet S.A., its parent company, to secure internal approvals necessary to implement its investment plan. Eramet's investment plan contemplates investing approximately $40 million in capital investments to upgrade its Marietta facility. (Joint Ex. 1 at 1). Eramet argues that it will not secure the required approvals from Eramet S.A. absent a reasonable arrangement that is responsive to its electricity costs and predictability needs. (Eramet Brief at 2-3). In response to these concerns, the Stipulation proposes a rate $.04224 per kilowatt hour from the effective date of the reasonable arrangement until December 31, 2011. From January 1, 2012, through December 31, 2018, the Stipulation proposes that Eramet's rate will be calculated as a percentage discount off the applicable tariff rate, with the percentage discount descending each year, until it reaches zero January 1, 2019.

Eramet contends that successful capital investment is required to enable Eramet's ongoing operation in southeastern Ohio and allow for operation and environmental performance improvements at its facilities. Eramet also contends that the reasonable arrangement, as set forth in the Stipulation, will place it in a position to focus its energies on planning for long-term investments at the Marietta facility that will facilitate its competitiveness in the global economy, in furtherance of Ohio's policy in Section 4928.02, Revised Code. (Id. at 2). With these long-term investments, Eramet's total capital investment in its Marietta facility will approach $100 million.

OCC and OEG contend that the reasonable arrangement, as set forth in the Stipulation, fails to benefit ratepayers and the public interest because it does not set a hard ceiling on the subsidy residential consumers could be asked to pay, does not address how the discounts made available to Eramet will be funded, and permits Eramet to receive discounted electricity rates before it has obtained corporate approval of its capital investments.

CSP argues that the Stipulation, should not be approved by the Commission, as CSP has not agreed to it. CSP also contends that the Stipulation does not, and should not, provide for an exclusive supplier relationship between itself and Eramet, and if the reasonable arrangement is approved, CSP is legally entitled to full recovery of revenue foregone as a result of the reasonable arrangement, without any offset.

The Commission finds that Eramet's application for a reasonable arrangement, as set forth in the Stipulation, should be approved, subject to the modifications set forth below.

Terms of the Reasonable Arrangement

As set forth in the Stipulation, the term of the reasonable arrangement will be ten years. Eramet retains the ability to seek to reopen and modify the rates and conditions of the reasonable arrangement in conjunction with its effort to secure corporate approvals required to make a total capital investment of approximately $100 million in its Marietta facility.

CSP will supply and deliver to Eramet electric service of the same quality as that which CSP is obligated to provide Eramet under CSP's tariff. CSP must provide Eramet with electricity according to its full requirements. Eramet, in turn, must consume and purchase electricity from CSP to the same extent as it would otherwise if Eramet was served by CSP at tariff rates.

The price for electricity supplied and delivered to Eramet under the terms of the reasonable arrangement includes all generation, transmission, and distribution charges, plus any surcharges, riders, or other adders, as applied to a base level of usage. During the term of the arrangement, the base usage is not to exceed 38,000,000 kWh per month, at a maximum demand level of 65 MVa, unless CSP is informed in writing that one of the following events is going to occur: the North Side facility will be resuming operations; Eramet will be resuming operations of its existing three furnaces; or operations of both the North Side facility and its three existing furnaces will be resumed. In those three situations, the base usage quantity will be set at 46,000,000 kWh per month with a maximum demand level of 78 MVa; 48,000,000 kWh per month with a maximum demand level of 81 MVa; or 56,000,000 kWh per month with a maximum demand level of 95 MVa, respectively.

The base usage, all-in price for service rendered by CSP from the effective date of the agreement through December 31, 2011, will be $.04224 per kWh, exclusive of any charges for Ohio's kWh tax, provided that CSP's minimum monthly bill during the period is equal to 60 percent of Eramet's highest monthly kVA usage in the six-month period preceding each monthly bill. For service rendered by CSP in excess of such base usage for the term through December 31, 2011, the price is to be determined in accordance with the tariff rate otherwise applicable, using Eramet's actual demand and energy consumption figures.

For service rendered from January 1, 2012, through December 31, 2012, the price applied to CSP's service to Eramet will be computed pursuant to the otherwise applicable tariff schedule, using Eramet's actual monthly demand and usage, with such adjustments to the tariff rate as are required to result in a monthly bill that is 20 percent less than the monthly bill would be pursuant to the tariff.

For service rendered from January 1, 2013, through December 31, 2018, the price applied to CSP's service to Eramet shall be computed pursuant to the otherwise applicable tariff schedule, using Eramet's actual monthly demand and usage, with adjustments to the tariff rate to result in a monthly bill that is: 18 percent less in 2013; 16 percent less in 2014; 14 percent less in 2015; 12 percent less in 2016; 8 percent less in 2017; 4 percent less in 2018; and 0 percent less in 2019.

As set forth in the Stipulation, during the initial pricing period ending December 31, 2011, Eramet must make a capital investment of at least $20 million in its current Ohio manufacturing operations. Thereafter, and before December 31, 2014, Eramet must make an additional capital investment of $20 million in its current Ohio manufacturing operations, for a total investment over the combined periods of at least $40,000,000. Eramet must also maintain a minimum average annual employment of 200 people during the term of the reasonable arrangement. The Stipulation requires Eramet to provide the Commission with annual documentation of its compliance with these commitments. The Commission also retains the ability, for good cause shown, to amend, modify, or terminate the reasonable arrangement or its schedule if Eramet's performance relative to the commitments it has made is not substantially aligned with such commitments.

In addition, Eramet commits, under the Stipulation, to work in good faith with CSP to determine how and to what extent Eramet's customer-sited capabilities might be committed to CSP for integration into its portfolio for purposes of complying with Ohio's portfolio requirements.

With respect to the above terms, the intervenors in this proceeding have raised a number of arguments specifically related to the following issues: (1) delta revenue recovery and POLR charges; (2) customer-sited capabilities and demand response programs; and (3) the approvability of the proposed reasonable arrangement. We will discuss each of these arguments in turn.

(1) Delta Revenue Recovery and POLR Charges

OCC and OEG argue that the reasonable arrangement fails to benefit ratepayers and the public interest because it fails to set a hard cap or ceiling on the subsidy customers could be required to pay. OCC and OEG contend that two provisions in the Stipulation, when taken together, negate any purported ceiling on delta revenues that customers could be required to pay CSP to fund the discount to Eramet. OCC and OEG assert that these provisions allow Eramet to increase base usage without first seeking approval to do so, and further allow Eramet to seek to reopen and modify the rates and conditions of the arrangement, so long as the reopening is related to its efforts to secure the corporate approvals required to make a potential total investment of $100 million in the facility.

OCC and OEG contend that Eramet's ability under the Stipulation to set new base usage levels at any point during the term of the agreement may lead to increased delta revenues, which CSP customers could be required to fund. Under calculations performed by OCC witness Ibrahim, customers could ultimately fund delta revenues as great as $57.7 million. (OCC Ex. 9B at 9). OCC and OEG argue that this result is unreasonable, as Eramet has firmly committed to finance capital expenditures of only $40 million. In light of Eramet's commitments, OCC and OEG recommend that a hard dollar cap on delta revenue should be set at the lesser of $40 million or 100% of the actual capital improvements agreed to in the Stipulation.

Additionally, OCC and OEG argue that the provisions of the Stipulation that allow Eramet to seek to reopen and modify the rates and conditions of the agreement will increase delta revenues. OCC and OEG point to Staff witness Fortney's testimony, in which he indicated that it is likely that delta revenues will rise under any of the scenarios resulting from the potential reopening of the arrangement. (Tr. III at 489-492).

CSP argues that the provisions of the Stipulation allowing Eramet to seek to reopen and modify the rates and conditions of the agreement indicate that the arrangement is not an "exclusive supplier" arrangement. CSP witness Baker testified, however, that even if it was an exclusive supplier arrangement, exclusive supplier provisions are "contrary to the basic premise of SB 3 and SB 221," in that they hinder the development of competitive electric generation markets for retail customers in Ohio. (CSP Ex. 1 at 4-5). CSP contends that the reasonable arrangement at issue should be implemented in a manner that best preserves customer choice, instead of one that creates an exclusive supplier relationship between Eramet and CSP.

In the same vein, CSP contends that it is legally entitled to full recovery of any revenue forgone due to the reasonable arrangement, without any offset. CSP argues that its delta revenue recovery should include recovery of provider of last resort (POLR) charges. CSP contends that there should be no POLR revenue offset to its full delta revenue recovery, despite the Commission's decision in *In the Matter of the Application of Ormet Primary Aluminum Corporation for Approval of a Unique Arrangement with Ohio Power Company and Columbus Southern Power Company*, Case No. 09-119-EL-AEC (July 15, 2009).

CSP argues that because no exclusive supplier relationship exists between itself and Eramet, there is a risk that, during the term of the reasonable arrangement, Eramet will switch to a Competitive Retail Electric Service (CRES) provider if market prices are lower than the contract prices under the reasonable arrangement. CSP notes that both the Commission and Eramet are permitted to reopen the agreement during the term of the contract and order or request modifications, further increasing the risk that Eramet will switch to a CRES provider during the term of the arrangement. Thus, CSP contends that it incurs a POLR risk, and that it should not have to credit any POLR charges paid by Eramet to the delta revenue recovered from other customers.

CSP further argues that the terms of the Stipulation allowing both the Commission and Eramet to reopen the agreement during the term of the contract and order or request modifications, combined with the Stipulation's provision regarding the level of firm/full requirements service has the effect of Eramet receiving SSO service based on a different pricing method. Given that the reasonable arrangement in essence places Eramet on a discounted SSO tariff rate, CSP argues that offsetting any recovery of delta revenue by the POLR revenue would squarely conflict with the Commission's decision in CSP's ESP case, which rejected the proposal of customers to avoid POLR charges by promising not to shop. Accordingly, CSP posits that Eramet should not be able to avoid POLR charges under the proposed arrangement by merely promising it will not shop for the term of the arrangement, and that CSP should not be required to offset its delta revenue recovery by any POLR revenue it recovers from Eramet.

Conversely, OCC and OEG assert that, under the terms of the Stipulation, CSP is the exclusive electric supplier to Eramet. (OCC/OEG Brief at 18). Both OCC and OEG dispute CSP's assertion that the ability of both Eramet and the Commission to modify the arrangement at any time provides an opportunity for Eramet to shop for a different supplier. (OCC/OEG Brief at 13). OCC and OEG state that there is no risk to CSP that Eramet will shop for competitive generation and then return to CSP's POLR service while the contract is in effect. (Id.). As a result, OCC witness Ibrahim recommended that the Commission exclude any POLR charges from the amount of delta revenues authorized to be recovered by CSP. (OCC Ex. 9 at 32-35). OCC and OEG contend that the mechanism of crediting CSP's customers for Eramet's POLR payment is consistent with the Commission's determination in *Ormet*, and note that Staff recommends that *Ormet* be used as a source of "guidelines for which future applications for reasonable arrangements are reviewed." (OCC/OEG Brief at 18; Staff Ex. 1 at 2).

The Stipulation does not speak to delta revenue recovery or any offsets. Additionally, neither Eramet nor Staff have advanced any specific argument regarding the POLR adjustment question. In fact, Staff indicated in its brief that it has no position on the matter. (Staff Brief at 6).

Based upon the evidence in the record, the Commission finds that that Eramet knowingly decided that it would not shop for electric service in exchange for securing a long-term power contract with CSP. Eramet witness Bjorklund testified that with the ten-year discounted power contract with CSP, Eramet will not need to shop. (Tr. I at 104). The Stipulation further memorializes Eramet's decision not to shop in order to secure the power discounts necessary for corporate approval of capital expenditures in the Marietta facility by detailing that access to and successful deployment of capital by Eramet SA at the Marietta facility are predicated, in part, on Eramet's ability to secure a reliable supply of electricity pursuant to terms and conditions that will provide it with a reasonable and predictable price over a permissible term. (Joint Ex. 1 at 1).

The period during which Eramet cannot shop, as contemplated by the Stipulation, is the duration of the reasonable arrangement. However, as noted in the September 15, 2009 *Ormet* Entry on Rehearing, it is not necessary to reach the question of whether Eramet can shop "beyond the duration of the current ESP because no determination has been made whether future standard services offers will include a comparable POLR charge." (Entry on Rehearing at 8 (September 15, 2009)). Under the reasonable arrangement, CSP will supply power to Eramet for the period beginning with the effective date of the agreement, and lasting through December 31, 2018. For the period lasting through the duration of the current ESP, however, we find that CSP will not be subject to POLR risk (i.e., the risk that Eramet may shop and subsequently seek to return to CSP's standard service offer) and, therefore, CSP should not be compensated for bearing this risk. Although CSP argues that there is a risk of Eramet shopping and then returning to CSP's standard service offer because the reasonable arrangement remains under the Commission's continuing jurisdiction and because Eramet retains the ability to modify the arrangement, any modification to the reasonable arrangement not explicitly set forth in the Stipulation would take place only after notice and an opportunity to be heard for any party affected by such modification, which would also require our approval.

CSP further argues that the Commission lacks authority to preclude CSP from recovering all revenue foregone as a result of the reasonable arrangement and that the failure to permit CSP to recover all revenue foregone conflicts with CSP's approved ESP. CSP contends that the plain language of Section 4905.31, Revised Code, provides the Commission with no statutory authority to offset the recovery of the revenue foregone by any expense the Commission believes will not be incurred by the electric utility due to the reasonable arrangement.

Despite CSP's arguments, the plain language of Section 4905.31, Revised Code, does not require the Commission to approve the full recovery of all delta revenue resulting from a reasonable arrangement. Section 4905.31, Revised Code, states that a reasonable arrangement "*may include* a device to recover *costs incurred* in conjunction with any economic development and job retention program . . . including recovery of revenue foregone." Much as we determined in *Ormet*, we find that the use of "may" in this section indicates that approval of the recovery of delta revenues is discretionary, not mandatory. (*Ormet*, Entry on Rehearing at 10-11). If the General Assembly had intended to require the recovery of delta revenues, it would have used "shall" or "must" rather than "may." Moreover, Section 4905.31, Revised Code, states that "[e]very . . . reasonable arrangement shall be under the supervision and regulation of the commission, and is subject to change, alteration, or modification by the commission." This provision imbues the Commission with broad authority to change, alter, or modify proposed reasonable arrangements and includes no prohibition on exercising that authority with respect to the recovery of delta revenues. Thus, the Commission finds that, according to the plain language of the statute, as well as our prior decisions, the recovery of delta revenues is a matter for the Commission's discretion.

CSP also contends that the non-payment of POLR charges is contrary to the Commission's order approving CSP's ESP. CSP alleges that the Commission determined in the ESP proceeding that all customers would pay the POLR charge for the entire time they are served under CSP's SSO and that customers would avoid POLR charges during the period they are actually served by a CRES provider if they agreed to return at a market price. Further, CSP contends that the Commission cannot distinguish its decision in the ESP proceeding from this case because the same POLR risk that formed the basis for the POLR charge adopted in the ESP proceeding is present with Eramet.

OCC and OEG argue that Section 4905.31, Revised Code, does not preclude the Commission from requiring that the POLR charge for Eramet be credited to the economic development rider to offset the recovery of delta revenues created by reasonable arrangements. OCC and OEG claim that the POLR provisions of CSP's ESP do not apply to Eramet, as Eramet is not receiving service under CSP's SSO.

Section 4905.31, Revised Code, allows for the recovery of "costs incurred." We have determined that there is no risk that Eramet will shop for a competitive supplier during CSP's current approved ESP. If there is no risk of Eramet shopping and returning to standard offer service during CSP's ESP, CSP will incur no costs for providing POLR service that can be recovered under Section 4905.31, Revised Code. Accordingly, the Commission finds that CSP should credit any POLR charges paid by Eramet to its economic development rider in order to reduce the amount of delta revenues recovered from other ratepayers.

Further, as we noted in *Ormet*, the Commission finds that CSP's reliance upon our orders approving its ESP to be misplaced. Under the reasonable arrangement, Eramet will not be receiving service under CSP's SSO, but rather, Eramet will be receiving service under a reasonable arrangement. Although CSP posits that this is a distinction without a difference, the Commission has opined that the service under a reasonable arrangement is authorized by Section 4905.31, Revised Code, whereas service under the SSO is authorized by Section 4928.141, Revised Code. Thus by its very nature, service under a unique arrangement provides for service under different prices, terms, and conditions than service under the SSO. (*Ormet*, Entry on Rehearing at 11). For the reasons discussed above, we find that providing service to Eramet does not present the same POLR risk as providing service to customers on the SSO. Accordingly, CSP must credit any POLR charges paid by Eramet to its economic development rider.

(2) Customer-Sited Capabilities and Demand Response Programs

In both its application and the Stipulation, Eramet refers to its commitment to work with CSP to determine how and to what extent Eramet's customer-sited capabilities might be committed to CSP for assistance in meeting its statutory energy efficiency requirements. Eramet witness Flygar testified that Eramet is contemplating several customer-sited energy efficiency projects that it is willing to consider committing to CSP to help CSP to meet its portfolio requirements, including projects involving recycling of silicomanganese fines during the casting process; installing high-efficiency lighting; installing plant substation capacitor upgrades that will improve power factor; and converting the administration building from steam to high efficiency heating. (Eramet Ex. 3A at 12). CSP contends that no weight should be assigned by the Commission to the possible future commitments by Eramet of its to-be-built customer-sited capabilities.

In the Stipulation, Eramet and Staff note that Eramet has already registered and is committed to participate in PJM's Reliability Pricing Model – Interruptible Load for Reliability (ILR) Program for PJM's 2009-2010 planning year. As such, Staff and Eramet recommend that the Commission authorize Eramet to continue its participation in PJM demand response programs, without penalty, for the 2009-2010 planning year. CSP argues that a customer already receiving a discount from CSP, as Eramet will be if the reasonable arrangement is approved, should make its demand response capabilities available for commitment to CSP in order to help reduce the peak demand reduction compliance costs borne by all customers. As an extension of this argument, CSP argues that Eramet should commit its demand response capabilities to CSP in exchange for receiving its service discount subsidy from other customers. (CSP Ex. 1 at 11-12; CSP Post-hearing Brief at 29).

The Commission urges Eramet to commit, to the fullest extent possible, its customer sited-capabilities to CSP for integration into CSP's portfolio. Accordingly, Eramet and CSP shall work in good faith to determine how and to what extent Eramet's customer-sited capabilities, as referenced by Eramet witness Flygar, can be committed to CSP. With regard to Eramet's participation in PJM's ILR Program, Eramet is authorized to continue its participation in PJM demand response programs for the 2009-2010 planning year. Thereafter, however, Eramet must make its demand response capabilities available to CSP in order to reduce peak demand reduction compliance costs.

(3) <u>Approvability of the Reasonable Arrangement</u>

Pursuant to Rule 4901:1-38-05(B)(1), O.A.C., a mercantile customer that files for Commission approval of a unique arrangement bears the burden of proof that the proposed arrangement is reasonable and does not violate Sections 4905.33 and 4905.35, Revised Code. Further, Rule 4901:1-38-05(C), O.A.C., requires a showing that a unique arrangement furthers the policy of the state of Ohio set forth in Section 4928.02, Revised Code.

The Commission applies a three-part test when evaluating the reasonableness of settlements: whether the settlement is a product of serious bargaining among capable, knowledgeable parties; whether the settlement, as a package, benefits ratepayers and the public interest; and whether the settlement package violates any important regulatory principles or practices. See *Consumers' Counsel v. Public Utilities Commission* (1992), 64 Ohio St.3d 123, 126.

Eramet argues that it is one of the largest industrial employers in Washington County, with an impact on the state and local economy through active employees, retiree benefits, vendor payments, and state and local taxes of at least $120 million in 2008. (Eramet Ex. 7 at 3-4). Based upon a number of letters filed in the docket in this case, it appears that strong local support exists for Eramet's proposed reasonable arrangement. Additionally, no party contested testimony introduced at the hearing that it is in the public interest and good for the state of Ohio for Eramet to continue and even increase operations at its Marietta plant. (Tr. IV at 554-555).

As noted above, OCC recommended that the Commission impose a specific dollar cap on the delta revenues of the lesser of $40 million or 100 percent of the actual capital improvements to which Eramet committed in the Stipulation. Staff witness Fortney testified, however, that the structure of the Stipulation, which bases Eramet's discount for electric service on a descending percentage off the applicable tariff rate, year by year, effectively imposes a ceiling or cap on delta revenues. However, he conceded that the

Stipulation does not include an absolute dollar ceiling on the amount of delta revenues that are created by the reasonable arrangement. (Tr. III at 428).

OCC also recommended that the Commission require written notice that Eramet has received all of the necessary corporate approvals from Eramet SA to proceed with the proposed capital expenditures before the Commission applies the discounted rates sought in the reasonable arrangement. Eramet witness Bjorklund testified that Eramet's ability to secure the parental approvals required to obtain capital to implement its investment plan depends on Eramet's ability to get predictable electricity prices at a reasonable level over a period of time that is judged to be sufficient to rationalize the capital investment. (Eramet Ex. 2A at 2). As such, Eramet stated that it will not obtain the parental approvals necessary to make a substantial capital investment in its Marietta facility without a long-term power arrangement.

CSP argues that a reasonable arrangement proposed by an electric utility's mercantile customer, such as Eramet, cannot be approved under Section 4905.31, Revised Code, unless the electric utility agrees to be bound by the arrangement. CSP, therefore, contends that because it has not given its approval to Eramet's proposed reasonable arrangement, the Commission cannot approve it. However, as noted in *Ormet*, in Am. Sub. Senate Bill 221, the General Assembly expressly authorized mercantile customers to file applications with the Commission for reasonable arrangements. If the General Assembly had intended on retaining the requirement that an electric utility agree to a proposed reasonable arrangement, there would have been no need for the General Assembly to amend Section 4905.31, Revised Code, to authorize the filing of an application by a mercantile customer. (*Ormet*, Entry on Rehearing at 17).

Eramet witness Flygar testified that the proposed reasonable arrangement would facilitate the policy of the state by ensuring the availability of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service, and ensuring the availability of retail electric service that provides Eramet with the supplier, price, terms, conditions, and quality options it believes will meet its needs. (Eramet Ex. 3A at 10). Additionally, Eramet witness Flygar testified that because Eramet is the sole domestic producer of medium and low carbon ferromanganese, ensuring that Eramet can continue to produce those products facilitates the state's effectiveness in the global economy. (Id. at 6).

Staff testified that all of the parties involved in this proceeding engaged in settlement discussions, and that the parties further agreed to the process by which the Stipulation was submitted for the Commission's consideration. (Staff Ex. 2 at 3-4; Tr. IV at 6-7). The parties to the settlement, or their representatives, regularly participate in rate proceedings before the Commission and are knowledgeable in regulatory matters, the rate structure of CSP, and the operations of Eramet. (Staff Ex. 2 at 3).

Additionally, as discussed above, Eramet's commitments, outlined by the application and modified by the Stipulation, benefit ratepayers and are in the public interest. Eramet commits to retain a minimum of 200 employees and to maintain operations at its Marietta facility for the term of the agreement. (Joint Ex. 1 at 8). It has also committed to make significant capital investments in its Marietta facility. (Id.).

We find that the Stipulation appears to be the product of serious bargaining among capable, knowledgeable parties. (Staff Ex. 2 at 3). The record also reflects that the Stipulation, as a package, advances the public interest, in that it addresses the concerns of OCC, OEG, and CSP, and provides significant benefits to ratepayers, including ensuring job retention and, potentially encouraging new employment through potential for growth. The Stipulation also contributes to the regional economy through significant local and state tax dollars and employment and other business opportunities resulting from the viable operation of the facility. (Id. at 5; Joint Ex. 1 at 5; Eramet Ex. 7 at 3-4). Additionally, as discussed above at length, the Stipulation does not violate any important regulatory principle or practice. Accordingly, we find that the Stipulation, as modified herein, should be approved.

(4) Implementation of the Reasonable Arrangement

In order for the arrangement to be implemented in a reasonable timeframe, the Commission finds that Eramet and CSP should be required to meet and provide within 14 days of the effective date of this Opinion and Order a contract incorporating the terms of the Stipulation. The final contract should be filed in this docket; however, the parties may seek to protect any proprietary, confidential, or trade secret information, as necessary. Such contract, and the reasonable arrangement, shall become effective for services rendered on and after the date the contract is filed with the Commission. As set forth in the Stipulation, the Commission retains the ability to, at any time and after notice and an opportunity to be heard, consider and make modifications to Eramet's reasonable arrangement in the event that we determine that Eramet has not satisfied its commitments under the reasonable arrangement, that reasonable progress with regard to the effort to secure corporate approvals to make a total capital investment of $100 million has not occurred, or for good cause shown.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) On June 19, 2009, Eramet filed an application pursuant to Section 4905.31, Revised Code, to establish a reasonable arrangement with CSP for electric service to its manganese alloy-producing facility in Marietta, Ohio.

(2) Comments regarding Eramet's application were filed by OCC, OEG, and CSP.

(3) Based upon the comments submitted, the attorney examiner set this matter for hearing before the Commission.

(4) The hearing in this matter commenced on August 4, 2009, and concluded on August 14, 2009.

(5) On August 5, 2009, Eramet and Staff filed a joint stipulation and recommendation in support of the reasonable arrangement.

(6) The joint stipulation and recommendation is reasonable and should be approved as modified by the Commission.

ORDER:

It is, therefore,

ORDERED, That the joint stipulation and recommendation filed by Eramet and Staff be approved as modified by the Commission. It is, further,

ORDERED, That Eramet and CSP file an executed power agreement in this docket that conforms to the provisions ordered by the Commission within 14 days of the effective date of this order. It is, further,

ORDERED, That the approved reasonable arrangement be effective for services rendered following the filing in this docket of an executed power contract. 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

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

RLH:ct

Entered in the Journal

OCT 1 5 2009

Reneé J. Jenkins
Secretary

ATTACHMENT B

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application for Establishment of a Reasonable Arrangement Between Eramet Marietta, Inc. and Columbus Southern Power Company.	))))	Case No. 09-516-EL-AEC

ENTRY ON REHEARING

The Commission finds:

(1) On June 19, 2009, Eramet Marietta, Inc. (Eramet) filed an application pursuant to Section 4905.31, Revised Code, to establish a reasonable arrangement with Columbus Southern Power Company (CSP) for electric service to its manganese alloy-producing facility in Marietta, Ohio (Application). In its application, Eramet requests that the Commission establish a reasonable arrangement for electric service with CSP that will permit Eramet to secure a reliable supply of electricity with a reasonable, predictable price over a term that will allow for the investment of approximately $40 million in capital investments to upgrade the Marietta facility.

(2) A hearing on the matter commenced on August 4, 2009. During the course of the hearing, on August 5, 2009, Eramet and Staff filed a Joint Stipulation and Recommendation (Stipulation), which addressed several of the issues and concerns related to Eramet's Application.

(3) On October 15, 2009, the Commission issued its Opinion and Order, approving the Stipulation, with modifications.

(4) Section 4903.10, Revised Code, states that any party to a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission within 30 days of the entry of the order upon the Commission's journal.

(5) On November 13, 2009, CSP filed an application for rehearing, alleging that the Opinion and Order was unreasonable and unlawful on the following grounds:

(a) The Commission's finding that Eramet cannot shop through the period ending with the expiration of CSP's Electric Security Plan (ESP) is contrary to the evidence in the record and to the public policy codified in Ohio law.

(b) Basing the determination of whether Eramet can shop under the terms of a ten-year contract on only three of those ten years is unreasonable and unlawful.

(c) Basing the determination of whether Eramet can shop under the terms of a ten-year contract on the period of time for which CSP's current provider of last resort (POLR) charge has been authorized is unreasonable and unlawful.

(d) Finding that there is not a risk that Eramet will be permitted, at some point during the term of the unique arrangement, to shop for competitive generation and then return to generation service under CSP's standard service offer is unreasonable and unlawful.

(e) Requiring CSP to reduce its recovery of delta revenues (i.e., revenue foregone) as a result of the contract with Eramet is unreasonable and unlawful.

(f) Requiring CSP to credit any POLR charges paid by Eramet under the CSP/Eramet contract to CSP's economic development rider is unreasonable and unlawful.

(g) Requiring CSP to enter into a contract with Eramet, which conforms to the Commission's order, is unreasonable and unlawful.

(h) Requiring CSP to enter into a contract, which results in a reduction in CSP's revenues, and not permitting CSP to recover the full amount of that reduction, is unreasonable and unlawful.

(6) Moreover, on November 16, 2009, the Office of the Ohio Consumers' Counsel (OCC) and the Ohio Energy Group (OEG) jointly filed an application for rehearing, alleging that the Opinion and Order was unreasonable and unlawful on the following grounds:

(a) The Commission erred in failing to adopt the regulatory principle established in the *Ormet* case, specifying how CSP will apply the credit for the full amount of POLR charges that will reduce what customers will have to pay for Eramet's unique arrangement.

(b) The Commission erred by failing to adopt the regulatory principle established in the *Ormet* case, specifying that CSP and Eramet shall not be permitted to reduce the delta revenue credit, for example, by negotiating a discount to the POLR charge, that is intended by the Commission to reduce what customers will have to pay for Eramet's unique arrangement.

(c) The two-party Stipulation does not benefit the public and is not in the public interest because it does not set a hard cap or ceiling on the subsidy that customers could be asked to pay.

(i) The Commission's failure to establish a hard cap on the delta revenues is a violation of the precedent set in Ormet that a reasonable arrangement should set a maximum amount of delta revenues which the ratepayers should be expected to pay. Thus, the two-party Stipulation fails to meet the third prong of the Commission's stipulation criteria.

(ii) The Commission's failure to establish a hard cap on the delta revenues also resulted in the two-party Stipulation failing to meet the second prong of the stipulation criteria – that this Stipulation benefits ratepayers and is in the public interest.

(d) The Commission erred by failing to meet the requirements of Section 4903.09, Revised Code, to set forth reasons prompting its decision, based upon findings of fact, with regard to the arguments of OCC and OEG on a hard cap or ceiling.

(e) The two-party Stipulation does not benefit the public and is not in the public interest because it requires customers to fund electric rate discounts to Eramet before Eramet has obtained corporate approval for the capital investment, which is the basis for granting Eramet the discounts.

(f) The Commission erred in concluding that the two-party Stipulation meets the first prong of the stipulation criteria. Because the two-party Stipulation does not reflect any diverse interests, it must fail.

(7) Further, on November 16, 2009, Eramet filed a motion for rehearing, requesting that the Commission grant rehearing for the purpose of confirming that it approved the Stipulation, including, without modification, the provision in which Eramet committed to work in good faith with CSP to determine how and to what extent Eramet's customer-sited capabilities might be committed to CSP for integration into its portfolio for purposes of complying with Ohio's portfolio requirements.

(8) On November 23, 2009, Eramet filed a memorandum contra the applications for rehearing of CSP, OCC, and OEG. On the same day, OCC and OEG jointly filed a memorandum contra CSP's application for rehearing. Additionally, on November 25, 2009, CSP filed memoranda contra Eramet's application for rehearing and the application for rehearing filed by OCC and OEG.

(9) The Commission grants the applications for rehearing filed by CSP, OCC and OEG, and Eramet. We believe that sufficient reason has been set forth by the parties seeking rehearing to warrant further consideration of the matters specified in the applications for rehearing.

It is, therefore,

ORDERED, That the applications for rehearing filed by CSP, OCC and OEG, and Eramet be granted. It is, further, ORDERED, That a copy of this Entry on Rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

RLH:ct

Entered in the Journal
DEC 11 2009

Reneé J. Jenkins
Secretary

ATTACHMENT C

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application for Establishment of a Reasonable Arrangement Between Eramet Marietta, Inc. and Columbus Southern Power Company.	)))))	Case No. 09-516-EL-AEC

ENTRY ON REHEARING

The Commission finds:

(1) On June 19, 2009, Eramet Marietta, Inc. (Eramet) filed an application (Application) pursuant to Section 4905.31, Revised Code, to establish a reasonable arrangement with Columbus Southern Power Company (CSP) for electric service to its manganese alloy-producing facility in Marietta, Ohio. In its Application, Eramet requests that the Commission establish a reasonable arrangement for electric service with CSP that will permit Eramet to secure a reliable supply of electricity with a reasonable, predictable price over a term that will allow for the investment of approximately $40 million in capital investments to upgrade the Marietta facility.

(2) A hearing on the matter commenced on August 4, 2009. During the course of the hearing, on August 5, 2009, Eramet and Staff filed a Joint Stipulation and Recommendation (Stipulation), which addressed several of the issues and concerns related to Eramet's Application.

(3) On October 15, 2009, the Commission issued its Opinion and Order (Order), approving the Stipulation, with modifications.

(4) Section 4903.10, Revised Code, states that any party to a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission within 30 days of the entry of the order upon the Commission's journal.

(5) On November 13, 2009, CSP filed an application for rehearing, alleging that the Opinion and Order was unreasonable and unlawful based on eight assignments of error. Moreover, on November 16, 2009, the Office of the Ohio Consumers' Counsel (OCC) and the Ohio Energy Group (OEG) jointly filed an

application for rehearing, setting forth six assignments of error. Eramet also filed an application for rehearing on November 16, 2009.

(6) On November 23, 2009, Eramet filed a memorandum contra the applications for rehearing of CSP and OCC and OEG. On the same day, OCC and OEG jointly filed a memorandum contra CSP's application for rehearing. Additionally, on November 25, 2009, CSP filed memorandum contra Eramet's application for rehearing and the application for rehearing filed by OCC and OEG.

(7) In its first assignment of error, CSP argues that the Commission's finding that Eramet cannot shop through the period ending with the expiration of CSP's electric security plan (ESP) is contrary to the evidence in the record and public policy, as codified in Ohio law. CSP also argues in its second assignment of error that basing the determination of whether Eramet can shop under the terms of a ten-year contract on only three of those ten years is unreasonable and unlawful. Further, CSP contends in its third assignment of error that basing the determination of whether Eramet can shop under the terms of a ten-year contract on the limited period of time for which CSP's current provider of last resort (POLR) charge has been authorized is unreasonable and unlawful.

(8) In their memorandum contra CSP's application for rehearing, OCC and OEG argue that CSP has not shown that the Commission's finding that Eramet cannot shop through the end of the ESP is against the weight of the evidence or unsupported by the record. Further, OCC and OEG argue that permitting Eramet to choose exclusive service from CSP does not violate any public policy of the state, but rather furthers state policies of facilitating reasonable rates and customer choice. OCC and OEG additionally argue that the Commission's focus on the first three years of the reasonable arrangement is appropriate because that is the only period during which CSP's POLR rates are currently in effect.

(9) As an initial matter, the Commission finds that its decision of whether Eramet can shop to the period ending with the expiration of CSP's ESP is reasonable and appropriate. CSP's argument in support of its second and third assignments of error disregards the circumstances surrounding the arrangement. CSP's ESP, and thus, its authority to assess POLR charges to its standard service offer (SSO) customers, expires on December 31, 2011. The Commission

narrowly focused upon the first 26 months of the contract, or the term of the current ESP, specifically because no determination has been made as to whether future SSOs will include POLR charges. Because no determination regarding POLR charges in future ESPs has been made, at this point, the Commission would be forced to speculate in order to determine whether Eramet has the right to shop after the expiration of the current ESP. CSP's second and third assignments of error should be denied.

(10) With regard to record support for the Commission's determination that Eramet cannot shop for the term of its current ESP, CSP references Eramet witness Bjorklund, who testified that, with the discounted rates proposed in the ESP, "Eramet will not need to shop" to argue that his testimony did not amount to a renunciation of Eramet's right to shop, as construed by the Commission. (Tr. I at 104.) CSP also notes that the Commission relied upon a statement in the Stipulation that Eramet sought "a reliable supply of electricity pursuant to terms and conditions that will provide it with a reasonable and predictable price over a permissible term." (Joint Ex. 1 at 1.) CSP argues, however, that, similar to witness Bjorklund's testimony, this statement does not support the Commission's conclusion that Eramet cannot shop for the term of the ESP. CSP additionally argues that Eramet's desire for a reliable supply of electricity pursuant to terms and conditions that provide a reasonable and predictable price over a permissible term may not be something that can be satisfied strictly by CSP.

Despite CSP's argument that it is not the only competitive retail electric service provider that can provide Eramet with service, Eramet specifically chose CSP as its electric service provider for its reasonable arrangement application. This choice further evidences Eramet's desire not to shop. The Commission believes that the evidence in the record, including witness Bjorklund's statement that Eramet will not need to shop under the reasonable arrangement, and Eramet's stated goal in seeking the reasonable arrangement, as advanced in the Stipulation, strongly supports the conclusion that Eramet should not be allowed to shop for the term of CSP's current ESP.

(11) CSP further argues that approval of the Stipulation is contrary to Ohio's public policy to promote competitive markets for electric generation service. CSP notes that the basic premise of Am. Sub. S.B. 3 (SB 3) and Am. Sub. S.B. 221 (SB 221) is the development of

competitive electric generation markets for retail customers in Ohio. CSP argues that a contract by which one of CSP's largest customers commits not to pursue competitive options for an extended period of time serves to stifle the development of a competitive retail electric generation market, in contravention of the goals of SB 3 and SB 221. In support of its argument, CSP cites the following provision:

> "[W]here there is a strong public policy against a particular practice, a contract or clause inimical to that policy will likely be declared unconscionable and unenforceable unless the policy is clearly outweighed by some legitimate interest in favor of the individual benefited by the provision." 8 Williston on Contracts (4th Ed. 1998) 43, Section 18:7.

While CSP advances this non-binding tenet in support of its position, the Commission finds that the concept of customer choice functions as a "legitimate interest," as outlined in the above passage, that outweighs the public policy considerations upon which CSP focuses. OCC and OEG argue in their memorandum contra that competition, in and of itself, is not the end-all purpose of SB 221. Along this line of reasoning, one of the policies of the state, as set forth in Section 4928.02(A), Revised Code, is to "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, non-discriminatory, and reasonably priced retail electric service." Here, Eramet has chosen to take service from CSP pursuant to the reasonable arrangement in order to secure reliable electric service at a reasonable, predictable price. Accordingly, rehearing on CSP's first assignment of error is not merited, and should be denied.

(12) In its fourth assignment of error, CSP argues that finding that there is not a risk that Eramet will be permitted, at some point during the term of the reasonable arrangement, to shop for competitive generation and then return to generation service under CSP's SSO, is unreasonable and unlawful. CSP contends that, because the Commission retains jurisdiction over the reasonable arrangement, and can change, alter, or modify the arrangement, there is a risk of Eramet shopping and then returning to POLR service from CSP. In their memorandum contra, OCC and OEG note that the likelihood of the Commission altering the contract and allowing Eramet to

shop, causing POLR expenses to be incurred by CSP, as CSP submits, is extremely unlikely.

(13) The Commission finds that CSP has not raised any new arguments under this assignment of error. Our continued jurisdiction over the matter does not create a risk of shopping that necessitates a POLR charge, as CSP suggests. Therefore, rehearing should be denied on CSP's fourth assignment of error.

(14) In its fifth and sixth assignments of error, CSP contends that the Commission's decision requiring it to reduce its recovery of delta revenues resulting from the contract with Eramet and to credit any POLR charges paid by Eramet to CSP's economic development rider (EDR) is unreasonable and unlawful. CSP argues that the plain language of Section 4905.31, Revised Code, does not authorize the Commission to offset the revenue of recovery *foregone* by any expenses the Commission believes will not be incurred by the electric utility due to the unique arrangement. CSP additionally argues that the Commission's continued application of its *Ormet* precedent on POLR credits could result in every mercantile customer avoiding paying the POLR charge by agreeing to make their electric utility their exclusive supplier. OCC and OEG respond that Section 4095.31, Revised Code, is unambiguous, and provides the Commission with the discretion to approve or disapprove a device within a special arrangement seeking to recover revenue foregone under an economic development program. OCC and OEG further argue that the POLR offset ordered by the Commission is not contrary to CSP's ESP order, and that modifications of the ESP were contemplated for economic development arrangements such as Eramet's reasonable arrangement.

(15) The Commission notes that CSP repeats in its application for rehearing the arguments it presented on this topic in its hearing briefs. Consequently, we find that CSP has not raised any new arguments under this assignment of error. We reiterate the analysis set forth in our Order, wherein we conclude that "the recovery of delta revenues is a matter for the Commission's discretion," and that because CSP will incur no costs for providing POLR service that can be recovered under Section 4905.31, Revised Code, "CSP should *credit any POLR charges paid by Eramet to its* economic development rider in order to reduce the amount of delta

revenues recovered from other ratepayers." Order at 8-9. Rehearing should be denied on these assignments of error.

(16) In its seventh and eighth assignments of error, CSP argues that requiring it to enter into a contract with Eramet that conforms to the Commission's order and results in a reduction in CSP's revenues is unreasonable and unlawful. CSP contends that the Commission's order is based on two improper conclusions of law: (1) that the Commission can deny recovery of revenues foregone under an arrangement made pursuant to Section 4905.31, Revised Code; and (2) that the Commission can require an electric utility to enter into a special arrangement with a customer, even if the utility objects to the contract. In its memorandum contra CSP's application for rehearing, Eramet responds that the General Assembly would not have amended Section 4905.31, Revised Code, to authorize the filing of an application for a reasonable arrangement by a mercantile customer, if the General Assembly intended on retaining the requirement that an electric utility agree to a proposed reasonable arrangement.

(17) The arguments CSP advances in support of these assignments of error simply repeat the arguments it made in its hearing briefs. The Commission has already rejected these arguments. As we noted in *In the Matter of the Application of Ormet Primary Aluminum Corporation for Approval of a Unique Arrangement with Ohio Power Company and Columbus Southern Power Company*, Case No. 09-119-EL-AEC, Opinion and Order at 11 (July 15, 2009); Entry on Rehearing at 17 (September 15, 2009) (*Ormet*): if the General Assembly had intended on retaining the requirement that an electric utility agree to a proposed reasonable arrangement, "there would have been no need * * * to amend Section 4905.31, Revised Code, *to authorize the filing of an application by a mercantile customer*." We find that rehearing should be denied on CSP's seventh and eighth assignments of error.

(18) Turning to OCC and OEG's joint application for rehearing, in their first assignment of error, OCC and OEG argue that the Commission failed to specify how CSP will apply the credit for the full amount of POLR charges that will reduce what all customers will have to pay for the reasonable arrangement through the economic development rider (EDR). In their second assignment of error, OCC and OEG likewise argue that the Commission erred by failing to specify that CSP and Eramet shall not be permitted to reduce the

delta revenue credit that is intended to reduce the amount all customers will have to pay for the reasonable arrangement through the EDR. OCC and OEG request that the Commission clarify its Order and adopt the precedent set forth in *Ormet* by precluding CSP and Eramet from negotiating a discount to the POLR charge as part of Eramet's discounted rate under the reasonable arrangement. In its memorandum contra, CSP recognizes that the Commission addressed this issue in the *Ormet* Entry on Rehearing, but requests that the Commission reconsider its *Ormet* precedent.

(19) The Commission finds that rehearing should be granted on these two assignments of error in order to clarify the manner in which POLR charges paid by Eramet should be credited to the EDR. Despite CSP's request that the Commission reconsider its *Ormet* precedent on this issue, we find that it is sound precedent that is directly on point. Therefore, consistent with our decision in *Ormet*, we find that CSP should credit the full amount of the POLR component of the tariff rate that would otherwise apply, on a per MWh basis, to the EDR. Additionally, Eramet and CSP shall not take action to reduce the delta revenue credit arising from the reasonable arrangement, such that the amount all customers will have to pay for the reasonable arrangement will increase.

(20) In their third assignment of error, OCC and OEG contend that the Stipulation does not benefit the public and is not in the public interest because it does not set a hard cap or ceiling on the subsidy that all customers could be asked to pay. OCC and OEG also argue that the Commission's failure to establish a hard cap on delta revenues violates the regulatory precedent set forth in *Ormet*, which stated that a reasonable arrangement should set a maximum amount of delta revenues that the ratepayers should be expected to pay. In their fourth assignment of error, OCC and OEG argue that the Commission erred by failing to meet the requirements of Section 4903.09, Revised Code, to set forth reasons prompting its decision, based upon findings of fact, with regard to the arguments of OCC and OEG on a hard cap or ceiling. Eramet responds that OCC and OEG have failed to demonstrate that the Stipulation is not in the public interest or violates any important regulatory principle by not including a hard cap on delta revenue. Eramet further contends that although OCC and OEG assert that the Commission failed to comply with the regulatory principle of setting a maximum amount of delta revenues that may be

recovered, as advanced in *Ormet*, OCC and OEG do not explain how the regulatory principle was violated.

(21) OCC and OEG advance the same argument they presented at hearing and in their briefs with regard to the absence of a hard cap on delta revenues in support of their third assignment of error. They raise no new arguments. As such, we find that rehearing on their third assignment of error should be denied.

(22) With regard to OCC and OEG's fourth assignment of error, the Commission noted in the Order that Staff witness Fortney testified that "the structure of the stipulation, which bases Eramet's discount for electric service on a descending percentage off the applicable tariff rate, year by year, effectively imposes a ceiling or cap on delta revenues." Order at 10. Notwithstanding our reliance on that language, we will grant rehearing to clarify that, although the Stipulation does not explicitly include an absolute dollar ceiling on the amount of delta revenues created by the reasonable arrangement, the Stipulation is structured in such a manner as to safely cap delta revenues at reasonable levels. Therefore, we find that the regulatory principle regarding delta revenue limitations set forth in *Ormet* has not been violated.

(23) In their fifth assignment of error, OCC and OEG argue that the Stipulation is not in the public interest because it requires customers to fund an electric rate discount to Eramet before Eramet has obtained corporate approval for its capital investments, which are the basis for granting Eramet the discount. OCC and OEG argue that allowing the discounts pursuant to the reasonable arrangement only upon Eramet's corporate commitment to the investment would provide a safeguard that Eramet will fulfill its capital investment commitment. Eramet asserts that OCC and OEG have failed to demonstrate that the Commission's decision not to require corporate approvals prior to approving the reasonable arrangement is unreasonable or unlawful. Further, Eramet contends that if the Commission were to impose a requirement that Eramet obtain corporate approval for its capital investment prior to the effectiveness of the reasonable arrangement, the arrangement would be rendered incapable of being used for its intended purpose.

(24) As we opined in the Order, Eramet's ability to secure the parental approvals required to obtain capital to implement its investment

plan depends on Eramet's ability "to get predictable electricity prices at a reasonable level over a period of time that is judged to be sufficient to rationalize the capital investment." Order at 11. OCC and OEG merely reiterate the arguments they made at the hearing and in their briefs in support of this issue. As such, the Commission finds that rehearing on OCC and OEG's fifth assignment of error should be denied.

(25) In their sixth assignment of error, OCC and OEG contend that the Commission erred in concluding that the Stipulation reflects diverse interests. In support of their argument, OCC and OEG contend that the only interests in the proceeding that were diverse were the interests of customers and the interests of CSP, neither of which signed the Stipulation. Eramet explained that all parties were invited to and participated in extensive settlement negotiations. Eramet further contends that the Supreme Court of Ohio has never held that stipulations approved by the Commission must be supported by all parties or all customer classes in order to reflect diverse interests.

(26) The Commission finds that OCC and OEG have again replicated the arguments they made at the hearing and in their briefs in support of their sixth assignment of error. Because no new arguments have been raised, we find that rehearing on OCC and OEG's sixth assignment of error should be denied.

(27) Turning to Eramet's application for rehearing, Eramet requests that the Commission grant rehearing for the purpose of confirming that it approved the Stipulation, including, without modification, the provision in which Eramet committed to work in good faith with CSP to determine how and to what extent Eramet's customer-sited capabilities might be committed to CSP to assist in meeting CSP's statutory energy efficiency requirements. In connection with its customer-sited capabilities, Eramet specifically references its willingness to participate in a CSP demand response program that would provide Eramet with an opportunity equal to the opportunities available under the PJM demand response programs in which it has participated in the past.

(28) On page ten of our Order, the Commission states the following with regard to Eramet's commitment of its customer-sited capabilities to CSP:

> The Commission urges Eramet to commit, to the fullest extent possible, its customer sited-capabilities to CSP for integration into CSP's portfolio. Accordingly, Eramet and CSP shall work in good faith to determine how and to what extent Eramet's customer-sited capabilities, as referenced by Eramet witness Flygar, can be committed to CSP. With regard to Eramet's participation in PJM's [Interruptible Load for Reliability] Program, Eramet is authorized to continue its participation in PJM demand response programs for the 2009-2010 planning year. Thereafter, however, Eramet must make its demand response capabilities available to CSP in order to reduce peak demand reduction compliance costs.

(29) Our Order encouraged Eramet to commit its customer-sited capabilities to CSP, and urged CSP and Eramet to work in good faith in order to determine how to facilitate such a circumstance. The Order additionally directed Eramet to make its demand response capabilities available to CSP in order to reduce peak-demand reduction compliance costs after the PJM 2009-2010 planning year.

(30) On December 10, 2009, subsequent to the issuance of our Order, Rule 4901:1-39-05, O.A.C., was adopted. Rule 4901:1-39-05(E)(2), O.A.C., states:

> (E) An electric utility may satisfy its peak-demand reduction benchmarks through a combination of energy efficiency and peak-demand response programs implemented by electric utilities and/or programs implemented on mercantile customer sites where the mercantile program is committed to the electric utility.
>
> > (2) For demand response programs, an electric utility may count demand reductions towards satisfying some or all of the peak-demand reduction benchmarks by demonstrating that either the electric utility has reduced its actual peak demand, or has the capability to

reduce its peak demand and such capability is created under either of the following circumstances:

(a) A peak-demand reduc-tion program meets the requirements to be counted as a capacity resource under the tariff of a regional trans-mission organization approved by the Federal Energy Regulatory Commission.

(b) A peak-demand reduc-tion program equivalent to a regional trans-mission organization program, which has been approved by [the Commission].

(31) Rule 4901:1-39-05(G), O.A.C., additionally provides that a mercantile customer may file, either individually or jointly with an electric utility, an application to commit the customer's demand reduction, demand response, or energy efficiency programs for integration with the electric utility's demand reduction, demand response, and energy efficiency programs, pursuant to Section 4928.66(A)(2)(d), Revised Code. Rule 4901:1-39-05(G), O.A.C., also identifies five requirements that each such application must fulfill.

(32) On February 12, 2010, Eramet filed an individual application, pursuant to Rule 4901:1-39-05, O.A.C., to commit its peak-demand reduction capabilities to CSP, through Eramet's participation in the FERC-approved PJM Reliability Pricing Model – Interruptible Load for Reliability (PJM-ILR) program. Eramet asserts that it filed the application in order to comply with our Order, and to allow CSP to integrate Eramet's demand reduction with any of its other demand reduction initiatives, and, therefore, count Eramet's participation in the PJM-ILR toward CSP's compliance with yearly statutory demand reduction targets, as required by Section 4928.66(A)(2), Revised Code. See *In the Matter of the Application of Eramet Marietta, Inc. to Incorporate Customer's Peak Demand Reduction Capabilities into*

Columbus Southern Power Company's Demand Reduction Program, Case No. 10-188-EL-EEC, Application at 4 (February 12, 2010).

(33) The Commission finds that rehearing should be granted pursuant to Eramet's request, in order to clarify that Eramet's commitment to CSP of its demand response capabilities rendered through participation in the PJM-ILR program satisfies our requirement that Eramet make its demand response capabilities available to CSP in order to reduce CSP's peak demand reduction compliance costs and is consistent with Rule 4901:1-39-05(E)(2)(a). Accordingly, we grant Eramet's request for rehearing. While we recognize that AEP-Ohio recently filed, on March 19, 2010, in Case Nos. 10-343-EL-ATA and 10-344-EL-ATA, an application to amend its emergency curtailment service riders and establish a second demand response program, we find that it is not necessary to reach a decision at this time regarding the reasonableness of that application in order for us to determine, in this case, that Eramet's reasonable arrangement and commitment to integrate are consistent with our Order and our rules.

It is, therefore,

ORDERED, That the application for rehearing filed by Eramet be granted, that the application for rehearing filed by CSP be denied, and that the application for rehearing filed by OCC and OEG be granted, in part, and denied, in part. It is, further, ORDERED, That a copy of this Entry on Rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

RLH/dah

Entered in the Journal

MAR 2 4 2010

Reneé J. Jenkins
Secretary

PROOF OF SERVICE

I certify that Columbus Southern Power Company's Notice of Appeal was served by First-Class U.S. Mail upon counsel for all parties to the proceeding before the Public Utilities Commission of Ohio identified below and pursuant to Section 4903.13 of the Ohio Revised Code, this 26th day of April, 2010.

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CERTIFICATE OF FILING

I hereby certify that, in accordance with Supreme Court Rule of Practice XIV, Section 2 (C)(2), Columbus Southern Power Company's Notice of Appeal has been filed with the docketing division of the Public Utilities Commission of Ohio and with the Chairman of the Public Utilities Commission of Ohio by leaving a copy at the office of the Chairman in Columbus, Ohio, in accordance with Rules 4901-1-02 (A) and 4901-1-36 of the Ohio Administrative Code, on April 26th, 2010.

Steven T. Nourse
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Columbus Southern Power Company

FILE

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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application for Establishment of a Reasonable Arrangement Between Eramet Marietta, Inc. and Columbus Southern Power Company	)	**Case 09-516-EL-AEC**

COLUMBUS SOUTHER POWER COMPANY'S APPLICATION FOR REHEARING

On June 19, 2009, Eramet Marietta Inc. (Eramet) filed an application pursuant to §4905.31, Ohio Rev. Code to establish a reasonable arrangement with Columbus Southern Power Company (CSP or the Company) for service to Eramet's Marietta, Ohio facility.

On August 5, 2009, a Joint Stipulation and Recommendation (Stipulation) entered into by Eramet and the Commission's Staff was filed in this proceeding. The parties representing CSP customers (Office of Consumers' Counsel - OCC- and Ohio Energy Group – OEG) and CSP, the would-be party to the proposed contract, did not sign the Stipulation and opposed its adoption by the Commission.

CSP's opposition to the Stipulation did not focus on Eramet's need for a reasonable arrangement or the sufficiency of Eramet's commitments regarding future investments in Ohio and regarding employment levels.[1] Instead, CSP opposed the Stipulation because:

[1] In this regard, the Commission's October 15, 2009, Opinion and Order in this case in several places refers to Eramet making a "total capital investment" of $100 million in its Marietta facility. (See pp. 3 and 12). It is not clear from the context of these statement whether the $100 million reference is intended to be in addition to the two $20 million commitments Eramet has made (assuming approval of its application), or includes the cost of those commitments. CSP believes the Commission should clarify this matter on rehearing.

1. it failed to confirm that the reasonable arrangement did not restrict Eramet's ability to shop for generation service from other suppliers and to confirm that CSP was entitled to full recovery of the revenue foregone which would result from the proposed reasonable arrangement, without any offset;

2. CSP had not agreed to be bound by the terms of the reasonable arrangement; and

3. the reference to Eramet's potential customer-sited capabilities fell short of a binding commitment and, therefore, could not support the imposition of a reasonable arrangement.

With regard to these issues, the Commission's October 15, 2009, Opinion and Order held that for the remainder of CSP's Electric Security Plan (ESP) "Eramet cannot shop." (Opinion and Order, p. 7). Based on that conclusion, the Commission went on to decide "that CSP will not be subject to POLR risk (i.e. the risk that Eramet may shop and subsequently seek to return to CSP's standard service offer) and, therefore, CSP should not be compensated for bearing this risk." (*Id.*) Based on these conclusions the Commission ordered CSP to "credit any POLR charges paid by Eramet to its economic development rider in order to reduce the amount of delta revenues recovered from other ratepayers." (*Id.* at 9). Finally, the Commission directed Eramet to "make its demand response capabilities available to CSP in order to reduce peak demand reduction compliance costs." (*Id.* at 10). The Commission also urged Eramet "to commit, to the fullest extent possible, its customer sited-capabilities to CSP for integration into CSP's portfolio." (*Id.*)

Pursuant to §4903.10, Ohio Rev. Code, and §4901-1-35 (A), Ohio Admin. Code, CSP seeks rehearing of the Commission's October 15, 2009 Opinion and Order in this case. CSP asserts that the Commission's order is unlawful and/or unreasonable in the following respects:

1. The Commission's finding that Eramet cannot shop through the period ending with the expiration of CSP's ESP is contrary to the evidence in the record and to the public policy codified in Ohio law.

2. Basing the determination of whether Eramet can shop under the terms of a ten-year contract on only three of those ten years is unreasonable and unlawful.

3. Basing the determination of whether Eramet can shop under the terms of a ten-year contract on the period time for which CSP's current POLR charge has been authorized is unreasonable and unlawful.

4. Finding there is not a risk that any time during the term of the Unique Arrangement Eramet will be permitted to shop for competitive generation and then return to generation service under CSP's standard service offer is unreasonable and unlawful.

5. Requiring CSP to reduce its recovery of delta revenues, i.e., revenue foregone, resulting from the contract with Eramet is unreasonable and unlawful.

6. Requiring CSP to credit any POLR charges paid by Eramet under the CSP/Eramet contract to CSP's economic development rider is unreasonable and unlawful.

7. Requiring CSP to enter into a contract with Eramet which conforms to the Commission's order is unreasonable and unlawful.

8. Requiring CSP to enter into a contract which results in a reduction in CSP's revenues, and not permitting CSP to recover the full amount of that reduction, is unreasonable and unlawful.

Based on these errors, the Commission should modify its order on rehearing to permit CSP to recover, without any offset, the full amount of the revenue foregone as a result of CSP executing the contract with Eramet pursuant to the Commission's order.

MEMORANDUM IN SUPPORT OF REHEARING

1. The Commission's finding that Eramet cannot shop through the period ending with the expiration of CSP's ESP is contrary to the evidence in the record and to the public policy codified in Ohio law. (Allegation of Error No. 1).

2. Basing the determination of whether Eramet can shop under the terms of a ten-year contract on only three of those ten years is unreasonable and unlawful. (Allegation of Error No. 2).

3. Basing the determination of whether Eramet can shop under the terms of a ten-year contract on the period time for which CSP's current POLR charge has been authorized is unreasonable and unlawful. (Allegation of Error No. 3).

Among the eight Commission errors raised in this Application for Rehearing, the following three errors all relate to the Commission's narrowly focused determination that Eramet cannot shop for the period of time (through the end of CSP's ESP) the Commission determined was relevant. Aside from being unsupported in the record, this narrow finding does not support the broad implications ascribed to it by the Commission. Indeed the problems with the Commission's determination are plentiful.

The first problem is that the Commission analyzed only 26 months of a contract that by its terms could last as long as 110 months. Whether a contract permits a party to take a particular action, such as shop for generation service from a competitive supplier, must necessarily be analyzed over the entirety of the contract, not just the first quarter of the term of the contract.

The Commission's order sets rate discounts for Eramet through December 31, 2018.2 (Opinion and Order, p.4). During the entire term of the contract the Commission "retains the ability for good cause shown to amend, modify, or terminate the reasonable arrangement or its schedule if Eramet's performance relative to the commitments it has made is not substantially aligned with such commitments." (*Id.*). Further, "Eramet retains the ability to seek to reopen and modify the rates and conditions of the reasonable arrangement in conjunction with its effort to secure corporate approvals required to make a total capital investment of approximately $100 million in its Marietta facility." (*Id.* at 3).

It is clear that these two provisions, which the Commission itself recited, provide the means by which contractual provisions can change during the full term of the contract. Confining an analysis of a nearly ten-year contract to just over the first two years of the contract is contrary to any notion of reasonable contractual interpretation. The Commission's failure to consider the entirety of the contractual term and determine that over the course of the contract Eramet had the right to shop for generation from a competitive supplier was unlawful and unreasonable and should be reversed on rehearing.

The Commission justified its narrow focus on only the first 26 months of the contract's term, by stating that "it is not necessary to reach the question of whether Eramet can shop 'beyond the duration of the current ESP because no determination has been made whether future standard services offers will include a comparable POLR charge.'"[3] (*Id.* at 7). While CSP is indeed interested in the Commission's treatment of

[2] The Commission states the "the term of the reasonable arrangement will be ten years." (p.3). Elsewhere it states that the rate discounts end at December 31, 2018, as requested by Eramet. The Commission should clarify that the reasonable arrangement ends on December 31, 2018.
[3] The Commission was quoting from its Entry on Rehearing in the *Ormet* case.

POLR revenues in the context of collecting otherwise unrecovered costs through its EDR, the question of whether Eramet has the right to shop for generation service from a competitive supplier is a question that applies to the entire term of the contract and should be resolved independent of the POLR-related consequences. Eramet either has the right to shop or it does not. The answer to that question must be based on an analysis of the entire life of the contract. The Commission's reliance on the current POLR charge being authorized for the term of CSP's ESP as the reason supporting the Commission's short-term analysis is unlawful and unreasonable and should be reversed on rehearing.

Even assuming that the Commission's short-term analysis were permissible, its conclusion is unsupported by the record in this proceeding. The testimony upon which the Commission relied in its order demonstrates the point. The Commission states that Eramet witness Bjorklund testified that with the discounted rate "Eramet will not need to shop." (*Id.* at. 7). The Commission further relies on a statement in the Stipulation that Eramet sought "a reliable supply of electricity pursuant to terms and conditions that will provide it with a reasonable and predictable price over a permissible term." (*Id.*). Neither of these statements supports the Commission's conclusion that "Eramet cannot shop." (*Id.*)

Considering Mr. Bjorklund's statement first, his testimony that Eramet "will not need to shop" is a far cry from his asserting that Eramet was giving up its right to shop. It would have been easy for Mr. Bjorklund to testify that Eramet would not have the right to shop throughout the term of the contract if that were what Eramet was agreeing to. His statement amounts to nothing more than a current belief that Eramet will not need to shop during that time.

As for the language in the Stipulation, the gloss the Commission places on these words directly contradicts its earlier statement on the same page of its Order that:

> The Stipulation does not speak to delta revenue recovery or any offsets. Additionally, neither Eramet nor Staff have advanced any specific argument regarding the POLR adjustment question. (*Id.* at 7).

The Commission appears to believe that the question of "freedom to shop" versus "exclusive supplier" is at the heart of the debate over the propriety of offsetting delta revenue recovery by an adjustment for POLR revenues. That being the case, if the Stipulation did not speak to delta revenue and neither Eramet nor Staff took a position regarding the POLR adjustment question, then the Stipulation could not have intended to address whether Eramet had forfeited its right to shop as a term of the Stipulation.

Further, Eramet's desire for a reliable supply of electricity pursuant to terms and conditions that provide a reasonable and predictable price over a permissible term is not something that can be satisfied only by CSP. Those traits -- terms and conditions that provide a reasonable and predictable price over a permissible term -- are the epitome of what a Competitive Retail Electric Service (CRES) provider would offer to large customers such as Eramet. There simply is no meaning in the words of the Stipulation on which the Commission relies, nor by reading in between the lines of the Stipulation, that suggest whether Eramet was expressing its intent to forfeit or retain the right to shop. Consequently, the Commission is left with the phrase chosen by Eramet's president, Mr. Bjorlund – he did not see a need for Eramet to shop. These are carefully chosen words by the individual responsible for running Eramet -- words which have the effect of keeping open Eramet's options, not shutting them off. The Commission's conclusion that under the Stipulation Eramet cannot shop is not only unsupported by the record, it is contrary to the record. On rehearing the Commission should reverse this unreasonable and unlawful conclusion.

Assuming the Stipulation did serve to forfeit Eramet's right to shop, approval of the Stipulation would be contrary to Ohio's public policy to promote competitive markets for electric generation service. The basic premise of SB 3 and SB 221 is the development of competitive electric generation markets for retail customers in Ohio. In fact, the preamble to SB 3 indicates that one of its purposes is "to provide for competition in retail electric service." SB 3 together with amendments made in SB 221 set forth the State's policy to ensure diversity of electricity supplies and suppliers,[4] to recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment,[5] and to ensure effective competition in the provision of retail electric service.[6] From these policy pronouncements it is clear that a contract by which one of CSP's largest customers commits to not pursue competitive options for 10 years would stifle the development of a competitive retail electric generation market. Therefore, the Commission should not approve such a provision.

The concept of "customer choice" should be honored in a manner consistent with the policies set out by Ohio's General Assembly. "[W]here there is a strong public policy against a particular practice, a contract or clause inimical to that policy will likely be declared unconscionable and unenforceable unless the policy is clearly outweighed by some legitimate interest in favor of the individual benefited by the provision." 8 Williston on Contracts (4th Ed.1998) 43, Section 18:7. The Supreme Court of Ohio has declared contracts unconscionable and void where the contract purports to violate

4 §4928.02 (C), Ohio Rev. Code
5 §4928.02 (G), Ohio Rev. Code
6 §4928.02 (H), Ohio Rev. Code

important public policies, including policies articulated by the General Assembly in statutes. *See e.g. Taylor Building Corp. of America v. Benfield*, 117 Ohio St.3d 352, 884 N.E.2d 12 (2008). An "exclusive supplier" provision that contradicts the public interest as expressed in Ohio's policy adopted in SB 3 and SB 221 should be considered void as against public policy and unenforceable. The Commission's adoption of a contractual provision which is contrary to public policy and casts uncertainty over the enforceability of the contract is unreasonable and unlawful and should be reversed on rehearing.

There is no reason that Eramet would need to forfeit its right to exercise choice over the life of the contract. Indeed, it did not. Consequently, the Commission should reverse its decision to adopt the Stipulation as the Commission has interpreted it.

4. There is a risk that any time during the term of the Unique Arrangement Eramet will be permitted to shop for competitive generation and then return to generation service under CSP's standard service offer. (Allegation of Error No. 4)

Based on its finding that the Stipulation would make CSP Eramet's exclusive supplier, the Commission also concluded that CSP will not be subject to the POLR risk that Eramet may shop for competitive generation and then return to CSP's Standard Service Offer. (Opinion and Order p. 7). This conclusion is unlawful and unreasonable because it ignores applicable statutory authority granted to the Commission. Therefore, the Commission should reverse its conclusion regarding risk.

As a matter of law, a schedule or reasonable arrangement approved by the Commission pursuant to §4905.31, Ohio Rev. Code, "shall be under the supervision and regulation of the commission, and is subject to change, alteration or modification by the commission." The Commission's authority over these matters is continuous in nature.

Therefore, as circumstances change, the Commission can order a modification of the Eramet contract.[7] It is natural that the Commission would preserve its options regarding the contract terms it previously approved. The conditions imposed on Eramet by the Stipulation also reflect the POLR risk associated with this contract.

Based on the Commission's continuing jurisdiction over an arrangement, the Commission should reverse its conclusion that there is no risk of Eramet shopping and then returning to POLR service from CSP.

5. Requiring CSP to reduce its recovery of delta revenues i.e., revenue foregone, resulting from the contract with Eramet is unreasonable and unlawful. (Allegation of Error No. 5).

6. Requiring CSP to credit any POLR charges paid by Eramet under the CSP/Eramet contract to CSP's economic development rider is unreasonable and unlawful. (Allegation of Error No. 6).

As amended by SB 221, §4905.31, Ohio Rev.Code, provides, in part, as follows:

> Chapters 4901., 4903., 4905., 4907., 4909., 4921., 4923., 4927., 4928., and 4929. of the Revised Code do not prohibit a public utility from filing a schedule or establishing or entering into any reasonable arrangement ... with one or more customers ... and do not prohibit a mercantile customer of an electric distribution utility... from establishing a reasonable arrangement with that utility or another public utility electric light company, providing for any of the following:
>
> (E) Any other financial device *that may be practical or advantageous to the parties interested.* In the case of a schedule or arrangement concerning a public utility electric light company, such other financial device may include a device to recover costs incurred in conjunction with any economic development and job retention program of the utility within its certified territory, including recovery of revenue foregone as a result of any such program...

[7] Of course, both parties to the contract would be entitled to terminate the contract if they did not accept the Commission's modifications --just as they could reject the initial contract if they did not accept its terms.

***

> Every such schedule or reasonable arrangement shall be under the supervision and regulation of the commission, and is subject to change, alteration, or modification by the commission. (emphasis added).

An analysis of the plain language of this statute reveals that nothing in §4905.31, Ohio Rev. Code, authorizes the Commission to offset the recovery of the revenue foregone by any expenses the Commission believes will not be incurred by the electric utility due to the unique arrangement. Any such reduction in recovery of revenue foregone would not be "advantageous" to both parties to the contract. In addition, such a result conflicts with the Commission's recent orders in CSP's ESP case.

The Commission cannot read into the statutory language the authority to offset the recovery of revenues foregone by an actual or perceived avoidance of an expense by the electric utility. While such authority is not found in §4905.31, Ohio Rev. Code, elsewhere in SB 221 the General Assembly provided such offset authority in contexts other than §4905.31, Ohio Rev. Code.

For instance, in §4928.142 (D), Ohio Rev. Code, the General Assembly provided that:

> In making any adjustment to the most recent standard service offer price on the basis of costs described in division (D) of this section, the commission shall include the benefits that may become available to the electric distribution utility as a result of or in connection with the costs included in the adjustment... and accordingly, the *commission may impose such conditions on the adjustment to ensure that any such benefits are properly aligned with the associated cost* responsibility. The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The *commission shall not apply its consideration of the return on common equity to reduce any adjustments authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess* of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. (emphasis added).

Another example of an explicit offset provision is found in §4928.143 (B) (2) (c), Ohio Rev. Code, where the General Assembly provided that:

> Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

These provisions demonstrate that in some instances the General Assembly chose to have the Commission offset revenue recovery by cost savings or other considerations such as impact on return on equity. In those instances, the Commission was given explicit authority to make such an offset. The absence of such authorization in §4905.31, Ohio Rev. Code, is particularly telling in light of the presence of such authorization in other provisions in the same piece of legislation. The legislative canon *expressio unius est exclusio alterius* applies, meaning the inclusion of one thing implies exclusion of the other. *See Crawford-Cole v. Lucas Co.Dept. of Jobs & Family Services*, 121 Ohio St.3d 560, 566, 906 N.E.2d 409, 414 (2009). As supplied to this issue, the inclusion of authority to make a rate offset in certain statutes, but not in the amendment to §4905.31, Ohio Rev. Code, enacted in the same legislation, compels a finding that §4905.31, Ohio Rev. Code, does not provide the Commission with authority to make a rate offset in matters addressed in that statute.

CSP is aware that the Commission believes that §4905.31, Ohio Rev. Code's use of the words "may include" "indicates that approval of the recovery of delta revenues is discretionary, not mandatory." (Opinion and Order, p. 8). This interpretation is faulty for at least two reasons. First, when this statute is viewed in its entirety, it can be seen that it permits reasonable arrangements that provide "for any of the following." The statute then goes on to list, in divisions (A) through (E), five categories of reasonable arrangements and/or schedules that can be entered into between customers and utilities. The reference in Division (E) to "may include a device to recover costs incurred in conjunction with any economic development and job retention program" is one of the elements permissible under the "any of the following" introductory language. It is not an invitation to the Commission to disallow recovery of costs and particularly costs that are not "incurred in conjunction with any economic development and job retention program." That is, even if the cost associated with the POLR risk were avoided under the Eramet contract, it is not a cost arising from the contract itself.

The second problem with the Commission's interpretation is that it leads to the conclusion that if the Commission wanted it could disallow recovery of all revenues foregone under a contract filed unilaterally by a mercantile customer. While CSP realizes that the Commission is permitting recovery of revenues foregone (minus the POLR credit) due to the Eramet contract, the true test of the merits of the Commission's interpretation is whether it stands the test of reasonableness in the context of other possible outcomes. Requiring a utility to enter into a contract, and then denying recovery of the revenues foregone under that contract cannot be permitted under §4905.31, Ohio Rev. Code. Nonetheless, such a result is possible under the Commission's interpretation of the statute.

The Commission's order that CSP's recovery of revenue foregone should be offset by POLR charges also is contrary to the Commission's order in CSP's ESP proceeding. The ESP order specifically rejected arguments that POLR charges can be avoided if a customer agrees not to shop. That conclusion was affirmed on rehearing as recently as July 29, 2009.

In particular, the Commission's entry on rehearing in the ESP cases explicitly referenced Ohio Energy Group's (OEG) position that the POLR rider should be "avoidable by those customers who agree not to shop during the ESP through a legally binding commitment." (*ESP Cases*, Entry on Rehearing, p. 25). The Entry on Rehearing's discussion of OEG's request referenced OEG's application for rehearing at page 6. (*Id.*) OEG's application for rehearing in the ESP cases argued (at p. 6):

> [T]here is no cost or risk to the Companies of being the POLR if a customer makes a legally binding commitment not to shop during the ESP. *** If a customer elects to waive its rights to shop during the three-year ESP term, then there is no risk or cost to the Companies and no basis for the Companies to impose the POLR option charge. Therefore, customers who agree not to shop during the ESP should not pay the POLR charge.

OEG's position in the *ESP Cases* was based on the testimony of its witness Mr. Baron, who presented specific proposals for customers to "opt out" of POLR by entering into a legally binding agreement not to shop during the ESP – proposals that were discussed in detail in prefiled testimony and during cross examination. (*ESP Cases*, OEG Ex, 2 at pp. 10-12; Transcript II, pp. 133-160). Notwithstanding the extensive development of OEG's proposals in the record and the Commission's explicit consideration of those proposals in its orders in the *ESP Cases*, the Commission did not accept the invitation to allow customers to avoid the POLR charge by agreeing that AEP Ohio would be the customer's exclusive provider.

On the contrary, the Commission adopted a nonbypassable POLR charge reflecting 90 percent of the estimated POLR costs presented by the Companies and found that only customers who agreed to return at a market price at the time they decide to shop will avoid the POLR charge during the time they are served by a CRES provider. (*ESP*

Cases, Opinion and Order, p.40.) In other words, regardless of whether a customer promised not to shop during the ESP term, all customers would pay the POLR charge for the entire time they are served under CSP's Standard Service Offer (SSO) and would only avoid POLR charges during the period they are actually served by a CRES provider if they promised to return at a market price. Thus, the Commission explicitly wrestled this issue to the ground in the *ESP Cases* and only allowed the POLR charge to be bypassed under narrow circumstances – rejecting OEG's broader proposal to avoid POLR charges any time a customer promised not to shop. The Commission's Entry on Rehearing (at p. 26) in the *ESP Cases* stated that "the Commission carefully considered all of the arguments, testimony, and evidence in the proceeding and determined that the Companies should be compensated for the cost of carrying the risk associated with being the POLR provider, including the migration risk." The result reached in the Opinion and Order in the instant case squarely conflicts with the decision in the *ESP Cases* to reject OEG's proposal to avoid the POLR charge by promising not to shop. That proposal is no different in substance than the "exclusive supplier" provision the Commission believes exists in the Stipulation in this case and the decision to reach a different result here should be reconsidered on that basis and reversed.

The Commission attempted to distinguish its ESP ruling from its ruling in this case on the basis that the ESP ruling applies to Standard Service Offer while the Eramet ruling applies to a reasonable arrangement under §4905.31, Ohio Rev. Code. This rationale is a classic example of there being a distinction without difference. The same POLR risk analysis that formed the basis for the POLR charge adopted in the *ESP Cases* is present with Eramet. Both the Commission and Eramet are permitted to reopen the agreement during the term of the contract and order or request modifications. Moreover, as noted earlier in this memorandum "an exclusive supplier" provision would violate the state policy of promoting competition (thus leading to the same conclusion that Eramet could shop in the future). Based on these considerations, it is evident that the effect of the Stipulation is to receive SSO service based on a different pricing method. Notwithstanding the Commission's bare statement that the SSO POLR risks do not apply to the Eramet contract, the above-discussed findings and conclusions reached in the *ESP Cases* must lead to the conclusion that the POLR risks do apply to the Eramet agreement.

As a related matter, CSP's ESP, as modified by the Commission, reflects a total package that the Commission held to be more favorable, in the aggregate, than a Market Rate Offer. The position taken by the Commission in this case, results in a further modification of CSP's ESP – even after those aspects of the *ESP Cases* have been finalized. It is inappropriate to make rulings which modify CSP's ESP without a record-based conclusion that such a modification was necessary in order to ensure that the modified ESP "is more favorable in the aggregate as compared to the expected results that would otherwise apply" under a market rate offer. *See* §4928.143(C)(1), Ohio Rev. Code. CSP also submits that any such changes are especially inappropriate without also changing other ESP provisions which would restore the balance of the Commission's ESP order.

As it stands now, the overall package and balancing of interests reached in the *ESP Cases* is undermined by the order in this case. As the Commission extends its *Ormet* POLR credit precedent to other customers, every mercantile customer could avoid paying the POLR charge by agreeing to make their electric utility their exclusive supplier.[8] Consequently, the potential for competition in Ohio would be significantly impaired. That result would substantially undermine the Commission's orders in the *ESP Cases*. In the *ESP Cases*, the Commission plainly stated that "[t]he POLR charge was proposed to collect a POLR *revenue requirement* of $108.2 million for CSP and $60.9 million for OP." (*ESP Cases*, Opinion and Order, p.38) (emphasis added). Similarly, when deciding to grant 90% of the POLR proposed rate, the Commission ordered that "the POLR rider shall be established to collect a POLR *revenue requirement* of $97.4 million for CSP and $54.8 million for OP." (*Id.*, p. 40) (emphasis added). This demonstrates that the Commission's intention was to increase CSP's revenue requirements and create a nonbypassable revenue stream as part of the overall ESP decision – not just create a charge that can simply be avoided by a promise not to shop. It is unreasonable and unlawful for the Commission to issue an order months later that undermines that result.[9]

The facts and the applicable law provide for recovery of all revenues foregone under the contract with Eramet. There is no statutory authority for the Commission to offset these revenues foregone by an amount of expense reductions, whether actual or not. The revenues foregone should equal the difference between what Eramet would pay

[8] *In the Matter of the Application of Ormet Primary Aluminum Corporation for Approval of a Unique Arrangement with Ohio Power Company and Columbus Southern Power Company*, Case No. 09-119-EL-AEC.

[9] The orders in the *ESP Cases* were issued pursuant to § 4928.143, Ohio Rev. Code. That statute specifies the parameters for setting Standard Service Offer rates by establishing an Electric Security Plan. Alternatively, an EDU can set its Standard Service Offer rates by establishing a Market Rate Offer under § 4928.142, Ohio Rev. Code. CSP submits that the Commission lacks authority under § 4905.31, Ohio Rev. Code, to approve the proposed Eramet arrangement without providing for full recovery of foregone revenues and that argument is presented in greater detail elsewhere in this memorandum. But in this context of discussing the orders in the *ESP Cases*, CSP submits that it is unlawful for the Commission to approve SSO rates under either the ESP or the MRO statute only to proceed to undermine those rates (and in the case of the POLR charge, an explicit revenue requirement) by approving a unique arrangement in a separate case.

under CSP's applicable rate schedules and what it would pay under the Unique Arrangement rate – no more and no less. If the Commission's intent was to reduce the impact of the unique arrangement on other ratepayers' bills, the proper course of action would have been to reduce the amount of the maximum discount to which Eramet would be entitled.

7. Requiring CSP to enter into a contract with Eramet which conforms to the Commission's order is unreasonable and unlawful. (Allegation of Error No. 7).

8. Requiring CSP to enter into a contract which results in a reduction in CSP's revenues, and not permitting CSP to recover the full amount of that reduction is unreasonable and unlawful. (Allegation of Error No. 8).

The Commission's order is based on two conclusions of law, each of which when considered independently is incorrect. These conclusions are that the Commission can deny recovery of revenues foregone under a §4905.31, Ohio Rev. Code, arrangement and that the Commission can require the utility to enter into a special arrangement with a customer, even if the utility objects to the contract. The first argument already has been discussed in this memorandum. The second argument is addressed in this portion of this memorandum. The point to be made, however, is that when these two unlawful conclusions are applied in tandem it results in the obviously unlawful conclusion that the Commission can force a contract upon the utility and then refuse to provide recovery of the revenues lost as a result of that contract. This result cannot have been what the General Assembly intended, and is not what the plain meaning of §4905.31, Ohio Rev. Code, permits.

Prior to the enactment of SB 221, §4905.31, Ohio Rev. Code, allowed a "public utility" to file a schedule or enter into "any reasonable arrangement" with another public utility or with "its customers, consumers or employees" providing for certain enumerated outcomes, including variable rates and different classifications of service. The statute provided that no "such arrangement" is lawful until it was filed with and approved by the Commission.

SB 221 amended §4905.31, Ohio Rev. Code, in three significant respects:

> 1) It now provides that a public utility is allowed to file a schedule or "establish or" enter into any reasonable arrangement with another public utility or with "one or more of" its customers, consumers or employees.
>
> 2) It now also provides that "a mercantile customer of an electric distribution utility" or a group of such customers may establish a reasonable arrangement with "that utility (the EDU serving the service territory in which the customer is located) or another public utility electric light company."
>
> 3) The application for approval of an arrangement may be filed with the Commission by either the public utility or the mercantile customer(s).

The Commission's order reads the statute as now allowing mercantile customers to establish an arrangement without the agreement of the electric distribution utility by unilaterally submitting a proposed arrangement for approval by the Commission. An analysis of the statute as modified shows there can be no arrangement approved by the Commission if the public utility to be bound by the arrangement does not agree to its terms.

a. Common usage interpretation of the statute, as amended.

As a general rule the words in a statute must be read in accordance with the common usage of the terms.[10] Therefore, the terms "establish" and "arrangement" should be given their ordinary meaning. The term "establish" is not ambiguous; it is commonly used as a synonym for "create, originate or bring into existence."[11] "Arrangement" is ambiguous; it may mean either a "mutual agreement or understanding" or "a preliminary step or measure."[12] To ascertain which meaning of "arrangement" is intended in this instance, it is necessary to look at the context in which the words appear. The statute states that a "mercantile customer of an electric distribution utility" is not prohibited "from establishing a reasonable arrangement with that utility or another public utility electric light company." Since "establishing" means "creating or bringing into existence," then the ambiguity of "arrangement" suggests that the statute means either that:

> a mercantile customer is not prohibited from creating or bringing into existence a reasonable [*mutual agreement or understanding*] with its EDU or other public utility electric light company; or
>
> a mercantile customer is not prohibited from creating or bringing into existence a reasonable [*preliminary step or measure*] with its EDU or other public utility.

The former is a fair and reasonable interpretation of the statute; the latter is not.

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[10] §1.42, Ohio Rev. Code, provides: "Words and phrases shall be read in context and construed according to the rules of grammar and common usage. Words and phrases that have acquired a technical or particular meaning, whether by legislative definition or otherwise, shall be construed accordingly." See also *Weiss v. Pub. Util. Comm.*, 90 Ohio St.3d 15, 17 (2000).

[11] Webster's Third New International Dictionary at 778; Black's Law Dictionary (8th ed.) at 568.

[12] Webster's at 120.

In common usage one would not speak of creating a preliminary measure with another. "Creating" connotes that the object created has a sense of finality or permanence; it has come into existence. A preliminary step or measure lacks this quality of permanence and instead implies that something more needs to happen before the object is established. On the other hand, one would speak of creating a mutual agreement or understanding with another, and in such instances permanence and finality are implied. Thus, a mercantile customer can work with a utility to mutually establish an arrangement but cannot independently do so.

It also is significant that the statute provides that the mercantile customer may establish "a reasonable arrangement *with* [its EDU] or another public utility electric light company." The clear indication is that the customer is working cooperatively *with* the utility to jointly establish the arrangement.

b. <u>The context of the statute.</u>

The paragraph of the statute requiring Commission approval also confirms that the mutual agreement interpretation is the better reading of the statute. It states that "no such . . . arrangement is lawful unless it is filed with and approved by the commission." The statute goes on to provide that the public utility "is required to conform its schedules of rates, tolls, and charges to such arrangement." The statute thus envisions that the arrangement submitted to the Commission is an arrangement already in existence [i.e. established] which becomes lawful and immediately enforceable upon approval. As a matter of common usage and basic contract law, a preliminary step or measure lacks the requisite finality to become a lawful and enforceable arrangement upon approval by the

Commission.[13] Indeed it is difficult to imagine how the Commission could "approve" a mere preliminary measure or how a public utility could be "required to conform its schedules of rates, tolls and charges to [a preliminary measure]" that had not evolved into an agreement or understanding.

c. <u>Giving effect to the amendment</u>.

1. *the amendment to allow a utility to "establish" an arrangement.*

Another equally important rule of statutory interpretation applicable here is that all portions of the statute must be given effect.[14] Applied in this context, the rule requires that there be some reason for the General Assembly to have amended §4905.31, Ohio Rev. Code, to allow a public utility to "establish" a reasonable arrangement with "one or more" of its customers, when the statute already provided that a public utility could "enter into" an arrangement with its customers. Such reason exists.

In an early case interpreting the statute, an Ohio appellate court had held that a public utility could not enforce a special contract with one of its customers because the utility had filed only a generic arrangement with the Commission and had not submitted for approval the actual contract signed by the customer.[15] Yet, as we now know, at times a public utility may want to offer a general arrangement to all its customers or to customers in a specific class and leave it to the individual customer to decide whether to

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[13] *Extracorporeal Alliance LLC v. Rosteck*, 285 F. Supp. 2d 1028 (N.D. Ohio 2003); *Kostelnik v. Helper*, 96 Ohio St. 3d 1, 2002-Ohio-2985; Motorist *Mut. Ins. Co. v. Columbus Fin. Inc.*, 168 Ohio App.3d 691, 2006-Ohio-5090.

[14] §1.47(B), Ohio Rev. Code, provides that in enacting statutes, it is presumed that "The entire statute is intended to be effective."

[15] *Lake Erie Power & Light Co. v. The Telling-Belle Vernon Co.*, 57 Ohio App. 467 (Cuyahoga, 1937).

actually "enter into" the offered arrangement.[16] SB 221's amendment to the statute clarifies that this type of arrangement - a generic offer to enter into a particular special contract with customers - can be submitted to the Commission for approval even though the utility and any particular customer have not yet formally entered into such arrangement. The amendment also expressly clarifies that a special arrangement need not be offered to all customers and may be established or entered into with "one or more customers" but less than all.

2. *the amendment to allow a customer to establish an arrangement.*

In order to read the SB 221 amendment as authorizing only mutually agreeable arrangements between a utility and one or more customers, there also has to be a reason why the General Assembly would have authorized the mercantile customer, as well as the utility, to establish an arrangement and to submit it to the Commission for approval. Such reason also exists.

Prior to the amendment, the statute authorized a public utility to enter into a special contract only with its own customers. A utility could not enter into a special contract with a party not already a customer nor could a customer enter into a special contract with a utility operating in a different certified territory. SB 221 fills in this gap for mercantile customers of EDUs, consistent with the overall goal of the act of fostering competition in the electric industry. The new language recognizes that a mercantile customer has the option of establishing a special contract not only with its EDU but also

[16] See e.g., *In the Matter of the Application of The Cleveland Electric Illuminating Company for Authority to Expand its Competitive Pilot Program*, Case No. 93-0142; *Weiss v. Pub. Util. Comm.* (discussing lawfulness of CEI's Competitive Pilot Program).

with some other public utility electric light company.[17] This language also suggests mutual agreement – it would be strange for the Commission to force a CRES provider or an EDU serving another territory to enter into an arrangement – yet the serving EDU and the non-serving EDU/CRES provider are on equal footing under the language used in the statute.

SB 221 also gives the mercantile customer and its EDU or another public utility electric light company the option of having the customer submit the application for approval of the mutual arrangement. There is an obvious reason for this change too. Two likely reasons for proposing a special contract are to have the arrangement support economic development or to further energy efficiency. In both of these situations, the customer has the key role to play in persuading the Commission that the arrangement furthers the intended purpose. For example, to justify an economic development arrangement, the customer has to provide the documentation to establish, among other things, the number of jobs that will be created, the customer's financial viability and the secondary and tertiary benefits of the project. §4901:1-38-03(A) (2), Ohio Admin. Code. In the case of an energy efficiency arrangement, the customer must describe its status in the community and how the arrangement furthers state policy and must submit verifiable information to establish that it meets the criteria for an energy efficiency arrangement. §4901:1-38-04(A) (1) & (2), Ohio Admin. Code. The fact that in some instances the customer logically bears the burden of establishing the reasonableness of the arrangement is a good reason for allowing the customer, instead of the public utility, to submit the application for approval.

[17] In this connection, see §4928.146, Ohio Rev. Code, which provides that §4928.141 to 4928.145, Ohio Rev. Code, do not prohibit electric distribution utilities from providing competitive retail electric service to electric load centers within the certified territory of another such utility.

Another good reason for allowing the customer, in lieu of the public utility, to submit the arrangement to the Commission is that the utility may not want to actively support or bear the burden of persuasion regarding the amount of discount being requested by the mercantile customer, leaving that determination to the Commission. This consideration is applicable not only in reasonable arrangements for economic development and energy efficiency, but also for unique arrangements under §4901:1-38-05, Ohio Admin. Code.

Thus, §4905.31, Ohio Rev. Code, as amended, is properly read, according to common usage, as continuing to allow only arrangements agreed to by the public utility and its customer(s), as opposed to opening the door to unilateral arrangements proposed by the customer and not supported by the public utility. In fact, this is the reading given to the statute by the Commission itself. In its September 17, 2008, Finding and Order adopting Chapter 4901:1-38, Ohio Admin. Code, the Commission "determined that it is necessary to approve all reasonable arrangements *entered into between the utility and one or more of its customers.*" (emphasis added).[18]

On rehearing, the Commission should reverse the POLR adjustment provision of its order and reaffirm its earlier recognition that §4905.31, Ohio Rev. Code, pertains to reasonable arrangements entered into between the utility and one or more of its customers. Unilateral agreements cannot be imposed on the utility.

[18] *In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17 and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221*, Case No. 08-777-EL-ORD.Finding and Order (Sept. 17, 2008), p. 7.

CONCLUSION

The Commission cannot compel a utility to enter into a contract to which the utility objects. Moreover, the Commission cannot deny a utility the right to recover all revenues which will be foregone under a contract approved under §4905.31, Ohio Rev. Code. A Commission order which violates both of these principles by compelling the utility to execute a contract to which it objects and requiring that the recovery of revenues foregone under the contract be offset by a perceived cost savings by the utility is unlawful and unreasonable. The Commission should correct all of the errors previously discussed on rehearing.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of Columbus Southern Power Company's Application for Rehearing was served by U.S. Mail upon the individuals listed below this 13th day of November 2009.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	Case No. 08-918-EL-SSO

OPINION AND ORDER

The Commission, considering the above-entitled applications and the record in these proceedings, hereby issues its opinion and order in this matter.

APPEARANCES:

Marvin I. Resnik and Steven T. Nourse, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, and Porter, Wright, Morris & Arthur, by Daniel R. Conway, 41 South High Street, Columbus, Ohio 43215, on behalf of Columbus Southern Power Company and Ohio Power Company.

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Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, on behalf of Ohio Environmental Council and Dominion Retail, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Mike Settineri and Betsy L. Elder, 52 East Gay Street, Columbus, Ohio 43216-1008, and Bobby Singh, Integrys Energy, 300 West Wilson Bridge Road, Worthington, Ohio 43085, on behalf of Integrys Energy.

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Bricker & Eckler, Thomas J. O'Brien, 100 South Third Street, Columbus, Ohio, and Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Ohio Hospital Association.

Bell & Royer Co., LPA, by Langdon D. Bell, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Kevin Schmidt, 33 North High Street, Columbus, Ohio 43215-3005, on behalf of Ohio Manufacturers' Association.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Direct Energy Services, LLC.

McDermott, Will & Emery, LLP, by Grace C. Wung, 600 Thirteenth Street, N.W., Washington, D.C. 20005, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., LP, Macy's, Inc., and BJ's Wholesale Club, Inc.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, on behalf of Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators.

Michael R. Smalz and Joseph E. Maskovyak, Ohio State Legal Services Association, 555 Buttles Avenue, Columbus, Ohio 43215, on behalf of Appalachian People's Action Coalition.

OPINION:

I. HISTORY OF PROCEEDINGS

On July 31, 2008, Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. The application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

By entries issued August 5, 2008, and September 5, 2008, the procedural schedule in this matter was established, including the scheduling of a technical conference and the evidentiary hearing. A technical conference was held regarding AEP-Ohio's application on August 19, 2008. A prehearing conference was held on November 10, 2008, and the evidentiary hearing commenced on November 17, 2008, and concluded on December 10, 2008. The Commission also scheduled five local public hearings throughout the Companies' service area.

The following parties were granted intervention by entries dated September 19, 2008, and October 29, 2008: Ohio Energy Group (OEG); the Office of the Ohio Consumers' Counsel (OCC); Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU); Ohio Partners for Affordable Energy (OPAE); Appalachian People's Action Coalition (APAC); Ohio Hospital Association (OHA); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Natural Resources Defense Council (NRDC); Sierra Club – Ohio Chapter (Sierra); National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); Ohio Manufacturers' Association (OMA); Ohio Farm Bureau Federation (OFBF); American Wind Energy Association, Wind on Wires, and Ohio Advance Energy (Wind Energy); Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (collectively, Schools); Ormet Primary Aluminum Corporation (Ormet); Consumer Powerline; Morgan Stanley Capital Group Inc.; Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (collectively, Commercial Group); EnerNoc, Inc.; and the Association of Independent Colleges and Universities of Ohio.

At the hearing, AEP-Ohio offered the testimony of 11 witnesses in support of the Companies' application, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of Staff. At the local public hearings held in this matter, 124 witnesses testified. Briefs were filed on December 30, 2008, and reply briefs were filed on January 14, 2009.

A. Summary of the Local Public Hearings

Five local public hearings were held in order to allow CSP's and OP's customers the opportunity to express their opinions regarding the issues in this proceeding. The hearings were held in the evenings in Marietta, Canton, Lima, and Columbus. Additionally, an afternoon hearing was held in Columbus. At those hearings, public testimony was heard from 21 customers in Marietta, 21 customers in Canton, 17 customers in Lima, 25 customers at the afternoon hearing in Columbus and 40 customers at the evening hearing in Columbus. In addition to the public testimony, numerous letters were filed in the docket by customers stating concern about the applications.

The principal concern expressed by customers, both at the public hearings and in letters, was over the increases in customer rates that would result from the approval of the ESP applications. Witnesses stated that any increase in rates would negatively impact low-income customers, the elderly, and those on fixed incomes. Customers cited the recent downturn in the economy as the primary source of their apprehension. It was noted by many at the hearings that customers are also facing increases in other utility charges, gasoline, food, and medical expenses and that the proposed increases would cause undue hardship. On the other hand, some witnesses at the public hearings and in the letters filed in the docket acknowledged AEP-Ohio as a good corporate partner in their respective communities.

B. Procedural Matters

1. Motion to Strike

On January 7, 2009, AEP-Ohio filed a motion to strike a section of the brief jointly filed by OCC and Sierra (collectively, OCEA). More specifically, AEP-Ohio filed to strike the sentence starting on line 2 of page 63 ["In fact,"] through the first two lines of page 64, including footnotes 244 to 248. AEP-Ohio argues that the above-cited portion of OCEA's brief, regarding the deferral of fuel expenses and the carrying charges and the tax effect thereof, relies upon testimony offered by OCC witness Effron in the FirstEnergy Distribution Case.[1] AEP-Ohio notes that Mr. Effron was not a witness in this ESP proceeding and, therefore, was not available for the Companies, or any other party, to cross-examine. Accordingly, the Companies argue that consideration of Mr. Effron's testimony in this matter would be a denial of the Companies' due process rights, and request that the specified portion of OCEA's brief be stricken. On January 14, 2009, OCC filed a memorandum contra the motion to strike. OCC agreed to withdraw the second and third sentences on page 63, the quoted testimony of Mr. Effron on page 63, and footnotes 244 to 248 on pages 63 and 64. However, OCC contends that AEP-Ohio's

1 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and Toledo Edison Company*, Case No. 07-551-EL-AIR, et al. (FirstEnergy Distribution Case).

motion is overly broad and the remaining portion of the brief that AEP-Ohio seeks to strike is appropriate legal argument regarding deferrals on a net-of-tax basis and, therefore, should remain. AEP-Ohio filed a reply on January 16, 2009. AEP-Ohio first notes that because the memorandum contra was filed by OCC only and Sierra did not respond to the motion, it is not clear whether Sierra is also willing to withdraw the portions of the brief listed in the memorandum contra. AEP-Ohio also argues that the remaining portion of this particular argument in OCEA's brief should be stricken with the removal of the footnotes. With this removal, AEP-Ohio then argues that there is no longer any support in the brief for such arguments. By letter docketed January 22, 2009, Sierra confirmed that it joins OCC in OCC's withdrawal of the limited portions of the OCEA brief as stated by OCC in its January 14, 2009, reply.

The Commission grants, in part, and denies, in part, AEP-Ohio's motion to strike OCEA's brief. The Commission agrees with AEP-Ohio and OCC that the use of Mr. Effron's testimony filed in the FirstEnergy Distribution Case in this proceeding was inappropriate and, therefore, we accept OCC's and Sierra's withdrawal of that portion of their brief. As for the remaining portion of OCEA's brief that AEP-Ohio has requested to be stricken, we agree with OCC that the language that discusses the calculation of deferred fuel expenses on a net-of-tax basis could be construed to be legal argument on brief, which rationalized why the issue should be decided in OCEA's favor. Moreover, we can surmise that if OCEA had recognized its error in the drafting stage of the brief, that OCEA would have drafted similar legal arguments without referencing Mr. Effron's testimony. Accordingly, we will only strike the portions of OCEA's brief that OCC and Sierra have agreed to withdraw.

2. Motion for AEP-Ohio to Cease and Desist

On February 25, 2009, Integrys filed a motion with the Commission requesting that the Commission direct AEP-Ohio to cease and desist the Companies' refusal to process SSO retail customer applications to enroll in the Interruptible Load for Reliability (ILR) Program of PJM Interconnection, LLC (PJM). Integrys also filed a request for an expedited ruling; however, Integrys represented that counsel for AEP-Ohio objected to the expedited ruling request. Integrys is a registered curtailment service provider with PJM and as such receives notices from PJM and coordinates with retail customers to curtail load. Integrys argues that retail customer participation in PJM demand response programs was raised in the Companies' ESP application and has not yet been decided by the Commission. For this reason, Integrys contends that AEP-Ohio lacks the authority to refuse to process the ILR applications and the denial of the application violates the Companies' tariffs. Two other curtailment service providers in the AEP-Ohio service territory, Constellation and KOREnergy, Ltd., filed memoranda in support of Integrys' motion.[2]

On March 2, 2009, AEP-Ohio filed a memorandum contra the motion to cease and desist. AEP-Ohio affirms the arguments made in this proceeding to prohibit retail customers from participating in PJM's demand response programs. Further, AEP-Ohio argues, among other things, that despite the claims of Integrys andConstellation, AEP-Ohio is providing, in a timely manner, the load data required for customer enrollment in the PJM ILR program, informs the customer that AEP-Ohio is not consenting to the customer's participation in the program, and discloses that the matter is currently pending before the Commission.

On March 9, 2009, Integrys and Constellation filed a withdrawal of the motion to direct AEP-Ohio to cease and desist. The movants state that despite AEP-Ohio's assertions that the applicants were not eligible to participate in PJM's demand response programs, PJM rejected AEP-Ohio's opposition to the ILR applications and processed the ILR applications. Integrys and Constellation further state that, except for two pending applications, all their customers in the AEP-Ohio service territory have been certified for participation in the PJM programs.

As the parties acknowledge, this matter was presented for the Commission's consideration as part of the ESP application. The Commission, therefore, specifically addresses and discusses the issues raised concerning SSO retail customer participation in PJM demand response programs at Section VI.C of this opinion and order. Accordingly, we grant Integrys' and Constellation's request to withdraw their motion to cease and desist.

II. <u>DISCUSSION</u>

A. <u>Applicable Law</u>

Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing AEP-Ohio's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, which was amended by Senate Bill 221 (SB 221).

Section 4928.02, Revised Code, states that it is the policy of the state, inter alia, to:

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2 KOREnergy, Ltd., has not filed to intervene in this proceeding and, therefore, its memoranda in support will not be considered.

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

(2) Ensure the availability of unbundled and comparable retail electric service.

(3) Ensure diversity of electric supplies and suppliers.

(4) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management (DSM), time-differentiated pricing, and implementation of advanced metering infrastructure (AMI).

(5) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality.

(6) Ensure effective retail competition by avoiding anticompetitive subsidies.

(7) Ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power.

(8) Provide a means of giving incentives to technologies that can adapt to potential environmental mandates.

(9) Encourage implementation of distributed generation across customer classes by reviewing and updating rules governing issues such as interconnection, standby charges, and net metering.

(10) Protect at-risk populations including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

In addition, *SB 221* amended Section *4928.14*, Revised Code, which now provides that on January 1, 2009, electric utilities must provide consumers with an SSO, consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the electric utility's default SSO. The law provides that electric utilities may apply simultaneously for both an

MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP. Section 4928.141, Revised Code, specifically provides that an SSO shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the electric utility's rate plan. In the event an SSO is not authorized by January 1, 2009, Section 4928.141, Revised Code, provides that the current rate plan of an electric utility shall continue until an SSO is authorized under either Section 4928.142 or 4928.143, Revised Code.

AEP-Ohio's application in this proceeding proposes an ESP, pursuant to Section 4928.143, Revised Code. Paragraph (B) of Section 4928.141, Revised Code, requires the Commission to hold a hearing on an application filed under Section 4928.143, Revised Code, to send notice of the hearing to the electric utility, and to publish notice in a newspaper of general circulation in each county in the electric utility's certified territory.

Section 4928.143, Revised Code, sets out the requirements for an ESP. Under paragraph (B) of Section 4928.143, Revised Code, an ESP must include provisions relating to the supply and pricing of generation service. The plan, according to paragraph (B)(2) of Section 4928.143, Revised Code, may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress (CWIP), an unavoidable surcharge for the cost of certain new generation facilities, conditions or charges relating to customer shopping, automatic increases or decreases, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development.

The statute provides that the Commission is required to approve, or modify and approve the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

The Commission may, under Section 4928.144, Revised Code, order any just and reasonable phase-in of any rate or price established under Section 4928.141, 4928.142, or 4928.143, Revised Code, including carrying charges. If the Commission does provide for a phase-in, it must also provide for the creation of regulatory assets by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount, and shall authorize the deferral's collection through an unavoidable surcharge.

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD (SSO Rules Case), the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.06, 4928.14, 4928.17, and 4905.31, Revised Code. The rules adopted in the SSO Rules Case were subsequently amended by the entry on rehearing issued February 11, 2009.

B. State Policy – Section 4928.02, Revised Code

AEP-Ohio submits that, contrary to the views of the intervenors, Section 4928.02, Revised Code, does not impose additional requirements on an ESP and the ESP should not be modified or rejected because it does not satisfy all of the policies of the state. According to the Companies, "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15).

OHA asserts that the Commission "must view the 'more favorable in the aggregate' standard through the lens of the overriding 'public interest,'" and that the public interest cannot be served if the result is not reasonable (OHA Br. at 10). OPAE/APAC seems to state that the ESP must be more favorable in the aggregate and comply with the state policy, but also recognizes that state policies are to be used to guide the Commission in its approval of an ESP (OPAE/APAC Br. at 3). OEG agrees that the policy objectives are required to be met prior to the approval of an ESP (OEG Br. at 1). The Commercial Group submits that costs must be properly allocated to ensure that the policies of the state are met, to improve price signals, and to ensure effective retail competition (Commercial Group Br. at 5).

In its reply brief, AEP-Ohio maintains that its proposed ESP is consistent with the policy of the state as delineated in Sections 4928.02(A) through (N), Revised Code, and is "worthy of approval, without modification" (Cos. Reply Br. a 7). According to the Companies, the ESP advances the general policy objectives of the policy of the state (Id. at 6-7). Furthermore, the Companies argue that the concerns raised by some intervenors regarding the impact of AEP-Ohio's ESP on the difficult economic conditions would have the Commission ignore the statutory standard for approving an ESP and, instead, establish rates based on the current economic conditions (Cos. Reply Br. at 7). While the Companies believe that aspects of the proposed ESP address these concerns (e.g., fuel deferrals), they argue that their SSO must be established in accordance with applicable ESP statutory provisions (Id.).

As explained above, and previously in our opinion and order issued in the FirstEnergy ESP proceeding,[3] the Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives,

[3] *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 08-935-EL-SSO, Opinion and Order at 12 (December 19, 2008) (FirstEnergy ESP Case).

which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. As noted in the FirstEnergy ESP case, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, we take into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code. Accordingly, we agree with AEP-Ohio and will use these policies as a guide in our decision-making in this case, just as we did in the FirstEnergy ESP Case (Cos. Reply Br. at 6).[4] The Commission has reviewed the ESP proposal presented by AEP-Ohio, as well as the issues raised by the various intervenors, and we believe that, with the modifications set forth herein, we have appropriately reached a conclusion advancing the public's interest.

C. Application Overview

In their application, the Companies are requesting authority to establish an SSO in the form of an ESP pursuant to the provisions of Sections 4928.141 and 4928.143, Revised Code. The proposed ESP is to be effective for a three-year period commencing January 1, 2009. According to the Companies, pursuant to the proposed ESP, the overall, estimated increases in total customer rates, including generation, transmission, and distribution, would be an average of 13.41 percent for CSP and 13 percent for OP in 2009, and 15 percent in 2010 and 2011 for both CSP and OP (Cos. Ex. 1, Exhibit DMR-1). The Companies also propose a 15 percent cap per year on the total allowable increases for each customer rate schedule should the actual costs be higher than expected, excluding transmission costs and costs associated with new government mandates (Cos. App. at 6).

III. GENERATION

A. Fuel Adjustment Clause (FAC)

The Companies contend that Section 4928.143(B)(2)(a), Revised Code, authorizes the implementation of a FAC mechanism to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations (Cos. Ex. 7 at 4-7).

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4 Some intervenors recognize that the state policy objective must be used as a guide to implement the ESP provision (IEU Br. at 19; OPAE/APAC Br. at 3).

1. FAC Costs

The Companies proposed to include in the FAC mechanism types of costs recovered through the electric fuel component (EFC) previously used in Ohio[5] (Cos. Ex. 7 at 3-4). In addition to those types of costs, the Companies stated that Section 4928.143(B)(2)(a), Revised Code, provides for a broader cost-based adjustment mechanism that authorizes the inclusion of all prudently incurred fuel, purchased power, and environmental components (Id. at 4). Companies' witness Nelson itemized and described the accounts that the Companies proposed to include in their FAC mechanism (Id. at 5-7).

Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCEA Br. at 47-48, 67-68; OCC Ex. 11 at 4-5, 31-40). Specifically, Staff witness Strom testified that the costs proposed to be recovered through the FAC mechanism are appropriate and recovery of those costs through a FAC mechanism is logical (Staff Ex. 8 at 3). OCC and Sierra also agree that Section 4928.143(B)(2)(a), Revised Code, authorizes the enactment of a FAC mechanism to automatically recover certain prudently incurred costs (OCEA Br. at 47), and OCC does not seem to oppose the list of categories of accounts proposed to be included in the FAC by Companies witness Nelson (OCC Ex. 11 at 18-20). Additionally, Staff recommended that annual reviews of the prudency and appropriateness of the accounting of FAC costs be conducted (Staff Ex. 8 at 3-4), and OCC recommended that an interest charge be paid to customers on any over-recovered fuel costs in a quarterly period until the subsequent reconciliation occurs, similar to the carrying charge for any under-recovery that she believed the Companies were proposing to collect[6] (OCC Ex. 11 at 4). Kroger and IEU, however, seem to state that a FAC mechanism cannot be established until a cost-of-service or earnings test is completed (Kroger Br. at 9-10; IEU Br. at 12-15). IEU also questioned the appropriate term of the proposed FAC mechanism (IEU Br. at 13; Tr. Vol. IX at 143-146).

The Commission believes that the establishment of a FAC mechanism as part of an ESP is authorized pursuant to Section 4928.143(B)(2)(a), Revised Code, to recover prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations. Given that the FAC mechanism is authorized pursuant to the ESP provision of SB 221, we will limit our authorization, at this time, to the term of the ESP.

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5 See Sections 4905.01(G), 4905.66 through 4905.69, and 4909.159, Revised Code (repealed January 1, 2001); Chapter 4901:1-11, Ohio Administrative Code (O.A.C.) (rescinded November 27, 2003).

6 In AEP's Brief, the Companies clarified that they did not propose to collect a carrying charge on any FAC under-recovery in one quarterly period until a reconciliation in the subsequent period occurred. The only carrying charge that they proposed was on the FAC deferrals that would not be collected until 2012-2018 (Cos. Br. at 27).

With regard to interest charges assessed on any over- or under-recoveries for FAC costs within the quarterly period until the subsequent reconciliation occurs, we agree with OCC witness Medine that symmetry should exist if interest charges were assessed on any under-recoveries (Tr. Vol. VI at 210). However, we do not conclude that any interest charges on either over- or under-recoveries are necessary as a deterrent to the creation of over- or under-recoveries as OCC witness Medine suggests (Id. at 210-211). As proposed by the Companies and supported by others, the FAC mechanism includes a quarterly reconciliation to actual FAC costs incurred, which will establish the new charge for the subsequent quarter. These quarterly adjustments combined with the annual review proposed by Staff to review the appropriateness of the accounting of the FAC costs and the prudency of decisions made are sufficient to control the over- or under-recoveries that may occur within a particular quarter. Therefore, we find that the FAC mechanism with quarterly adjustments as proposed by the Companies, as well as an annual prudency and accounting review recommended by Staff, is reasonable and should be approved and implemented as set forth herein.

(a) Market Purchases

As part of the FAC costs, the Companies proposed to purchase incremental power on a "slice of the system basis" equal to 5 percent of each company's load in 2009, 10 percent in 2010, and 15 percent in 2011 (Cos. Ex. 2-A at 21). The Companies argue that while these purchases will be included in the FAC mechanism, as the appropriate recovery mechanism for these costs, the purchases are permitted as a discretionary component of an ESP filing authorized by Section 4928.143(B)(2), Revised Code, which states: "The plan may provide for or include, without limitation, any of the following:" (emphasis added) (Cos. Br. at 37). To support its proposal, AEP-Ohio states that the purchases reflect the continued transition to market rates and represent an appropriate recognition of the Companies' incorporation of the loads of Ormet Primary Aluminum Company (Ormet) and the certified territory formerly served by Monongahela Power Company (MonPower) (Cos. Ex. 2-A at 21-22). The Companies further assert that, during the ESP, they should be able to continue to recover a market-based generation price for serving these loads, as was previously authorized by the Commission during the RSP period.

Staff supported market purchases sufficient to meet the additional load responsibilities that the Companies assumed for the addition of the former MonPower customers and Ormet to the Companies' system, which equals approximately 7.5 percent of the Companies' total loads (Staff Ex. 10 at 5). However, based on the size of the additional load assumed by the Companies, Staff only recommended that the incremental power purchases equal, on average, 5 percent of each company's load in 2009, 7.5 percent in 2010, and 10 percent in 2011 (Id.).

The Companies responded to Staff's reduction in the amount of market purchases by adding that the Companies also intended to utilize their proposed levels of market purchases to encourage economic development (Cos. Ex. 2-E at 7).

Various parties oppose the inclusion of incremental "slice of the system" power purchases in AEP-Ohio's ESP. OEG witness Kollen testified that the Commission should reject this provision of AEP-Ohio's ESP because the Companies have not demonstrated a need for the excess generation purchased on the market to meet its existing load, and such "purchases are not prudent because they will uneconomically displace lower cost Company owned generation and cost-based purchased power that is available to meet their loads" (OEG Ex. 3 at 3, 9-10). IEU witness Bowser agrees that this portion of the ESP should be rejected (IEU Ex. 10 at 9). Kroger witness Higgins also concurs, stating: "The only apparent purpose of these slice-of-system purchases is to serve as a device for increasing prices charged to customers" (Kroger Ex. 1 at 9). OCEA concurs with the testimony offered by these intervenor witnesses (OCEA Br. at 53-55). Intervenors also question this provision in light of the AEP Interconnection Agreement (OEG Ex. 3 at 10-14; OCEA Br. at 54-55).

Given that AEP-Ohio has explicitly stated that the purchased power is not a prerequisite for adequately serving the additional load requirements assumed by AEP-Ohio when adding Ormet and the MonPower customers to its system (Cos. Ex. 2-E at 7), the Commission finds that Staff's rationale for the support of the proposal, as well as the recommendation for a reduction in the amount of purchased power proposed to equal the additional load, fails. We struggle, along with the other parties, to find a rational basis to approve such a proposal in the absence of need. The Commission notes that while we appreciate AEP-Ohio's willingness and cooperation with regard to the inclusion of Ormet and MonPower customers into its system, we believe that the Companies have been able to prepare and plan for the additions to its system under the current regulatory scheme and have been compensated during the transitional period. As for the reliance on the market purchases to promote economic development, the Commission believes that this goal can be more appropriately achieved through other means as outlined in this opinion and order, the Commission's recently adopted rules, and SB 221. Accordingly, we find that AEP-Ohio's ESP shall be modified to exclude this provision.

(b) Off-System Sales (OSS)

Kroger and OEG contend that FAC costs must be offset by a credit for OSS margins, stating that other jurisdictions governing other operating companies of AEP Corporation require such an OSS offset to revenue requirements (Kroger Br. at 11-12; Kroger Ex. 1 at 3, 9, 10; OEG Br. at 10; OEG Ex. 3 at 14-15, 16-17). Kroger argues that it is incongruent to allow a rate increase based on certain costs without examining AEP-Ohio's net costs to determine that AEP-Ohio's costs have actually increased (Kroger Br. at 11-12). OEG notes that the Companies' profits for 2007 from off-system sales were $146.7 million for OP and $124.1 million for CSP (OEG Ex. 3 at 14). OEG reasons that because the cost of the power plants used to generate off-system sales are included in rates, all revenue from the power plants should be a rate credit (OEG Br. 10). OCEA raises similar arguments to those of OEG and Kroger in its brief (OCEA Br. at 57-59). More specifically, OCEA argues that the Companies' proposal to eliminate off-system sales expenses from Ohio ratepayers is not equivalent to providing customers the benefit of off-system sales margins. OCEA notes that, in other cases, the Commission has required electric utilities to share the benefits of off-system sales revenue with jurisdictional customers (OCEA Br. at 58-59).

Staff did not take a position in regard to the intervenors' arguments to offset FAC costs by the OSS margin. Staff, however, concluded that the costs sought to be recovered through the FAC are appropriate (Staff Ex. 10 at 4; Staff Ex. 8 at 3; Staff Br. at 2).

The Companies argue that an OSS offset to FAC charges is not required by Section 4928.143(B)(2)(a), Revised Code, or any other provision in SB 221 (Cos. Ex. 2-E at 8-9; Cos. Reply Br. at 12). The Companies also state that the regulatory or statutory regimes in other states have no bearing on Ohio or Ohio's statutory requirements (Id.). As to the other arguments raised by OEG and OCEA, the Companies argue that the intervenors' arguments ignore the fact that the Companies' ESP reduces the FAC and environmental carrying cost expenses for AEP-Ohio customers based on the calculation of the pool capacity payments in the FAC and use of the pool allocation factor (Cos. Ex. 7, Exhibits PJN-1, PJN-2, PJN-6 and PJN-8).

Upon a review of the record in this case, the Commission is not persuaded by the intervenors' arguments. We do not believe that the testimony presented offered adequate justification for modifying the Companies' proposed ESP to offset OSS margins from the FAC costs. Section 4928.143(B)(2)(a), Revised Code, specifically provides for the automatic recovery, without limitation, of prudently incurred costs for fuel, purchased power, capacity cost, and power acquired from an affiliate. As recognized by the Companies, the pertinent statutory provisions do not require that there be an offset to the allowable fuel costs for any OSS margins. Additionally, Ohio law governs the Companies' ESP application, and thus, we are not persuaded by the arguments of Kroger regarding how other jurisdictions handle OSS margins. Moreover, consistent with our discussion in Section VII of our opinion and order, we do not believe that OSS should be a component of the Companies' ESP, or factored into our decision in this proceeding. Intervenors cannot have it both ways: they cannot request that OSS margins be credited against the fuel costs (i.e., offset the expenses); and, at the same time, ask us to count the OSS margins as earnings for purposes of the significantly excessive earnings test (SEET) calculation.

(c) Alternate Energy Portfolio Standards (including Renewable Energy Credit program)

Section 4928.64, Revised Code, establishes alternative energy portfolio standards which consist of requirements for both renewable energy and advanced energy resources. Section 4928.64(B)(2), Revised Code, introduces specific annual benchmarks for renewable energy resources and solar energy resources beginning in 2009.

The Companies' ESP application included, as a part of the FAC costs, cost recovery for renewable energy purchases and renewable energy credits (RECs) with purchased power reflected in Account 555 and RECs reflected in Account 557 (Cos. Ex. 7 at 6-7, 14). The Companies stated that they plan to purchase almost all of the RECs required for 2009. The Companies further state that they will enter into renewable energy purchase agreements (REPAs) to meet compliance requirements for the remainder of the ESP period, for which they have already conducted a request for proposal (Cos. Ex. 9 at 10-11). The Companies also recognized that recovery of such costs to comply with Section 4928.64(E), Revised Code, is, as stated in the statute,avoidable. Therefore, the Companies explained that they intend to include all of the renewable energy costs within the FAC mechanism and not as part of any FAC deferral. The Companies, however, recognized that their request for proposal and procurement practices for renewable energy will be subject to a prudency review and the renewable purchases subject to a financial audit (Cos. Br. at 96-98).

Staff and OPAE/APAC express concern with the Companies' plan to include renewable energy purchases and RECs as a component of the FAC mechanism (Staff Ex. 4 at 6-7; Staff Br. at 4-5; OPAE/APAC Br. at 11).

The Commission notes that the renewable energy purchases and RECs requirements are based on Section 4928.64(E), Revised Code, and any recovery of such costs is, as the statute provides, bypassable. With the Companies' recognition that such costs must be accounted for separately from fuel costs, and is not to be deferred, the Commission finds that Staff's and OPAE/APAC's issue is adequately addressed. Accordingly, with that clarification, the Commission finds that this aspect of the Companies' ESP application is reasonable and should be adopted.

2. FAC Baseline

The Companies proposed establishing a baseline FAC rate by identifying the FAC components of the current SSO. The Companies started with the EFC rates that were unbundled as part of the electric transition plan (ETP) proceedings (those in effect as of October 5, 1999) (step #1), and then added calendar year 1999 amounts for the additional fuel, purchased power, and environmental accounts that are included in the requested

FAC mechanism for this proceeding (1999 data from FERC Form 1 and other financial records were used as the base period for the additional components that were not in the frozen EFC rates) (step #2) (Cos. Ex. 7 at 8). The Companies then adjusted the 1999 frozen EFC rates (step #1) and the 1999-level rates developed for the additional components (step #2) for subsequent rate changes (step #3) to get the base FAC component that is equal to the fuel-related costs presently embedded in the Companies' most recent SSO (i.e., the RSP) (Id.). The subsequent rate changes that occurred during the RSP period and reflected in step #3 of the Companies' calculation included annual increases of 7 percent for OP and 3 percent for CSP, an increase in CSP's generation rates for 2007 by approximately 4.43 percent through the Power Acquisition Rider, and a reduction in OP's base period FAC rate by the amount of the Gavin Cap and mine investment shutdown cost recovery component that was in OP's 1999 EFC rate given that the Regulatory Asset Charge (RAC) established in the ETP case expired (Id. at 9).

Staff argued that the actual costs should be used in determining the FAC baseline and, therefore, recommended using 2007 actual data, escalated by 3 percent for CSP and 7 percent for OP, as a reasonable proxy for 2008 (Staff Ex. 10 at 3-4). Staff explained that utilizing actual 2007 costs and updating them to 2008 is appropriate given that the resulting amounts should be the costs that the Companies are currently recovering for fuel-related costs (Id.). Additionally, Staff notes that this proposal produces a result that is very close to the result produced by utilizing the Companies' methodology (Staff Br. at 3).

OCC recommended the use of 2008 actual fuel costs to establish the FAC baseline, which will be reconciled to actual costs in the future FAC proceeding (OCC Ex. 10 at 11-14). OCC's witness testified that her concern is that if the FAC baseline is established too low, the base portion of the generation rates (the non-FAC portion) will be established too high (OCC Ex. 10 at 13). In its Brief, OPAE/APAC opposed the Companies' use of 1999 rates as the baseline and seems to support OCC's recommendation to use 2008 fuel costs (OPAE/APAC Br. at 11-12). The Companies' responded by explaining that they did not use 1999 rates as the baseline, rather the 1999 level was just the starting point to calculating the baseline (Cos. Reply Br. at 21). The Companies also stated that a variable baseline was not appropriate as it would result in a variable non-FAC generation rate as well since the non-FAC component of the current generation SSO was determined to be the residual after subtracting out the FAC component (Id.).

As noted by OCC's witness, the 2008 actual fuel costs were not known at the time of the hearing (OCC Ex. 10 at 14). Thus, the Companies and Staff proposed methodologies to obtain a proxy for 2008 fuel costs. While both had a different starting point to the calculation of the 2008 proxy, we agree that in the absence of known actual costs, a proxy is appropriate to establish a baseline. Therefore, based on the evidence presented, we agree with Staff's resulting value as the appropriate FAC baseline.

3. FAC Deferrals

The Companies proposed to mitigate the rate impact on customers of any FAC increases by phasing in their new ESP rates by deferring a portion of the annual incremental FAC costs during the ESP (Cos. App. at 4-5; Cos. Ex. 3 at 11; Cos. Ex. 1 at 13-15). The amount of the incremental FAC expense that would be recovered from customers would be limited so that total bill increases would not be more than 15 percent for each of the three years of the ESP (Id.). The 15 percent target for FAC does not include cost increases associated with the transmission cost recovery rider (TCRR) or with any new government mandates (the Companies' could apply to the Commission for recovery of costs incurred in conjunction with compliance of new government mandates, including any Commission rules imposed after the filing of the AEP-Ohio application (Cos. App. at 6)). The Companies proposed to periodically reconcile the FAC to actual costs, subject to the maximum phase-in rates (Cos. Ex. 1 at 14-15). Under the Companies' proposal, any incremental FAC expense that exceeds the maximum rate levels will be deferred. The Companies project the deferrals under the proposed ESP to be $146 million by December 31, 2011 for CSP and $554 million by December 31, 2011 for OP (Cos. Ex. 6, Exhibit LVA-1). If the projected FAC expense in a given period is less than the maximum phase-in FAC rates, the Companies proposed to give the Commission the option of charging the customer the actual FAC expense amount or increasing the FAC rates up to the maximum levels in order to reduce any existing deferred FAC expense balance (Id.). Any deferred FAC expense remaining at the end of 2011 would be recovered, with a carrying cost at the Weighted Average Cost of Capital (WACC), as an unavoidable surcharge from 2012 to 2018 (Id.).

As noted previously, Staff, OCC, and Sierra support the FAC mechanism that will be updated and reconciled quarterly (Staff. Ex. 8 at 3-4; OCC Ex. at 11 at 4-5, 31-40; OCEA Br. at 47-48, 67-68). Staff, OCC, and Sierra, however, oppose the creation of any long-term deferrals for fuel costs (Staff Ex. 10 at 5; OCEA Br. at 62). Similarly, the Commercial Group recommended that "customers pay the full cost of fuel during the ESP" (Commercial Group Ex. 1 at 9). Constellation argued that the deferral proposal should be rejected because it masks the true cost of the ESP generation, deferrals have the effect of artificially suppressing conservation, the carrying costs proposed by the Companies would be set at the Companies' cost of capital, which would include equity, and customers do not want to pay interest on any deferred amounts (instead, customers would rather pay when the costs are incurred so as to not pay the interest) (Constellation Br. at 8-9). The Schools also questioned the need for the phase-in of rates, as well as the avoidability of the surcharge that would be created to collect the deferred fuel costs, with carrying charges, from 2012 to 2018 (Schools Br. at 3).

If the Commission, however, authorizes such deferrals to levelize rates during the ESP period, Staff, OCC, and Sierra believe that the deferrals should be short-term deferrals that do not extend beyond the ESP period (Staff Ex. 10 at 5; OCEA Br. at 62). IEU also supports the use of a phase-in to stabilize rates, but does not believe that Section 4928.144, Revised Code, allows the deferrals to extend beyond the ESP term (IEU Br. at 27-29).

Furthermore, OCC opposed the Companies' use of WACC, stating that such an approach is not reasonable and results in excessive payments by customers (OCC Ex. 10 at 34). Through testimony, OCC asserts that the carrying charges on deferrals should be based on the current long-term cost of debt (OCC Ex. 10 at 34-35; Tr. Vol. VI at 157-158). However, in its joint brief, OCC seems to have modified its position and is now arguing that the carrying charges should be calculated to reflect the short-term actual cost of debt, excluding equity (OCEA Br. at 62). In reliance on OCC's testimony, Constellation submits that it is appropriate to use the long-term cost of debt (Constellation Br. at 8). The Commercial Group also opposed the use of WACC; instead, Commercial Group witness Gorman recommended that the Companies finance the FAC phase-in deferrals entirely with short-term debt given that the accruals are a temporary investment and not long-term capital (Commercial Group Ex. 1 at 9-11).

Additionally, the Commercial Group and OCC argued that the deferred fuel expenses should be calculated to reflect the net of applicable deferred income taxes (Commercial Group Ex. 1 at 9-10; OCEA Br. at 63). Commercial Group witness Gorman testified that if a company does not recover the fuel expense in the year that it was incurred, the company will reduce its current tax expense and record a deferred tax obligation. The deferred tax obligation would then represent a temporary recovery of the fuel expense via a reduction to the current income tax expense (Commercial Group Ex. 1 at 10). Commercial Group witness Gorman then goes on to recognize that the income tax will ultimately have to be paid after the incremental fuel cost is recovered from customers, but states that, while deferred, the company will partially recover its deferred fuel balance through the reduced income tax expense (Id.). To bolster their argument that deferred fuel expenses should be calculated on a net-of-tax basis, OCC and Sierra relied, in their brief, on a witness' testimony in an unrelated proceeding, which has been subsequently withdrawn as explained above. Neither OCC nor Sierra offered any record evidence to support its position.

AEP-Ohio, on the other hand, argued that the calculation of carrying charges for the deferrals should not be done on a net-of-tax basis. AEP-Ohio witness Assante testified that limiting the application of the carrying cost rate to a net-of-tax balance of FAC deferrals improperly utilizes a traditional cost-of-service ratemaking approach in a generation pricing proceeding (Tr. Vol. IV at 158-160). Additionally, while the Companies proposed the phase-in proposal to help mitigate increases and believe that their proposal is reasonable, in light of the opposition received from several parties, the Companies stated that they would accept a modification to their ESP that eliminated such deferrals (Cos. Reply Br. at 41-42).

To ensure rate or price stability for consumers, Section 4928.144, Revised Code, authorizes the Commission to order any just and reasonable phase-in of any electric utility rate or price established pursuant to 4928.143, Revised Code, with carrying charges, through the creation of regulatory assets. Section 4928.144, Revised Code, also mandates that any deferrals associated with the phase-in authorized by the Commission shall be collected through an unavoidable surcharge. Section 4928.144, Revised Code, does not, however, limit the time period of the phase-in or the recovery of the deferrals created by the phase-in through the unavoidable surcharge.

Contrary to OCC and others,[7] we believe that a phase-in of the increases is necessary to ensure rate or price stability and to mitigate the impact on customers during this difficult economic period, even with the modifications to the ESP that we have made herein. To this end, the Commission appreciates the Companies' recognition that over 15 percent rate increases on customers' bills would cause a severe hardship on customers. Nonetheless, given the current economic climate, we believe that the 15 percent cap proposed by the Companies is too high.[8] Therefore, we exercise our authority pursuant to Section 4928.144, Revised Code, and find that the Companies should phase-in any authorized increases so as not to exceed, on a total bill basis, an increase of 7percent for CSP and 8percent for OP for 2009, an increase of 6percent for CSP and 7percent for OP for 2010, and an increase of 6percent for CSP and 8percent for OP for 2011 are more appropriate levels.

Based on the application, as modified herein, the resulting increases amount to approximate overall average generation rates of 5.47 cents/kWh and 4.29 cents/kWh for CSP and OP, respectively in 2009; 6.07 cents/kWh and 4.75 cents/kWh for CSP and OP, respectively, in 2010; and 6.31 cents/kWh and 5.31 cents/kWh for CSP and OP, respectively, in 2011.

Any amount over the allowable total bill increase percentage levels will be deferred pursuant to Section 4928.144, Revised Code, with carrying costs. If the FAC expense in a given period is less than the maximum phase-in FAC rate established herein, the Companies shall begin amortization of the prior deferred FAC balance and increase the FAC rates up to the maximum levels allowed to reduce any existing deferred FAC expense balance, including carrying costs. As required by Section 4928.144, Revised Code, any deferred FAC expense balance remaining at the end of 2011 shall be recovered

7 See, e.g., OCC Reply Br. at 45-46; Constellation Br. at 6-9.

8 Numerous letters filed in the docket by various customers confirm our belief.

via an unavoidable surcharge. We believe that this approach balances our objectives of limiting the total bill increases that customers will be charged in any one year with minimizing the deferrals and carrying charges collected from customers.

Based on the record in this proceeding, we do not find the intervenors' arguments concerning the calculation of the carrying charges persuasive. Instead, for purposes of a phase-in approach in which the Companies are expected to carry the fuel expenses incurred for electric service already provided to the customers,[9] we find that the Companies have met their burden of demonstrating that the carrying cost rate calculated based on the WACC is reasonable as proposed by the Companies. As explained previously, Section 4928.144, Revised Code, provides the Commission with discretion regarding the creation and duration of the phase-in of a rate or price established pursuant to Sections 4928.141 through 4928.143, Revised Code. The Commission is not convinced by arguments that limit the collection of the deferrals to the term of the ESP. Limiting the phase-in to the term of the ESP may not ensure rate or price stability for consumers within that three-year period and may create excessive increases, which may defeat the purpose for establishing a phase-in. The limitation of any deferrals to the ESP term may also negate the cap established by the Commission herein to provide stability to consumers. Therefore, we find that the collection of any deferrals, with carrying costs, created by the phase-in that are remaining at the end of the ESP term shall occur from 2012 to 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs.

Regarding OCC's, Sierra's, and the Commercial Group's recommendations that the tax deductibility of the debt rate be reflected in the carrying charges on a net-of-tax basis,[10] we have recently explained that this recommendation accounts for the deductibility of the debt rate, but does not account for the fact that the revenues collected are taxable.[11] If we were to adopt the net-of-tax recommendation, the Companies would not recover the full carrying charges on the authorized deferrals. We believe that this outcome would be inconsistent with the explicit directive of Section 4928.144, Revised

9 We agree with the Companies that this decision is consistent with our decision in the recent TCRR and accounting cases with regard to the calculation based on the long-term cost of debt. See *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) and *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1301-EL-UNC, Finding and Order (December 19, 2008). However, we believe that, with regard to the equity component, these cases are distinguishable from the current ESP proceeding, where we are establishing the standard service offer and requiring the Companies to defer the collection of incurred generation costs associated with fuel over a longer period. We also believe that this decision is reasonable in light of our reduction to the Companies' proposed FAC deferral cap, which may have the effect of requiring the Companies to defer a higher percentage of FAC costs than what was otherwise proposed.

10 OCEA Br. at 63-64; Commercial Group Ex. 1 at 9-10.

11 *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 07-551-El-AIR, et al., Opinion and Order at 10 (January 21, 2009).

Code: "If the commission's order includes such a phase-in, the order also shall provide for the creation of regulatory assets pursuant to generally accepted accounting principles, by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount." Therefore, we find that the carrying charges on the FAC deferrals should be calculated on a gross-of-tax rather than a net-of-tax basis in order to ensure that the Companies recover their actual fuel expenses. Accordingly, we modify the deferral provision of the Companies' ESP to lower the overall amount that may be charged to customers in any one year.

B. Incremental Carrying Cost for 2001-2008 Environmental Investment and the Carrying Cost Rate

A component of the non-FAC generation increase is the incremental, ongoing carrying costs associated with environmental investments made during 2001-2008. The Companies propose to include, as a part of their ESP, costs directly related to energy produced or purchased. While the Companies are not proposing to include the recovery of capital carrying costs on environmental capital investments in the FAC, the Companies are requesting recovery of carrying charges for the incremental amount of the environmental investments made at their generating facilities from 2001 to 2008. The Companies' annual capital carrying costs for the incremental 2001-2008 environmental investments not currently reflected in rates equals $84 million for OP and $26 million for CSP. The Companies' ESP includes capital carrying costs for 2001 through 2008 net of cumulative environmental capital expenditures for each company multiplied by the carrying cost rate.

Each company's capital expenditures in the ESP are determined by the expenditures made since the start of the market development period as offset by the estimate included in the Companies' rate stabilization plan (RSP) case, Case No. 04-169-EL-UNC, and the environmental expenditures included in the Companies' adjustments received in the RSP 4 Percent Cases[12] (Cos. Ex. 7 at 15-17, Exhibits PJN-8, PJN-12). The Companies calculated the carrying cost rate based on levelized investment and depreciation over the 25-year life of the environmental investment. CSP and OP utilized a capital structure of 50 percent common equity and 50 percent debt to calculate the carrying charges, asserting that such is consistent with the capital structure as of March 31, 2008, and consistent with the expected capital structure during the ESP period. Short-term debt and the Gavin Lease were excluded from OP's capital structure. AEP-Ohio asserts that such was the process in the RSP 4 Percent Cases. AEP-Ohio also argues that, for ratemaking purposes, the Gavin Lease is considered an operating lease as opposed to a component of rate base. Further, the Companies reason that the WACC incorporated a 10.5 percent ROE as used by the Commission in the proceeding to transfer

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12 *In re Columbus Southern Power Company and Ohio Power Company*, Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, and 07-1278-EL-UNC (RSP 4 Percent Cases).

MonPower's certified territory to CSP (MonPower Transfer Case)[13] (Cos. Ex. 7 at 16-17, 19, Exhibit PJN-8, Exhibits PJN-10 - PJN-13; Cos. Ex. 7-B at 7).

Staff testified that the Companies should be allowed to recover carrying costs associated with capitalized investments to comply with environmental requirements made between 2001-2008 that are not currently reflected in rates (Staff Ex. 6 at 2, 4-5). Staff confirmed that AEP-Ohio's estimated revenue increases for incremental carrying costs associated with additional environmental investments in the amounts of $26 million for CSP and $84 million for OP are not currently reflected in rates (Id.).

OCEA and OEG oppose the Companies' request for recovery of environmental carrying charges on investments made prior to January 1, 2009. OEG contends that the rates in the RSP Case included recovery for environmental capital improvements made through December 31, 2008, as reflected in the RSP 4 Percent Cases. Further, OCEA and OEG argue that SB 221 only permits the recovery of carrying costs associated with environmental expenditures that are prudently incurred and that occur on or after January 1, 2009, pursuant to Section 4928.143(B)(2)(b), Revised Code (OCEA Ex. 10 at 32; OEG Ex. 3 at 21). Thus, OCEA reasons that approval of such expenditures necessitates an after-the-fact review, which cannot be considered in this proceeding. OEG, however, is not opposed to the Companies' increases due to environmental capital additions made after January 1, 2009, in the ESP in accordance with Section 4928.143(B)(2)(b), Revised Code (OEG Ex. 3 at 20). OEG and Kroger argue that the Companies' assertion that existing rates do not reflect environmental carrying costs ignores the Companies' non-environmental investment and the effects of accumulated depreciation and, therefore, according to OEG and Kroger, fails to demonstrate any net under-recovery of generation costs in total by the Companies (OEG Ex. 3 at 21; Kroger Ex. 1 at 10-11). OCEA and APAC/OPAE agree that the Companies have failed to demonstrate that they lack the earnings to make the environmental investments (OCEA Ex. 10 at 32; APAC/OPAE Br. at 5-6).

Further, OCEA asserts that there are several reasons that the Companies' attempt to recover environmental carrying cost during the ESP is unlawful. OCEA contends that it is retroactive ratemaking[14] and Senate Bill 3, which was the governing law from 2001 to 2005, included rate caps pursuant to Section 4928.34(A)(6), Revised Code, and the RSP, applicable to 2006 through 2008, included limitations on the rate increases. Therefore, the Companies can not collect now for costs incurred during those periods. Further, OCEA

13 *In the Matter of the Transfer of Monongahela Power Company's Certified Territory in Ohio to the Columbus Southern Power Company*, Case No. 05-765-EL-UNC.

14 *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 25.

states that allowing for recovery of such environmental carrying costs would also violate the Stipulation and the Commission's order in the ETP case.[15]

OCEA argues that, should the Commission allow AEP-Ohio to recover carrying costs on environmental investments, the Companies' carrying charges should be based on actual investments made, not actual and forecasted environmental expenditures, and the carrying costs should be adjusted. More specifically, OCEA recommends that because the Companies failed to provide any support or explanation of the calculation of the property taxes or general and administrative components of the carrying cost calculation, the Commission should not grant recovery of these aspects of the Companies' request. Additionally, OCEA and IEU argue that the proposed carrying cost rates do not reflect actual financing for environmental investments, which could impact the calculation of the carrying cost rates (IEU Br. at 21-22, citing IEU Ex. 7 at 132-133; Tr. Vol. XI at 111-113; OCEA Br. at 71-72). The carrying cost rates, according to IEU and OCEA, should be revised to reflect actual financing, including the use of pollution control bonds that have been secured by the Companies (Id.). To support their argument, IEU and OCEA rely on Staff witness Cahaan who testified at the hearing that "if specific financing mechanisms can be identified that would be appropriate and applicable to the assets being financed, I see no reason why those shouldn't be specifically used"[16] (IEU Br. at 21-22; OCEA Br. at 72-73). However, Staff witness Cahaan also stated that "[A]t the time when we looked at the carrying cost calculations it seemed reasonable, given the cost of debt and cost of equity of the company,"[17] which is consistent with his prefiled testimony that said: "I have examined the carrying costs rates provided to Mr. Soliman and found them to be reasonable" (Staff Ex. 10 at 7).

OCEA also recommends that the carrying costs for deferrals of environmental costs be revised to reflect actual short-term cost of debt, as opposed to WACC as proposed by the Companies, and that the calculated carrying charges should not be based on the original cost of the environmental investment but at cost minus depreciation. Thus, OCEA argues that the Companies are seeking a return on and a return of their investment as would be the case under traditional ratemaking, but overstating the depreciation component. OCEA also advocates that the carrying cost rates, 13.98 percent for OP and 14.94 percent for CSP, are too high in light of the economic environment at this time (OCEA Br. at 73-74). Finally, OCEA urges the Commission to offset the Companies' request for carrying charges by the Section 199 provision of the Internal Revenue Code (Section 199). Section 199 allows the Companies to take a tax deduction for "qualified production activities income" equal to 6 percent in 2009 and 9 percent in 2010 and

15 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order (September 28, 2000).

16 Tr. Vol. XII at 237.

17 Id.

thereafter. IEU, OEG, and OCEA request that the Commission adjust the carrying costs for the Section 199 deduction as the Commission has found appropriate in the Companies' 07-63 Case[18] and in the FirstEnergy ESP Case. OCEA argues that while Section 4928.143(B)(2)(a), Revised Code, allows the Companies to automatically recover the cost of federally mandated carbon or energy taxes, which will be passed on to customers, customers should be afforded the benefits of the Section 199 tax deduction (OCEA Br. at 74-75; IEU Br. at 21; IEU Ex. 10 at 6; OEG Ex. 3 at 23).

The Companies emphasize that their request for carrying costs is for the incremental carrying charges on the 2001-2008 investments that the Companies will incur post-January 1, 2009. AEP-Ohio explained that the carrying costs themselves are the costs that the Companies will incur after January 1, 2009, and, therefore, the Companies reason that the "without limitation" language in Section 4928.143(B)(2), Revised Code, supports their request (Tr. Vol. XIV at 93, 114). AEP-Ohio stresses that Section 4928.143(B)(2), Revised Code, is the basis for the carrying cost request as opposed to paragraph (B)(2)(a) of Section 4928.143, Revised Code, as OCEA and OEG claim and, therefore, the arguments as to retroactive ratemaking are misplaced (Cos. Reply Br. at 29-30). Further, the Companies insist that Section 4928.143(B)(2)(b), Revised Code, supports their request, as the carrying charges are necessary to recover the ongoing cost of investments in environmental facilities and equipment that are essential to keep the generation units operating. The Companies assert that the operating costs of their generation units remain well below the cost of securing the power on the market (Cos. Ex. 7-B at 7).

As to the claims that the carrying costs are overstated, the Companies claim that the levelized depreciation approach used by the Companies is better for customers than traditional ratemaking given the relative newness of the environmental investments (Tr. Vol. V at 55-56; Tr. Vol. VII at 22-23). The Companies also argue that the Companies' investments in environmental compliance equipment during 2001-2008 were not factored into the rates unbundled in 2000 and capped under the ETP case as alleged. The rate increase approved, as part of the RSP, and the RSP 4 Percent Cases did not, according to the Companies, provide recovery of the carrying costs to be incurred during the ESP period (Cos. Ex. 7, Exhibits PJN-8 - PJN-9 and PJN-12). The Companies reply that the intervenors' request to adjust carrying charges for the Section 199 deduction is flawed. AEP-Ohio states that the Section 199 deduction is not a reduction to the statutory tax rate used in the WACC, a fact which AEP-Ohio asserts has been recognized by FERC and the Financial Accounting Standards Board. The Companies further note that IEU witness Bowser indeed confirmed that Section 199 does not reduce the statutory tax rate (Tr. Vol. XI at 271-273). The Companies also argue, and IEU witness Bowser agreed, that the Section 199 tax deduction is applicable to AEP Corporation as a whole and not to each operating subsidiary. The Companies note, therefore, that any deduction available to

18 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC, Opinion and Order (October 3, 2007) (07-63 Case).

AEP-Ohio is reduced if one of the other AEP Corporation operating affiliates is not eligible for the Section 199 deduction (Cos. Br. 36; Tr. Vol. XI at 266-267). Accordingly, the Companies state that AEP-Ohio has not been able to take the full deduction (Tr. Vol. XIV at 115-117). Further, the Companies argue that the intervenors have misinterpreted the Commission's decision in the FirstEnergy ESP Case to imply that the Commission made an adjustment to account for the Section 199 deduction. For these reasons, the Companies request that the Commission reconsider adjusting carrying charges for the potential Section 199 deduction.

Upon review of the record, we agree with Staff that AEP-Ohio should be allowed to recover the incremental capital carrying costs that will be incurred after January 1, 2009, on past environmental investments (2001-2008) that are not presently reflected in the Companies' existing rates, as contemplated in AEP-Ohio's RSP Case. Further, the Commission finds that this decision regarding the recovery of continuing carrying costs on environmental investments, based on the WACC, is consistent with our decision in the 07-63 Case and the RSP 4 Percent Cases. Additionally, we agree with Staff that the levelized carrying cost rates proposed by AEP-Ohio are reasonable and, therefore, should be approved. We further find, as we concluded in the FirstEnergy ESP Case, that adequate modifications to the Companies' ESP application have been made in this order to account for the possibility of any applicable Section 199 tax deductions.

C. Annual Non-FAC Increases

The Companies proposed to increase the non-FAC portion of their generation rates by 3 percent for CSP and 7 percent for OP for each year of the ESP to provide a recovery mechanism for increasing costs related to matters such as carrying costs associated with new environmental investments made during the ESP period, increases in the general costs of providing generation service, and unanticipated, non-mandated generation-related cost increases. Specifically, as part of this automatic increase, the Companies intend to recover the carrying costs associated with anticipated environmental investments that will be necessary during the ESP period (2009-2011) (Cos. Br. at 27; Cos. Reply Br. at 46-49). The Companies argued that the annual increases are not cost-based and are avoidable for those customers who shop. The Companies also proposed two exceptions to the fixed, annual increases, one for generation plant closures and the other for OP's lease associated with the scrubber at the Gavin Plant, which would require additional Commission approval during the ESP. After establishing the FAC component of the current generation SSO to get a FAC baseline, the Companies determined that the remainder of the current generation SSO would be the non-FAC base component.

The intervenors oppose automatic annual increases in the non-FAC component of the generation rate, and argue that any generation increases should be cost-based (IEU Br.

at 24; OPAE/APAC Br. at 6; OEG Br. at 12; OCEA Br. 29-31). OEG contends that since the Companies have not provided any support for the automatic annual increases, which could result in total rate increases over the three-year period of $87 million for CSP and $262 million for OP, the annual increases should be disallowed (OEG Ex. 3 at 18-19); Similarly, Kroger argues that AEP-Ohio did not appropriately account for costs associated with the non-FAC component of the proposed generation rates (Kroger Br. at 14).

Staff opposes CSP's and OP's recommended annual, non-FAC increases of 3 and 7 percent, respectively (Staff Ex. 10 at 4). Instead, Staff stated that it believes a more appropriate escalation of the non-FAC generation component would be half of the proposed amounts; therefore, recommending annual increases of 1.5 percent for CSP and 3.5 percent for OP (Id.). Staff witness Cahaan rationalized the proposed reduction by stating that "an average of 5% for the two companies may have been a reasonable expectation of cost increases at the time that the ESP was contemplated, but not now. With the recent financial crises, we are entering a recessionary, and possibly a deflationary, period and any expectations of price increases need to be revised downward" (Id.). Furthermore, while recognizing that the ultimate balancing of interests lies with the Commission, Staff witness Cahaan testified that Staff's recommended reduction in the proposed increases was a reasonable balance between the Companies' obligation and costs to serve customers and the current economic conditions (Tr. Vol. XII at 211). The Companies rejected Staff's rationalization for the reduction in their proposed non-FAC increases (Cos. Reply Br. at 49). IEU also rejected Staff's rationalization for the reduction, arguing that no automatic increases are warranted (IEU Br. at 24).

Stating that it is in the public interest for the Companies to continue investing in environmental equipment and to be in compliance with current and future environmental requirements, Staff witness Soliman also recommended that AEP-Ohio be permitted to recover carrying costs for anticipated environmental investments made during the ESP period (Staff Ex. 6 at 5). Staff recommended that this recovery occur through a future proceeding upon the request of the Companies for recovery of additional carrying costs associated with actual environmental investment after the investments have been made (Staff Br. at 6-7). Specifically, Staff suggested that the Commission require the Companies to file an application in 2010 for recovery of 2009 actual environmental investment cost and annually thereafter for each succeeding year to reflect actual expenditures (Tr. Vol. XII at 132; Staff Ex. 10 at 7). OCEA seems to agree with Staff's recommendation (OCEA Br. at 71).

The Companies further respond that Section 4928.143, Revised Code, does not require that the SSO price be cost-based and, instead, Section 4928.143(B)(2)(e), Revised Code, authorizes electric utilities to include in their ESP provisions for automatic increases in any component of the SSO price (Cos. Reply Br. at 48-49).

The Commission finds Staff's approach with regard to the recovery of the carrying costs for anticipated environmental investments made during the ESP to be reasonable, and, therefore, we direct the Companies to request, through an annual filing, recovery of additional carrying costs after the investments have been made.

We also agree with Staff that the economic conditions must be balanced against the Companies' provision of electric service under an ESP. In balancing these two interests, as well as considering all components of the ESP, we believe that it is appropriate to modify this provision of the Companies' ESP and remove the inclusion of any automatic non-FAC increases. As recognized by several intervenors, the record is void of sufficient support to rationalize automatic, annual generation increases that are not cost-based, but that are significant, equaling approximately $87 million for CSP and $262 million for OP (see, i.e., OCEA Br. at 29-30, citing Tr. Vol. XIV at 208-209). We also believe the modification is warranted in light of the fact that we have removed one of the Companies' significant costs factored into establishing the proposed automatic increases. Accordingly, we find that the ESP should be modified to eliminate any automatic increases in the non-FAC portion of the Companies' generation rates.

IV. DISTRIBUTION

A. Annual Distribution Increases

To support initiatives to improve the Companies' distribution system and service to customers, the Companies proposed the following two plans, which will result in annual distribution rate increases of 7 percent for CSP and 6.5 percent for OP:

1. Enhanced Service Reliability Plan (ESRP)

The Companies proposed to implement a new, three-year ESRP pursuant to 4928.143(B)(2)(h), Revised Code,[19] which includes an enhanced vegetation initiative, an enhanced underground cable initiative, a distribution automation initiative, and an enhanced overhead inspection and mitigation initiative (Cos. Ex. 11 at 3). While noting that they are providing adequate and reliable electric service, the Companies justify the need for the ESRP by stating that customers' service reliability expectations are increasing, and in order to maintain and enhance reliability, the ESRP is required (Id. at 3, 8, 10-14). AEP-Ohio further states that the three-year ESRP, consisting of the four reliability

[19] On page 72 of its brief, the Companies rely on Section 4928.154(B)(2)(h), Revised Code, to support their request to receive cost recovery for the incremental costs of the incremental ESRP activities. We are assuming that the reference was a typographical error and that the Companies intended to cite to Section 4928.143(B)(2)(h), Revised Code (see Cos. Reply Br. at 50-51).

programs, is designed to modernize and improve the Companies' distribution infrastructure (Id.).

(a) Enhanced vegetation initiative

The Companies state that the purpose of this new initiative is to improve the customer's overall service experience by reducing and/or eliminating momentary interruptions and/or sustained outages caused by vegetation. The Companies proposed to accomplish this goal by balancing its performance-based approach to reflect a greater consideration of cycle-based factors (Id. at 26-28). The Companies state that under their proposed vegetation initiative, they will employ additional resources (approximately double the current number of tree crews in Ohio), employ greater emphasis on cycle-based planning and scheduling, increase the level of vegetation management work performed so that all distribution rights-of-way can be inspected and maintained, and utilize improved technologies to collect tree inventory data to optimize planning and scheduling by predicting problem areas before outages occur (Id. at 28-29).

(b) Enhanced underground cable initiative

The Companies state that the purpose of this initiative is to reduce momentary interruptions and sustained outages due to failures of aging underground cable. The Companies' plan to target underground cables manufactured prior to 1992 to replace and/or restore the integrity of the cable insulation (Id. at 31).

(c) Distribution automation (DA) initiative

The Companies explain that DA is a critical component of their proposed gridSMART distribution initiative that is described below. DA is an advanced technology that improves service reliability by minimizing, quickly identifying and isolating faulted distribution line sections, and remotely restoring service interruptions (Id. at 34-35).

(d) Enhanced overhead inspection and mitigation initiative

The Companies state that the purpose of this initiative is to improve the customer's overall service experience by reducing equipment-related momentary interruptions and sustained outages. The Companies intend to accomplish this goal through a comprehensive overhead inspection process that will proactively identify equipment that is prone to fail (Id. at 18). The Companies also state that the new program will go beyond the current inspection program required by the electric service and safety (ESSS) rules, which is a basic visual assessment of the general condition of the distribution facilities, by conducting a comprehensive inspection of the equipment on each structure via walking the circuit lines and physically climbing or using a bucket truck to inspect (Id. at 19). In conjunction with this program, AEP-Ohio proposes to focus on five targeted overhead asset initiatives, including cutout replacement, arrester replacement, recloser replacement, 34.5 kV protection, and fault indicator (Id. at 20-22).

Generally, numerous intervenors and Staff opposed the distribution initiatives and cost recovery of such initiatives through this proceeding. Many parties advocated for deferral of these distribution initiatives, and the ESRP as a whole, for consideration in a future distribution base rate case (Staff Br. at 7; Staff Ex. 1 at 6-7; OPAE/APAC at 19; IEU Br. at 25-26; Kroger Br. at 18; OHA Br. at 17; OMA Br. at 6). Further, OCEA argued that the Companies have not demonstrated that the ESRP is incremental to what the Companies are required to do and spend under the current ESSS rules and current distribution rates (OCEA Br. at 44; OCC Ex. 13 at 8-11). While supporting several aspects of the Companies' ESRP programs, Staff witness Roberts also questioned the incremental nature of the proposed ESRP programs (Staff Ex. 2 at 4-6, 13, 17, 18; Tr. Vol. VIII at 70-77).

The Commission agrees, in part, with Staff and the intervenors. The Commission recognizes that Section 4928.143(B)(2)(h), Revised Code, authorizes the Companies to include in its ESP provisions regarding single-issue ratemaking for distribution infrastructure and modernization incentives. However, while SB 221 may have allowed Companies to include such provisions in its ESP, the intent could not have been to provide a 'blank check' to electric utilities. In deciding whether to approve an ESP that contains provisions for distribution infrastructure and modernization incentives, Section 4928.143(B)(2)(h), Revised Code, specifically requires the Commission to examine the reliability of the electric utility's distribution system and ensure that customers' and the electric utilities' expectations are aligned, and to ensure that the electric utility is emphasizing and dedicating sufficient resources to the reliability of its distribution system. Given AEP-Ohio's proposed ESRP, the only way to examine the full distribution system, the reliability of such system, and customers' expectations, as well as whether the programs proposed by AEP-Ohio are "enhanced" initiatives (truly incremental), is through a distribution rate case where all components of distribution rates are subject to review. Therefore, at this time, the Commission denies the Companies' request to implement, as well as recover costs associated therewith, the enhanced underground cable initiative, the distribution automation initiative, and the enhanced overhead inspection and mitigation initiative. With regard to these issues, we concur with OHA: "The record in this case reflects the fact that the distribution prong of AEP's electric service deserves further Commission scrutiny – but not in the context of this accelerated ESP proceeding" (OHA Br. at 17).

Nonetheless, the Commission finds that AEP-Ohio has demonstrated in the record of this proceeding that it faces increased costs for vegetation management and that a specific need exists for the implementation of the enhanced vegetation initiative, as proposed as part of the three-year ESRP, to support an incremental level of reliability activities in order to maintain and improve service levels. The Companies' current approach to its vegetation management program is mostly reactive (Staff Ex. 2 at 10). While we recognize the difficulties that recent events have caused, we believe that it is important to have a balanced approach that not only reacts to certain incidents and problems, but that also proactively limits or reduces the impact of weather events or incidents. In addition to reacting to problems that occur, it is imperative that AEP-Ohio implements a cycle-based approach to maintain the overall system. To this end, the Companies have demonstrated in the record that increased spending earmarked for specific vegetation initiatives can reduce tree-caused outages, resulting in better reliability (Cos. Ex. 11 at 27-31). OCC witness Cleaver also recognized a problem with the current vegetation management program, and supported the adoption of a new, hybrid approach that incorporates a cycle-based tree-trimming program with a performance-based program (OCC Ex. 13 at 30, 35). Staff witness Roberts further supported the move to a new, four-year cycle-based approach and recommended that the enhanced vegetation initiative include the following: end-to-end circuit rights-of-way inspections and maintenance; mid-point circuit inspections to review vegetation clearance from conductors, equipment, and facilities; greater clearance of all overhang above three-phase primary lines and single-phase lines; removal of danger trees located outside of rights-of-ways where property owner's permission can be secured, and using technology to collect tree inventory data to optimize planning and scheduling (Staff Ex. 2 at 13).

The Commission is satisfied that the Companies have demonstrated in the record that the costs associated with the proposed vegetation initiative, included as part of the proposed three-year ESRP, are incremental to the current Distribution Vegetation Management Program and the costs embedded in distribution rates (Cos. Ex. 11 at 26-31). Specifically, the Companies proposed to employ additional resources in Ohio, place a greater emphasis on cycle-based planning and scheduling, and increase the level of vegetation management work performed (Id. at 28-29). Although OCC's witness questions the incremental nature of the costs proposed to be included in the enhanced vegetation initiative, OCC offered no evidence that the proposed initiative is already included in the current vegetation management program, and thus, is not incremental (OCC Ex. 13 at 30-36). Rather, OCC seems to quibble with the definition of "enhanced." OCC witness Cleaver stated: "I recommend that the Commission rule that the Company's proposed Vegetation Management Programs, while an improvement over its current performance based program, is *not an enhancement* but *rather a reflection of additional* tree trimming needed as a result of their prior program" (Id. at 35 (emphasis added)). Furthermore, we believe that the record clearly reflects customers' expectations as to tree-caused outages, service interruptions, and reliability of customers' service.[20] We also believe that, presently, those customer expectations are not aligned with the Companies' expectations. However, as required by Section 4928.143(B)(2)(h), Revised Code, we believe that the Companies' proposal for a new vegetation initiative more closely aligns

[20] A common theme from the customers throughout the local public hearings was that outages due to vegetation have been problematic.

the customers' expectations with the Companies' expectations as it relates to tree-caused outages, importance of reliability, and the increasing frustration surrounding momentary outages with the emergence of new technology.

Accordingly, in balancing the customers' expectations and needs with the issues raised by several intervenors, the Commission finds that the enhanced vegetation initiative proposed by the Companies, with Staff's additional recommendations, is a reasonable program that will advance the state policy. To this end, the Commission approves the establishment of an ESRP rider as the appropriate mechanism pursuant to Section 4928.143(B)(2)(h), Revised Code, to recover such costs. The ESRP rider initially will include only the incremental costs associated with the Companies' proposed enhanced vegetation initiative (Cos. Ex. 11 at 31, Chart 7) as set forth herein. Consistent with prior decisions,[21] the Commission also believes that, pursuant to the sound policy goals of Section 4928.02, Revised Code, a distribution rider established pursuant to Section 4928.143(B)(2)(h), Revised Code, should be based upon the electric utility's prudently incurred costs. Therefore, the ESRP rider will be subject to Commission review and reconciliation on an annual basis.

As for the recovery of any costs associated with the Companies' remaining initiatives (i.e., enhanced underground cable initiative, distribution automation initiative, and enhanced overhead inspection and mitigation initiative), the ESRP rider will not include costs for any of these programs until such time as the Commission has reviewed the programs, and associated costs, in conjunction with the current distribution system in the context of a distribution rate case as explained above. If the Commission, in a subsequent proceeding, determines that the programs regarding the remaining initiatives should be implemented, and thus, the associated costs should be recovered, those costs may, at that time, be included in the ESRP rider for future recovery, subject to reconciliation as discussed above.

2. GridSMART

The Companies propose, as part of their ESP, to initiate Phase 1 of gridSMART, a three-year pilot, in northeast central Ohio. GridSMART will include three main components, AMI, DA, and Home Area Network (HAN). The AMI system features include smart meters, two-way communications networks, and the information technology systems to support system interaction. AEP-Ohio contends that AMI will use internal communications systems to convey real-time energy usage and load information to both the customer and the company. According to the Companies, AMI will provide the capability to monitor equipment and convey information about certain malfunctions and operating conditions. DA will provide real-time control and monitoring of select

[21] *In re Ohio Edison Co., The Cleveland Electric Illuminating Co., Toledo Edison Co.*, Case No. 08-935-EL-SSO, Opinion and Order at 41 (December 19, 2008).

electrical components with the distribution system, including capacitor banks, voltage regulators, reclosers, and automated line switches. HAN will be installed in the customer's home or business and will provide the customer with information to allow the customer to conserve energy. HAN includes providing residential and business customers who have central air conditioning with a programmable communicating thermostat (PCT) and a load control switch (LCS), which is installed ahead of a major electrical appliance and will turn the appliance on and off or cycle the appliance on and off. AEP-Ohio reasons that central air conditioners are typically the largest piece of electrical equipment in the home and will yield the most significant demand response benefit (Tr. Vol. III at 304). LCS will provide customers who have a direct load control or interruptible tariff the ability to receive commands from the meter and the option to respond and signal the appropriate action to the meter for confirmation. The Companies propose a phased-in implementation of Phase 1 gridSMART to approximately 110,000 meters and 70 distribution circuits in an approximately 100 square mile area within CSP's service territory (Cos. Ex. 4 at 9, 12-13; Tr. Vol. III at 303-304). The Companies further propose to extend the installation of DA to 20 circuits in areas beyond the gridSMART Phase 1 program. The Companies propose a phased-in approach to fully implement gridSMART throughout their service area over the next 7 to 10 years, if granted appropriate regulatory treatment. The Companies estimate the net cost of gridSMART Phase 1 to be approximately $109 million (including the projected net savings of $2.7 million) over the three-year period (Cos. Ex. 4 at 15-16, KLS-1). The rate design for gridSMART includes the projected cost of the program over the life of the equipment. The Companies have requested recovery during the ESP of only the costs to be incurred during the three-year term of the ESP (Cos. Ex. 1 at DMR-4). Thus, AEP-Ohio asserts that it is inappropriate to consider the long-term operational cost savings when the long-term costs of gridSMART have not been included in the ESP for recovery.

Although Staff generally supports the Companies' implementation of gridSMART, particularly the AMI and DA components, Staff raises a few concerns with this aspect of the Companies' ESP application. Staff is concerned that the overhead costs for meter purchasing is overstated and recommends that the overhead costs be reviewed before approval to ensure that the costs are not duplicative of the overhead meter purchasing costs currently recovered in the Companies' rates (Staff Ex. 3 at 3). Staff argues that there is no reason for the Companies to restrict the PCTs to customers with air conditioning only, and recommends that the device be offered to any customer that desires to own this type of thermostat to control air conditioning or other electrical appliances (Staff Br. at 12). Staff and OCC also argue that customers who have invested in advanced technological equipment for gridSMART will not benefit from dynamic pricing and time differentiated rates if the Companies do not simultaneously file tariffs for such services (Staff Ex. 3 at 5; OCEA Br. at 82). Staff recommends that the Companies offer some form of a critical peak pricing rebate for residential customers, and some form of hedged price for commercial customers for a fixed amount of the customers' demand (Staff Ex. 3 at 5).

Further, Staff argues that the Companies' gridSMART proposal does not contain sufficient information regarding any risk-sharing between the ratepayers and shareholders, operational savings, or a cost/benefit analysis, and states that AEP-Ohio did not quantify any customer or societal benefits of the proposed gridSMART initiative (Staff Br. at 12-13). Staff notes that according to the Companies, DA will not be implemented until 2011, the third year of the ESP, and that the ESP proposes to install DA beyond the Phase I gridSMART area (Tr. Vol. III at 246). Staff opposes DA outside of the Phase I area because the Companies' cannot estimate the expected reliability improvements associated with the installation of DA. Staff also argues that DA costs should be recovered through a DA rider. The cost of gridSMART, per AEP-Ohio's proposal, is to be recovered by adjusting distribution rates. Staff is opposed to increasing distribution rates in this proceeding (Staff Ex. 5 at 6). Instead, Staff recommends that a rider be established and set at zero. The Staff argues that a rider has several benefits over the proposed increase to distribution rates, including separate accounting for gridSMART costs, an opportunity to approve and update the plan annually, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. Finally, Staff also advocates that the Companies share the financial risk of gridSMART between ratepayers and shareholders, as there is a benefit to the Companies. Additionally, Staff questions whether gridSMART will meet minimum reliability standards. Lastly, Staff asserts that AEP-Ohio should conduct a study that quantifies both customer and societal benefits of its gridSMART plan (Staff Br. at 14).

OCC, Sierra, and OPAE/APAC argue that the Companies' ESP fails to demonstrate that its gridSMART program is cost-effective as required by Sections 4928.02(D) and 4928.64(E), Revised Code, and state that AEP-Ohio's assumption that the societal and customer benefits are self-evident is misplaced (OCEA Br. at 77-80; OPAE/APAC Br. at 17-18). OCC, Sierra, and OPAE/APAC note that there are a number of factors about the program that the Companies have not determined or evaluated, which are essential to the Commission's consideration of the plan. OCC, Sierra, and OPAE/APAC state that the Companies have failed to include any full gridSMART implementation plan or costs, the anticipated life cycle of various components of gridSMART, a methodology for evaluating performance of gridSMART Phase I, an estimate of a customer's bill savings, or the positive impact to the environment or job creation (OCEA Br. at 79-80; OPAE\APAC Br. at 17-18). Further, OCC's witness states that the ESP fails to acknowledge that full system implementation is required before many of the benefits of gridSMART can actually be realized (OCC Ex. 12 at 6). OCC recommends that Phase I have its own set of performance measures, a more detailed project plan, including budget, resource allocation, and life cycle operating cost projections for the full 7-10 year implementation period of gridSMART and beyond, and performance measures for the Commission's approval (OCC Ex. 12 at 18).

AEP-Ohio regards the Staff's proposal to offer PCTs to any customer as overly generous, particularly given that Staff is recommending that the rider be set initially at zero (Cos. Br. at 68-69). AEP-Ohio also submits that it has committed to offering new service tariffs associated with Phase I of gridSMART once the technology is installed and the billing functionalities available (Cos. Ex. 1 at 6; Tr. Vol. III at 304-305; Cos. Br. at 68-69). Further, regarding Staff's policy of risk-sharing, the Companies contend that the assertion that the gridSMART investment benefits CSP just as much as it does customers is not true and, given that the operational savings do not equal or exceed the cost of the program, is without any basis presented in the record. Thus, AEP-Ohio argues that discounting the net cost to be recovered by CSP is unfair and inappropriate (Cos. Reply Br. at 63-64). The Companies are unclear how the Staff expects to determine whether gridSMART meets the minimum reliability standards and contend that this issue was first raised in the Staff's brief. Nonetheless, the Companies argue that imposing reliability standards as to gridSMART Phase 1 is inappropriate, primarily because strict accountability for achieving the expected reliability impacts does not take into account the many dynamic factors that impact service reliability index performance. Moreover, accurate measurement and verification of the discrete impact of gridSMART deployment on a particular reliability index would be difficult. The Companies also explain that the expected reliability impacts provided to the Staff were based on good faith estimates of the full implementation of gridSMART Phase 1 as proposed by the Companies. Thus, the Companies would prefer the establishment of deployment project milestones as opposed to specific reliability impact standards.

Although the Companies maintain that their percentage of distribution increase is reasonable and an appropriate part of the ESP package, in recognition of Staff's preference for a distribution rider and to address various parties' concerns regarding the accuracy of AEP-Ohio's cost estimates for gridSMART Phase I, the Companies would agree to a gridSMART Phase I rider set at the 2009 revenue requirement subject to annual true-up and reconciliation based on CSP's prudently incurred net costs (Cos. Reply Br. at 70; Cos. Ex. 1, Exhibit DMR-4).

The Commission believes it is important that steps be taken by the electric utilities to explore and implement technologies, such as AMI, that will potentially provide long-term benefits to customers and the electric utility. GridSMART Phase I will provide CSP with beneficial information as to implementation, equipment preferences, customer expectations, and customer education requirements. A properly designed AMI system and DA can decrease the scope and duration of electric outages. More reliable service is clearly beneficial to CSP's customers. The Commission strongly supports the implementation of AMI and DA, with HAN, as we believe these advanced technologies are the foundation for AEP-Ohio providing its customers the ability to better manage their energy usage and reduce their energy costs. Thus, we encourage CSP to be more expedient in its efforts to implement these components of gridSMART. While we agree that additional information is necessary to implement a successful Phase I program, we do not believe that all information is required before the Commission can conclude that the program is beneficial to ratepayers and should be implemented. Therefore, we will approve the development of a gridSMART rider, as we agree with the Staff that a rider has several benefits over the proposed annual increase to distribution rates, including separate accounting for gridSMART, an opportunity to approve and update the plan each year, assurance that expenditures are made before cost recovery occurs, and an opportunity to audit expenditures prior to recovery. The Commission notes that recent federal legislation makes matching funds available to smart grid projects. Accordingly, the Companies' gridSMART proposal contained in its proposed ESP to recover $109 million over the term of ESP, should be revised to $54.5 million, which is half of the Companies' requested amount. Additionally, we direct CSP to make the necessary filing for federal matching funds under the American Recovery and Reinvestment Act of 2009 for the balance of the projected costs of gridSMART Phase I. The gridSMART rider shall be initially established at $33.6 million for the 2009 projected expenses subject to annual true-up and reconciliation based on the company's prudently incurred costs.

With the creation of the ESRP rider and the gridSMART rider, the Commission finds that annual distribution rate increases in the amounts of 7 percent for CSP and 6.5 percent for OP to recover the costs for the ESRP and gridSMART programs are unnecessary and should be rejected. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to include the ESRP rider and the gridSMART rider, as approved herein, and to eliminate the annual distribution rate increases.

B. Riders

1. Provider of Last Resort (POLR) Rider

The Companies proposed to include in their ESP a distribution non-bypassable POLR rider (Cos. App. at 6-8). The POLR charge was proposed to collect a POLR revenue requirement of $108.2 million for CSP and $60.9 million for OP (Cos. Ex. 2-A at 34; Cos. Ex. 1, Exhibit DMR-5). The Companies stated that they have a statutory obligation to be the POLR,[22] and thus, the proposed POLR charge is based on a quantitative analysis of the cost to the Companies to provide to customers the optionality associated with POLR service (Cos. Ex. 2-A at 25-26). AEP-Ohio argued that this charge covers the cost of allowing a customer to remain with the Companies, or to switch to a Competitive Retail Electric Service (CRES) provider and then return to the Companies' SSO after shopping (Id.). To further support the proposed increase, the Companies added that their current POLR charge is significantly below other Ohio electric utilities' POLR charges (Cos. Ex. 2 at 8). The Companies utilized the Black-Scholes Model to calculate their cost of fulfilling

[22] See Section 4928.141(A) and 4928.14, Revised Code.

the POLR obligation, comparing the customers' rights to "a series of options on power" (Cos. Br. at 43; Cos. Ex. 2-A at 31). AEP-Ohio listed the five quantitative inputs used in the Black-Scholes Model: 1) the market price of the underlying asset; 2) the strike price; 3) the time frame that the option covers; 4) the risk free interest rate; and 5) the volatility of the underlying asset (Id.). The Companies assert that the resulting POLR charge is conservatively low (Cos. Br. at 44).

The numerous intervenors and Staff opposed the level of POLR charge proposed by the Companies, as well as the use of the Black-Scholes Model to calculate the POLR charge (OPAE/APAC Br. at 14-17; OCC Ex. 11 at 8-14). Specifically, OCC and others questioned the use of the LIBOR rate as the input for the risk-free interest rate (Tr. Vol. X at 165-182, 188-189; Tr. Vol. XI at 166-182). Staff questioned the risk that the POLR charge was intended to compensate the Companies for, explaining that there are only two risks involved: one risk is the risk of customers returning to the SSO and the other risk is that the customers leave and take service from a CRES provider (migration risk) (Staff Ex. 10 at 6). Staff witness Cahaan testified that the risk associated with customers returning to the SSO could be avoided by requiring the customer to return at a market price, instead of the SSO rate, which would either be paid directly by the returning customer or any incremental cost of the purchased power could be flown through the FAC (Id.). Staff witness Cahaan admitted that if customers are permitted to return at the SSO rate, without paying the market price or without compensating the Companies for any incremental costs of the additional purchased power that they would be required to purchase, then the Companies would be at risk (Tr. Vol. XIII at 36-37). Thus, Staff witness Cahaan concluded that, if the risk of returning is addressed, then the migration risk is the only risk that should be compensated through a POLR charge (Id. at 7).

The Companies responded that their risk is not alleviated by customers agreeing to return at market price, arguing that future circumstances or policy considerations may require them to relieve customers of their promises to pay market price when circumstances change (Cos. Ex. 2-A at 27-30). AEP-Ohio's witness expressed skepticism as to a future Commission upholding such promises (Id). AEP-Ohio also opposed recovering any costs for market purchases incurred for returning customers through the FAC as an improper subsidization of those customers who chose to shop, and then return to the electric utility, by non-shopping customers (Cos. Ex. 2-E at 14-16). Furthermore, the Companies claim that their risk of being the POLR exists, regardless of historic or current shopping levels (Id.). Nonetheless, AEP witness Baker testified that, even adopting Staff witness Cahaan's theory that the Companies are only at risk for migration (the right of customers to leave the SSO), migration risk equals approximately 90 percent of the Companies' POLR costs pursuant to the Black-Scholes model (Tr. Vol. XIV at 204-205; Cos. Ex. 2-E at 15-16).

As the POLR, the Commission believes that the Companies do have some risks associated with customers switching to CRES providers and returning to the electric utility's SSO rate at the conclusion of CRES contracts or during times of rising prices. However, we agree with the intervenors and Staff that the POLR charge as proposed by the Companies is too high, but we do not agree that there is no risk or a very minimal risk as suggested by some. As noted by several intervenors and Staff, the risk of returning customers may be mitigated, not eliminated, by requiring customers that switch to an alternative supplier (either through a governmental aggregation or individual CRES providers) to agree to return to market price, and pay market price, if they return to the electric utility after taking service from a CRES provider, for the remaining period of the ESP term or until the customer switches to another alternative supplier. In exchange for this commitment, those customers shall avoid paying the POLR charge. We believe that this outcome is consistent with the requirement in Section 4928.20(J), Revised Code, which allows governmental aggregations to elect not to pay standby service charges, in exchange for agreeing to pay market price for power if they return to the electric utility. Therefore, based on the record before us, we conclude that the Companies' proposed ESP should be modified such that the POLR rider will be based on the cost to the Companies to be the POLR and carry the risks associated therewith, including the migration risk. The Commission accepts the Companies' witness' quantification of that risk to equal 90 percent of the estimated POLR costs,[23] and thus, finds that the POLR rider shall be established to collect a POLR revenue requirement of $97.4 million for CSP and $54.8 million for OP. Additionally, the POLR rider shall be avoidable for those customers who shop and agree to return at a market price and pay the market price of power incurred by the Companies to serve the returning customers. Accordingly, the Commission finds that the POLR rider, which is avoidable, should be approved as modified herein.

2. Regulatory Asset Rider

The Companies proposed to begin the recovery of a variety of regulatory assets that were authorized in various Commission proceedings regarding the Companies' electric transition plan (ETP), rate stabilization plan (RSP), line extension program, green pricing power program, and the transfer of the MonPower's service territory to CSP. In their application, the Companies proposed to begin the amortization of these regulatory assets in 2011 and complete the amortization over an eight-year period. The projected balances at the end of 2010 to amortize are $120.5 million for CSP and $80.3 million for OP. AEP-Ohio asserts that these projected balances, or the value on June 30, 2008, were not challenged by any party. To recover these regulatory assets, the Companies created a RAC rider to be collected from customers in 2011 through 2018. The rider revenues will be reconciled on an annual basis for any over- or under-recoveries.

23 See Cos. Ex. 1, Exhibit DMR-5.

Staff proposed that the eight-year amortization period proposal be deferred until the Companies' next distribution rate case where all components of distribution rates are subject to review (Staff Ex. 1 at 4). AEP-Ohio responded that SB 221 authorizes single-issue ratemaking related to distribution service, which is what it is proposing. AEP-Ohio also notes that the only opposition to the Companies' proposal is with regard to the collection of the historic regulatory assets, which was by Staff (Cos. Reply Br. at 94). The Companies submit that Staff's preference to deal with this issue in a distribution rate case is irrelevant and inconsistent with the statute.

The Commission finds that the Companies have not demonstrated that the creation of the RAC rider in its proposed ESP, as a single-issue ratemaking item for distribution infrastructure and modernization incentives, fulfills the requirements of SB 221 or advances the state policy. Therefore, the Commission finds that the RAC rider should not be approved in this proceeding. We note, however, that we agree with Staff that the consideration of the requested amortization of regulatory assets is more appropriate within the context of a distribution rate case where all distribution related costs and issues can be examined collectively. Accordingly, the Commission finds that AEP-Ohio's proposed ESP should be modified to eliminate the RAC rider.

3. Energy Efficiency, Peak Demand Reduction, Demand Response, and Interruptible Capabilities

(a) Energy Efficiency and Peak Demand Reduction

Section 4928.66, Revised Code, requires the electric utilities to implement energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the electric utility's peak demand. Specifically, an electric utility must achieve energy savings in 2009, 2010, and 2011 of .3 percent, .5 percent, and .7 percent, respectively, of the normalized annual kWh sales of the electric utility during the preceding three calendar years. This savings continues to rise until the cumulative savings reach 22 percent by 2025. Peak demand must be reduced by one percent in 2009 and by .75 percent annually until 2018.

CSP and OP include, as part of their ESP, an unavoidable Energy Efficiency and Peak Demand Reduction Cost Recovery Rider (EE/PDR rider). The estimated annual DSM program cost (including both EE and PDR) is to be trued-up annually to actual cost and compared to the amortization of the actual deferral on an annual basis via the EE/PDR rider (Cos. Ex. 6 at 47-48).

(b) Baselines and Benchmarks

In the ESP, the Companies have established the baselines for meeting the benchmarks for statutory compliance by weather normalizing retail sales, excluding economic development load, accounting for the load of former MonPower service territory and the Ormet/Hannibal Real Estate load, accounting for future load growth due to the Companies' economic development efforts, and accounting for increased load associated with the funds for economic development purposes pursuant to the order in Case No. 04-169-EL-ORD (RSP Order)[24] (Cos. Ex. 8 at 4; Cos. Ex. 2A at 46-51). The Companies contend that its process is consistent with Sections 4928.64(B) and 4928.66(A)(2)(a), Revised Code. The Companies request that the methodology be adopted in this proceeding so as to provide the Companies clear guidance with statutory compliance mandates. Further, the Companies reserve their right to request additional adjustments due to regulatory, economic, or technological reasons beyond the reasonable control of the Companies.

As to the calculation of the Companies' baseline, Staff asserts that the former MonPower load was acquired prior to the three-year period (2006 to 2008) and is not truly economic development. Therefore, Staff contends that the MonPower load is not a reasonable adjustment to the baseline. Staff suggests that the Companies' savings and peak demand reductions for 2009 be as set forth by Staff witness Scheck (Staff Ex. 3 at 6-8, Ex. GCS-1 and Ex. GCS-2). Staff recommends that CSP and OP make a case-by-case filing with the Commission to receive credit for the energy savings and peak demand reduction efforts of the electric utility's mercantile customers. Staff argues that because programs like PJM's demand response programs are not committed for integration into the electric utilities' energy efficiency and peak reduction programs, such credits should not count towards AEP-Ohio's annual benchmarks and retail customers who have such agreements should not receive an exemption from AEP-Ohio's energy efficiency cost recovery mechanism (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

Kroger recommends an opt-out provision of the rider for non-residential customers that are above a threshold aggregate load (10 MW at a single site or aggregated at multiple sites) within the AEP-Ohio service territories. Kroger proposes that, at the time of the opt-out request, the customer would be required to self-certify or attest to AEP-Ohio that for each facility, or aggregated facilities, the customer has conducted an energy audit or analysis within the past three years and has implemented or plans to implement the cost-effective measures identified in the audit or analysis. Kroger argues that the unavoidable rider penalizes customers who have implemented cost efficient DSM measures. Kroger contends that this is consistent with the intent of Section 4928.66(A)(2)(c), Revised Code (Kroger Ex. 1 at 13-14).

IEU notes that the Commission has previously rejected a proposal similar to Kroger's opt-out proposal with a demand threshold for mercantile customers in Duke's

24 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-ORD, Opinion and Order (January 26, 2005) (RSP Order).

ESP case.[25] IEU urges the Commission, consistent with Section 4928.66, Revised Code, and its determination in the Duke ESP case, to reject Kroger's request (IEU Reply Br. at 22).

The Commission concludes that the acquisition of the former MonPower load should not be excluded from baseline. The MonPower load was not a load that CSP served and would have lost, but for some action by CSP. Therefore, we find that the Companies' exclusion of the MonPower load in the energy efficiency baseline is inappropriate. The Commission does not believe that all economic development should automatically result in an exclusion from baseline. On the other hand, we agree with the Companies' adjustment to the baseline for the Ormet load. We note that the Companies and Staff agree that the impact of customer-sited specific DSM resources will be included in the Companies' compliance benchmarks and adjusted for any existing resources that had historic implication during the years 2006-2008. The Commission also recognizes that Staff and the Companies agree that the appropriate approach would be for the Companies to make case-by-case filings with the Commission to receive credit for contributions by mercantile customers.

In regards to Kroger's recommendation, for an opt-out process for certain commercial or industrial customers, the Commission finds Kroger's proposal, as advocated by Kroger witness Higgins, too speculative. It is best that the Commission determine the inclusion or exemption of a mercantile customer's DSM on a case-by-case basis. We note that Section 4928.66(A)(2)(c), Revised Code, provides, in pertinent part, the following:

> Any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customer to commit those capabilities to those programs.

This provision of the statute permits the Commission to approve a rider that exempts mercantile customers who commit their capabilities to the electric utility. However, the statute does not dictate a minimum consumption level. For these reasons, the Commission rejects Kroger's proposal.

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25 *In re Duke Energy Ohio, Inc.*, Case No. 08-920-EL-SSO, et al., Opinion and Order (December 17, 2008) (Duke ESP Order).

(c) Energy Efficiency and Peak Demand Reduction Programs

The Companies propose ten energy efficiency and peak demand reduction programs that will be refined and supplemented at the completion of the Market Potential Study through the creation of a working collaborative group of stakeholders.

As part of the Companies' energy efficiency and peak demand reduction plan, the Companies propose to spend $178 million on the following programs: (1) Residential Standard Offer Program, Small Commercial and Industrial Standard Offer Program, Commercial and Industrial Standard Offer Program; (2) Targeted Energy Efficient Weatherization Program; (3) Low Income Weatherization Program; (4) Residential and Small Commercial Compact Fluorescent Lighting Program; (5) Commercial and Industrial Lighting Program; (6) State and Municipal Light Emitting Diode Program; (7) Energy Star® New Homes Program; (8) Energy Star® Home Appliance Program; (9) Renewable Energy Technology Program; (10) Industrial Process Partners Program (Cos. Ex. 4 at 20-22). OEG supports the Companies EE/PDR rider as a reasonable proposal (OEG Ex. 2 at 13). OPAE generally supports the Companies proposed programs as reasonable for low-income and moderate income customers. However, OPAE requests that the Companies be required to empower the collaborative to design appropriate programs, provide funding for existing programs that can rapidly provide energy efficiency and demand response reductions, and to retain a third-party administrator to manage program implementation (OPAE Ex. 1 at 16-17; OPAE/APAC Br. at 21-22).

Staff also generally approves of the Companies' demand-side management and energy efficiency programs. However, Staff notes that certain of AEP-Ohio's programs are expensive and should be required to comply with the Total Resources Cost Test (Staff Br. at 17-19; Staff Ex. 3 at 6-11).

OCC makes five specific recommendations (OCC Ex. 5 at 9). First, OCC contends that the Companies DSM programs for low-income residential customers are adequate but should be available to all residential customers in Ohio. Second, OCC recommends that AEP-Ohio work with Columbia Gas of Ohio, Inc., to develop a one-stop home performance program in year two of the ESP. Third, OCC recommends that programs for consumers above 175 percent of the federal poverty level should be competitively bid and customers charged for services according to a sliding fee scale based on income. Fourth, like Staff, OCC contends that all programs should be evaluated for cost-effectiveness pursuant to the Total Resource Cost Test. Finally, OCC expresses concern regarding the administrative costs of the programs, in comparison to energy efficiency programs offered by other Ohio utilities and recommends that the administrative cost of the DSM program (administrative, educational, and marketing expenses) be determined by the collaborative, and limited to 25 percent of the program costs to ensure that the majority of the program dollars reach the customers (Id.).

The Commission directs, as the Companies submit in their ESP, that the collaborative process be used to contain administrative cost of the EE/PDR programs and to ensure, with the possible exception of low-income weatherization programs, that all programs comply with the Total Resource Cost Test. We do not agree with OPAE/APAC that a third-party administrator is necessary to act as a liaison between the Companies and the collaborative. Thus, the Companies should proceed with the proposed EE/PDR programs proposed in its ESP as justified by the market project study and as refined by the collaborative.

(d) Interruptible Capacity

The Companies count their interruptible service towards their peak demand reduction requirements in accordance with Section 4928.66(A)(2)(b), Revised Code. More specifically, the Companies propose to increase the limit of OP's Interruptible Power-Discretionary Schedule (Schedule IRP-D) to 450 Megawatts (MW) from the current limit of 256 MW and to modify CSP's Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS) to make the services more attractive to customers. The Companies request that the Commission recognize the Companies' ability to curtail customer usage as part of the peak demand reductions (Cos. Ex. 1 at 5-6).

Staff advocates that any credits awarded for the annual peak demand reduction targets for the Companies' interruptible programs should only apply when actual reductions occur (Staff Ex. 3 at 11). OCEA argues that interruptible load should not be counted toward AEP-Ohio's peak demand reduction as it is contrary to the intent of SB 221 to improve grid reliability and would be based on load under the control of the customer rather than AEP-Ohio. Further, OCEA argues that the Companies would reap an inequitable benefit from interruptible load (possibly in the form of off-system sales) that is not reduced at peak which would allow the Companies to sell the load or avoid buying additional power. OCEA contends that any such benefit is not passed on to customers (OCEA Br. at 102-103; Tr. Vol. IX at 68-69).

The Companies argue that capacity associated with interruptible customers should be counted toward compliance with the requirements of Section 4928.66, Revised Code, as the ability to interrupt is a significant demand reduction resource to AEP-Ohio. Further, the Companies state that interruptions have a real impact on customers and the Companies do not want to interrupt service when there is no system or market requirement to do so (Cos. Ex. 1 at 6). The Companies note that Section 4928.66(A)(1)(b), Revised Code, requires the electric utility to implement programs "designed to achieve" a specified peak demand reduction level as opposed to "achieve" a specified level of energy savings as required by Section 4928.66(A)(1)(a), Revised Code. Staff witness Scheck admits that the plain meaning of "designed to achieve" and "achieve" are different (Tr. Vol. VIII at 208). The Companies argue that the different language in the statutory requirements is intended to recognize the differences between energy efficiency programs and peak demand reduction programs. As such, the Companies contend that Staff's position is not supported by the language of the statute and it does not overcome the policy rationale presented by the Companies. The Companies also note that, in the context of integrated resource planning, interruptible capabilities are counted as capacity and evaluated in the need to plan for new power facilities. Finally, the Companies note that the Commission defines native load as internal load minus interruptible load.[26] For these reasons, the Companies contend that their interruptible capacity should be counted toward their compliance with the peak demand reduction benchmarks (Cos. Br. 114-115; Cos. Reply Br. at 90-93).

Further, the Companies claim that interruptible customers receive a benefit in the form of a reduced rate for taking interruptible service irrespective of whether their service is actually curtailed. AEP-Ohio notes that it includes such interruptible service as a part of its supply portfolio, unlike the PJM demand response programs, which is based on PJM's zonal load. Therefore, AEP-Ohio asserts there is no disparate treatment between counting interruptible capabilities as part of peak demand reduction compliance requirements and prohibiting retail participation in wholesale PJM demand reduction programs (Cos. Reply Br. at 90-91). Further, as to OCEA's claims regarding interruptible customer load, the Companies argue that the assertions are without merit or basis in the statute. The Companies argue that counting interruptible load fits squarely within the stated intent of the statute that programs be "designed to achieve" peak demand reduction and facilitates the ability to avoid the construction of new power plants. As to the customer's control of interruptible load argument, the Companies note that the customer has a choice to "buy through" to obtain replacement power at market prices to avoid curtailment and in such situations the Companies' supply portfolio is not affected. Regarding OCEA's assertion that the Companies might benefit from the associated interruption, AEP-Ohio acknowledges that off-system sales are indirectly possible, as are other circumstances, based on the market price. Nonetheless, AEP-Ohio argues that such does not alter the fact that AEP-Ohio's retail supply obligation is reduced and the supply portfolio is not accessed to serve the retail customer. Accordingly, AEP-Ohio asserts that interruptible tariff capabilities should count toward the Companies' peak demand reduction compliance requirements.

The Commission agrees with the Staff and OCEA that interruptible load should not be counted in the Companies' determination of its EE/PDR compliance requirements unless and until the load is actually interrupted. As the Companies recognize, it is imperative, with regard to the PJM demand response programs, that the Companies have

[26] See proposed Rule 4901:5-5-01(Q), O.A.C., *In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technologies and Resources, and Emission Control Reporting Requirements, and Amendment of Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code, Pursuant to Chapter 4928, Revised Code, to Implement Senate Bill No. 221*, Case No. 08-888-EL-ORD (Green Rules).

some control or commitment from the customer to be included as a part of AEP-Ohio's Section 4928.66, Revised Code, compliance requirements.

Further, the Commission emphasizes that we expect that applications filed pursuant to Section 4928.66(A)(2)(b), Revised Code, to be initiated by the electric utility only when the circumstances are justified. At the time of such filing by an electric utility, the Commission will determine whether the electric utility's continued compliance is possible under the circumstances.

4. Economic Development Cost Recovery Rider and the Partnership with Ohio Fund

The Companies' ESP application includes an unavoidable Economic Development Rider as a mechanism to recover costs, incentives and foregone revenue associated with new or expanding Commission-approved special arrangements for economic development and job retention. The Companies propose quarterly filings to establish rates based on a percentage of base distribution revenue subject to a true-up of any under- or over-collection in subsequent quarterly filings. In addition, the Companies propose the development of a "Partnership with Ohio" fund from shareholders. The fund would consist of a $75 million commitment, $25 million per year of the ESP, from shareholders. The Companies' goal is for approximately half of the fund to be used to provide assistance to low-income customers, including energy efficiency programs for such customers, and the balance to be used to attract and retain business development within the AEP-Ohio service area (Cos. Ex. 1 at 12; Cos. Ex. 3 at 15-16; Cos. Ex. 6 at 49; Tr. Vol. III at 115-119).

OCC proposes that the Commission continue its policy of dividing the recovery of forgone revenue subsidies equally from AEP-Ohio's shareholders and customers or require shareholders to pay a larger percentage. Further, OCC expresses some concern that the rider may be used in an anti-competitive manner as it is not likely that incentives and/or discounts will be offered to shopping customers. To address OCC's anticompetitive concerns, OCC proposes that the Commission make the economic development rider avoidable or establish the charge as a percentage of the customer's entire bill rather than a percentage of distribution charges. OCC also recommends that all parties participate in the initial and annual review of the economic development contracts and that, at the annual review, if the customer has not fulfilled its obligation, the arrangement be cancelled, the subsidy paid back, and the Companies directed to credit the rider for the discounts (OCC Ex. 14 at 4-8; OCEA Br. at 104-106).

The Companies contend that Section 4905.31, Revised Code, as amended by SB 221, explicitly provides for the recovery of foregone revenues for entering into reasonable arrangements for economic development and, thus, OCC's recommendation to continue the Commission's previous policy is misplaced. Further, the Companies note that the

Commission's approval of any special arrangement will include a public interest determination. Thus, the Companies argue that OCC's recommendation for all parties to initially and annually review economic development arrangements is unnecessary, bureaucratic and burdensome, and should be rejected. The Companies contend that economic development and full recovery of the foregone revenue for economic development is consistent with SB 221 and a significant feature of the Companies' ESP, which should not be modified by the Commission (Cos. Br. at 132).

The Commission finds that OCC's concerns are unfounded and unnecessary at this stage. The Commission is vested with the authority to review and determine whether or not economic development arrangements are in the public interest. OCC's request is denied.

OPAE and APAC argue that the Companies have not provided any assurances that the $75 million will be spent from the Partnership with Ohio fund if the Commission modifies the ESP and fails to state how much of the fund will be spent on low-income, at-risk populations (OPAE/APAC Br. at 19-20). The Companies submit that, if the ESP is modified, they can then evaluate the modified ESP in its entirety to determine whether this fund proposal contained in the ESP requires elimination or modification (Tr. Vol. III at 137-138; Tr. Vol. X at 232-233).

While the Partnership with Ohio fund is a key component of the economic development proposal, in light of the modifications made to the ESP pursuant to this opinion and order, we find that the Companies' shareholders should fund the Partnership with Ohio fund, at a minimum of $15 million, over the three-year ESP period, with all of the funds going to low-income, at-risk customer programs. Accordingly, we direct AEP-Ohio to consult with Staff to administer the program established herein.

C. Line Extensions

In its ESP, AEP-Ohio proposes to modify certain existing line extension policies and charges included in its schedules (Cos. Ex. 10 at 5-14). Specifically, the Companies requested a modification to their definition of line extension and system improvements, a continuation of the up-front payment concept established in Case No. 01-2708-EL-COI,[27] an increase in the up-front residential line extension charges, implementation of a uniform, up-front line extension charge for all nonresidential projects, the elimination of the end use customer's monthly surcharge, and the elimination of the alternative construction option (Id. at 3-4, 6-7, 10-12).

[27] *In the Matter of the Commission's Investigation into the Policies and Procedures of Ohio Power Company, Columbus Southern Power Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, The Toledo Edison Company and Monongahela Power Company Regarding the Installation of New Line Extensions*, Case No. 01-2708-EL-COI, et al., Opinion and Order (November 7, 2002).

Staff testified that distribution-related issues and costs, such as those related to line extensions, be examined in the context of a distribution rate case (Staff Ex. 13 at 4). IEU concurred with Staff's position (IEU Br. at 25). OCC also agreed and added that AEP-Ohio should be required to demonstrate in that rate proceeding that its costs related to line extensions have substantially increased, thereby justifying AEP-Ohio's proposed increase to the up-front residential line extension charges (OCEA Br. at 87).

Per SB 221, the Commission is required to adopt uniform, statewide line extension rules for nonresidential customers within six months of the effective date of the law. The Commission adopted such rules for nonresidential and residential customers on November 5, 2008.[28] Applications for rehearing were filed, which the Commission is still considering. Accordingly, the new line extension rules are not yet effective.

The Commission finds that AEP-Ohio has not demonstrated that its proposal to continue, in its ESP, its existing line extension policies regarding up-front payments, with modifications, is consistent with SB 221 or advances the policy of the state. Therefore, in light of the SB 221 mandate that the Commission adopt statewide line extension rules that will apply to AEP-Ohio, we do not believe that it makes sense to adopt a unique policy for AEP-Ohio at this time. As such, the Companies' ESP should be modified to eliminate the provision regarding line extensions, which would have the effect of also eliminating the alternative construction option as requested by the Companies. AEP-Ohio is, however, directed to account for all line extension expenditures, excluding premium services, in plant in service until the new line extension rules become effective, where the recovery of such will be reviewed in the context of a distribution rate case. The Companies may continue to charge customers for premium services pursuant to their existing practices.

V. TRANSMISSION

In its ESP, the Companies requested to retain the current TCRR, except the marginal loss fuel credit will now be reflected in the FAC instead of the TCRR. We concur with the Companies' request. We find the Companies' request to be consistent with our determination in the Companies' recent TCRR Case,[29] and thus, approve the TCRR rider as proposed by the Companies. Additionally, as contemplated by our prior order in the TCRR Case, any overrecovery of transmission loss-related costs, which has

28 See *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code*, Case No. 06-653-EL-ORD, Finding and Order (November 5, 2008), Entry on Rehearing (December 17, 2008) (06-653 Case).

29 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Company's Transmission Cost Recovery Rider*, Case No. 08-1202-EL-UNC, Finding and Order (December 17, 2008) (TCRR Case).

occurred due to the timing of our approval of the Companies' ESP and proposed FAC, shall be reconciled in the over/underrecovery process in the Companies' next TCRR rider update filing.

VI. OTHER ISSUES

A. Corporate Separation

1. Functional Separation

In its ESP application, AEP-Ohio requested to remain functionally separated for the term of the ESP, as was previously authorized by the Commission in the Companies' rate stabilization plan proceeding,[30] pursuant to Section 4928.17(C), Revised Code (Cos. App. at 14; Cos. Br. at 86). The Companies also requested to modify their corporate separation plan to allow each company to retain its distribution and, for now, transmission assets and that, upon the expiration of functional separation, the Companies would sell or transfer their generation assets to an affiliate (Id.).

Staff testified that the Companies' generating assets have not been structurally separated from the operating companies (Staff Ex. 7 at 2-3). Staff also recommended that, in accordance with the recently adopted corporate separation rules issued by the Commission in the SSO Rules Case,[31] the Companies should file for approval of their corporate separations plan within 60 days after the rules become effective. Furthermore, Staff proposes that the Companies' corporate separation plan should be audited by an independent auditor within the first year of approval of the ESP, the audit should be funded by the Companies, but managed by Staff, and the audit should cover compliance with the Commission's rules on corporate separation (Staff Ex. 7 at 3-4). No party opposed AEP-Ohio's request to remain functionally separate.

Accordingly, the Commission finds that, while the ESP may move forward for approval, as noted by Staff, in accordance with our recently adopted rules in the SSO Rules Case, the Companies must file for approval of their corporate separation plan within 60 days after the rules become effective.

30 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 04-169-EL-UNC, Opinion and Order at 35 (January 26, 2005).

31 *In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221*, Case No. 08-777-EL-ORD, Finding and Order (September 17, 2008), and Entry on Rehearing (February 11, 2009) (SSO Rules Case).

2. Transfer of Generating Assets

The Companies request authorization for CSP to sell or transfer two recently acquired generating facilities (Waterford Energy Center and the Darby Electric Generating Station) that have not been included in rate base for ratemaking purposes and the costs of operating and maintaining the plants are not built into the current rates) (Cos. Ex. 2-A at 42; Cos. Ex. 2-E at 20). CSP purchased the Waterford Energy Center, a natural gas combined cycle power plant, on September 28, 2005, which has a generating capacity of 821 MW (Cos. App. at 14). On April 25, 2007, CSP purchased the Darby Electric Generating Station, a natural gas simple cycle generating facility, with a generating capacity of 480 MW and a summer capacity of approximately 450 MW (Id.). Although AEP-Ohio is requesting authority to transfer these generating assets pursuant to Section 4928.17(E), Revised Code, CSP has no immediate plans to sell or transfer the generating facilities. If AEP-Ohio obtains authorization to sell these generating assets through this proceeding, AEP-Ohio will notify the Commission prior to any such transaction (Id. at 15).

Through its application, the Companies also notify the Commission of their contractual entitlements/arrangements to the output from the Ohio Valley Electric Corporation generating facilities and the Lawrenceburg Generation Station that the Companies intend to sell or transfer in the future, but argue that any sale or transfer of those entitlements do not require Commission authorization because the entitlements do not represent generating assets wholly or partly owned by the Companies pursuant to Section 4928.17(E), Revised Code (Id.).

The Companies argue that, if the Commission does not grant authorization to transfer these plants or entitlements, then any expense related to the plants or entitlements not recovered in the FAC should be recovered in the non-FAC portion of the generation rate (Cos. Br. at 89; Cos. Ex. 2-E at 20-21). AEP-Ohio states that this rate recovery would include approximately $50 million of carrying costs and expenses related to the Waterford Energy Center and the Darby Electric Generating Station annually, and $70 million annually for the contract entitlements (Id.).

Staff witness Buckley testified that, while Staff does not necessarily disagree with the proposal to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, Staff believes that the transfers could have a potential financial and policy impact at the time of the transfer (Staff Ex. 7 at 3). Thus, Staff recommended that the Companies file a separation application, in accordance with the Commission's SSO rules, at the time that the transfer will occur (Id.). Several other parties agree that, in the absence of a current plan to sell or transfer, the Commission should not approve a future sale or transfer. Rather, the parties argue that the Companies should seek approval, pursuant to Section 4928.17(E), Revised Code, at the time of the actual sale or transfer (OCEA Br. at 100; IEU Br. at 26-27; OEG Br. at 16).

The Commission agrees with Staff and the intervenors that the request to transfer the Waterford Energy Center and the Darby Electric Generating Station facilities, as well as any contractual entitlements/arrangements to the output of certain facilities, is premature. AEP-Ohio should file a separate application, in accordance with the Commission's rules, at the time that it wishes to sell or transfer these generation facilities. The Commission, however, recognizes that these generating assets have not and are not included in rate base and, thus, the Companies cannot collect any expenses related thereto, even if the facilities or contractual outputs have been used for the benefit of Ohio customers. If the Commission is going to require that the electric utilities retain these generating assets, then the Commission should also allow the Companies to recover Ohio customers' jurisdictional share of any costs associated with maintaining and operating such facilities. Accordingly, we find that while the Companies still own the generating facilities, they should be allowed to obtain recovery for the Ohio customers' jurisdictional share of any costs associated therewith. Thus, we believe that any expense related to these generating facilities and contract entitlements that are not recovered in the FAC shall be recoverable in the non-FAC portion of the generation rate as proposed by the Companies. The Commission, therefore, directs AEP-Ohio to modify its ESP consistent with our determination herein.

B. Possible Early Plant Closures

The Companies include as a part of their application in these cases a request for authority to establish a regulatory asset to defer any unanticipated net cost associated with the early closure of a generating unit or units. The Companies assert that, during the ESP period, generating units may experience failures or safety issues that would prevent the Companies from continuing to cost-effectively operate the generation unit prior to the end of the depreciation accrual (unanticipated shut down) (Cos. App. at 18-19; Cos. Ex. 2-A at 51-52). The Companies request authority to include net early closure cost in Account 182.3, Other Regulatory Assets. In the event of an unanticipated shut down, the Companies state they will timely file a request with the Commission for recovery of such prudent early closure costs via a non-bypassable rider over a relatively short period of time. The Companies are requesting that the rider include carrying cost at the WACC rate (Cos. App. at 18-19; Cos. Ex 6 at 25-26). The Companies also request authority to come before the Commission to determine the appropriate treatment for accelerated depreciation and other net early closure costs in the event that the Companies find it necessary to close a generation plant earlier that otherwise expected (earlier than anticipated shut down) (Cos. Ex. 6 at 28).

OCEA posits that the Companies' request for accounting treatment for early plant closure is wrong and should be rejected. OCEA reasons that the plant was included in rate base under traditional ratemaking regulation to give the Companies the opportunity to earn a return on the investment and the Companies accepted the risk that the plant might not be fully depreciated when it was removed from service. OCEA asserts it is not appropriate to guarantee the Companies recovery of their investment. If the Commission determines to allow the Companies to establish the requested accounting treatment, OCEA asks that the Commission adopt the Staff's "offset" recommendation (OCEA Br. at 102).

Staff argues that the value of the generation fleet was determined in the Companies' ETP cases,[32] wherein, pursuant to the stipulation, AEP-Ohio agreed not to impose any lost generation cost on switching customers during the market development period. Staff notes that, although the economic value of the generation plants was never specifically addressed by the Commission, it is reasonable to assume that the net value of the Companies' fleet was not stranded. Accordingly, Staff opposes the Companies' requests to impose on customers the cost or risk of uneconomic plants without accounting for the offset of the positive economic value of the rest of the Companies' generation plants (Staff Ex. 1 at 8).

Based on the record in this proceeding, the Commission is not convinced that it is appropriate to approve the Companies' request for recovery of net cost associated with an unanticipated shut down. Despite the arguments of the Companies to the contrary, we are persuaded by the arguments of the Staff that there may be offsetting positive value associated with the Companies generation fleet. Accordingly, while we will grant the Companies the authority to establish the accounting mechanism to separate net early closure cost, the Companies must file an application before the Commission for recovery of such costs. Accordingly, this aspect of the Companies' ESP application is denied. As to the Companies' request for authority to file with the Commission to determine the appropriate treatment associated with an earlier-than-anticipated shut down, the Commission finds this aspect of the application to be reasonable and, accordingly, the request should be granted.

C. PJM Demand Response Programs

Through the ESP, the Companies propose to revise certain tariff provisions to prohibit customers receiving SSO from participating in the demand response programs offered by PJM, either directly or indirectly through a third-party. Under the PJM programs retail customers can receive payment for being available to curtail even if the

32 *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order at 15-18 (September 28, 2000).

customer's service is not actually curtailed. AEP-Ohio argues that allowing its retail customers receiving SSO to also participate in PJM demand response programs is a no-win situation for AEP-Ohio and its other customers and inconsistent with the requirements of SB 221. The Companies contend that PJM demand response programs are intended to ensure the proper price signal to wholesale customers, not to address retail rate issues (Cos. Ex. 1 at 5-7). AEP-Ohio argues that retail customers should participate through AEP-Ohio-sponsored and Commission-approved programs. The Companies contend that FERC has granted state commissions, or- more precisely, the "relevant electric retail regulatory authority," the authority to preclude retail customer participation in wholesale demand response programs. *Wholesale Competition in Regions with Organized Electric Markets* (Docket Nos. RM07-19-000 and AD07-7-000), 125 FERC ¶ 61,071 at 18 CFR Part 35 (October 17, 2008) (Final Rule) (Cos. Br. at 119)

AEP-Ohio notes that it has consistently challenged retail customers' ability to participate in such programs and argued that the terms and conditions of its tariff prohibited such and, therefore, demand response retail participants should not be surprised by the Companies' position in this proceeding (Tr. Vol. IX at 212). AEP-Ohio argues that Ohio businesses participating in PJM's demand response programs have not invested their own capital or assets, taken any financial risk, or added any value to the services for which they are being compensated through PJM. The Companies assert, as stated by Staff witness Scheck, that the PJM demand response programs cost AEP-Ohio's other customers as the load of such PJM program participants continues to count toward the Companies' Fixed Resource Requirements (FRR) option and such cost is reflected in AEP-Ohio's retail rates (Tr. Vol. VIII at 165-166). Further, the PJM program participant/customer's ability to interrupt is of no use to AEP-Ohio, as the Companies claim that PJM's curtailment request is based on PJM's zonal load and not AEP-Ohio's peak load (Cos. Br. at 122-123).

The Companies reason that SB 221 includes a process whereby mercantile customer-sited resources can be committed to the utility to comply with the peak demand reduction benchmarks as set forth in Section 4928.66(A)(2)(d), Revised Code. Further, AEP-Ohio argues that it is unclear how the interruptible capacity of a customer participating in PJM's demand response program can count toward the Companies' benchmarks without being under the control of the Companies and "designed to achieve" peak demand reductions as required by the statue. As such, the Companies argue that, if participation in the PJM demand response program is allowed, PJM will be in direct competition with the electric distribution companies' efforts to comply with energy efficiency and peak demand reduction benchmarks and thus, render the mercantile customer commitment provisions largely ineffective. For these reasons, AEP-Ohio states that it should incorporate participation in PJM's demand response programs through AEP-Ohio and AEP-Ohio would then be in a position to pass some of the economic benefits associated with participation in PJM programs on to retail customers through complementary retail tariff programs and to pursue mercantile customer-sited arrangements to achieve benchmark compliance, thus allowing the Companies to avoid duplicate supply costs (Cos. Br. at 124-126).

This aspect of the Companies' ESP proposal is opposed by Integrys, OMA, Commercial Group, OEG, and IEU. Most of the intervenors contend that AEP-Ohio, in essence, considers retail customer participation in PJM programs the reselling of power provided to them by AEP-Ohio. Integrys makes the most comprehensive arguments opposing AEP-Ohio's request for approval to prohibit customer participation in the PJM demand response programs. Integrys argues that 18 C.F.R. 35.28(g) only permits this Commission to prohibit a retail customer's participation in demand response programs at the wholesale level through law or regulation. Section 18 C.F.R. 35.28(g) states:

> Each Commission-approved independent system operator and regional transmission organization must permit a qualified aggregator of retail customers to bid demand response on behalf of retail customers directly into the Commission-approved independent system operator's or regional transmission organization's organized markets, *unless the laws and regulations of the relevant electric retail regulatory authority expressly do not permit a retail customer to participate*. [Emphasis added.]

Thus, Integrys reasons that a ban on participation in wholesale demand response programs through AEP-Ohio's tariff is not equivalent to an act of the General Assembly or rule of the Commission. Accordingly, Integrys reasons that any attempt by the Commission to prohibit participation in this proceeding is beyond the authority granted by FERC and will be preempted. Further, Integrys and Constellation argue that AEP-Ohio has failed to state under what authority the Commission could bar customer participation in PJM's demand response and reliability programs. Constellation and Integrys posit that it is not in the public interest for the Commission to approve the prohibition from participation in such programs (Constellation Br. at 20-23; Constellation Ex. 2 at 18; Integrys Ex. 2 at 15; Integrys Br. at 2).

Even if the Commission concludes that it has the authority to grant AEP-Ohio's request to revise the tariff as requested, Integrys asserts that the Companies have not met their burden to justify prohibiting participation in PJM demand response programs. Integrys asserts that the request is not properly a part of the ESP applications and should have been part of an application not for an increase in rates pursuant to Section 4909.18, Revised Code. Nonetheless, Integrys concludes that under Section 4928.143 or Section 4909.18, Revised Code, the burden of proof is on the electric utility company to show that its proposal is just and reasonable.

The Companies, according to Integrys and the Commercial Group, have failed to present any demonstration that the Companies' programs are more beneficial to customers than the PJM programs. On the other hand, Integrys asserts that the PJM programs are more favorable to customers than the programs offered by AEP-Ohio as to notification, the number of curtailments per year, the hours of curtailments, payments and payment options, and penalties for non-compliance (Integrys Ex. 2 at 10-12; Commercial Group Br. at 9). In addition, certain interveners note, and the Companies agree, that PJM has not curtailed any customers since AEP-Ohio joined PJM (Tr. Vol. IX at 48). Furthermore, the intervenors contend that participation in the demand response programs provides improved grid reliability and improved efficiency of the market due to competition (Integrys Ex. 2 at 8).

Integrys also notes that the Ohio customers receive significant financial benefits from load serving entities beyond Ohio (Tr. Vol. IX at 52-52, 118). Integrys argues that AEP-Ohio wishes to ban customer participation in wholesale demand response programs to facilitate the increase in OSS of capacity to the benefit of the Companies' shareholders. Integrys reasons that because AEP-Ohio can count load enrolled in its interruptible service offerings as a part of the PJM ILR demand response program, the Companies will receive credit against its FRR commitment. The Companies, according to Integrys, hope that additional load will come from the customers currently participating in PJM's demand response programs in Ohio (Tr. Vol. IX at 53-58; Integrys Br. at 20-22). Integrys proposes, as an alternative to prohibiting customer participation in wholesale demand response programs, that the Commission count participation in the programs towards AEP-Ohio's peak demand reduction goals in accordance with the requirements of Section 4928.66, Revised Code. Integrys argues that the load can be certified, as it is today with the PJM demand response programs, or the electric services company could be required to register the committed load with the Commission.

Furthermore, Integrys reasons that the Commission can not retroactively interfere with existing contracts between customers and the customer's electric service provider in relation to the commitment contracts with PJM. With that in mind and if the Commission decides to grant AEP-Ohio's request to prohibit participation in wholesale demand response programs, Integrys requests that customers currently committed to participate in PJM programs for the 2008-2009 planning period and the 2009-2010 planning period be permitted to honor their commitments (Integrys Br. at 27-28).

Integrys argues that the Companies' claim that taking SSO and participating in a wholesale demand response program is a resale of power and a violation of the terms and conditions of their tariffs is misplaced. Integrys opines that there is no actual resale of energy, but, instead, there is a reduction in the customer's consumption of energy upon a call from the regional transmission operator (in this case, PJM). The customer is not purchasing energy from AEP-Ohio, so any energy purchased by AEP-Ohio can be transferred to another purchaser. Thus, Integrys asserts that AEP-Ohio's argument regarding participation in a wholesale demand response program is fiction and not based on FERC's interpretation of participation in such programs. Finally, Integrys contends that AEP-Ohio's proposal is a violation of Section 4928.40(D), Revised Code, as such prohibits electric utilities from prohibiting the resale of electric generation service.

The Commercial Group asserts, that because AEP-Ohio has not performed any studies or analyses, the Companies' assertion that wholesale demands response programs must be different from a demand response program offered by AEP-Ohio is unsupported by the record (Tr. Vol. IX at 47). The Commercial Group requests that the Companies be directed to design energy efficiency and demand response programs that incorporate all available programs (Commercial Group at Br. 9).

OEG argues that, to the extent there are real benefits to the Companies as well as to their retail customers in the form of improved grid reliability, AEP-Ohio should be required to offer PJM demand response programs to its large industrial customers by way of a tariff rider or through a third-party supplier (OEG Ex. 2 at 13). IEU adds that the Companies currently use the capabilities of their interruptible customers to assist the Companies in satisfying their generation capacity requirements to PJM. According to IEU, SB 221 gives mercantile customers the option of whether or not to dedicate their customer-sited capabilities to the Companies for integration into the Companies' portfolio (IEU Ex. 1 at 12).

Constellation argues that AEP-Ohio's proposal violates Section 4928.20, Revised Code, and the clear intent of SB 221. Further, Constellation argues that approving AEP-Ohio's request to prohibit Ohio businesses from conservation programs during this period of economic hardship is ill-advised, especially considering that other businesses with which Ohio businesses' must compete are able to participate in the PJM programs. As such, consistent with the Commission's decision in Duke's ESP case (Case No. 08-920-EL-SSO, et al.), Constellation encourages the Commission to reject AEP-Ohio's request to prohibit SSO customers from participating in PJM demand response programs and give Ohio's business customers all available opportunities to reduce demand, conserve energy, and invest in conservation equipment (Constellation Br. at 23). OMA supports the claims of Constellation (OMA Br. at 10).

First, we will address the claims regarding the Commission's authority, or as claimed by Integrys, the lack of authority, for the Commission to determine whether or not Ohio's retail customers are permitted to participate in wholesale demand response programs. The Commission finds that the General Assembly has vested the Commission with broad authority to address the rate, charges, and service issues of Ohio's public utilities as evidenced in Title 49 of the Revised Code. Accordingly, we consider this Commission the entity to which FERC was referring in the Final Rule when it referred to the "relevant electric retail regulatory authority." We are not convinced by Integrys' arguments that a specific act of the General Assembly is necessary to grant the Commission the authority to determine whether or not Ohio's retail customers are permitted to participate in the RTO's demand response programs.

Next, the Commission acknowledges that the PJM programs offer benefits to program participants. We are, however, concerned that the record indicates that PJM demand response programs cost AEP-Ohio's other customers as the load of AEP-Ohio's FRR and the cost of meeting that requirement is reflected in AEP-Ohio's retail rates. Finally, we are not convinced, as AEP-Ohio argues that a customer's participation in demand response programs is the resale of energy provided by AEP-Ohio. For these reasons, we find that we do not have sufficient information to consider both the potential benefits to program participants and the costs to Ohio ratepayers to determine whether this provision of the ESP will produce a significant net benefit to AEP-Ohio consumers. The Commission, therefore, concludes that this issue must be deferred and addressed in a separate proceeding, which will be established pursuant to a subsequent entry. Although we are not making a determination at this time as to the appropriateness of such a provision, we direct AEP to modify its ESP to eliminate the provision that prohibits participation in PJM demand response programs.

D. Integrated Gasification Combined Cycle (IGCC)

In Case No. 05-376-EL-UNC, the Commission concluded that it was vested with the authority to establish a mechanism for recovery of the costs related to the design, construction, and operation of an IGCC generating plant where that plant fulfills AEP-Ohio's POLR obligation and, therefore, approved the Phase I cost recovery mechanism included in the Companies' application.[33] Applications for rehearing of the Commission's IGCC Order were timely filed and by entry on rehearing issued June 28, 2006, the Commission denied each of the applications for rehearing (IGCC Rehearing Entry). Further, the IGCC Rehearing Entry conditioned the Commission's approval of the application, stating that: (a) all Phase I costs would be subject to subsequent audit(s) to determine whether such expenditures were reasonable and prudently incurred to construct the proposed IGCC facility; and (b) if the proposed IGCC facility was not constructed and in operation within five years after the date of the entry on rehearing, all Phase I charges collected must be refunded to Ohio ratepayers with interest.

In this ESP proceeding, AEP-Ohio witness Baker testified that, although the Companies have not abandoned their interest in constructing and operating an IGCC facility in Meigs County, Ohio, certain provisions of SB 221 are a barrier to construction and operation of an IGCC facility. As AEP-Ohio interprets SB 221, the Companies may be

33 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 05-376-EL-UNC, Opinion and Order (April 10, 2006) (IGCC Order).

required to remain in an ESP to assure an opportunity for cost recovery for an IGCC facility; the construction work in process (CWIP) provision which requires the facility to be at least 75 percent complete before it can be included in rate base; the limit on CWIP as a percentage of total rate base which the witness contends causes particular uncertainties since the concept of a generation rate base has no applicability under SB 221; and the effect of "mirror CWIP" (Cos. Ex. 2-A at 52-56). The Companies assert that not only are these barriers to the construction of an IGCC facility but also to any base load generation facility in Ohio. Nonetheless, the Companies state that they are encouraged by the fact that SB 221 recognizes the need for advanced energy resources and clean coal technology, such as an IGCC. Finally, the Companies' witness notes that, since the time the Companies proposed the IGCC facility, CSP has acquired additional generating capacity. According to Company witness Baker, the Companies hope to work with the Governor's administration, the General Assembly, and other interested parties to enact legislation that will make an IGCC facility in Meigs County a reality (Cos. Ex. 2-A at 55-56).

OCEA opines that SB 221 did not eliminate the existing requirement that electric utilities must satisfy to earn a return on CWIP and, since the Companies do not ask for the Commission to make any determination in this proceeding or at any definite time in the future as to the IGCC facility, the Commission should take no action on this issue (OCEA Br. at 98-99).

The Commission notes that the Ohio Supreme Court remanded, in part, the Commission's IGCC Order, for further proceedings and, accordingly, the matter is currently pending before the Commission. Further, as OCEA asserts, there does not appear to be any request from the Companies as to the IGCC facility in this proceeding. Accordingly, we find it inappropriate to rule, at this time, on any matter regarding the Meigs County IGCC facility in this proceeding. We will address the matter as part of the pending IGCC proceeding.

E. <u>Alternate Feed Service</u>

As part of the ESP, the Companies propose a new alternate feed service (AFS) schedule. For customers who desire a higher level of reliability, a second distribution feed, in addition to the customer's basic service, will be offered. Existing AEP-Ohio customers that are currently paying for AFS will continue to receive the service at the same cost under the proposed tariff. Existing customers who have AFS and are not paying for the service will continue to receive such service until AEP-Ohio upgrades or otherwise makes a new investment in the facilities that provide AFS to that customer. At such time, the customer will have 6 months to decide to discontinue AFS, take partial AFS, or continue AFS and pay for the service in accordance with the effective tariff schedule (Cos. Ex. 1 at 8). While OHA supports the implementation of an AFS schedule offering with clearly defined terms and conditions, OHA takes issue with two aspects of the AFS proposal. OHA witness Solganick testified that it is his understanding that the customer will have six months after the customer is notified by the company to make a decision (OHA Ex. 4 at 15). However, OHA witness Solganick advocated that six months was insufficient because critical-use customers, like hospitals, require more lead time to evaluate their electric supply infrastructure and needs (Id.). As such, he argued that 24 months would be more appropriate for planning purposes (Id.). Moreover, OHA argued that, because this issue involves the overall management and cost of operating AEP-Ohio's distribution system, the Commission should defer consideration of the proposed AFS until AEP-Ohio's next distribution rate case where there will be a more deliberate treatment of the issue as opposed to this 150-day proceeding (OHA Br. at 23). OHA believes that a distribution rate proceeding would better ensure that the underlying rate structure for AFS is correct, similar to the argument for deferring decision on other distribution rate issues presented in this ESP proceeding (Id.). Staff and IEU also agree that the issue should be addressed in a distribution rate case (Staff Ex. 1 at 4; IEU Ex. 10 at 11). However, IEU further recommends that the Commission deny the Companies' request because it is not based on prudently incurred costs (IEU Br. at 25-26).

The Companies retort that, while they may have some flexibility as to the notice provided customers, such notice is limited by the Companies' planning horizon for distribution facilities and the lead time required to complete construction of upgraded AFS facilities (Cos. Reply Br. at 122). The Companies reason that, while more than 6 months may be feasible, anything more than 12 months would not be prudent and, in certain rare circumstances, would not facilitate the construction of complex facilities (Id.). Nonetheless, the Companies stated that they will commit to 12 months notice to existing AFS customers for the need to make an election of service (Id.). However, the Companies vehemently opposed deferring approval of their proposed AFS schedule to some future proceeding, stating that the proposed AFS tariff codifies existing practices currently being addressed on a customer-by-customer contract addendum basis (Id.). Further, the Companies argue that IEU has not presented any basis to support the implication that the AFS schedule will recover imprudently incurred costs (Id. at 123). Thus, AEP-Ohio contends there is no good reason to delay implementation of the AFS schedule with the understanding that the Companies will provide up to 12 months notice to existing customers (Id. at 122-123).

As previously noted in this order in regards to other distribution rate issues, the Commission believes that the establishment of various distribution riders and rates, including the proposed new AFS schedule, is best reviewed in a distribution rate case where all components of distribution rates are subject to review.

F. Net Energy Metering Service

The Companies' ESP application includes several tariff revisions. More specifically, the Companies propose toeliminate the one percent limitation on the total rated generation capacity for customer-generators on the Companies' Net Energy

Metering Service (NEMS) and add a new Net Energy Metering Service for Hospitals (NEMS-H). The Companies note that, at the time the ESP application was filed, they had filed a proposed tariff modification to the NEMS and Minimum Requirements for Distribution System Interconnection and Standby Service in Case No. 05-1500-EL-COI.[34] The Companies state that upon approval of the modifications filed in 05-1500, the approved modifications will be incorporated into the tariffs filed in the ESP case (Cos. Ex. 1 at 8-9).

OHA identifies two issues with the Companies' proposed NEMS-H schedule. First, OHA asserts the conditions of service are unduly restrictive to the extent that NEMS-H requires the hospital customer-generator's facility must be owned and operated by the customer and located on the customer-generator's premises. OHA asserts that this requirement prevents hospitals from benefiting from economies of scale by utilizing the expertise of distributed generation or cogeneration companies, centralized operation and maintenance of such facilities, and shared expertise and expenses. Further, OHA asserts that the requirement that the facility be located on the hospital's premises is a barrier because space limitations and legal and/or financing requirements may suggest that a generation facility be located on property not owned by the hospital. OHA argues that the Companies do not cite any regulatory, operational, financial, or other reason why the ownership requirement is necessary. Therefore, OHA requests that the Commission delete this condition of service and require only that the hospital contract for service and comply with the Companies' interconnection requirements (OHA Ex. 4 at 8-10).

AEP-Ohio responds that the requirement that the generation facility be on-site and owned and operated by the customer is a provision of the currently effective NEMS schedule. Further, the Companies argue that economies of scale may be accomplished with multiple hospitals contracting with a third-party to operate and maintain the generation facilities of each hospital. Further, AEP-Ohio argues that there is no support for the claim that efficiencies can not be had if the hospital, rather than a third-party developer, is the ultimate owner of such facilities (Cos. Br. at 128). As to OHA's opposition to the requirement that the hospital own and operate the generation facility on its premises, AEP-Ohio contends that such is required based on the language in the definitions of a customer-generator, net metering system, and self-generator at Section 4928.02(A)(29) to (32), Revised Code (Cos. Reply Br. at 124-125).

Second, OHA argues that the payment for net deliveries of energy should include credits for transmission costs that are avoided and energy losses on the subtransmission and distribution systems that are avoided or reduced. Further, OHA requests that such payments for net deliveries should be made monthly without a requirement for the

[34] *In the Matter of the Application of the Commission's Review to Provisions of the Federal Energy Policy Act of 2005 Regarding Net Metering, Smart Metering, Demand Response, Cogeneration, and Power Production*, Case No. 05-1500-EL-COI (05-1500).

customer-generator to request any net payment. The Companies propose to make such payment annually upon the customer's request (OHA Ex. 4 at 11-12). The Companies assert that OHA assumes that the customer-generator's activities will reduce transmission, subtransmission, and distribution line losses and there is no support for OHA's contention. Further, AEP-Ohio argues that annual payment is in compliance with Rule 4901:1-10-28(E)(3), Ohio Administrative Code (O.A.C.) (Cos. Reply Br. at 124). OHA witness Solganick conceded that the annual payment requirement is in compliance with the Commission's rule (Tr. Vol. X at 118-119).

Staff submits that the Companies' proposed NEMS-H tariff is premature given that requirements for hospital net metering are currently pending rehearing before the Commission in the 06-653 Case. Thus, Staff proposes, and OHA supports, that the Companies withdraw their proposed NEMS-H and refile the tariff once the new requirements are effective or with the Companies' next base rate proceeding, whichever occurs first (Staff Ex. 5 at 9; OHA Reply Br. at 9). AEP-Ohio argues that the status of the 06-653 Case should not postpone the implementation of one of the objectives of SB 221 and notes that, if the final requirements adopted in the 06-653 Case impact the Companies' NEMS-H, the adopted requirements can be incorporated into the NEMS-H schedule at that time.

As the Commission is in the process of determining the net energy meter service requirements pursuant to SB 221 in the 06-653 Case, the Commission finds AEP-Ohio's revisions to its net energy metering service schedules premature. Therefore, the Commission finds, as proposed by Staff and supported by OHA, the Companies should refile their net metering tariffs to be consistent with the requirements adopted by the Commission in the 06-653 Case or with the Companies' next base rate proceeding.

G. Green Pricing and Renewable Energy Credit Purchase Programs

OCEA proposes that the Commission order AEP-Ohio to continue, with the input of the DSM collaborative, the Companies' Green Pricing Program and to require the Companies to develop a separate residential and small commercial net-metering customer renewable energy credit (REC) purchase program. OCC witness Gonzalez recommended a market-based pricing for RECs. On brief, OCEA proposes an Ohio mandatory market-based rate for in-state solar electric application and a different rate for in-state wind and other renewable resources. OCEA asserts that the programs will assist customers with the cost of owning and using renewable energy and assist the Companies in meeting the renewable energy requirements (OCC Ex. 5 at 10-11; Tr. Vol. IV at 232-234; OCEA Br. at 97-98).

The Companies argue that, pursuant to the stipulation agreement approved by the Commission in Case No. 06-1153-EL-UNC,[35] the Green Pricing Program expired December 31, 2008. Further, the Companies note that the Commission approved the expiration of the Green Pricing Program by the Finding and Order issued in Case No. 08-1302-EL-ATA.[36] However, the Companies state that they intend to offer a new green tariff option during the ESP term (Cos. Ex. 3 at 13). Accordingly, the Companies request that the Commission OCEA's request to detail or adopt a new green tariff option at this time. In regards to OCEA's REC proposal, the Companies assert that the prescriptive pricing recommendation presented on brief is at odds with the testimony of OCC's witness. Further, the Companies note that OCC's witness acknowledged the administrative and cost-effective issues associated with the proposal. Thus, the Companies note that, as OCC's witness acknowledged, the proposal requires further study before being implemented.

While the Commission believes there is merit to green pricing and REC programs and, therefore, encourages the Companies to evaluate the feasibility and benefits to implementing such programs as soon as practicable , we decline to order the Companies to initiate such programs as part of this ESP proceeding, as it is not necessary that these optional requests be pursued by the Companies at this time. Accordingly, we find that it is unnecessary to modify AEP-Ohio's ESP to include any green pricing and REC programs, and we decline to do such modification at this time.

H. Gavin Scrubber Lease

The Companies note that in the Gavin Scrubber Case,[37] the Commission authorized OP to enter into a lease agreement with JMG Funding, L.P. (JMG) for a scrubber/solid waste disposal facilities (scrubber) at the Gavin Power Plant. Under the terms of the lease agreement, the agreement may not be cancelled for the initial 15-year term. After the initial 15-year period, under the Gavin lease agreement, OP has the option to renew or extend the lease for an additional 19 years. OP entered into the lease on January 25, 1995. Therefore, the initial lease period ends in 2010, and at that time, OP will have the option of renewing the Gavin scrubber lease for an additional 19 years, until 2029. On April 4, 2008, OP filed an application for authority to assume the obligations of JMG and restructure the financing for certain JMG obligations in the OP and JMG case.[38] In the OP and JMG case, the Commission approved OP's request subject to two conditions: OP must seek Commission approval to exercise the option to purchase the

35 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 06-1153-EL-UNC (May 2, 2007).

36 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA (December 19, 2008).

37 *In re Ohio Power Company*, Case No. 93-793-EL-AIS, Opinion and Order (December 9, 1993).

38 *In re Ohio Power Company*, Case No. 08-498-EL-AIS, Finding and Order (June 4, 2008).

Gavin scrubbers or terminate the lease agreement; and OP must provide the Commission with details of how the company intends to incorporate the project into its ESP (Cos. Ex. 2-A at 56-58).

As part of the Companies' ESP application, OP requests authority to return to the Commission to recover any increased costs associated with the Gavin lease (Cos. Ex. 2-A at 56-58). The Companies state that a decision on the Gavin scrubber lease has not been made because the market value of the scrubbers and the analysis to determine the least cost option is not available at this time.

The Commission recognizes that additional information is necessary for the Companies to evaluate the options of the Gavin lease agreement and, to that end, we believe that AEP-Ohio should be permitted to file an application to request recognition of the Gavin lease at the time that it makes its decision as to purchasing or terminating the lease. Once the Companies have made their election, they should conduct a cost-benefit analysis and file it with the Commission prior to seeking recovery of any incremental costs associated with the Gavin scrubber lease.

I. Section V.E (Interim Plan)

The Companies assert that this provision is part of the total ESP package and should be adopted. The Companies requested that the Commission authorize a rider to collect the difference between the ESP approved rates and the rates under the Companies' current SSO for the length of time between the end of the December 2008 billing month and the effective date of the new ESP rates.

We find Section I.E of the proposed ESP to be moot with this opinion and order. The Commission issued finding and orders on December 19, 2008, and February 25, 2009, interpreting the statutory provision in Section 4928.14(C)(1), Revised Code, and approving rates for an interim period until such time as the Commission issues its order on AEP's proposed ESP.[39] Those rates have been in effect with the first billing cycle in January 2009. Consistent with Section 4928.141, Revised Code, which requires an electric utility to provide consumers, beginning on January 1, 2009, a SSO established in accordance with Section 4928.142 or 4928.143, Revised Code, and given that AEP-Ohio's proposed ESP term begins on January 1, 2009, and continues through December 31, 2011, we are authorizing the approval of AEP's ESP, as modified herein, effective January 1, 2009. However, any revenues collected from customers during the interim period must be recognized and offset by the new rates and charges approved by this opinion and order.

39 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-1302-EL-ATA, Finding and Order at 2-3 (December 19, 2008) and Finding and Order at 2 (February 25, 2009).

VII. SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)

Section 4928.143(F), Revised Code, requires that, at the end of each year of the ESP, the Commission shall consider if any adjustments provided for in the ESP:

> ...resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate.

AEP-Ohio's proposed ESP SEET process may be summarized as follows: The book measure of earnings for CSP and OP is determined by calculating net income divided by beginning book equity. The Companies then propose that the ROE for CSP and OP should be blended as the book equity amounts for AEP-Ohio is more meaningful since CSP and OP are supported by AEP Corporation. To develop a comparable risk peer group, including public utilities, with similar business and financial risk, AEP-Ohio's process includes evaluating all publicly traded U.S. firms. By using data from both Value Line and Compustat, AEP-Ohio applies the standard decile portfolio technique, to divide the firms into 10 different business risk groups and 10 different financial risk groups (lowest to highest). AEP-Ohio would then select the cell which includes AEP Corporation. To account for the fact that the business and financial risks of CSP and OP may differ from AEP Corporation, this aspect of the process is repeated for CSP and OP and taken into consideration in determining whether CSP's or OP's ROEs are excessive. The ESP evaluates business risk by using unlevered Capital Asset Pricing Model betas (or asset betas) and the financial risk by evaluating the book equity ratio. The Companies assert that the book equity ratio is more stable from year to year and, therefore, is considered by fixed-income investors and credit rating agencies. The ESP utilized two standard deviations (which is equivalent to the traditional 95 percent confidence level) about the mean ROEs of the comparable risk peer group and the utility peer group to determine the starting point for which CSP's or OP's ROE may be considered excessive (Cos. Ex. 5 at 13-42). Finally, AEP-Ohio advocates that the earnings for each year the SEET is applied should be adjusted to exclude the margins associated with OSS and accounting earnings for fuel adjustment clause deferrals for which the Companies will not have collected revenues (Cos. Ex. 2-A at 37-38; Cos. Ex. 6 at 16-17; Cos. Ex. 2 at 39-40).

OCC, OEG, and the Commercial Group each take issue with the development of the comparable firms and the threshold of significantly excessive earnings. Kroger and OCEA argue that the Companies' statistical process for determining when CSP and OP have earned significantly excessive earnings improperly shifts the burden of proof set forth in the statute from the company to other parties.

OCC witness Woolridge developed a proxy group of electric utilities to establish the business and financial risk indicators, then uses Value Line to develop a data base of companies with business and financial risk indicators within the range of the electric utility proxy group. Woolridge suggests computing the benchmark ROE for the comparable companies and adjusting the benchmark ROE for the capital structure of Ohio's electric utility companies and adjusting the benchmark by the FERC 150 basis points ROE adder to determine significantly excessive earnings (OCC Ex. 2 at 5-6, 20). AEP-Ohio argues that OCC's process is contrary to the language and spirit of Section 4928.143(F), Revised Code, as the statute requires the comparable firms include non-utility firms. The SEET proposed by OCC witness Woolridge results in the same comparable list of firms for each Ohio electric utility evaluated (Cos. Ex. 5-A at 5-6).

OEG proposes a method to establish the comparable group of firms by utilizing the entire list of publicly traded electric utilities in Value Line's Datafile,[40] and one group of non-utility firms. The comparable non-utility group is composed of Companies' with gross plant to revenue between 1.2 and 5.0, gross plant in excess of $1 billion and companies for which Value Line has a beta (OEG Ex. 4 at 4-6). OEG then calculates the difference in the average beta of electric utility group and the non-utility group and adjust it by the average historical risk premium for the period 1926 to 2008, which equals 7.0 percent to determine the adjustment to account for the reduced risk associated with utilities. Thus, for example, for the year 2007 OEG determined that the average non-utility earned return of 14.14 percent yields a risk-adjusted return of 12.82 percent. OEG then applies an adjustment to recognize the financial risk differences of AEP-Ohio to the utility and non-utility comparison groups. Finally, to determine the level at which earnings are "significantly excessive," OEG suggests an adder of the 200 basis points to encourage investments (OEG Ex. 4 at 7-9). OEG argues that the use of statistical confidence ranges as proposed by AEP-Ohio would severely limit any finding of excessive earnings as a two-tailed 95 percent confidence interval would mean that only 2.5 percent of all observations of all the sample company groups would be deemed to have excessive earnings. Further, OEG argues that as a statistical analysis the AEP-Ohio-proposed method eliminates most, if not all, of the Commission's flexibility to adjust to economic circumstances and determine whether the utility company's earnings are significantly excessive (OEG Ex. 4 at 9-10).

AEP-Ohio contends that OEG's SEET method fails to comply with the statutory requirements for the SEET, fails to control for financial risk of the comparable sample groups, fails to account for business risk and will, like the process proposed by OCC,

40 OEG would eliminate one company with a significant negative return on equity for 2007.

produce the same comparable non-utility and utility group for each of the Ohio electric utilities (Cos. Ex. 5-A at 8-9).

The Commercial Group asserts that AEP-Ohio's proposed SEET methodology will produce volatile earned return on equity thresholds and, therefore, does not meet the primary objective of an ESP which is to stabilize rates and support the economic development of the state. Further, AEP-Ohio's SEET method, according to the Commercial Group, fails to compose a comparable proxy group with business risk similar to CSP and OP, including unregulated nuclear subsidiaries and deregulated generation subsidiaries. Thus, Commercial Group recommends a comparable group consist of publicly traded regulated utility companies as determined by the Edison Electric Institute (EEI). Commercial Group witness Gorman notes that using EEI's designated group of regulated entities and Value Lines earned return on common equity shows that the regulated companies had an average return on equity of approximately 9 percent for the period 2005 through 2008. Witness Gorman contends that over the period 2005 through 2008 and projected over the next 3 to 5 years, approximately 85 percent of the earned return on equity observations for the designated regulated electric utility companies will be at 12.5 percent return on equity or less. Therefore, Commercial Group recommends that the SEET test be based on the Commission-approved return on equity plus a spread of 200 basis points. Commercial Group witness Gorman reasons that the average risk, extreme risk and beta spread over AEP-Ohio's proxy group suggest that a 2 percent/200 basis points is a conservative determination of the excessive earnings threshold (Commercial Group Ex. 1 at 3, 12-17).

AEP-Ohio argues that the Commercial Group's proposed SEET fails to develop a comparable group as required by the SEET and ignores the fact that the rate of return is a forward-looking analysis and the SEET is retrospective. Thus, AEP-Ohio concludes that this method does not address the measurement of financial and business risk (Cos. Ex. 5-A at 9-10).

OCC opposes the exclusion of accounting earnings for fuel adjustment clause deferrals and the deduction of revenues associated withOSS, as OSS are not one-time write-offs or non-recurring items (OCC Ex. 2 at 21). OCC contends that revenues associated with the deferrals are reported during the same period with the Companies fuel-related expenses and to eliminate the deferrals, as AEP-Ohio proposes, would reduce the revenues for the period without deducting for the underlying expense (OCC Reply Br. 69-70). Similarly, Kroger proposes that AEP-Ohio credit the fuel adjustment clause for the margin generated by OSS and notes that AEP Corporation's West Virginia and Virginia electric distribution subsidiaries currently do so despite AEP-Ohio's assertion that such is in violation of federal law (Kroger Ex. 1 at 9).

Staff advocates a single SEET methodology for all electric distribution utilities as to the selection of comparable firms and, further, proposes a workshop or technical conference to develop the process to determine the "comparable group earnings" for the SEET. Staff witness Cahaan reasons that the SEET proposed by AEP-Ohio as a technical, statistical analysis, if incorrectly formulated shifts the burden of proof from the company to the other parties. Staff also contends that the Companies' SEET proposal is based upon a definition of significance which would create internal inconsistencies if applied to the statute. Further, Staff believes the "zone of reasonable" earnings can be framed by a return on equity with an adder in the range of 200 to 400 basis points. Further, Staff recognizes that if, as AEP-Ohio suggests, revenues from OSS are excluded from SEET, other adjustments would be required. Staff believes it would be unreasonable to predetermine those other adjustments as this time. Thus, Staff proposes that this proceeding determine the method of establishing the comparable group and specify the basis points that will be used to determine "significantly excessive earnings." Staff claims that under its proposed process, at the end of the year, the ROE of the comparable group could be compared to the electric utility's 10-K or FERC-1 and, if the electric utility's ROE is less than that of the sum of the comparable group's ROE plus the adder, it will be presumed that the electric utility's earnings were not significantly excessive. Further, Staff asserts that any party that wishes to challenge the presumption would be required to demonstrate otherwise. If, however, the electric utility's earned ROE is greater than the average of the comparable group plus the adder, the electric utility would be required to demonstrate that its earnings are not significantly excessive (Staff Ex. 10 at 8, 16, 19, 21-24, 26-27; Staff Br. at 27).

OCEA, OMA, and the Commercial Group recommend that the comparable firm process for the SEET be determined, as Staff proposes, as part of a workshop (OCEA Br. at 110; OMA Br. at 13; Commercial Group Br. at 9).

The Commission believes that the determination of the appropriate methodology for the SEET is extremely important. As evidenced by the extensive testimony in this case concerning the test, there are many different views concerning what is intended by the statute and what methodology should be utilized. However, as pointed out by several parties, whatever the ultimate determination of what the methodology should be for the test, the test itself will not be actually applied until 2010 and, as proposed by the Companies, will not commence until August 2010, after Compustat information is made publicly available (Cos. Ex. 5 at 11-12). Therefore, consistent with our opinion and order issued in the FirstEnergy ESP Case,[41] the Commission agrees with Staff that it would be wise to examine the methodology for the excessive earnings test set forth in the statute within the framework of a workshop. This is consistent with the Commission's finding that the goal of the workshop will be for Staff to develop a common methodology for the

41 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, Opinion and Order (December 19, 2008).

excessive earnings test that should be adopted for all of the electric utilities and then for Staff to report back to the Commission on its findings. Despite AEP-Ohio's assertions that FirstEnergy's ESP is no longer applicable since the FirstEnergy companies rejected the modified ESP, the Commission finds that a common methodology for significantly excessive earnings continues to be appropriate given that other ESP applications are currently pending and, even under AEP-Ohio's ESP application, the SEET information is not available until the July of the following year. Accordingly, the Commission finds that Staff should convene a workshop consistent with this determination. However, notwithstanding the Commission's conclusion that a workshop process is the method by which the SEET will be developed, we recognize that AEP-Ohio must evaluate and determine whether to accept the ESP as modified herein or reject the modified ESP and, therefore, require clarification of our decision as to OSS and deferrals (Cos. Reply Br. at 134). We find that a determination of the Companies' earnings as "significantly excessive" in accordance with Section 4928.143(F), Revised Code, necessarily excludes OSS and deferrals, as well as the related expenses associated with the deferrals, consistent with our decision regarding an offset to fuel costs for any OSS margins in Section III.A.1.b of this order. The Commission believes that deferrals should not have an impact on the SEET until the revenues associated with deferrals are received. Further, although we conclude that it is appropriate to exclude off-system sales from the SEET calculation, we do not wish to discourage the efficient use of OP's generation facilities and, to the extent that the Companies' earnings result from wholesale sources, they should not be considered in the SEET calculation.

VIII. MRO V. ESP

The Companies argue that "[t]he public interest is served if the ESP is more favorable in the aggregate than the expected results of an MRO" (Cos. Br. at 15). The Companies' further argue that the state policy set forth in Section 4928.02(A), Revised Code, is satisfied if the price for electric service, as part of the ESP as a whole, is more favorable than the expected results of an MRO (Id.). The Companies aver that not only is the SSO proposed under the ESP more attractive than the SSO resulting froman MRO, other non-SSO factors exist adding to the favorability of the ESP over the MRO (Cos. Ex. 2-A at 4, 8; Cos. Ex. 3 at 14-19). Specifically, AEP calculated the market price competitive benchmark for the expected cost of electricity supply for retail electric generation SSO customers in the Companies' service territories for the next three years as $88.15 per MWH for CSP and $85.32 per MWH for OP for full requirements service (Cos. Ex. 2-A at 5). These competitive benchmark prices were calculated by AEP using market data from the first five days of each of the first three quarters of 2008, and averaging the data (Id. at 15).

AEP-Ohio witness Baker then compared the ESP-based SSO with the MRO-based SSO, analyzing the following components: market prices for 2009 through 2011; the phase-in of the MRO over a period of time pursuant to Section 4928.142, Revised Code, at 10 percent, 20 percent, and 30 percent; the full requirements pricing components of the states of Delaware and Maryland; PJM costs; incremental environmental costs, POLR costs, and other non-market portions of an MRO-based SSO (Cos. Ex. 2-A at 3-17). AEP-Ohio witness Baker also considered non-SSO costs in the comparison, such as the distribution-related costs of $150 million for CSP and $133 million for OP (Id. at 16-17). AEP-Ohio concluded that the cost of the ESP is $1.2 billion and the cost of the MRO is $1.5 billion for CSP, while the cost of the ESP is $1.4 billion and the cost of the MRO is $1.7 billion for OP (Cos. Ex. 2-B, Revised Exhibit JCB-2). Therefore, AEP-Ohio states that the ESP for the Companies in the aggregate and for each individual company is clearly more favorable for customers, and would result in a net benefit to the customers under the ESP as compared to the MRO of $ 292 million for CSP and $262 million for OP (Id.; Cos. Br. at 135).

The Companies state that, in addition to the generation component, the ESP has other elements that, when taken in the aggregate, make the ESP considerably more favorable to customers than an MRO alternative (Cos. Ex. 2-A at 17-18). AEP-Ohio explains that the benefits in the ESP that are not available in an MRO, include: a shareholder-funded commitment focused on economic development and low-income customer assistance programs; price certainty and stability for generation service for a specified three-year period; and gridSMART and enhanced distribution reliability initiatives (Cos. Ex. 2-A at 17-18; Cos. Ex. 3 at 16-18; Cos. Br. at 135-137).

The Companies contend that once the Commission determines that the ESP is more favorable in the aggregate, then the Commission is required to approve the ESP. If the Commission determines that the ESP is not more favorable in the aggregate, then the Commission may modify the ESP to make it more favorable or it may disapprove the ESP application.

Staff states that, as a general principle, Staff believes that the Companies' proposed ESP is more favorable than what would be expected under an MRO (Staff Br. at 2). However, Staff explains that modifications to the proposed ESP are necessary to make the ESP reasonable (Id.). With Staff's proposed adjustments to the ESP rates, Staff witness Hess testified that the Companies' proposed ESP "results in very reasonable rates" (Staff Ex. 1 at 10). Furthermore, Staff witness Hess demonstrated, utilizing Staff witness Johnson's estimated market rates, that the ESP is more favorable in the aggregate as compared to the expected results of an MRO (Staff Ex. 1-A, Revised Exhibit JEH-1; Staff Br. at 26).

Several intervenors are critical of various components of AEP-Ohio's proposed ESP and thus conclude that the ESP, as proposed, is not more favorable in the aggregate and should be rejected or substantially modified, or that AEP-Ohio has failed to meet its burden of proof under the statute that the proposed ESP, in the aggregate, is more favorable than an MRO (OPAE Br. at 3, 22-23; OMA Br. at 3; Kroger Br. at 4; OHA Br. at 11; Commercial Group Br. at 2-3; OEG Br. at 2-3; Constellation Br. at 16-18). More specifically, OHA contends that the Commission must take into account all terms and conditions of the proposed ESP, not just pricing (OHA Br. at 8-9). OHA further explains that the Commission must weigh the totality of the circumstances presented in the proposed ESP with the totality of the expected results of an MRO (Id. at 9). OHA also states that the proposed ESP fails to mitigate the harmful effects of new regulatory assets, proposed deferrals, and rate increases on hospitals and, therefore, the ESP does not provide benefits that make it more favorable than a simple MRO (Id. at 11). IEU asserts that both the Companies' and Staff's comparison of the ESP to an MRO are flawed because the comparisons fail to reflect the projected costs of deferrals, assume the maximum blending percentages allowed under 4928.142, Revised Code, and fail to demonstrate the incremental effects of the maximum blending percentages on the FAC costs (IEU Br. at 33, citing Cos. Ex. 2-A, Staff Ex. 1, Exhibit JEH-1, Tr. Vol. XI at 78-82, and Tr. Vol. XIII at 87-88).

OCEA disputes the Companies' comparison of the ESP to the MRO, stating that the Companies have overstated the competitive benchmark prices (OCC Ex. 10 at 15; OCEA Br. at 19-24). Based on data from the fourth quarter 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the updated competitive benchmark prices should be $73.94 for CSP and $71.07 for OP (OCC Ex. 10 at 15-24). OCEA also questioned other underlying components of AEP witness Baker's comparison of the MRO to the ESP regarding the proposed ESP, as well as the exclusion of certain costs in the MRO calculation (Id. at 37-40). Nonetheless, OCEA ultimately concludes that AEP's ESP, if appropriately modified, is more favorable than an MRO (OCEA Br. at 19-24; OCC Ex. 10 at 39). Constellation also submits that the forward market prices for energy have fallen significantly since the Companies' filed their application and submitted their supporting testimony (Constellation Ex. 2 at 16).

Contrary to the position taken by Constellation and OCEA,[42] AEP-Ohio contends that the market price analysis supplied in support of the ESP does not need to be updated in order for the Commission to determine whether the ESP is more favorable that the expected result of the MRO. Furthermore, AEP-Ohio responds that the appropriate method is to look over a longer period of time, and not just focus on the recent decline in forward market prices. (Cos. Reply Br. at 130-131).

Contrary to arguments raised by various intervenors, AEP-Ohio avers that the legal standard to approve the ESP is not whether the Commission can make the ESP even more favorable, whether the rates are just and reasonable, whether the costs are prudently

[42] Constellation Br. at 17; OCEA Br. at 19-24.

incurred, whether the plan provisions are cost-based, or whether each provision of the plan is more favorable than an MRO (Cos. Reply Br. at 1-6). The Companies contend that the Commission only has authority to modify a proposed ESP if the Commission determines that the ESP is not more favorable than the expected results of an MRO (Id. at 4). As some intervenors have recognized,[43] the Commission does not agree that our authority to make modifications is limited to an after-the-fact determination of whether the proposed ESP is more favorable in the aggregate. Rather, the Commission finds that our statutory authority includes the authority to make modifications supported by the evidence in the record in this case. Based upon our opinion and order and using Staff witness Hess' methodology of the quantification of the ESP v. MRO comparison, as modified herein, we believe that the cost of the ESP is $673 million for CSP and $747 million for OP, and the cost of the MRO is $1.3 billion for CSP and $1.6 billion for OP.

Accordingly, upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

IX. CONCLUSION

The Commission believes that it is essential that the plan we approve be one that provides rate stability for the Companies, provides future revenue certainty for the Companies, and affords rate predictability for the customers. Upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. Therefore, the Commission finds that the proposed three-year ESP should be approved with the modifications set forth in this order. To the extent that intervenors have proposed modifications to the Companies' ESP that have not been addressed by this opinion and order, the Commission concludes that the requests for such modifications are denied.

Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this order, to be effective with bills rendered January 1, 2009. In light of the timing of the effective date of the tariffs, the Commission finds that the revised tariffs shall be approved upon filing, effective January 1, 2009, as set forth herein, and contingent upon final review by the Commission.

43 OEG Br. at 3.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) CSP and OP are public utilities as defined in Section 4905.02, Revised Code, and, as such, the companies are subject to the jurisdiction of this Commission.

(2) On July 31, 2008, CSP and OP filed applications for an SSO in accordance with Section 4928.141, Revised Code.

(3) On August 19, 2008, a technical conference was held regarding AEP-Ohio's applications and on November 10, 2008, a prehearing conference was held in these matters.

(4) On September 19, 2008, and October 29, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OPAE; APAC; OHA; Constellation; Dominion; NRDC; Sierra; NEMA; Integrys; Direct Energy; OMA; OFBF; Wind Energy; OASBO/OSBA/BASA; Ormet; Consumer Powerline; Morgan Stanley Capital Group Inc.; Commercial Group; EnerNoc, Inc.; and AICUO.

(5) The hearing in these proceedings commenced on November 17, 2008, and concluded on December 10, 2008. Eleven witnesses testified on behalf of AEP-Ohio, 22 witnesses testified on behalf of various intervenors, and 10 witnesses testified on behalf of the Commission Staff.

(6) Five local hearings were held in these matters at which a total of 124 witnesses testified.

(7) Briefs and reply briefs were filed on December 30, 2008, and January 14, 2009, respectively.

(8) AEP-Ohio's applications were filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.

(9) The proposed ESP, as modified by this opinion and order, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

ORDER:

It is, therefore,

ORDERED, That the Companies' application for approval of an ESP, pursuant to Sections 4928.141 and 4928.143, Revised Code, be modified and approved, to the extent set forth herein. It is, further,

ORDERED, That the Companies file their revised tariffs consistent with this opinion and order and that the revised tariffs be approved effective January 1, 2009, on a bills-rendered basis, contingent upon final review and approval by the Commission. It is further,

ORDERED, That each company is authorized to file in final form four complete, printed copies of its tariffs consistent with this opinion and order, and to cancel and withdraw its superseded tariffs. The Companies shall file one copy in this case docket and one copy in each Company's TRF docket (or may make such filing electronically, as directed in Case No. 06-900-AU-WVR). The remaining two copies shall be designated for distribution to Staff. It is, further,

ORDERED, That the Companies notify all affected customers of the changes to the tariff via bill message or bill insert within 45 days of the effective date of the tariffs. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further, ORDERED, That a copy of this opinion and order be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

KWB/GNS:vrm/ct

Entered in the Journal
MAR 1 8 2009

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	Case No. 08-918-EL-SSO

CONCURRING OPINION OF CHAIRMAN ALAN R. SCHRIBER

AND COMMISSIONER PAUL A. CENTOLELLA

We agree with the Commission's decision and write this concurring opinion to express additional rationales supporting the Commission's decision in two areas.

gridSMART Rider

The Order sets the initial amount to be recovered through the gridSMART rider based on the availability of federal matching funds for smart grid demonstrations and deployments under the American Recovery and Reinvestment Act of 2009. AEP-Ohio should promptly take the necessary steps to apply for available federal funding. Additionally, AEP-Ohio should work with staff and the collaborative established under the Order to refine its Phase 1 plan and initiate deployments in a timely and reasonable manner.

The foundation of a smart grid is an open-architecture communications system which, first, provides a common platform for implementing distribution automation, advanced metering, time-differentiated and dynamic pricing, home area networks, and other applications and, second, integrates these applications with existing systems to improve reliability, reduce costs, and enable consumers to better control their electric bills.

These capabilities can provide significant consumer and societal benefits. In the near term, participating consumers will have new capabilities for managing their energy usage to take advantage of lower power costs and reduce their electric bills. AEP-Ohio will be able to provide consumers feedback regarding their electric usage patterns and improved customer service. And, the combination of distribution automation and advanced metering should enable AEP-Ohio to rapidly locate damaged and degraded distribution equipment, reduce outages, and minimize the duration of any service interruptions. We expect that consumers will experience a material improvement in service and reliability.

SB 221 made it state policy to encourage time-differentiated pricing, implementation of advanced metering infrastructure, development of performance standards and targets for service quality for all consumers, and implementation of distributed generation. Section 4928.02 of the Revised Code. The Commission's Order advances these policies.

AEP-Ohio and its customers are likely to face significant challenges over the next decade from rising costs, requirements for improved reliability, and environmental constraints. Our Order will enable AEP-Ohio to take a first step in developing a modern grid capable of providing affordable, reliable, and environmentally sustainable electric service into the future.

PJM Demand Response Program

First, we wish to emphasize that the Commission supports demand response initiatives.

Second, it is essential that consumers benefit from demand response in terms of a reduction in the capacity for which AEP-Ohio customers are responsible. We encourage AEP-Ohio to work with PJM, the Commission, and interested stakeholders to ensure that predictable consumer demand response is recognized as a reduction in capacity that it must carry under PJM market rules.

Finally, consumers should have the opportunity to see and respond to changes in the cost of the power that they use. While an ESP may set the overall level of prices, consumers should have additional opportunities to benefit by reducing consumption when wholesale power prices are high. We would encourage the companies to work with staff to develop additional dynamic pricing options for commercial and industrial SSO customers who have the interval metering needed to support such rates. Such options should enable eligible consumers to directly manage risk and optimize their energy usage.

Alan R. Schriber

Paul A. Centolella

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)))))	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	))))	Case No. 08-918-EL-SSO

ENTRY ON REHEARING

The Commission finds:

(1) On July 31, 2008, The Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. The application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

(2) On March 18, 2009, the Commission issued its opinion and order (Order) in these matters approving, with modifications, AEP-Ohio's proposed ESP. On March 30, 2009, the Commission amended, nunc pro tunc, its Order.

(3) Section 4903.10, Revised Code, states that any party to a Commission proceeding may apply for rehearing with respect to any matters determined by the Commission, within 30 days of the entry of the order upon the Commission's journal.

(4) On April 16, 2009, Ohio Energy Group (OEG) and Industrial Energy Users-Ohio (IEU) each filed applications for rehearing. Applications for rehearing were also filed by the Office of the Ohio Consumers' Counsel (OCC); Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (collectively, Schools); Ohio Hospital Association (OHA); Ohio

Manufacturers' Association (OMA); Kroger Company (Kroger); and AEP-Ohio on April 17, 2009. Memoranda contra the various applications for rehearing were filed by Kroger, OCC, AEP-Ohio, IEU, OEG, Integrys Energy Service, Inc. (Integrys), and Ohio Partners for Affordable Energy (OPAE). In their applications for rehearing, the various intervenors raised a number of assignments of error, alleging that the Order is unreasonable and unlawful.

(5) By entry dated May 13, 2009, the Commission granted rehearing for further consideration of the matters specified in the applications for rehearing. In this entry, the Commission will address the assignments of error by subject matter as set forth below.

(6) The Commission has reviewed and considered all of the arguments on rehearing. Any arguments on rehearing not specifically discussed herein have been thoroughly and adequately considered by the Commission and are being denied.

(7) IEU filed a motion for immediate relief from electric rate increases on April 20, 2009, and AEP-Ohio filed a memorandum contra on April 23, 2009. IEU filed a reply on April 24, 2009. Further, on June 5, 2009, OCC, OMA, Kroger, and OEG filed a motion for a refund to AEP-Ohio's customers and a motion for AEP-Ohio to cease and desist future collections related to its arrangement with Ormet Primary Aluminum Corporation (Ormet) from its customers. AEP-Ohio and Ormet filed memoranda contra the motions on June 12, 2009, and June 23, 2009, respectively, and the movants replied on June 17, 2009, and June 30, 2009. OCC also indicates in its application for rehearing that it is seeking rehearing on the two March 30, 2009, orders issued by the Commission, which includes the Entry Nunc Pro Tunc that amended the Order in this proceeding, as well as the order issued denying a motion for a stay. The Commission will address the substance of all of the motions, and all responsive pleadings, within our discussion of and decision on the merits of the applications for rehearing as set forth below. Accordingly, with the consideration herein of the issues raised in the motions, the motions are granted or denied as discussed herein.

I. GENERATION

A. Fuel Adjustment Clause (FAC)

(8) AEP-Ohio asserts that limiting the FAC to only three years (the term of the ESP) is unreasonably restrictive (Cos. App. at 37-38). AEP-Ohio argues that it is unreasonable to allow the FAC to expire given that a FAC may be required in a future SSO established in accordance with Section 4928.141, Revised Code.

(9) IEU and OCC disagree with AEP-Ohio and submit that there is no valid reason for the FAC mechanism to extend beyond the life of the ESP (IEU Memo Contra at 13; OCC Memo Contra at 6-7).

(10) The Commission finds that AEP-Ohio's argument lacks merit, and therefore AEP-Ohio's rehearing request on this ground should be denied. The Commission limited the authorized FAC mechanism, established as part of the proposed ESP, to the term of the ESP approved by the Commission. If a FAC mechanism is proposed in a subsequent SSO application filed pursuant to Section 4928.141, Revised Code, the Commission will determine the appropriateness of the SSO proposal, including all of its terms, at that time. It is unnecessary, at this time, to extend this provision of the ESP beyond the term of the approved ESP.

1. FAC Costs

(a) Off-System Sales (OSS)

(11) OCC contends that the Commission erred by not crediting customers for revenues from OSS and for not following its own precedent (OCC App. at 16). OCC relies on past Commission decisions concerning electric fuel clause (EFC) proceedings.

(12) IEU also disagrees with the exclusion of an offset to the FAC costs for revenues associated with OSS, claiming that the Commission did not explain the basis for its decision (IEU App. at 11).

(13) AEP-Ohio notes that OCC's arguments were already rejected by the Commission in its Order, and that the Commission's decision is not inconsistent with any of its precedents regarding the sharing of profits from OSS between a utility and its customers (Cos. Memo Contra at 40). AEP-Ohio distinguishes previous EFC proceedings from proceedings filed pursuant to SB 221.

(14) The Commission first explains that this is not an EFC proceeding. While some aspects of the automatic recovery mechanism contained in Section 4928.143(B)(2)(a), Revised Code, may be analogous to the EFC mechanism, the statutory provisions regarding the EFC were repealed many years ago. Thus, OCC's cited precedent is irrelevant to our ruling in this case with respect to the OSS. Secondly, contrary to IEU's assertion, the Commission has already fully considered and addressed, in the Order at pages 16-17, all of the arguments raised on rehearing by OCC, as well as those raised by other intervenors in the proceeding. The Commission explained that Section 4928.143(B)(2)(a), Revised Code, specifically provides for the automatic recovery, without limitation, of certain prudently incurred costs: the cost of fuel used to generate the electricity supplied under the SSO; the cost of purchased power supplied under the SSO, including the cost of energy and capacity and power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes. Given that OCC and IEU have failed to raise any new arguments regarding this issue, rehearing on these grounds should be denied. However, we emphasize that FAC costs are to continue to be allocated on a least cost basis to POLR customers and then to other types of sale customers. Allocating the lowest fuel cost to POLR service customers is consistent with the electric utilities' obligation to POLR customers and will minimize the burden on most ratepayers.

2. FAC Baseline

(15) OCC's first assignment of error is that the Commission's adoption of the FAC baseline was not based on actual data in the record, and that the Company bears the burden of creating such a record in order to collect fuel costs pursuant to Section 4928.143(B)(2)(a), Revised Code (OCC App. at 12). OCC

recognizes that an ESP may recover the costs of fuel, but argues that these costs must be "prudently incurred" (Id.). OCC adds that "[t]he clear language [of SB 221] must be read to include recovery of only actual costs as anything more would not be prudent to recover from customers" (Id.). Nonetheless, OCC then admits that the actual 2008 fuel costs were not known at the time of the hearing,[1] but requests that the Commission order the Companies to produce actual fuel costs for 2008, after the record of the case has been closed, for purposes of establishing the baseline. Thus, OCC would have the Commission do exactly what its first assignment of error is criticizing the Commission's order for doing, which is use data that is not in the record.

(16) Similarly, IEU argues that, based on information and reports that have been subsequently developed and filed in other jurisdictions, Staff's methodology was incorrect. Therefore, IEU requests that the Commission adopt a methodology that sets the baseline based on 2008 actual costs (IEU App. at 12-13).

(17) AEP-Ohio responds that the Commission's decision must be based on the record before it and it is not feasible to do what OCC and IEU request (Cos. Memo Contra at 39). Nonetheless, AEP-Ohio states that, even if the 2008 data was available in the record, it would be inappropriate to use absent substantial adjustments due to the volatility of fuel costs in 2008 and the extraordinary procurement activities that occurred (Id., citing Cos. Ex. 7B at 2-3; Tr. XIV at 74-75).

AEP-Ohio further argues that the Commission's modification of the Companies' baseline contained in its proposed ESP was unreasonable. AEP-Ohio argues that its methodology was the appropriate methodology because its methodology identifies the portion of the 2008 SSO rate that correlates to the new FAC rate, and is not a proxy for 2008 fuel costs (Cos. App. at 38-39). OCC disagrees and urges the Commission to reject AEP-Ohio's methodology, as well as Staff's, and adopt the actual 2008 fuel costs (OCC Memo Contra at 8).

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1 We will assume that OCC's reference to 2009 actual data was a typographical error and the reference should be to 2008 (see OCC App. at 13).

(18) As explained in the Order, the actual 2008 fuel costs were not known at the time of the hearing (Order at 19, citing OCC Ex. 10 at 14). Therefore, based on the evidence presented in the record, the Commission determined that a proxy should be used to calculate the appropriate baseline. After making this determination, the Commission reviewed all evidence in the record and all parties' arguments, and adopted Staff's methodology and resulting value as the appropriate FAC baseline. AEP-Ohio, OCC, and IEU have raised no new arguments regarding this issue. Accordingly, rehearing on this ground is denied.

3. <u>FAC Deferrals</u>

(19) OCC argues that the Commission erred by not requiring deferrals and carrying costs to be calculated on a net-of-tax basis, and the Commission's reliance on Section 4928.144, Revised Code, was misplaced because the FAC deferral approved by the Commission is not a phase-in of rates authorized by SB 221 (OCC App. at 14). The Schools, however, conclude that the Commission exercised its authority pursuant to Section 4928.144, Revised Code, when it found that AEP-Ohio should phase-in any authorized increases, and that those amounts over the allowable increase percentage levels would be deferred pursuant to Section 4928.144, Revised Code, with carrying costs (Schools App. at 4). Notwithstanding the Commission's statutory authority to phase-in increases through deferrals, the Schools assert that School Pool participants who buy generation service from competitive retail electric service (CRES) providers should receive a credit on their bills during the ESP equal to the fuel that is being deferred (even though FAC deferrals will not be recovered via an unavoidable surcharge until 2012, if necessary) (Id. at 5). The Schools rationalize that any other outcome would violate the policy of the state, specifically Section 4928.02(H), Revised Code (Id. at 6).

(20) OCC also argues that the Commission failed to follow its own precedent and that deferrals are incompatible with Section 4928.143(B)(2)(d), Revised Code, inasmuch as the deferrals destabilize customer prices, introduce uncertainty, and are unfair and unreasonable (OCC App. at 14, 42-44). OCC recognizes that SB 221 allows deferrals under an ESP, but states

that those deferrals are limited to those that stabilize or provide certainty (Id. at 42). OCC explains that deferrals will cause future rate increases and add carrying costs to the total amount that customers will pay. OCC adds that the record is void of any projection that electric rates will decrease following the ESP period, and, therefore, concludes that the deferrals will have a de-stabilizing effect on customers' electric bills beginning in 2012 (Id. at 42-43). The Commission notes that based on its analysis of the Companies' ESP, as approved in the Order and modified in this entry on rehearing, our projections indicate that deferred fuel cost will likely be fully amortized by the end of this ESP for CSP and within two to three years after the end of this ESP for OP.

(21) OCC further contends that the use of a weighted average cost of capital (WACC) to calculate the carrying costs associated with the FAC deferrals is unreasonable and will result in excessive payments by customers. OCC asserts that the carrying charges should instead be based on the actual financing required to carry the deferrals during the short-term period (Id. at 45).

(22) IEU submits that the Commission failed to require AEP-Ohio to limit the total bill increases to the percentage amounts specified in the Order (IEU App. at 40).

(23) AEP-Ohio supports the Commission's decision authorizing FAC deferrals, with carrying costs, and contends that the authorized phase-in of rate increases, and associated FAC deferrals, comply with Section 4928.144, Revised Code, and are compatible with Section 4928.143(B)(2)(d), Revised Code (Cos. Memo Contra at 42). AEP-Ohio also supports the use of WACC, rather than a short-term debt interest rate, given that the period of cost deferrals and their subsequent recovery will take place over the next ten years (Id. at 43).

(24) AEP-Ohio, however, argues that the Commission's adjustment to its phase-in proposal and 15 percent cap on the ESP rate increases were unreasonable, disrupting the balance between up-front revenue recovery and subsequent recovery of deferrals (Cos. App. at 12). To this end, AEP-Ohio contends that the Commission's authority under Section 4928.144, Revised Code, "must be exercised in the total context of Chapter 4928, Ohio

Rev. Code, particularly in the context of the standard for approval of an ESP without modification" (Id., n.6). AEP-Ohio adds that the Commission's modification of its 15 percent cap was "too severe," and requests that the Commission rebalance the amount of the authorized increases and the size of the deferrals to reflect, at a minimum, annual 10 percent increases during the ESP term (Id. at 12-13). While agreeing with AEP-Ohio that the Order is unjust and unreasonable, IEU disagrees that the balance favors customers. IEU argues that the Commission's imposition of limits on the total percentage increases on customers' bills has not been followed (IEU Memo Contra at 8-9).

(25) Furthermore, AEP-Ohio requests that, if the Commission does not modify the total percentage increases allowed, the Commission should clarify the intended scope of the limitations that it has imposed, and specify that the 15 percent cap does not include revenue increases associated with a distribution base rate case or the revenues associated with the Energy Efficiency and Peak Demand Reduction Cost Recovery (EE/PDR) Rider (Cos. App. at 13). OEG supports AEP-Ohio's clarification, while IEU urges the Commission to reject AEP-Ohio's requested clarification, and find that the limitations on the percentage increases imposed by the Commission in the Order apply on a total bill basis (OEG Memo Contra at 3; IEU Memo Contra at 9).

(26) Section 4928.144, Revised Code, authorizes the Commission to order any just and reasonable phase-in of any electric utility rate or price established pursuant to an ESP, with carrying charges, and requires that any deferrals associated with the authorized phase-in be collected through an unavoidable surcharge. The Commission continues to believe that a phase-in of the ESP increases, as authorized by Section 4928.144, Revised Code, is necessary to ensure rate or price stability and to mitigate the impact on customers. We further believe that our established limits on the total percentage increases on customers' bills in each year were just and reasonable and remain appropriate. Nonetheless, upon further review of the workpapers filed with the tariffs and the comments received from parties concerning the practical application of the total percentage increases on customers' bills, it has come to the Commission's attention that the Companies included in the total allowable revenue increase

an amount that equals the revenue shortfall associated with their joint service territory customer, Ormet. In their calculation, the Companies assumed that the joint service territory customer would continue paying the amount that it was paying on December 31, 2008 (established pursuant to a prior settlement), which was above the approved tariff rate for that rate schedule. Instead, the Companies should have calculated the allowable total revenue increase based on that customer paying the December 31, 2008, approved tariff rate for its rate schedule. Additionally, the Companies' calculation should have been levelized and not reflected any variations in customers' bills for tariff/voltage adjustments. Accordingly, we direct the Companies to recalculate the total allowable revenue increase approved by our Order issued on March 18, 2009, as clarified by the Entry Nunc Pro Tunc issued on March 30, 2009, and as modified herein, and file revised tariffs consistent with such calculation.

(27) Additionally, the Commission clarifies that the Transmission Cost Recovery (TCR) rider should not impact the allowable total percentage increase. As approved in the Order, the TCR rider will continue to be a pass-through of actual transmission costs incurred by the Companies that is reconciled quarterly. Similarly, any future adjustments to the EE/PDR Rider are excluded from the allowable total percentage increases. As explained in the Order, the EE/PDR Rider was designed to recover costs associated with the Companies' implementation of energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the Companies' peak demand pursuant to Section 4928.66, Revised Code (Order at 41). The costs included in the EE/PDR Rider will be trued-up annually to reflect actual costs.

(28) We further clarify that the phase-in/deferral structure does not include revenue increases associated with any distribution base rate case that may occur in the future. Any distribution rates established pursuant to a separate proceeding, outside of an SSO proceeding, will be considered separately. Section 4928.144, Revised Code, authorizes phase-in of rates or prices established pursuant to Sections 4928.141 to 4928.143, Revised Code, not distribution rates established pursuant to Section 4909.18, Revised Code.

(29) With respect to OCC's and the Schools' issues regarding the FAC deferrals and carrying charges, we find that those issues were thoroughly addressed in our Order at pages 20-24, and that the parties have raised no new arguments regarding those issues. Accordingly, the Commission finds that rehearing on those assignments of error are denied.

(30) Similarly, the Commission finds that AEP-Ohio's arguments regarding its proposed 15 percent cap were fully addressed in our Order, and AEP-Ohio has raised no new arguments to support its position. Additionally, AEP-Ohio's alternative proposal of an annual 10 percent cap fails on similar grounds. The Companies have offered no justification or support for its adjusted proposal. As such, the Commission finds that rehearing on this ground is denied.

(31) With respect to the other assignments of error raised, the Commission emphasizes that it was the intent of our Order to phase-in the authorized increases and to limit the total percentage increases on customers' bills to an increase of 7 percent for CSP and 8 percent for OP for 2009, an increase of 6 percent for CSP and 7 percent for OP for 2010, and an increase of 6 percent for CSP and 8 percent for OP for 2011, as explained herein. To the extent that the Commission's intent was not memorialized in the Companies' tariffs, or the application of those tariffs, we grant rehearing to correct the errors or clarify our Order as delineated above.

B. <u>Incremental Carrying Cost for 2001-2008 Environmental Investment and the Carrying Cost Rate</u>

(32) In the Order, the Commission concluded that AEP-Ohio should be allowed to recover the incremental capital carrying costs that will be incurred after January 1, 2009, on past environmental investments (2001-2008) that are not presently reflected in the Companies' existing rates, as contemplated in AEP-Ohio's RSP Case. Further, the Commission found that the recovery of continuing carrying costs on environmental investments, based

on WACC, is consistent with our decision in the 07-63 Case[2] and the RSP 4 Percent Cases.[3] The Commission agreed with the rationale presented by the Companies that the levelized carrying cost rates were reasonable and should be approved.

(33) First, IEU argues that the Commission's decision fails to comply with the requirements of Section 4903.09, Revised Code, to sufficiently set forth the reasons prompting the Commission's decision based upon the findings of fact in regards to carrying costs and several other issues (IEU App. at 4-26).

(34) IEU and OCC argue that Section 4928.143(B)(2)(b), Revised Code, limits any allowance for an environmental expenditure or cost to those incurred on or after January 1, 2009. IEU and OCC interpret Section 4928.143(B)(2)(b), Revised Code, to only allow the electric utility to recover a reasonable allowance for construction work in progress for any of the electric utility's costs for environmental expenditures for any electric generating facility, provided the costs are incurred or the expenditures occur on or after January 1, 2009 (IEU App. at 14; OCC App. at 38-39). OCC argues, as it did in its brief,[4] that both divisions (B)(2)(a) and (B)(2)(b) of Section 4928.143, Revised Code, require an after-the-fact determination that the expenditures were prudent and are, therefore, inappropriate for the Commission's consideration in this ESP proceeding (OCC App. at 38). OCC contends that the Order failed to address whether it was proper under the statute to collect carrying costs on the environmental investment as the Commission merely accepted Staff's position (OCC App. at 38-39). OCC concludes that the prudence of the environmental investment should be examined in a subsequent proceeding.

(35) Further, IEU and OCC also claim that the Commission failed to calculate the carrying charges on the various types of special financing available to finance environmental or pollution control assets, including the cost of short-term debt, consistent

2 *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC, Opinion and Order (October 3, 2007) (07-63 Case).

3 *In re Columbus Southern Power Company and Ohio Power Company*, Case Nos. 07-1132-EL-UNC, 07-1191-EL-UNC, and 07-1278-EL-UNC (RSP 4 Percent Cases).

4 OCC and the Sierra Club-Ohio Chapter joined together to file its brief in this matter and referred to themselves jointly as the Ohio Consumer and Environmental Advocates (OCEA).

with the Commission's rulings in other proceedings (IEU App. at 15; OCC App. at 46).[5]

(36) AEP-Ohio argues that to comply with the requirements of Section 4903.09, Revised Code, the Order must show, in sufficient detail, the facts in the record upon which the order is based, and the reasoning followed by the Commission in reaching its conclusion.[6] Thus, AEP-Ohio concludes that as long as there is a basic rationale and record evidence supporting the Order, no violation of Section 4903.09, Revised Code, exists (Cos. Memo Contra at 8-9).[7]

(37) Further, AEP-Ohio argues that OCC is mischaracterizing the Companies' request for environmental carrying costs pursuant to Section 4928.143(B)(2)(b), Revised Code. AEP-Ohio argues that its requests for environmental carrying costs incurred during the ESP period are based on the broader language of Section 4928.143(B)(2), Revised Code. AEP-Ohio notes that Section 4928.143(B)(2), Revised Code, states that a company's ESP may provide for or include, without limitation, any of the provisions itemized in paragraphs (a) through (i) of Section 4928.143(B)(2), Revised Code (Cos. Memo Contra at 45-46).

(38) The Commission affirms its decision to permit AEP-Ohio to recover the carrying costs to be incurred after January 1, 2009, on environmental investments made prior to 2008. The Commission interprets Section 4928.143(B)(2), Revised Code, like the Companies, to permit AEP-Ohio to include as a part of its ESP the carrying costs on environmental investments that are incurred January 1, 2009, through December 31, 2011, the ESP period. The carrying costs on the environmental investments fall within the ESP period and, therefore, may be included in the ESP pursuant to the broad language of Section 4928.143(B)(2), Revised Code, permitting recovery for unenumerated expenses.

5 See *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Company's Transmission Cost Recovery Rider*, Case No. 08-1202-EL-UNC, Finding and Order at 4 (December 17, 2008); *In the Matter of the Application of The Dayton Power and Light Company for Authority to Modify its Accounting Procedure for Certain Storm-Related Services Restoration Costs*, Case No. 08-1332-EL-AAM, Finding and Order at 1 (January 14, 2009).

6 *Indus. Energy Users-Ohio v. Public Util. Comm.* (2008), 117 Ohio St.3d 486, 493, quoting *MCI Telecommunications Corp. v. Pub. Util. Comm.* (1987), 32 Ohio St.3d 306, 312.

7 *Tongren v. Pub. Util. Comm.* (1999), 85 Ohio St.3d 87, 90.

As noted in the Order, approval of the continuing environmental carrying costs is consistent with the Commission's decisions in the 07-63 and the RSP 4 percent cases. Given our prior orders, we find that inclusion of these expenses is reasonable. IEU and OCC have not raised any new claims that the Commission have not previously considered regarding the carrying costs on AEP-Ohio's environmental investments. Accordingly, IEU's and OCC's requests for rehearing on this issue are denied.

C. Annual Non-FAC Increases

(39) AEP-Ohio asserts that the Commission's rejection of the proposed automatic annual increases to the non-FAC portion of the generation rates is unlawful and unreasonable (Cos. App. at 14-17). AEP-Ohio claims that the proposed annual increases of 3 percent for CSP and 7 percent for OP were intended to recover costs during the ESP period associated with environmental investments made during that period, as well as cost increases related to unanticipated, non-mandated, generation-related cost increases (Id. at 14). AEP-Ohio notes that, although the Order adopted Staff's proposal regarding recovery of carrying charges on new environmental investments, the Commission's failure to adopt any automatic, annual increases was unreasonable and unlawful pursuant to Section 4928.143(B)(2)(e), Revised Code (Id. at 15). The Companies specifically request that the Commission authorize the 3 and 7 percent automatic, annual increases, offset by whatever revenue increase is granted in relation to the recovery of carrying costs related to new environmental investment (Id. at 15-16). At one point, however, AEP-Ohio seems to be arguing that the Commission should adopt any automatic, annual increases, regardless as to whether it is the amount of increases proposed by AEP-Ohio or the amount recommended by Staff (Id. at 15).

(40) As noted by IEU and OCC, the Companies do not raise any new arguments with regard to allowing automatic, annual increases (IEU Memo Contra at 9-10; OCC Memo Contra at 10). Just as we concluded in the Order, the Companies have failed to sufficiently support the inclusion of such automatic increases, and the record is void of any justification for the increases.

AEP-Ohio has raised no new arguments, and thus, its request for rehearing on this ground is denied.

(41) With regard to the recovery of carrying charges on new environmental investments, AEP-Ohio questions the timing of when it may seek recovery of the carrying costs associated with the new investments made during the ESP (Cos. App. at 16).

(42) In our Order, we adopted Staff's approach regarding the recovery of the carrying costs for environmental investments made during the ESP period, and found that the Companies could request, through an annual filing, recovery of carrying costs after the investments have been made to reflect actual expenditures (Order at 29-30). The Commission cited Staff's example, which envisioned an application in 2010 for recovery of 2009 actual environmental investment costs and annually thereafter for each succeeding year to reflect the actual expenditures (Id., citing Tr. Vol. XII at 132; Staff Ex. 10 at 7). To clarify, we conclude that Staff's approach, requiring an application to request recovery of actual environmental investment expenditures after those expenditures have been incurred, is reasonable.

II. DISTRIBUTION

A. Annual Distribution Increases

(43) The Companies proposed two plans, an Enhanced Service Reliability Plan (ESRP) and gridSMART, to support initiatives to improve AEP-Ohio's distribution system and service to its customers. The Companies requested annual distribution rate increases of 7 percent for CSP and 6.5 percent for OP to implement the two plans. In the Order, the Commission considered the two plans separately and found that the annual distribution rate increases were unnecessary in light of the Commission's findings on the ESRP and gridSMART plans, and consequently eliminated the annual distribution rate increases from the ESP (Order at 30-38).

(44) Kroger maintains that the Commission properly rejected AEP-Ohio's annual distribution rate increases (Kroger Memo Contra at 7).

1. ESRP

(45) AEP-Ohio asserts that the Commission's deferment of certain aspects of its ESRP to a distribution rate case where all components of distribution rates would be subject to review is unreasonable and unlawful in violation of Section 4928.143(B)(2)(h), Revised Code (Cos. App. at 27). AEP-Ohio posits that the Commission's conclusion conflicts with the express provisions of SB 221, which permit single-issue ratemaking proposals for distribution infrastructure and modernization initiatives within ESP proposals (Id. at 27-28). AEP-Ohio further claims that it "merely sought incremental funding to support an incremental level of reliability activities designed to maintain and enhance service reliability levels" (Id. at 27).

(46) AEP-Ohio argues that the Commission erred by failing to find that three of the four ESRP initiatives met the statutory requirements of Section 4928.143(B)(2)(h), Revised Code (Id. at 28). While AEP-Ohio commends the Commission on its finding that the enhanced vegetation management program did meet the statutory requirements, it believes that the Commission should have reached similar conclusions on the other ESRP programs (Id.).

(47) Conversely, Kroger and OPAE contend that the Commission lawfully and reasonably deferred the decision to implement all but one of the ESRP initiatives to a distribution rate case (Kroger Memo Contra at 7-8; OPAE Memo Contra at 5). Kroger explains that, while Section 4928.143(B)(2)(h), Revised Code, allows an ESP to include provisions regarding single-issue ratemaking, it does not mandate that the Commission approve such provisions, and it especially does not require the Commission to authorize all distribution proposals included in an ESP (Id.).

(48) OCC opines that, although it agrees with the decision to defer ruling on the three ESRP initiatives, it believes that the Companies failed to meet their burden of proof in demonstrating that the vegetation management program complies with Ohio law and is in the public interest (OCC App. at 57-59). OCC also disputes the Commission's application of Section 4928.143(B)(2)(h), Revised Code, and states that the Commission erred in finding that the vegetation management

initiatives met the statutory requirements. OCC also submits that the Commission erred when it characterized the proposed vegetation initiative as "cycle-based" (OCC App. at 61).

(49) Moreover, OCC alleges that the Commission acted unlawfully when it approved an ESRP rider without specifying an identified amount and without receiving testimony on the need for the riders (Id. at 55).

(50) As stated in the Order, the Commission recognizes that Section 4928.143(B)(2)(h), Revised Code, authorizes the Companies to include in its proposed ESP provisions regarding single-issue ratemaking for distribution infrastructure and modernization incentives. However, the statute also dictates what the Commission must do as part of its determination as to whether to allow an ESP to include such provisions. Section 4928.143(B)(2)(h), Revised Code, states, in pertinent part:

> As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of *any provision* described in division (B)(2)(h) of this section, the commission *shall examine* the reliability of the electric distribution utility's distribution system *and ensure* that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

Section 4928.143(B)(2)(h), Revised Code (emphasis added).

The Commission examined the four initiatives included as part of the Companies' ESRP and determined that only one, the enhanced vegetation initiative, met these criteria. Contrary to AEP-Ohio's assertion,[8] the Commission did consider and evaluate each initiative and found that the enhanced vegetation initiative was the only initiative that was supported by the record in this proceeding (see Order at 30-32). The Commission concluded that, at the time of the Order, the record did not

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8 Cos. App. at 30.

contain sufficient evidence to support the other three initiatives and, thus, the Commission declined to implement the programs within the context of the ESP; however, the Commission stated that it would consider the initiatives further in the context of a distribution rate case.

(51) The Commission continues to believe that the appropriate vehicle to review, consider, and make a determination on the remaining initiatives, as well as the recovery of any costs associated with those initiatives, is through a distribution base rate case. Accordingly, AEP-Ohio's request for rehearing on this issue is denied.

(52) The Commission agrees with OCC with regard to the three initiatives referenced above. The Commission did not believe that the record supported the need for those programs and, thus, the Commission declined to include those programs in the ESRP, and declined to include any recovery for such programs in the ESRP rider. The Commission disagrees, however, that the record was void of any evidence regarding the vegetation management program and costs associated therewith. Several individuals, including an OCC witness, testified on the proposed plan, as well as the Companies' current practices (Cos. Ex. 11; OCC Ex. 13; Staff Ex. 2; Tr. Vol. VII 64-65, 84, 87-88; Tr. Vol. VIII at 60-62). Testimony was also heard on the expenditures associated with the proposed vegetation initiative and the recovery of those costs (Staff Ex. 2 at 9-13). The Commission created the ESRP Rider as a mechanism to recover the actual costs incurred so that the expenditures could be tracked, reviewed to determine that they were prudent and incremental to costs included in base rates, and reconciled annually. As fully discussed in the Order at pages 30-34, the Commission finds that the Companies did meet their burden of proof to demonstrate that the vegetation management program, with Staff's additional recommendations, was reasonable, in the public interest, and in compliance with the statutory requirements. OCC raises no new arguments on rehearing and, therefore, rehearing on this ground is denied.

(53) AEP-Ohio seeks clarification on the additional Staff recommendations that the Commission approved as part of the enhanced vegetation initiative (Cos. App. at 34).

(54) The Commission found that the enhanced vegetation initiative, with Staff's additional recommendations, was a reasonable program that will advance the state policy. The Commission emphasized the importance of a balanced approach that not only reacts to problems that occur, but that also maintains the overall system. To achieve this goal, the Commission fully expects the Companies to work with Staff to strike the correct balance within the cost level established by our Order, which is based on the Companies' proposed ESRP program.

(55) AEP-Ohio also seeks clarification on the final paragraph in the Order that discusses cost recovery associated with the three remaining initiatives proposed through the ESRP (Cos. App. at 32).

(56) The Commission further clarifies that the language regarding cost recovery and the inclusion of costs associated with the remaining initiatives in the ESRP rider is permissive and conditioned on subsequent Commission approval for including such costs. Specifically, the Commission stated: "*If* the Commission, in a subsequent proceeding, determines that the programs regarding the remaining initiatives should be implemented, and thus, the associated costs should be recovered, those costs *may*, at that time, be included in the ESRP rider for future recovery, subject to reconciliation as discussed above" (Order at 34 (emphasis added)).

2. <u>GridSMART</u>

(57) The Order recognized that federal matching funds under the American Recovery and Reinvestment Act of 2009 (ARR Act) are available for the installation of gridSMART Phase I and directed AEP-Ohio to make the necessary filing to request the federal funds. Given the availability of federal funds, the Commission reduced the Companies' request for gridSMART Phase I from $109 million (over the term of the ESP) by half to $54.5 million for the term of the ESP. Further, the Order established the gridSMART rider for 2009 at $33.6 million based on projected expenses, subject to an annual true-up and reconciliation of CSP's prudently incurred costs.

(58) In its application for rehearing, AEP-Ohio notes that CSP developed an incremental revenue requirement for gridSMART Phase I of approximately $64 million during the ESP term (Cos. Ex. 1 DMR-4) and, therefore, CSP's compliance tariffs reflect, consistent with the intent of the Order, half of the incremental revenue requirement. According to AEP-Ohio, as reflected in the Companies' compliance tariff filing, the initial gridSMART rider rate is designed to recover approximately $32 million or half of the gridSMART Phase I incremental revenue requirement (Cos. App. at 35, n.13).

(59) However, AEP-Ohio argues that the Commission's discussion of the ARR Act and the likelihood of AEP-Ohio obtaining such funds are beyond the scope of the record. Further, AEP-Ohio asserts that the details for federal funding of smart grid projects have not been fully developed. The Companies argue that, to the extent that the Order conclusively presumes that AEP-Ohio will secure federal matching funds for each dollar invested by the Companies and their customers, the Order is unreasonable and unlawful. AEP-Ohio states that the Commission's decision as to gridSMART places CSP in an unfunded mandate situation to the extent that CSP receives less than 50 percent for its gridSMART project or the U.S. Department of Energy institutes a cap of $20 million on each gridSMART project. For this reason, AEP-Ohio requests that the Commission clarify that it intends to fully fund the gridSMART Phase I project through rates. Otherwise, AEP-Ohio reasons that the Commission lacks the authority to order enhancement programs without recovery for the utility as to improvements ordered. *Forest Hills Utility Co. v. Pub. Util. Comm.* (1972), 31 Ohio St.2d 46, 57 (Cos. App. at 35-37).

(60) OCC contends that AEP-Ohio's assertion that the directive to proceed with gridSMART Phase I without commensurate rate relief contradicts *Forest Hills* and will be subject to reversal by the Supreme Court of Ohio is inappropriate at this time and unfounded. OCC reminds the Companies that, pursuant to the Order, the initial rider is established to provide AEP-Ohio $33.6 million for its 2009 gridSMART expenditures. Accordingly, OCC states that AEP-Ohio has not been denied funding and there has been no determination that AEP-Ohio's prudently incurred gridSMART costs will not be fully covered in the

future. Thus, OCC reasons that the Companies' claim of an unfunded mandate situation is premature, and the request for rehearing should be denied (OCC Memo Contra at 23-25).

(61) First, the Commission acknowledges that the Order inadvertently based the gridSMART component of the Companies' ESP on $109 million, which is the total projected investment costs, including operations and maintenance expenses, for the Companies' proposed gridSMART Phase I project. As the Companies explain, CSP's ESP application included a request for the incremental revenue requirement for gridSMART during the ESP of approximately $64 million (Cos. Ex. 1 DMR-4). As recognized by AEP-Ohio and implemented in its tariff filing, it was our intent to approve recovery of half of the gridSMART Phase I incremental revuene requirement, $32 million. Accordingly, rehearing is granted to correct this error in our Order.

(62) Next, the situation before the Supreme Court in *Forest Hills,* is factually different from the situation for CSP as to gridSMART Phase I. In *Forest Hills,* the court held that the utility had not been awarded funding to adequately maintain utility service much less the iron removal equipment and water storage tanks ordered by the Commission. In this instance, the initial gridSMART rider is set at $32 million for 2009 projected expenses, subject to annual true-up and reconciliation based on CSP's prudently incurred costs and application for federal funding. Based on the information presented at Cos. Ex. 1 DMR-4, $32 million represents sufficient revenues for CSP to commence its gridSMART program. As noted in the Order, the Commission wishes to encourage the expedient implementation of gridSMART. However, the Commission will not let the desire for the expedient implementation of gridSMART cloud the financial soundness of the costs to ultimately be incurred by Ohio's ratepayers. Consistent with our decision to approve the gridSMART Phase I project, we clarify that, once CSP properly applies for and otherwise meets its obligations to receive federal funds to offset the total costs of gridSMART Phase I, the Commission will review its gridSMART Phase I expenditures and, once the Commission concludes that such expenditures were prudently incurred by CSP, the Commission intends to approve recovery of CSP's gridSMART Phase I costs.

(63) IEU, OCC, and OPAE argue that the Order approved, in part, the Companies' request for gridSMART without addressing the intervenors' arguments that the gridSMART proposal was not cost-effective as required by Sections 4928.02(D) and 4928.64(E), Revised Code (IEU App. at 22, 39-40; OPAE Memo Contra at 6; OCC App. at 49-51). According to OCC, because AEP-Ohio failed to present a detailed cost/benefit analysis of gridSMART Phase I, the full deployment of costs of gridSMART, a risk sharing plan between ratepayers and shareholders, or the expected operational savings associated with the implementation of gridSMART, AEP-Ohio failed to meet its burden of proof that gridSMART is cost-effective (OCC App. at 49-51). OCC also argues that AEP-Ohio failed to present any evidence that gridSMART will benefit AEP-Ohio customers or society (OCC App. at 51-52). IEU and OCC argue that the Order fails to set forth the Commission's reasoning for its approval of the Companies' gridSMART proposal (IEU App. at 22, 39-40; OCC App. at 48-49). Further, OCC argues that the Order does not include in the findings of fact or conclusions of law any support for the Commission's adoption of gridSMART Phase I, in violation of Section 4903.09, Revised Code (OCC App. at 48-49). IEU argues that the Commission's approval of these aspects of the ESP can not be reconciled with the goal of keeping rate increases "as close to zero as possible" (IEU App. at 22, 39-40). For these reasons, IEU and OCC argue that the Order is unreasonable and unlawful.

(64) Regarding IEU's and OCC's claims that the Order fails to comply with Section 4903.09, Revised Code, AEP-Ohio retorts that IEU's and OCC's disagreement with the Commission's decision is not equivalent to a violation of Section 4903.09, Revised Code. The Companies note that the Order specifically recognized the features and benefits of proposed gridSMART Phase I, based on the record. Accordingly, AEP-Ohio argues that the Order presents the Commission's basic rationale and record support for gridSMART Phase I and, therefore, the Order meets the requirements of Section 4903.09, Revised Code (Cos. Memo Contra at 25-27).

(65) As to OCC's and IEU's claims that gridSMART has not been shown to be cost-effective in accordance with Sections

4928.02(D) and 4928.64(E), Revised Code, AEP-Ohio answers that these code provisions are policy arguments that are not binding on the Commission and, therefore, the arguments of OCC and IEU on the basis of Sections 4928.04(E) and 4928.64(E), Revised Code, are misguided. The Companies note that several statutes of the Ohio Revised Code promote the deployment of advanced metering infrastructure (AMI). Notably, AEP-Ohio points out that Section 4928.02(D), Revised Code, encourages the deployment of AMI as an example of cost-effective, demand-side, retail electric service; that Section 4905.31(E), Revised Code, in the context of an ESP, creates a specific cost recovery mechanism opportunity for the deployment of advanced meters; and that the General Assembly included a long-term energy delivery infrastructure modernization plan as an item that can be included in an ESP under Section 4928.143(B)(2)(h), Revised Code. Based on the potential of gridSMART technologies to significantly enhance customers' energy management capabilities, AEP-Ohio reasons that the legislature mandated the requirements in Section 4928.66, Revised Code, for energy efficiency and peak demand reductions (Cos. Memo Contra at 27-29). The Companies argue that, while OCC and IEU focus exclusively on one aspect of the stated policy, cost-effectiveness, the Commission has a responsibility to consider all of the policies presented in Section 4928.02, Revised Code. Cost-effective, as defined by AEP-Ohio, does not mean that a network component (or group of components like gridSMART) pays for itself but, rather that it is a reasonable and prudent approach to deploying needed functionalities and features. (Cos. Memo Contra at 27).

(66) In the Order, the Commission summarized the key components of CSP's gridSMART proposal and emphasized its support of smart grid technologies. The Commission noted the potential for a well-designed smart grid system to provide customers and the electric utility long-term benefits, including decreasing the scope and duration of electric outages, improvements in electric service reliability, and the ability to provide customers the opportunity to better manage their energy consumption and reduce their energy costs (Order at 34-35, 37).

The Commission's endorsement of gridSmart Phase I is based on the projects' ability to drive a broad range of potential economic benefits both to consumers and the utilities. While consumers are given the capabilities to reduce their bills, utilities earn the capability to manage their systems.

For customers, the ability to have real-time price information and the ability to respond to such prices means that they may develop consumption patterns that both save them dollars while helping the utilities shave their peaks. This price-responsive demand not only reduces the need for high-cost generation capacity, but also reduces the need to continually expand the costly transmission and distribution components. The essence of this project is an infrastructure that embraces the following elements: advanced metering, dynamic pricing, information feedback to consumers, automation hardware, education, and energy efficiency programs. If executed appropriately, customers will receive the benefits of demand reduction across all seasons.

From the utility infrastructure side, gridSmart may lead to much-needed improvements in reliability. In the digital world that presently exists, and in the technology-driven world into which we are moving, the demand for precise and reliable power delivery systems is imperative. As we move forward, there will be new demands placed upon the grid to accommodate variable and intermittent inputs, such as the various forms of alternative energy generators. One can hardly imagine what the technologies of the future will bring us; we understand, however, that they must be adaptable to our needs. This is the essence of the smart grid.

(67) Further, the statutes referenced by AEP-Ohio in its memorandum contra indicate the legislature's endorsement of AMI. Furthermore, to the extent that SB 221 encourages the deployment of AMI and clarifies the legislature's policy directives at Section 4928.02, Revised Code, and in light of the Commission's desire to implement infrastructure and technological advancements to enhance service efficiencies and improve electric usage, the Commission modified and adopted the Companies' gridSMART proposal. The Commission specifically directed AEP-Ohio to pursue federal funds, in an effort to reduce the gridSMART Phase I cost that could be passed on to Ohio ratepayers. We also, as suggested by Staff,

implemented a rider as opposed to the automatic increase proposed by the Companies. In keeping with the enunciated state policies for reasonable electric rates and the requirements of SB 221 that encourage the implementation of AMI, the Commission approved the adoption of a gridSMART rider. Our Order requires separate accounting for gridSMART, an opportunity for the gridSMART plan to be reviewed and updated annually and an opportunity for the Commission to review the gridSMART expenditures to ensure that they were prudently made prior to the Companies' recovery of any gridSMART costs.

For these reasons, the Commission concludes that the adopted gridSMART component of AEP-Ohio's ESP best meets the requirements of SB 221, and meets the Commission's obligation to the citizens of Ohio to encourage the implementation of AMI and ensure the availability of adequate, reliable, safe, efficient and reasonably priced electric service. As noted in the Order, we believe it is important that electric utilities take the necessary steps "to explore and implement technologies such as AMI that will potentially provide long-term benefits to customers and the electric utility." Thus, the Commission denies IEU's, OCC's, and OPAE's applications for rehearing as to the gridSMART component of the Companies' ordered ESP.

Because of the compelling need to alter the paradigm that has traditionally governed the relationship between the customer and the utility, we are ordering AEP to implement no later than June 30, 2010 a transition to an integrated smart grid within its Phase I project area. The goal should be to maximize benefits to consumers consistent with the aforementioned objectives.

B. Riders

1. Provider of Last Resort (POLR) Rider

(68) OCC and Kroger allege that the Commission's approval of the POLR charge to allow AEP-Ohio to collect 90 percent of the revenues that AEP-Ohio proposed in its POLR rider was unreasonable and unlawful given that the charge was calculated incorrectly and was established unreasonably high (OCC App. at 29-34; Kroger App. at 3-6). Kroger submits that reducing the

requested POLR amount by 10 percent to account for the reduction in risk by requiring shopping customers to pay market rates if they return to the Companies is insufficient. Kroger agrees that the POLR risk is reduced if returning customers are required to pay market prices, but Kroger believes that the reduction in the POLR risk to the Companies is greater than 10 percent (Kroger App. at 4-5). Kroger also opposes the use of the Black-Scholes model to calculate the amount of the POLR risk, stating that the Black-Scholes model exaggerates the Companies' POLR risk (Id.).

(69) OHA and OMA raise similar arguments, adding that the limited shopping that has occurred and the unlikelihood that it will occur in the future further reduces AEP-Ohio's risk and the need to compensate for that risk (OHA App. at 6-8; OMA App. at 5-6).

(70) OEG states that the Commission properly found that the POLR rider should be avoidable for those customers who shop and agree to return at a market price; however, OEG believes that the Commission did not go far enough. OEG requests that the Commission grant rehearing to allow the POLR rider to be avoidable by those customers who agree not to shop during the ESP through a legally binding commitment (OEG App. at 6).

(71) OCC further contends that the Commission's actions authorizing the collection of POLR charge revenues for January through March 2009 at the higher rates authorized by the Order, even though the new SSO rates were not in effect at that time, and customers were already paying a POLR charge, violated Section 4905.22, Revised Code, and case precedent (OCC App. at 34-36).

(72) Additionally, OCC alleges that the Commission violated Section 4928.20(J), Revised Code, when it required residential customers of governmental aggregators to pay a stand-by charge. OCC explains that the statute permits governmental aggregators to elect not to receive standby service on behalf of their residential customers, in exchange for electing to pay the market price for power if the residential customers return to the electric utility (OCC App. at 36-37).

(73) AEP-Ohio disagrees with the intervenors and argues that the POLR rider approved by the Commission was lawful and reasonable (Cos. Memo Contra at 3-8). AEP-Ohio asserts that the parties are raising issues that were fully litigated in the proceeding and have not raised any new arguments and thus the grounds for rehearing on the POLR-related issues should be denied.

(74) AEP-Ohio also explains that OCC misperceives the risk associated with the POLR obligation and argues that, as with other rate components that are part of the ESP, there is no double-recovery (Cos. Memo Contra at 24). Rather, the Companies' increased all charges embedded in the ESP, including the POLR charge, to reflect the 2009 revenue levels authorized by the Commission, and then offset the revenues that had been collected already in the first quarter (Id.).

(75) First, as explained by AEP and recognized by others,[9] we explicitly stated in our Order that customers in governmental aggregation programs and those who switch to an individual CRES provider can avoid paying the POLR charge if the customers agree to pay the market price upon return to the electric utility after taking service from a CRES provider (see Order at 40). As such, OCC's request for rehearing on this matter is denied.

(76) With regard to the amount of the POLR charge, the Commission carefully considered all of the arguments, testimony, and evidence in the proceeding and determined that the Companies should be compensated for the cost of carrying the risk associated with being the POLR provider, including the migration risk. Based on the evidence presented, the Commission adopted the Companies' witness' testimony who quantified that risk at 90 percent of the estimated POLR costs, using the Black-Scholes model (see Tr. Vol. XIV at 204-205; Cos. Ex. 2-E at 15-16; Cos. Ex. 1, Exhibit DMR-5). The parties have not raised any new issues for the Commission's consideration. Therefore, we deny rehearing regarding the various POLR issues that have been raised.

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9 See Cos. Memo Contra at 2-3; OEG App. at 6.

(77) As for the argument of double-recovery of POLR charges or retroactive ratemaking, the Commission finds that this argument is comparable to OCC's arguments concerning all of the ESP charges and finds similarly. As discussed in subsequent section III.C (Effective Date of the ESP), our Order authorized the Companies' to increase all charges embedded in the ESP, including the POLR charge, to reflect the 2009 revenue levels approved by the Commission. However, our Order also directed the Companies to offset any revenues that had been collected from customers in the first quarter to specifically prevent any double recovery. As such, rehearing on this issue is also denied.

2. Energy Efficiency, Peak Demand Reduction, Demand Response, and Interruptible Capabilities

(a) Baselines and Benchmarks

(78) The Companies proposed that the load of the former Monongahela Power Company's (MonPower) customers be excluded from the calculation of CSP's EE baseline to be established pursuant to Sections 4928.64 and 4928.66, Revised Code.[10] In the Order, the Commission concluded that the MonPower customer load shall be included in the Companies' EE baseline because the MonPower load was not a load that CSP served and would have lost, but for some action by CSP (Order at 43).

(79) AEP-Ohio requests rehearing on this aspect of the Order. AEP-Ohio, in its sixth assignment of error, argues that the Order erroneously failed to address the Companies' demonstration that the record in the MonPower Transfer Case reflected the Commission's concerns for MonPower's customers if they were not served under a rate stabilization plan (RSP). CSP notes that Staff witness Scheck acknowledged that MonPower customers were facing electricity prices directly based on wholesale market prices that far exceeded the level of retail prices offered by MonPower (Tr. Vol. VII at 201-202). CSP reminds the Commission that, in this proceeding, Staff recognized that there

10 *In the Matter of the Transfer of Monongahela Power Company's Certified Territory in Ohio to the Columbus Southern Power Company*, Case No. 05-765-EL-UNC, Opinion and Order (November 9, 2005) (MonPower Transfer Case).

were important "economic development" issues in the MonPower Transfer Case (Cos. Ex. 2A at 48). Further, CSP notes that, in the MonPower Transfer Case, the Commission concluded that "economic benefits will inure to all citizens and businesses in both regions by helping to sustain economic development in southeastern Ohio."[11] The Companies argue that it is not fair or reasonable for the Commission to now take such a narrow and technical view of economic development and request that the Commission exclude the MonPower load from the EE baseline. In the alternative, CSP requests that, should the Commission affirm its decision that the MonPower load was not economic development, the EE and PDR baselines be adjusted to ensure that the compliance measurement is not unduly influenced by other factors beyond CSP's control as requested in the Companies' Brief (See Cos. Br. at 103; Cos. App. at 17-20).

(80) The Commission affirms its decision to include the former MonPower customer load in the calculation of CSP's EE baseline to be established pursuant to Sections 4928.64 and 4928.66, Revised Code. While the Commission appreciates that CSP entered into an agreement to serve the former service territory of MonPower, as discussed in the Order, the transfer of such customer load was not economic development given that it was not a load CSP served and would have otherwise lost but for some action by CSP. We acknowledge that pursuant to Section 4928.66(A)(2)(b), Revised Code, the Commission may amend an electric utility's EE and PDR benchmarks if the Commission determines that an amendment is necessary because the electric utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control. We also acknowledge that Section 4928.66(A)(2)(c), Revised Code, requires the baseline to be normalized for certain changes including appropriate factors to ensure that the compliance measurement is not unduly influenced by factors outside the control of the electric utility. The Commission will consider such request for adjustments to the baseline by AEP-Ohio and other electric utility companies when appropriate.

11 MonPower Transfer Case, Opinion and Order at 11.

(b) Interruptible Capacity

(81) As a part of the ESP, the Companies' requested that their interruptible service load be counted towards their PDR requirements to comply with Section 4928.66(A)(2)(b), Revised Code. The Companies also proposed to increase the limit of OP's Interruptible Power-Discretionary Schedule (Schedule IRP-D) to 450 Megawatts (MW) from the current limit of 256 MW and to modify CSP's Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS) to make the services more attractive to customers. The Companies request that the Commission recognize the Companies' ability to curtail customer usage as part of the PDR compliance (Cos. Ex. 1 at 5-6).

(82) In the Order, the Commission agreed with Staff and OCEA that interruptible load should not be counted in the Companies' determination of its EE/PDR compliance requirements unless and until the load is actually interrupted. IEU argues that the Commission failed to present sufficient reasoning to support this position. IEU states that the Commission's reliance on the testimony of Staff and OCEA's discussion of the issue is limited (IEU App. at 51).

(83) As noted in the Order, OCEA argued that counting interruptible load is contrary to the objectives of SB 221 and, because the customer controls part of the load when non-mandatory reductions are requested, interruptible load should not be counted (Order at 46). IEU proffers that OCEA's arguments are contrary to the record evidence and common sense (IEU App. at 51). The Companies and IEU reason that Section 4928.66(A)(1)(b), Revised Code, dictates that the peak demand reduction programs merely be "designed to achieve" a reduction in peak demand (Cos. App. at 21; IEU App. at 52). The applicants for rehearing note that Staff witness Scheck acknowledged that "designed to achieve" is fundamentally different from a requirement to "achieve" as is required in Section 4928.66(A)(1)(a), Revised Code, regarding EE programs (Cos. App. at 21; IEU App. at 52). IEU agrees with the Companies' arguments on brief that interruptible service arrangements provide an on-system capability to satisfy reliability and efficiency objectives as part of a larger planning process (Cos. Brief at 112-115), and cites the regional

transmission organizations (RTO) programs as an example (IEU App. at 52). The Companies contend that, unlike unused energy savings capabilities, PDR programs create a capability to reduce peak demand that can either be exercised or reserved for future use as needed and, if the PDR resource or capability is not needed for operational reasons or because weather is mild, PDR capability is fully reserved for future use without depletion or diminishing its value as a resource (Cos. App. at 22). IEU also contends that an interruptible customer's buy-through of a non-mandatory interruptible event is not a reason to reject it as a part of an electric utility PDR program under Section 4928.66(A)(2)(c), Revised Code, and the Commission should reverse its decision. IEU states that excluding interruptible capacity will require the Companies to offer a program inferior to the programs available from the RTO (IEU App. at 52-53). Finally, AEP-Ohio emphasizes, as noted in the Companies' brief, that the Commission's Integrated Resource Plan (IRP) rules, as proposed by Staff, define "native load" of a system to mean the internal load minus interruptible loads at Rule 4901:5-5-01(R), O.A.C.[12] (Cos. Br. at 115; Cos. App. at 22-23). Thus, the applicants for rehearing reason that including interruptible load as a part of the Companies' EE/PDR compliance program is consistent with the goals of SB 221.

(84) OCC states that the Commission previously considered and rejected certain of the Companies' arguments on this issue. In light of the fact that the Commission has previously given this issue due consideration and rejected the Companies' arguments, OCC argues that the Companies' application for rehearing of this issued should be denied (OCC Memo Contra at 22-23).

(85) Upon further consideration of the issues raised, the Commission has determined that it is more appropriate to address interruptible capacity issues in AEP-Ohio's PDR portfolio plan proceeding docketed at Case Nos. 09-578-EL-EEC and 09-579-EL-EEC.

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12 See adopted Rule 4901:5-5-01(R), O.A.C., *In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technologies, Resources, and Climate Regulations, and Review of Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code, Pursuant to Section 4928.66, Revised Code, as Amended by Amended Substitute Senate Bill No. 221*, Case No. 08-888-EL-ORD (Green Rules) (April 15, 2009).

(c) EE/PDR Rider

(86) In its fourth assignment of error, AEP-Ohio requests, among other things, that the Commission clarify that the phase-in of the approved rate increase and deferral of total bill increases over the established cap do not include revenue increases associated with a distribution base rate case or the revenue associated with the energy efficiency and peak demand reduction cost recovery (EE/PDR) rider (Cos. App. at 13-14).

(87) As discussed in findings (27) and (28) above in regard to the TCR, we clarify that the percentage cap increase on total customer bills does not include the EE/PDR rider or future distribution base rates established pursuant to a separate proceeding.

3. Economic Development Cost Recovery Rider

(a) Shared recovery of forgone economic development revenue

(88) In its application for rehearing, OCC argues that the Commission Order is unreasonable to the extent that the Order fails to require the Companies to share a portion of the revenues foregone due to economic development programs (OCC App. at 39-41). OCC recognizes that Section 4928.143(B)(2)(i), Revised Code, permits an electric utility to file an ESP with provisions to implement economic development programs and to request that program costs be recovered from, and allocated to, all customer classes. OCC repeats the statements made in its briefs and rejected by the Commission in the Order that it has been the Commission's long-standing policy to equally divide the cost of the foregone revenue subsidies between the utility's shareholders and customers. OCC claims the Commission's ruling on this issue constitutes an unreasonable shift in established regulatory policy to the prejudice of AEP-Ohio's residential customers and a rejection of OCC's request to annually review each approved economic development arrangement. OCC interprets the Order to foreclose any such annual review and, except for the Companies and the Commission, to bar any other parties an opportunity to review

economic development contracts initially and periodically thereafter (OCC App. at 39-41).

(89) AEP-Ohio opposes OCC's request for rehearing on this matter. AEP-Ohio argues that, although OCC acknowledges that it is within the Commission's discretion to determine "the amount and allocation of the costs to be recovered" for foregone economic development revenue, at the same time, OCC claims that revenue sharing is within the Commission's discretion. AEP-Ohio asserts that despite OCC's claim that revenue sharing is an established Commission policy, the practice is not reflected in any of its special arrangements prior to the implementation of SB 221. The Companies proffer that, to the extent the alleged change in policy requires a reason, in SB 221, the General Assembly explicitly included recovery of foregone revenue as a part of economic development contracts in the amendments to Section 4905.31(E), Revised Code (Cos. Memo Contra at 36-37).

(90) The Commission finds that OCC has failed to present any new arguments for the Commission's consideration on this issue. We do not find it necessary or appropriate to require all parties to initially review and/or to annually review the economic development arrangements. Consistent with the current practice, the Commission will review economic development arrangements on a case-by-case basis which will afford interested parties an opportunity to be heard in individual economic arrangement cases. Accordingly, we deny OCC's request for rehearing.

(b) Economic development contract customer compliance review

(91) OCC also argues that the Economic Development Rider (EDR) is unfair, lacks accountability and fails to evaluate the Companies' or the customer's compliance with their respective obligations. OCC states that the EDR approved in the Order does not require that recovery be limited to AEP-Ohio's costs net of benefits of the economic development program. Further, OCC claims that, without any review or accountability of the customers receiving the economic development benefits of such approved arrangements, costs cannot be determined. OCC argues that the Commission failed to make any provisions for

recipients of economic development contracts to be held accountable for their obligations under the economic development arrangements. Further, OCC asserts that this absence of accountability of the customer-recipient is unreasonable because it allows anyone to receive an economic development discount with nothing more than representations that it will make investments in the state of Ohio. OCC contends that the Commission should only approve discounted economic development rates, recovery by the electric utility and EDRs if investment in Ohio actually occurs (OCC App. at 65-66).

(92) OCC also argues that the non-bypassable EDR is also unreasonable and unlawful because it is abusive, anticompetitive, and not proper. OCC states that AEP-Ohio does not intend to offer economic development rates to shopping customers, but will impose the EDR charges on shopping customers. OCC asserts that the lack of symmetry between the availability of the benefit, and who pays for the benefit, renders the EDR unlawful and unreasonable, as approved by the Commission (OCC App. at 66).

(93) The Companies state that OCC's arguments are premature. In defense of the Commission's decision, the Companies remind OCC that the Commission will review and address the specific circumstances of each economic development arrangement as it is presented for approval and, that if there are any enforcement issues in the future, the Commission's continuing jurisdiction over economic development arrangements can be used to address any issues that arise. Regarding OCC's claims that the non-bypassable nature of the EDR is unlawful, abusive, and anticompetitive, the Companies reason that the fact that the EDR is non-bypassable ensures that it is competitively neutral. AEP-Ohio explains that a bypassable EDR would give CRES providers an undue advantage and emphasizes that CRES provider rates do not reflect recovery of "public interest" discounts in comparison to the electric utility's regulated SSO rates, which reflect forgone economic development discounts. Further, the Companies reason that all customers and the community benefit from economic development (Cos. Memo Contra at 37-38).

(94) The Commission finds that OCC has not presented any new arguments that the Commission has not previously considered regarding review of economic development arrangements or the sharing of foregone revenues for economic development. We agree with the Companies that all customers and the community benefit from economic development and, therefore, find it is reasonable for the EDR to be non-bypassable as permitted by law. The Commission finds that its current procedure to review and analyze each proposed economic development arrangement is sufficient to address OCC's concerns regarding accountability and the electric utility's and economic development customer's contract compliance obligations. For these reasons, we deny OCC's request for rehearing.

C. Line Extensions

(95) AEP-Ohio avers that the Commission's rejection of its proposed line extension provisions is unlawful and unreasonable, and states that the Commission should authorize AEP-Ohio to implement up-front payments contemplated in the Commission's November 5, 2008, Finding and Order issued in Case No. 06-653-EL-ORD (Cos. App. at 6-9).[13]

(96) Recognizing that the line extension policies were still being considered at the time of the rehearing applications, OCC argues that AEP-Ohio's rehearing request is without support and should be denied (OCC Memo Contra at 19-20).

(97) As stated in our Order, the Commission is required to adopt uniform, statewide line extension rules for nonresidential customers pursuant to SB 221, which it has done in Case No. 06-653-EL-ORD. Although the rules are not yet effective, the Commission adopted modified line extension rules in its Entry

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13 The Ohio Home Builder's Association (OHBA) requested leave to file a limited memorandum contra AEP-Ohio's application for rehearing on April 27, 2009. AEP-Ohio responded to the request on May 5, 2009, and moved to strike the pleading. We find OHBA's motion to be improper and will not be considered because OHBA is not a party to these cases and because OHBA has not shown that its failure to enter a prior appearance is due to just cause and that its interests were not already adequately considered by the Commission. However, even if we were to consider the request and permit OHBA's memorandum contra, OHBA's arguments would not modify our decision regarding the line extension issue.

on Rehearing issued on May 6, 2009. AEP-Ohio was an active participant in the administrative rulemaking and concerns that it has regarding the matters included in that rulemaking process are not appropriate for these proceedings. AEP-Ohio has failed to raise any new arguments regarding this issue. Accordingly, rehearing on this ground is denied.

III. OTHER ISSUES

A. Corporate Separation

1. Transfer of Generating Assets

(98) IEU alleges that the Commission erred by allowing AEP-Ohio to recover, through the non-FAC portion of the generation rate, the Ohio customers' jurisdictional share of any costs associated with maintaining and operating the Waterford Energy Center and the Darby Electric Generating Station (IEU App. at 19-21). IEU states that the Commission's determination was without record evidence and a demonstration of need (Id.).

(99) AEP-Ohio responds that the Commission's actions were reasonable in light of SB 221 and the requirement that the Commission placed on AEP-Ohio to retain the generating facilities. AEP-Ohio also submits that the Commission's decision was lawful pursuant to Section 4928.143, Revised Code, which allows such flexibility in approving an ESP (AEP Memo Contra at 11-12).

(100) After further consideration, the Commission finds IEU's arguments persuasive and grants rehearing on the issue of recovery of costs associated with maintaining and operating the Waterford Energy Center and the Darby Electric Generating Station facilities through the non-FAC portion of the generation rate. The Companies have not demonstrated that their current revenue is inadequate to cover the costs associated with the generating facilities, and that those costs should be recoverable through the non-FAC portion of the generation rate from Ohio customers. We, therefore, direct AEP-Ohio to modify its ESP and remove the annual recovery of $51 million of expenses

including associated carrying charges related to these generation facilities.

B. PJM Demand Response Programs

(101) As a part of the ESP, the Companies proposed to revise certain tariff provisions to prohibit SSO customers from participating in the demand response programs (DRP) offered by PJM, both directly and indirectly through a third-party. The Commission concluded that, despite Integrys' arguments to the contrary, the Commission was vested with the broad authority to address the rate, charges, and service issues of Ohio's public utilities as evidenced in Title 49 of the Revised Code and, therefore, reasoned that this Commission is the entity to which the Federal Energy Regulatory Commission (FERC) was referring in the Final Rule.[14] However, the Commission ultimately determined that the record lacked sufficient information for the Commission to consider both the potential benefits to program participants and the costs to Ohio ratepayers to determine whether this provision of the ESP will produce a significant net benefit to AEP-Ohio consumers. As a result, the Commission deferred the issue to be addressed in a separate proceeding and requested that AEP-Ohio modify its ESP to eliminate the provision that prohibits participation in PJM DRP.

(102) The Companies request rehearing of the Commission's decision, arguing that deferring this matter to a subsequent proceeding and allowing continued participation in DRP is unreasonable and against the manifest weight of the evidence in the record. AEP-Ohio points to what it calls "exhaustive treatment" of the issue by the parties in their briefs, motions, memoranda, written testimony and hearing transcripts. AEP-Ohio submits that the Order allows current DRP participants to continue participation in such programs through mid-2010, halfway through the term of the ESP, but also permits other customers to register to participate since FERC has re-opened registration until May 1, 2009.[15] The Companies view the re-opening of registration by FERC as an opportunity for the Commission to prohibit current

14 *Wholesale Competition in Regions with Organized Electric Markets* (Docket Nos. RM07-19-000 and AD07-7-000), 125 FERC ¶ 61,071 at 18 CFR Part 35 (October 17, 2008) (Final Rule).

15 *PJM Interconnection*, 126 FERC ¶61,275, Order at ¶89 (March 26, 2009).

registrants' participation in DRP, without prejudice, by way of a timely decision to restrict retail participation.

(103) The Companies also argue that the Indiana Utility Regulatory Commission (URC) recently granted a request by an AEP-Ohio affiliate to continue the Commission's default prohibition against retail participation in the PJM DRP while that Commission continues to consider a more permanent resolution to this issue. However, the Indiana URC will consider individual customer requests to participate in DRP on a case-by-case basis.[16] AEP-Ohio advocates the Indiana URC's approach, which the Companies assert will facilitate the use of demand resources within Ohio and allow AEP-Ohio to refine its retail DRP to meet the mandates for PDR. AEP-Ohio contends that the Order creates uncertainty for the Companies and additional costs for ratepayers in two respects: (a) AEP-Ohio's PDR compliance costs increase with the exportation of Ohio's demand response resources through retail participation in the PJM programs; and (b) nonparticipating customers will incur additional long-term capacity costs due to AEP-Ohio's obligation to continue to provide firm service even though the participating customers are using their load in a manner that is akin to interruptible service. AEP-Ohio states that it is the Companies' goal to emulate the PJM DRP at the retail level to the extent possible. Further, AEP-Ohio proposes that, if the Commission restricts retail participation on rehearing and orders the Companies to modify their programs to the maximum extent possible, AEP-Ohio's customers would benefit from demand response in terms of a reduction in the capacity for which AEP-Ohio customers are responsible. According to AEP-Ohio, such a decision would also encourage AEP-Ohio to work with stakeholders to ensure that predictable consumer demand response is recognized as a reduction in capacity that CSP and OP carry under PJM market rules and support AEP-Ohio's PDR obligations (Cos. App. at 23-26).

(104) IEU, OCC, and Integrys each filed a memorandum contra this aspect of the Companies' request for rehearing. Like AEP-Ohio, IEU agrees that the Commission had sufficient information to

16 *In the Matter of the Commission's Investigation Into Any and All Matters Related to Demand Response Programs Offered by the Midwest ISO and PJM Interconnection*, Cause No. 43566 (February 25, 2009 Order).

decide this issue, but supports the Commission's conclusion to allow retail participation in DRP until a decision is ultimately made. Further, IEU asserts that the bases AEP-Ohio cites for support of its request for rehearing are inaccurate and/or misleading (IEU Memo Contra at 10-11). IEU and OCC state that AEP-Ohio has mischaracterized the Indiana URC's ruling. IEU contends that the Indiana URC's position is irrelevant as Indiana operates under a cost-based ratemaking regime unlike Ohio (IEU Memo Contra at 11). Further, OCC cites and IEU quotes the Indiana URC's order to state, in part:

> The initiation of the Commission's investigation in this Cause did not alter the Commission's existing regulatory practice of requiring approval prior to direct participation by a retail customer in an [regional transmission organization demand response program]. *Nor did the Commission's investigation prohibit Indiana end-use customers desiring to participate in PJM's DRPs from filing a petition seeking approval from the Commission.* Instead, the Commission commenced this investigation to determine whether, and in what manner, the Commission's regulatory procedure should be modified or *streamlined to address requests by end-use customers based on the importance of demand response and the increased interest in participation in RTO DRPs. [Emphasis added.]*[17]

IEU and OCC note that of the five Indiana customers that requested approval to participate in the RTO DRP, as of the filing of the memoranda, three requests had been approved and two were pending (IEU Memo Contra at 12, n.5; OCC Memo Contra at 13). In other words, IEU concludes that there is in fact no prohibition on customer participation in RTO DRP in Indiana (IEU Memo Contra at 11-12).

(105) Integrys and OCC state that there is no evidence in the record to support AEP-Ohio's claims that continued participation in RTO DRP will increase the Companies' compliance cost to meet its PDR requirements under Section 4928.66, Revised Code (Integrys Memo Contra at 8; OCC Memo Contra at 12). Integrys

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[17] *Id.* at 5.

explains that the statute does not require the use of in-state demand response resources, prohibit participation in RTO DRP or require the mercantile customer to integrate or commit their DRPs to AEP-Ohio. Commitment is at the mercantile customer's option. Further, Integrys interprets the Commission's decision in the Duke Energy of Ohio ESP case to affirm its interpretation[18] (Integrys Memo Contra at 5-6, 8; OCC Memo Contra at 12). OCC also argues that there is no evidence in the record to support the representation that customer participation in DRP will not benefit AEP-Ohio's customers by decreasing AEP-Ohio's load. OCC reasons, and Integrys agrees, that DRP improve grid reliability and make markets more efficient by avoiding the cost associated with new generation to service load and, as such, the intervenors reason that DRP are a benefit to all customers participating in the RTO's market (OCC Memo Contra at 12; Integrys Memo Contra at 9). Integrys rationalizes that customers participating in the PJM DRP under AEP-Ohio Schedules GS-2, GS-3 and GS-4 pay demand charges for firm capacity irrespective of whether the customer takes service or service is curtailed (Integrys Memo Contra at 9). IEU claims that AEP-Ohio's arguments implicitly concede that PJM's DRP are more valuable to customers than the interruptible service offered by CSP and OP, and IEU emphasizes that it is the mercantile customer's choice to dedicate customer-sited capabilities under SB 221. Also, IEU asserts that the Companies' assertion that the Order will cause additional long-term capacity costs for nonparticipating customers is misleading at best. IEU explains that, should any additional long-term capacity costs be incurred, it would not be the result of customers participating in RTO DRP, but AEP-Ohio's commitment to meet the generation resource adequacy requirement of all retail suppliers within its PJM zone for a period of five years through PJM's fixed resource requirement program (IEU Memo Contra at 12-13). Finally, OCC asks that the Commission retain an SSO customer's option to participate in a variety of competitive DRP as such is supported by the goals of SB 221 (OCC Memo Contra at 11).

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18 *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of an Electric Security Plan*, Case No. 08-920-EL-SSO, et al., Opinion and Order at 35 (December 17, 2008).

(106) Integrys and IEU assert that any failure of AEP-Ohio to comply with the PDR requirements of Section 4928.66, Revised Code, are not because of customer participation in PJM's DRP but the lack of attractive programs offered by AEP-Ohio (IEU Memo Contra at 13; Integrys Memo Contra at 7). Further, Integrys notes that the Companies' three interruptible service offerings (Schedule IRP-D, ECS Rider and PCS Rider) have only 8 AEP-Ohio customers (Integrys Memo Contra at 7). Further, Integrys suggests that, if the Companies believe that the DRP are affecting the Companies' PDR compliance plans, Section 4928.66(A)(2)(b), Revised Code, permits AEP-Ohio to request that its PDR goals be revised (Integrys Memo Contra at 7-8).

(107) As to the Companies' alleged desire to emulate RTO DRP, OCC argues that the Companies could have developed and filed DRP that mirrored PJM's programs as a part of their ESP application (OCC Memo Contra at 12). For these reasons, IEU, Integrys, and OCC request that the Commission deny AEP-Ohio's application for rehearing as to the PJM DRPs.

(108) The Commission rejects AEP-Ohio's proposal to direct DRP participants to withdraw from PJM programs at this time. The registration deadline of May 1, 2009, has passed and we consider this request to be moot. Furthermore, the Commission is not convinced by AEP-Ohio's claims that an abrupt change in the Commission's decision would not harm customers already registered to participate in PJM's DRP, given that customers may have entered into contractual arrangements, invested in new equipment, and agreed to operational commitments in reliance on the Commission's Order. Thus, we affirm our decision not to prohibit AEP-Ohio's SSO customers' from participating in PJM's DRP at this time and will reconsider our decision in a subsequent proceeding. Finally, the Commission notes that AEP-Ohio, IEU, Integrys nor OCC presented, in their respective briefs or memoranda, quantification of record evidence to address the Commission's primary concern with this provision of the ESP. The Commission requires additional information to consider the costs incurred by various customers to balance the interest of AEP-Ohio customers participating in PJM's DRP and the cost AEP-Ohio's other customers incur via the Companies' retail rates. Moreover, none of the arguments presented in the applications for rehearing or the memoranda

contra sufficiently address this aspect of the PJM DRP and, therefore, fail to persuade the Commission to reconsider its decision regarding PJM DRP participation. In further consideration of the need to balance the potential benefits to PJM DRP participants and the costs to AEP-Ohio ratepayers, the Commission clarifies that AEP-Ohio customers under reasonable arrangements with AEP-Ohio, including, but not limited to, EE/EDR, economic development arrangements, unique arrangements, and other special tariff schedules that offer service discounts from the applicable tariff rates, are prohibited from also participating in PJM DRP, unless and until the Commission decides otherwise in a subsequent proceeding. The remaining issues in the applications for rehearing on PJM DRP participation are denied.

C. Effective Date of the ESP

(109) OCC claims that the Commission erred by permitting AEP-Ohio to apply their amended tariff schedules to services rendered prior to the entry of the Commission approving such schedules, in violation of Sections 4905.22, 4905.32, and 4905.30, Revised Code, and the Ohio and United States Constitutions (OCC App. at 18-19, 24-25). OCC recognizes that the effective date of the tariffs, as corrected by the Entry Nunc Pro Tunc issued on March 30, 2009, was "not earlier than both the commencement of the Companies' April 2009 billing cycle and the date upon which the final tariffs are filed with the Commission" (Id.). However, OCC asserts that permitting the increased rates to be effective on a "bills-rendered" basis, instead of a "services-rendered" basis, authorizes increased rates prior to the approval of the new rates, which includes charges for electric energy already consumed. OCC opines that applying amended tariff schedules to services rendered prior to the Commission's entry that approves such schedules violates Sections 4905.22 and 4905.32, Revised Code (Id.).

(110) OCC also asserts that the Commission erred by establishing the term of the ESP beginning January 1, 2009, which equates to the Companies collecting retroactive rates for the period January 2009 through March 2009, in violation of Ohio law and case precedent (Id. at 20-24).

(111) OCC further alleges that the Order violates Section 4928.141(A), Revised Code, which OCC interprets to require an electric utility's rates in effect January 1, 2009, to continue if an SSO has not been approved by the Commission. OCC argues that, to the extent that, the Order replaced the rates in effect at January 1, 2009 without an approved SSO, it violates Section 4928.141(A), Revised Code (Id. at 25-26).

(112) Similar arguments were raised by several other intervenors (OMA App. at 3-4; OHA App. at 2-6; Kroger App. at 8-9).

(113) AEP-Ohio opposes the intervenors' claims regarding retroactive ratemaking, stating that the various claims are without merit and should be rejected (Cos. Memo Contra at 14-25). AEP-Ohio explains that the Commission's Order, as clarified by the Entry Nunc Pro Tunc, approved a modified ESP with a term commencing January 1, 2009, and ending December 31, 2011 (Id. at 14). AEP-Ohio filed compliance tariffs implementing the new rates adopted in the ESP, commencing with the first billing cycle of April 2009, which included an offset of the revenues collected from customers during the interim period (Id.). The Companies argue that Sections 4905.22 and 4905.32, Revised Code, require public utilities to charge rates that are authorized by the Commission, as reflected in approved tariffs at the time of the billing, which AEP-Ohio properly did, and OCC's general disagreement with adopting rate increases on a bills-rendered basis is not an issue unique to this proceeding (Id. at 16).

(114) AEP-Ohio further responds that the Commission authorized a three-year ESP with a term of January 1, 2009, through December 31, 2011, and required that the revenues that were collected during the interim period, pursuant to Case No. 08-1302-EL-ATA, be offset by the new rates (Id. at 17). AEP-Ohio states that the Commission did not establish retroactive rates but, instead, used a prospective rate mechanism to implement the full term of the ESP. The Companies also note that the Commission's decision did not provide for new rates during the first quarter of 2009 and did not require the Companies to backbill individual customers for service already provided and paid for.

(115) It has been a long standing Commission policy to approve the effective date of tariffs on either a bills-rendered or services-rendered basis depending on the specific facts of each case. As noted by the Companies, "[o]rdering rate increases effective on a bills-rendered basis is a widely used and established practice in various types of rate cases" (Cos. Memo Contra at 16).

(116) We also agree with AEP-Ohio that our decision does not constitute retroactive ratemaking in violation of *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254 (Cos. Memo Contra at 18). During the interim period (first quarter of 2009), the Commission approved rates pursuant to Section 4928.141(A), Revised Code,[19] and, subsequently, through our Order in this proceeding, we authorized the revenues collected during the interim period to be offset against the total allowable revenues that the Companies are authorized to receive pursuant to their ESP, as modified by the Commission (Order at 64, corrected by Entry Nunc Pro Tunc at 2). The Commission did not permit the Companies to go back to January 1, 2009, and re-bill customers for the consumption that they used during the first quarter of 2009 at the higher rate established by our Order. Had our Order allowed the Companies to re-bill customers at the higher rate based on actual consumption from January 1, 2009, through March 31, 2009, which it did not, we would agree that an order authorizing such rebilling would constitute retroactive ratemaking.

(117) As explained previously, our Order remains consistent with Section 4928.141, Revised Code, which requires an electric utility to provide consumers, beginning on January 1, 2009, a SSO established in accordance with Section 4928.142 or 4928.143, Revised Code (Order at 64, corrected by Entry Nunc Pro Tunc at 2). The Commission approved AEP-Ohio's three-year ESP, with modifications, but did not allow AEP to collect higher rates associated with that approved ESP until the first billing cycle of April 2009. We clarified our intent to this effect in our Entry Nunc Pro Tunc, pages 1- 2:

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19 *In re Columbus Sothern Power Co. and Ohio Power Co.*, Case No. 08-1302-EL-ATA, Finding and Order at 2-3 (December 19, 2008) and Finding and Order at 2 (February 25, 2009).

> It was not the Commission's intent to allow the Companies to re-bill customers at a higher rate for their first quarter usage. The new rates established pursuant to the ESP were not to go into effect until final review and approval by the Commission of the Companies' compliance tariffs. Given that our order was issued on March 18, 2009, and that the Companies' existing tariffs approved by the Commission were scheduled to expire no later than the last billing cycle of March 2009, it was anticipated that the new rates would not become effective until the first billing cycle of April.

(118) We further addressed these issues in our entry issued on March 30, 2009, when we denied the request for a stay (March 30 Entry). In that March 30 Entry, we specifically stated that we disagree with the characterization that our action allowed AEP-Ohio to retroactively collect rates (March 30 Entry at 3). In that same March 30 Entry, we also addressed the claim that the Order violated Section 4928.141(A), Revised Code. We explained that in our finding and order issued on December 19, 2008, in Case No. 08-1302-EL-ATA, the Commission established rates for the interim period, stating that "the rates in effect on July 31, 2008, would continue until an SSO is approved in accordance with Section 4928.142 or 4928.143, Revised Code" (March 30 Entry at 3). Moreover, we agree with AEP-Ohio's understanding of the offset required by our Order (Cos. Memo Contra at 22). The offset was an adjustment that the Commission believed to be fair in calculating the incrementally higher revenue authorized for 2009, in light of the timing of the Commission's decision on the ESP and the need for an interim plan. The Commission has considered all of the arguments raised surrounding these issues several times in multiple proceedings and has specifically addressed the arguments in its previous decisions. The parties have raised nothing new for the Commission's consideration. Accordingly, the Commission finds that its Order does not constitute retroactive ratemaking, and does not violate any statute or constitutional provision. Therefore, we deny rehearing on all grounds associated with the effective date of the new ESP rates.

(119) Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this entry, to be effective on a date not earlier than both the commencement of the Companies' August 2009 billing cycle, and the date upon which final tariffs are filed with the Commission. In light of the timing of the effective date of the new tariffs, the Commission finds that the tariffs shall be effective for bills rendered on or after the effective date, and contingent upon final review by the Commission.

IV. SIGNIFICANTLY EXCESSIVE EARNINGS TEST (SEET)

(120) In the Order, the Commission concluded that the SEET would be established within the framework of a workshop to develop a common methodology for all Ohio electric utilities. The Commission reasoned that, pursuant to Section 4928.143(F), Revised Code, there is time to develop a common methodology for all Ohio electric utilities because the SEET will not actually be applied until 2010 for the year 2009, consistent with the Commission's decision in the FirstEnergy ESP Case.[20] However, the Commission recognized that AEP-Ohio required certain information to evaluate the modified ESP. The Commission noted that the Companies' earnings from off-system sales would be excluded from fuel costs and, consistent with that decision, also excluded off-system sales margins from any SEET.

A. AEP-Ohio as a single-entity for SEET

(121) AEP-Ohio, in its thirteenth assignment of error, requests that the Commission provide further clarification of the SEET and the scope of the issues to be addressed at the SEET workshop. AEP-Ohio requests that the SEET apply to CSP and OP as a single entity because investments in the electric utilities are made and their operations are conducted on a combined basis. The Companies argue that the "single entity" approach was supported by Staff (Staff Ex. 10 at 25). The Companies also argue that a common SEET methodology does not require an

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20 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, Opinion and Order (December 19, 2008).

identical SEET methodology for each Ohio electric utility (Cos. App. at 40-41).

(122) While IEU does not take a position, at this time, on the merits of AEP-Ohio's request, IEU argues that the clarification need not be addressed as a part of the entry on rehearing and the issue is more appropriately deferred to the workshop (IEU Memo at 15). On the other hand, OCC opposes AEP-Ohio's request. OCC proffers that despite Staff's belief that the consolidated evaluation of the Companies' earnings for purposes of the SEET would help mitigate "asymmetrical" risk, Staff was reluctant to address the issue of whether such practice was permitted pursuant to SB 221. OCC argues that combining CSP and OP for SEET purposes is prohibited by the statute. OCC notes that paragraphs (C) and (E) of Section 4928.143, Revised Code, each refer to "the electric distribution utility" and that Section 4828.01(A)(6), Revised Code, defines electric distribution utility as "an electric utility that supplies at least retail electric distribution service." As such, OCC contends that the statute clearly expresses the legislative intent and the statute must be applied accordingly.[21] Thus, OCC reasons that the earnings of CSP and OP cannot be combined for calculation of the SEET pursuant to the statute (OCC Memo at 14-15).

(123) The Commission concludes that consideration of whether CSP and OP should be considered a single-entity, AEP-Ohio, for purposes of the SEET is an issue more appropriately addressed as a part of the SETT workshop.

B. <u>OSS</u>

(124) Kroger reasons that the Order is unreasonable and unlawful to the extent that the Order excluded OSS margins from the SEET and did not share OSS margins with customers as an offset to FAC. Kroger claims that the Order does not explain why OSS margins are excluded from the SEET (Kroger App. at 8). Further, Kroger clarifies that its request as to OSS was in the alternative. More precisely, Kroger requested that should the

21 *Time Warner v. Pub. Util. Comm.* (1996), 75 Ohio St.3d 229, 237, citing *Provident Bank v. Wood* (1973), 36 Ohio St.2d 101.

Commission exclude OSS margins as an offset to the FAC, then the Commission should then include OSS margins in the SEET. Kroger argues that the Order inappropriately allows AEP-Ohio to retain all of the benefits of OSS margins and AEP-Ohio's distinction between SB 221's focus on retail sales as opposed to wholesale transactions is unsupported by legal authority and contrary to Ohio law. Kroger reasons that AEP-Ohio's generating assets, which produce electricity for OSS, are included in the calculation of the Companies' common equity and, therefore, OSS should be included in the SEET. Further, according to Kroger, neither Section 4928.143(F), Revised Code, nor any other provision of the Revised Code excludes OSS from the calculation of the return on common equity. Thus, Kroger requests that the Commission reconsider the Order to at least share OSS margins with AEP-Ohio's customers (Kroger App. at 6-8).

(125) OCC argues that recognizing OSS profits and sharing the profits between customers and the electric utility is consistent with the Commission's decision in a prior CEI Rate Case.[22] Further, OCC asserts that the Commission has previously determined that providing OSS revenue to jurisdictional customers can assist in achieving the goal of providing reliable and safe service and is consistent with the state policy set forth in Section 4928.02(A), Revised Code.[23] OCC argues that, although the law does not explicitly require an allocation of OSS to customers, the law also does not explicitly prohibit it. Thus, OCC reasons that the Commission has failed to follow it own precedent[24] (OCC App. at 16-17). Further, OCC reasons that the order fails to offer any justification for changing its position on this issue or to demonstrate why its prior decisions were in error. For this reason, OCC alleges that the Commission's Order yields an unreasonable and unlawful result as to the SEET (OCC App. at 18).

22 *In the Matter of the Application of the Cleveland Electric Illuminating Company for Authority to Amend and to Increase Certain of it Filed Schedules Fixing Rates and Charges for Electric Service*, Case No. 84-188-EL-AIR, Opinion and Order at 21 (March 7, 1985).

23 *In the Matter of the Application of the Cincinnati Gas & Electric Company for an Increase in its Rates for Gas Service to All Jurisdictional Customers*, Case No. 95-656-GA-AIR, Entry on Rehearing at 6-7 (February 12, 1997).

24 *Cleveland Elec. Illuminating* (1975), 42 Ohio St.2d 403 at 431.

(126) OEG and OMA argue that the exclusion of OSS creates a fundamental asymmetry by comparing only part of the earnings of AEP-Ohio with the full earnings of the comparable companies (OEG App. at 2-4; OMA App. at 4-5). OEG argues that the "return on common equity that was earned" by the Companies includes profits from OSS. OEG contends there is no statutory basis for comparing only part of the earnings of AEP-Ohio with basis full earnings of the comparable companies and such a comparison distorts the analysis. As a key consumer protection provision of SB 221, OEG asserts that failing to include all of the Companies' earnings undermines the intentions of and the plain meaning of the statue. OEG notes that the record reveals that, during the term of the ESP, projected OSS profits are $431 million for OP and $360 million for CSP and ignoring such earnings misconstrues the statue and fails to provide meaningful consumer protection as intended by SB 221. On such basis, OEG and OMA argue that the SEET set forth in the Order is unlawful (OEG App. at 2-4; OMA App. at 4-5).

(127) As interpreted by OCC, Section 4928.143(F), Revised Code, requires the Commission to determine whether AEP-Ohio's ESP results in excessive earnings and includes all provisions of the ESP, including deferrals. OCC believes that eliminating deferrals from the SEET is an unauthorized adjustment and opines that the elimination of the deferrals is unlawful as it is not authorized by the statue. OCC argues that eliminating deferrals from the SEET will misstate the Companies' earnings, distorting the match between expenses and revenues and distorting the SEET. OCC asserts that the exclusion of the deferrals unlawfully gives AEP-Ohio a margin and virtually ensures that the Companies will not violate the SEET (OCC App. at 67-68).

(128) OEG agrees with the Commission's decision to exclude deferrals and the related expenses from the SEET so that deferrals are matched with revenues when revenues are received by the Companies. However, OEG seeks clarification of the Order to the extent that the Companies' annual earnings for purposes of the SEET will exclude all deferral of expenses and, once recovery of the deferral actually begins, all amortization expenses associated with amounts previously deferred (OEG App. at 4-6).

(129) We grant the intervenors' requests to reconsider the exclusion of OSS margins from the SEET calculation. We have decided that like our consideration of whether to treat AEP-Ohio as a single-entity for purposes of the SEET, OSS is an issue more appropriately addressed in the SEET workshop. Similarly, the Commission concludes that to further explore the issues of deferrals and related expenses, in regards to the SEET, we will also address these components of the SEET as part of the workshop.

V. MARKET-RATE OFFER (MRO) v. ESP

(130) AEP-Ohio argues that the Order is unlawful and unreasonable because Section 4928.143(C)(1), Revised Code, does not permit the Commission to modify the ESP if the proposed ESP is more favorable than the MRO (Cos. App. at 4-5). OCC disagrees and states that the Commission properly applied the statutory test when it compared the modified ESP to the results that would otherwise apply under a MRO (OCC Memo Contra at 9). Similarly, Kroger, OPAE, IEU, and OEG assert that the Commission properly exercised its statutory authority to modify the proposed ESP to make it more favorable than the expected results of a MRO (Kroger Memo Contra at 4; OPAE Memo Contra at 4-5; IEU Memo Contra at 7; OEG Memo Contra at 3).

(131) We agree with the intervenors. The statute contemplates modification of a proposed ESP by the Commission, and then a comparison of the modified ESP, as approved, to the results that would otherwise apply under a MRO. As explained in our Order, our statutory authority is not limited to an after-the-fact determination, but rather, includes the authority to make modifications to a proposed ESP that are supported by the record. Therefore, AEP-Ohio's rehearing request is denied on this ground.

(132) IEU argues that the costs associated with the POLR obligation should not be included in the MRO portion of the ESP versus MRO comparison (IEU App. at 43-44). IEU contends that the Commission lacks the authority to approve a POLR charge in a Section 4928.142, Revised Code, proceeding (Id. at 44).

(133) The Companies interpret IEU's argument as an erroneous belief that the Companies' POLR obligation terminates in the MRO context (Cos. Memo Contra at 13). AEP-Ohio contends that its risk associated with the POLR obligation under SB 221 continues regarding the non-market portion of the MRO, and that it is unrealistic to evaluate the cost of an MRO without including the POLR obligation (Id.).

(134) IEU also appears to be requesting rehearing claiming that the Order does not provide adequate justification or offer even the "slightest clue" for its decision as required by Section 4903.09, Revised Code (IEU App. at 22-26). However, IEU then argues that the market price that the Commission used in its comparison is too high and that, since testimony was filed in the proceeding, market prices have declined. IEU is suggesting that the Commission do on rehearing exactly what it criticizes the Commission's Order for doing, which is base its opinion on information and data that is not in the record of the proceeding. AEP-Ohio objects to IEU's approach of using extra-record information to state that the Commission's analysis was flawed (Cos. Memo Contra at 12).

(135) There was no need for IEU to search for clues in the workpapers. The Commission weighed the evidence in the record and adopted Staff's estimated market prices, as well as Staff's methodology, in the Order. At page 72, the Commission stated its basis: "Based upon our opinion and order *and using Staff witness Hess' methodology* of the quantification of the ESP v. MRO comparison . . ." (emphasis added). Prior to explicitly stating which quantification analysis that it used, the Commission explained that Staff witness Hess' methodology included the utilization of Staff witness Johnson's estimated market rates to demonstrate that the ESP is more favorable in the aggregate as compared to the expected results of an MRO (Order at 70). The Order also explained that the Companies calculated the estimated market prices to be $88.15 per MWH for CSP and $85.32 per MWH for OP. OCC provided testimony of estimated market prices of $73.94 per MWH and $71.07 per MWH for CSP and OP, respectively (OCC Ex. 10 at 15-24), while Staff offered testimony of estimated market prices of $74.71 per MWH and $73.59 per MWH for CSP and OP, respectively,

which were then utilized by Staff in an MRO v. ESP comparison (Staff Ex. 1-A, Revised Exhibit JEH-1). Utilizing their respective estimated market prices, both OCEA (which includes OCC) and Staff concluded that the ESP, if modified, was more favorable in the aggregate than an MRO (see Order at 70-71). Based on the record before it, it was reasonable for the Commission to adopt Staff's estimated market rates and Staff's methodology to quantify the ESP v. MRO comparison. IEU's argument to the contrary lacks merit and, thus, is rejected.

(136) With regard to the MRO versus ESP comparison, our analysis did not end with the rehearing requests. Upon review of the record in this case and all arguments raised on rehearing, the Commission does in fact find that the ESP, including deferrals and future recovery of deferrals, as modified by the Order and as further modified by this entry, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

(137) The Commission notes that, with this entry, it is further modifying AEP-Ohio's ESP to reduce the rate impacts on customers. The Commission believes that the modifications made in this entry increase the value of the Companies' ESP. Nonetheless, even if we do not include the POLR obligation in the calculation of the MRO versus ESP comparison, the Commission finds that the ESP is still more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

VI. SECTION 4903.09, REVISED CODE

(138) IEU generally argues that the Commission's decision fails to comply with the requirements of Section 4903.09, Revised Code, to sufficiently set forth the reasons prompting the Commission's decision based upon the findings of fact in regards to carrying costs, FAC, the rate increase limitation, POLR, the transfer of generation assets, gridSMART and other distribution rate increases, and the comparison of the ESP to the MRO (IEU App. at 4-26).

(139) Similarly, OCC argued that the Commission failed to meet the sufficiency requirements of Section 4903.09, Revised Code, when it denied OCC's motion for stay in its March 30, 2009, Entry Nunc Pro Tunc, and failed to make the Companies' collection of rates subject to refund, and when it approved the ESRP rider (OCC App. at 27-29, 55-57).

(140) AEP disagrees, stating that the Commission explained the bases for its determination of the issues raised in this proceeding in a manner that satisfies Section 4903.09, Revised Code, as well as Supreme Court precedent (AEP Memo Contra at 8-10).

(141) As discussed more fully in the individual sections dealing with each subject matter, the Commission finds that it fully and adequately set forth its decisions in its Order, consistent with Section 4903.09, Revised Code, and long standing precedent. See *Industrial Energy Users-Ohio v. Pub. Util. Comm.* (2008), 117 Ohio St.3d 486, 493, 2008 Ohio 990; *MCI Telecom. Corp. v. Pub. Util. Comm.* (1987), 32 Ohio St.3d 306, 513 N.E.2d 337; *Tongren v. Pub. Util. Com.* (1999), 85 Ohio St.3d 87, 1999 Ohio 206.

It is, therefore,

ORDERED, That the applications for rehearing be granted, in part, and denied, in part, as set forth herein. It is, further,

ORDERED, That the Companies file, for Commission review and approval, their revised tariffs consistent with this entry. It is, further, ORDERED, That a copy of this entry on rehearing be served upon all parties and other interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

See concurrence

Cheryl L. Roberto

KWB/GNS:ct

Entered in the Journal

JUL 23 2009

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	Case No. 08-918-EL-SSO

CONCURRING OPINION OF COMMISSIONER CHERYL L. ROBERTO

It is the Commission's responsibility to promote the policy of this state to "ensure the availability to consumers of ... reasonably priced retail electric service." R.C. 4928.02(A). We are mandated to approve or modify and approve an electric security plan (ESP) when we find that the plan or modified plan, including its pricing and all other terms and conditions, including any deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142. R.C. 4928.143(C)(1).

While an ESP may include components described in R.C. 4928.143(B)(2), nothing in S.B. 221 requires that it be built on a component by component basis. In fact, given that the ESP is not cost based, focusing on any component in which a cost increase is expected or demonstrated obscures the failure to conduct the corollary examination of components of the base rate in which savings have occurred or in which revenue has increased. Thus, we are practically limited in our examination of an ESP or modified ESP to the aggregate impact.

While I concur that the modified ESP is more favorable in the aggregate than what would be expected under an MRO, I do not agree with the underlying policy decisions expressed in paragraphs 18, 38, and 76 of the order and write separately to highlight that, while I do not agree as to these policy decisions. I do concur in the result. As to the FAC baseline, in a cost-based matter it would be unacceptable to sacrifice accuracy when, alternatively, the Commission could order the record to be reopened for the sole purpose of receiving updated testimony as is appropriate for information that could not have been known at the time of the hearing pursuant to Rule 4901-1-34 of the Ohio Administrative Code, or order that the baseline be trued-up to account for actual 2008 fuel costs during annual reconciliation. Further, I specifically do not agree that R.C.

4928.143(B)(2) contemplates recovery for pre-January 1, 2009 environmental expenditures or that carrying costs for environmental expenditures should be accrued at the weighted average cost of capital when there has been no finding that the debt has been prudently incurred taking into account the availability of pollution control funds. Nor can I find, as to the incremental increase in the provider of last resort cost, that the Black Scholes model is an appropriate tool to determine an appropriate POLR charge, or that an increased risk of migration exists which requires an incremental increase in POLR, as a POLR component was already included within the Companies' existing base rates.

The ultimate result of these policy decisions, however, is to increase the Companies' authorized revenue which, when combined with revenue realized from other components of the ESP, results in a particular price for retail electric service. It is this price, together with all the terms and conditions of the modified ESP, that must be more favorable in the aggregate than the results otherwise to be expected pursuant to R.C. 4928.142 in order for the modified ESP to be approved.

Evaluating the "expected" results that would otherwise apply under R.C. 4928.142 when compared to this price is of necessity speculative. The calculation must include a projected market cost. Within the existing record, I concur that the projected market cost has been appropriately defined.[1] I do, however, find that, as argued by IEU and as summarized in paragraph 132, such a calculation may not properly include an incremental POLR increase. However, as stated in paragraph 137, even when correcting for this error by eliminating the incremental POLR increase from the MRO cost, I specifically concur that the modified ESP is still more favorable in the aggregate as compared to the expected results of an MRO.

Cheryl L Roberto

Cheryl ~~A~~ L Roberto, Commissioner

1 Given the significantly different economic conditions which existed between the time of the record testimony and the time at which the Commission considered this matter (both as to the original entry and upon rehearing), I would, however, have supported reopening the record for the limited purpose of refreshing the market price projections as this information was not available at the time of the hearing.

PROOF OF SERVICE

I certify that Columbus Southern Power Company's Appendix of Appellant was served by First Class Mail upon counsel identified below for all parties of record this 27th day of July, 2010.

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