In The
SUPREME COURT OF OHIO

Ohio Power Company,	:	
	:	
Appellant/Cross-Appellee,	:	Case No. 2012-1484
	:	
v.	:	On appeal from the Public Utilities
	:	Commission of Ohio, Case Nos. 09-872-
The Public Utilities Commission of Ohio,	:	EL-FAC, *et al., In the Matter of the Fuel*
	:	*Adjustment Clauses of Columbus*
	:	*Southern Power Company and Ohio*
Appellee.	:	*Power Company.*

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

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MERIT BRIEF
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INTRODUCTION

What is the price of a ton of coal? That is the issue in this case. It is a purely factual matter that is determined by the entirety of what is exchanged to get that ton of coal. That is precisely how the Public Utilities Commission of Ohio (Commission) decided on a price of coal, by looking to the entirety of what was exchanged. American Electric Power Company (Appellant or Company) wanted the Commission and now this Court to ignore parts of the transaction, allowing the Company to keep the benefits of the transaction while forcing higher costs on ratepayers. The Commission sensibly considered all factors of the underlying transaction and its factual decision should be affirmed.

STATEMENT OF THE FACTS AND CASE

Appellant has been buying coal for many decades. In 1992, it entered into a long term contract. As time went on, the market for coal tightened and, by 2007, the 1992 contract allowed Appellant to purchase coal significantly below the then market price. This situation, not surprisingly, lead to a dispute between Appellant and the coal supplier. This dispute was resolved by mutual agreement. The coal supplier essentially bought out the contract by both making a cash payment to Appellant and giving Appellant some undeveloped coal reserves in West Virginia. This was, however, only part of the deal. As Appellant still needed the coal, it agreed to purchase coal from the supplier in 2008 and beyond at a price *much higher* than the price set by the 1992 agreement. At the end of the day, Appellant exchanged its cheap 1992 coal contract for three things: cash in hand; coal reserves in West Virginia; and a more expensive coal contract. The wisdom of this transaction is not questioned in this case.

Prior to the year 2000, the Commission set the price to be charged for what is now termed generation service for all customers. By statute, since repealed, the cost of fuel to produce this energy was recovered through a mechanism called the electric fuel component or, commonly, EFC. Since the passage of the first electric restructuring act in 2000, the Commission now sets only the rate to be charged for what is termed the standard service offer under plans that generally last about three years. The treatment of fuel costs under the standard service offers has varied somewhat. Although most standard service offer plans have included a review mechanism very similar to the old EFC, the plan in effect for Appellant in 2007 included no such provision. That plan was replaced in 2009 with another that does include an EFC-like review. The settlement described above then straddles this change, with the benefits, cash and coal reserves, being obtained by Appellant before the current plan was established and the higher costs being charged after the new plan took effect. Appellant wishes to split this transaction in two so as to keep the benefits of the settlement to itself and push the increased costs off on its customers.

The proceeding below had its genesis in the Commission's order in Appellant's standard service offer case which created an EFC-like mechanism called the fuel adjustment component (FAC). *See, In the Matter of the Fuel Adjustment Clauses of Columbus Southern Power Company and Ohio Power Company*, Case Nos. 09-872-EL-FAC, *et al.* (Opinion and Order at 2) (January 23, 2012) (hereinafter *FAC Order*), Appellant's App. at 9.[1] In keeping with the order establishing Appellant's FAC cases, the Commission selected an auditor to review Appellant's fuel acquisition costs in 2009. That auditor submitted a report in May, 2010 recommending that the Commission examine whether ratepayers should be credited with some portion of the value of the cash payment and coal reserves that Appellant obtained as a result of the settlement described above. A hearing was held and briefs were submitted. The Commission issued its Opinion and Order on January 23, 2012. Several entries on rehearing were made. While rehearing

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1 References to Appellant's Appendix are denoted "Appellant's App. at ___;" references to Appellee's appendix attached to this merit brief are denoted "App. at ___."

was pending, a premature appeal was taken to this Court, case number 2012-0976, that was later dismissed by the Court on September 5, 2012. Timely appeal and cross appeals ensued.

ARGUMENT

Proposition of Law No. I:

> **The Court will not reverse fact determinations where the record contains sufficient probative evidence to support those findings. The Court neither reweighs the evidence nor substitutes its opinion or judgment for that of the Commission on factual, evidentiary matters. *Discount Cellular v. Pub. Util. Comm.*, 112 Ohio St.3d 360, 2007-Ohio-53, 859 N.E.2d 957; *Payphone Ass'n v. Pub. Util. Comm.*, 109 Ohio St.3d 453, 2006-Ohio-2988, 849 N.E.2d 4.**

Appellant had two contracts in 2007 that would have allowed it to obtain coal at below-market prices. Both were renegotiated but on very different terms. The renegotiation that was the primary focus of the case below was termed the Settlement Agreement and the other the Production Bonus Agreement. Each will be discussed below.

A. Settlement Agreement

As to this transaction, the facts are clear. Appellant exchanged a cheap coal contract for cash, undeveloped coal reserves, and a more expensive coal contract. Getting value today, in the form of both cash and assets, in exchange for a promise to pay in the future is, substantively, a lot like a loan. Economically that is an effect of the transaction. The difficulty here is that Appellant wants to keep the loan proceeds yet still require its ratepayers to service the loan. The Commission properly rejected Appellant's nonsensical argument.

To determine the price of anything it is necessary to examine what is exchanged for it. When one buys a new automobile by paying $15,000 cash and trading in an older model, one would be foolish to imagine that the price paid was only $15,000. Obviously the cost was $15,000 plus the value of the trade-in. Likewise with the purchase of a house the real price is not just the down payment but rather the down payment plus the present value of the future payments to be made to service the mortgage note. In every case it is necessary to look to the entire transaction to understand the real price. That is exactly what the Commission did below.

The Commission examined the reality of what Appellant did. AEP had a valuable contract that included the right to obtain coal at below-market prices. Rather than keep that right, Appellant sold the right in exchange for cash and assets and the obligation to buy coal at a more market level price. Appellant monetized the advantage represented by its existing contract. Ratepayers will pay more per ton because Appellant pocketed the value inherent in the 1992 contract. When the Commission looked at this transaction to determine the actual price that each ton of coal cost it evaluated the entirety of the transaction, simply what was given up and what was gotten. As the Commission stated:

> Again, the Commission is only finding that to determine the real economic cost of coal during the audit period, the Commission must consider both the revenues and the benefits received by the Companies pursuant to the Settlement

> Agreement and not rely solely on the price paid for coal during 2009.

FAC Order at 13, Appellant's App. at 20. This is exactly as it should be. This Court has shown a preference for the Commission examining the entirety of a transaction. *Cleveland Electric Illuminating v. Pub. Util. Comm.*, 76 Ohio St.3d 521, 1996-Ohio-298, 668 N.E.2d 889. It has further noted "We are interested in the obligations and rights arising from the transaction, not the form of the transaction." *Mohawk Utilities v. Pub. Util. Comm.*, 37 Ohio St. 2d 47, 51, 307 N.E.2d 261, 265 (1974).

B. Production Bonus Agreement

As to the Production Bonus agreement, there is little clarity. Appellant paid a coal supplier, with whom Appellant had a favorably priced contract, an amount in 2007 to continue to provide the contracted coal. Why paying more to obtain what Appellant already had a contractual right to obtain is a good idea is not immediately obvious. It is all the more difficult to understand when Appellant was able to obtain substantial benefits, cash and reserves, from another supplier in (apparently) the same circumstances at the same time. The difficulty in understanding how such a transaction could benefit consumers is even embodied in the rule governing filing of electric security plans (ESPs) which include fuel adjustment mechanisms. Commission rules require that benefits associated with coal renegotiations be included in the mechanism but is silent as to losses. Ohio Adm. Code 4901:1-35-03(C)(9)(a), App. at 5-6. Confounding the situation is the distinct possibility that the rate plan[2] which was in force during 2007 may have directly allowed Appellant to recover its losses under the Production Bonus Agreement. To make matters more confusing, Appellant did not seek any recovery for these losses through the fuel adjustment clause (FAC) and the Commission's auditor did not recommend any adjustment. In sum, there was simply a failure of proof that any adjustment was required. The Commission reasoned:

> The Commission notes that the audit report did not recommend that the 2008 production bonus agreement be taken into consideration, in contrast to the auditor's recommendation in regards to the settlement agreement, nor recommend that the 2008 production bonus agreement be used as an offset to the benefits accrued as a result of the settlement agreement. Based on the generation rate increases built into the rate stabilization plan in effect prior to the first ESP in 2009, and the evidence of record in these proceedings, the Commission finds that the record does not support offsetting the adjustments to the deferred fuel costs for the settlement agreement, as directed in the FAC order, by the 2008 production bonus agreement. Accordingly, AEP-Ohio's seventh assignment of error is denied.

In the Matter of the Fuel Adjustment Clauses of Columbus Southern Power Company and Ohio Power Company, Case Nos. 09-872-EL-FAC, *et al.* (Entry on Rehearing at 8, ¶ 23) (April 11, 2012) (hereinafter *Second Entry on Rehearing*), Appellant's App. at 39. In

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2 In 2007 the provider of last resort service offered by Appellant was controlled by what was termed a "rate stabilization plan". Such rate stabilization plans were ordered by the Commission for all electric utilities during the period after the 2005 end of the statutory transition period created when the General Assembly allowed retail shopping. Rate Stabilization Plans were eliminated when the General Assembly passed S.B. 221 which created Electric Security Plans to establish the pricing for provider of last resort service among other things.

examining the facts as presented, the Commission found no reason to make an adjustment and, thus, it did not.

C. Conclusion

The Commission properly examined the facts presented. It concluded that the price of coal during the audit period depended on the Settlement Agreement but not the Production Bonus Agreement. This conclusion was supported by the facts of the case and the decision should, therefore, be affirmed.

Proposition of Law No. II:

> **Utility ratemaking by the Public Utilities Commission is prospective only. *Lucas Cty. Com'rs v. Pub. Util. Comm.*, 80 Ohio St.3d 344, 1997-Ohio-112, 686 N.E.2d 501; *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.*, 166 Ohio St. 254, 141 N.E.2d 465 (1957).**

The Commission must set rates that are prospective, and that is what it did. The Commission's task below was to set the price of fuel to be charged by the Appellant.[3] That was all that happened. There was nothing retroactive about the Commission decision. The Commission made this perfectly clear:

> Contrary to the Companies argument, the Commission is not seeking to reach into another audit period in order to modify rates charged during the audit period but rather is rendering

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3 Additionally there were management issues that are not involved here and were not particularly controversial below.

> its decision in order to match the revenues and benefits incurred during the [current] audit period.

FAC Order at 13, Appellant's App. at 20. The Commission did nothing whatever regarding any rates charged in earlier periods and therefore did not engage in retroactive ratemaking.

This Court has seen retroactive ratemaking in the past. In a recent case this Court found:

> AEP had sought a rate increase effective January 2009, but the commission did not issue an order until mid-March. Thus, from January through March, AEP collected less revenue than it would have if the application had been approved before January 1. In response to this delay in rate relief, the commission set AEP's rates at a level "intended to permit the companies to recover 12 months of revenue over a 9-month period."
>
> * * *
>
> This was retroactive ratemaking. Although the commission did not authorize AEP to rebill customers for usage from January through March, it reached the same financial result by setting rates from April through December 2009 at a level sufficient to recover lost revenues from January through March. In AEP's words, "the Commission's decision * * * yield[s] a similar financial impact as would have occurred if a decision had been issued by December 28, 2008 * * *." By approving rates that recouped losses due to past regulatory [*515] delay, the commission violated this court's case law on retroactive ratemaking...

In re Columbus S. Power Co., 128 Ohio St.3d 512, 514-515, 2011-Ohio-1788, 1791, 97 N.E.2d 655, 657-660. That case and that situation have nothing to do with this one. In the case below there was no regulatory delay and the Commission's decision left earlier rates unchanged. The rates charged by Appellant during the earlier rate plan are entirely unaffected by the decision below.

This Court has determined that:

> The Public Utilities Commission of Ohio is not statutorily authorized to order a refund of, or credit for, charges previously collected by a public utility where those charges were calculated in accordance with an experimental rate program which was approved by the commission, but which has expired by its own terms.

Lucas County Com'rs v. Pub. Util. Comm., 80 Ohio St. 3d 344, 349, 1997-Ohio-112, 115, 686 N.E.2d 501, 504. The Court reasoned that to do this would constitute retroactive ratemaking. Again, this finding does not apply to the case at bar. The Commission was not refunding or crediting any former rate as it was in *Lucas County*.[4] While Appellant argues that the Commission is changing the rates charged under its earlier rate plan, nothing of the sort actually happened. The Commission did not consider the rates charged during that earlier period in any way because there was no need to do so below. *Lucas County* simply has no application to the case at bar.

The most instructive retroactive ratemaking case actually supports the Commission's decision. This Court has found that it is not retroactive ratemaking for the Commission to reduce purchased gas rates paid by consumers by the amount of refunds received by the utility from its gas suppliers, *attributable to periods before the purchased gas mechanism was established. River Gas Co. v. Pub. Util. Comm.,* 69 Ohio St. 2d 509,

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4 This is to say no rate other than the fuel component that was being audited.

514, 433 N.E.2d 568, 572 (1982). Just as there was no retroactive rulemaking in *River Gas*, there is none here.

The lead case in the area of retroactive ratemaking is, of course, *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.,* 166 Ohio St. 254, 141 N.E.2d 465 (1957). In that situation a customer was seeking a refund of rates that it had paid pursuant to a Commission order that was subsequently found to be unreasonable. This Court found that there is no cause of action permitted under that circumstance. Quite obviously this has no application to the case below. No refund is sought, no Commission order has been found unreasonable.

The Commission discussed the question of retroactive ratemaking extensively and stated:

> AEP-Ohio's arguments concerning the applicability of *Keco* and *Lucas Cty*. Are likewise unavailing. According to the Companies, any attempt to credit amounts booked in 2008 during the prior rate plan would violate the longstanding prohibition against retroactive ratemaking established in *Keco*. However, *Keco* does not apply in this situation. The Commission is not considering modifying a previous rate established by a Commission order through the ratemaking process as the Court considered in *Keco*. Rather, the Commission, by ordering the Companies to credit more of the proceeds from the Settlement Agreement to OP's deferral balance, is establishing a future rate based upon the real cost of the coal used by the Companies to generate electricity during the 2009 FAC audit period. The proceeds AEP-Ohio received for entering into the Settlement Agreement are but one of the components which impact the Companies cost to provision electricity during 2009. Likewise, *Lucas Cty*. does not apply to the present situation. In *Lucas Cty*., the Court held that the Commission was not statutorily authorized to order a refund of, or credit for, charges previously collected by a public utility where those charges were calculated in accordance with an

> experimental rate program which has expired. As noted above, the Commission has not made a determination modifying the rate the Companies collected during 2009. Additionally, there is no experimental rate program involved in the current case. Thus, *Lucas Cty.* does not apply in this matter.

FAC Order at 13-14, Appellant's App. at 20-21. The Commission's reasoning is perfectly clear. There is no retroactive change to any rate whatsoever.

As the Appellant correctly notes, rates set by the Commission must not be retroactive. The rates below are just that, rates to be charged in the future[5]. The rates previously charged under the old rate plan were the rates charged under *that plan*. The two are **not related**. There is no retroactive ratemaking.

Proposition of Law No. III:

> **The Public Utilities Commission of Ohio controls regulatory accounting for public utilities. R.C. 4905.13, App. at 11-12.**

Appellant's argument springs from a fundamental misunderstanding. When Appellant renegotiated its coal agreement, it chose to book the cash and coal reserves that it received as gains in that year, increasing its calculated income for that year. The better approach would have been to have recognized the gains on the renegotiated contract with the coal as it was received on a per-ton basis. This would associate the benefits and the costs together in keeping with the accounting principle of matching. Appellant believes that the Commission should be bound by the way that Appellant chose to book the trans-

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5 The rates will be charged in the future. The FAC case below is a true-up mechanism of course to accurately correct the rates charged during the audit period.

action. This is, however, entirely backward. Pursuant to statute it is the Commission that controls accounting for regulated companies, not regulated companies that control the Commission's ratemaking. R.C. 4905.13, App. at 11-12. In the Commission's view, the better way to account for this renegotiation is to associate all the costs and benefits associated with each ton of coal with that ton of coal. The Commission made an accounting adjustment in the case below, specifically:

> In this case, the Commission is making an accounting adjustment to recognize extraordinary events affecting 2009 costs such that **the Companies 2009 real costs will be comparable to the proxy baseline selected in the ESP proceedings.**

FAC Order at 13, Appellant's App. at 20 (emphasis added). This is the import of the Commission's order. Pursuant to statute, it is the Commission's view of accounting matters that must control.

Proposition of Law No. IV:

> **An application for an ESP which includes an automatic fuel adjustment clause must include all benefits associated with fuel acquisition costs. Ohio Adm. Code 4901:1-35-03(C)(9)(a), App. at 5-6.**

Any fuel adjustment clause must consider benefits as well as costs associated with the acquisition of fuel. The reason for this is quite obvious. Ratepayers should only shoulder the real economic costs associated with fuel acquisition. The real economic costs are the net of the costs and the benefits. This is exactly what the Commission did below:

> Again, the Commission is only finding that to determine the real economic cost of coal during the audit period, the Com-

> mission must consider both the revenues and the benefits received by the Companies pursuant to the Settlement Agreement and not rely solely on the price paid for coal during 2009.

FAC Order at 13, Appellant's App. at 20.

The requirement of including the benefits with the costs is so fundamental that it is included in the basic filing requirements applicable to a utility application to establish the fuel adjustment mechanism. Commission rules provide:

> (C) An SSO application that contains a proposal for an ESP shall comply with the requirements set forth below.
>
> * * *
>
> (9) Specific information
>
> * * *
>
> (a) Division (B)(2)(a) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the automatic recovery of fuel, purchased power, and certain other specified costs. An application including such provisions shall include, at a minimum, the information described below:
>
> (i) The type of cost the electric utility is seeking recovery for under division (B)(2) of section 4928.143 of the Revised Code including a summary and detailed description of such cost. The description shall include the plant(s) that the cost pertains to as well as a narrative pertaining to the electric utility's procurement policies and procedures regarding such cost.
>
> (ii) *The electric utility shall include in the application any benefits available to the electric utility as a result of or in connection with such costs* including but not limited to profits from emission allowance sales and profits from resold coal contracts.

Ohio Adm. Code 4901:1-35-03(C)(9)(a), App. at 5-6 (emphasis added). The Commission properly applied this rule in this way below. *Second Entry on Rehearing* at 7, ¶ 21, Appellant's App. at 38. Thus, far from modifying the ESP order, the inclusion of the benefits associated with coal acquisition is built directly into the ESP rules themselves. The Commission did not change the earlier ESP order, it simply applied its rules as written to implement its order.

Proposition of Law No. V:

> **The scope of an automatic fuel adjustment mechanism, and any other component of an ESP, is defined by the Commission.**
> **R.C. 4928.143(B)(2)(a), (C)(1), App. at 17, 19.**

The automatic fuel adjustment mechanism below, the FAC, is a rate recovery mechanism wholly created by the Commission. Electric utilities must provide a standard service offer. R.C. 4928.141, App. at 12-13. This can be done either through the market rate offer (R.C. 4928.142, App. at 13-17) or the electric security plan (ESP) (R.C. 4928.143, App. at 17-21). An ESP may, as an option, include an automatic fuel adjustment mechanism and the current ESP for the Appellant does. R.C. 4928.143(B)(2)(a), App. at 17. All the terms of an ESP are controlled by the Commission through its order modifying and approving the Company's application. R.C. 4928.143(C)(1), App. at 19. If a company is unhappy with the terms imposed by the Commission it may terminate its application. R.C. 4928.143(C)(2)(a), App. at 19. In the absence of a termination by the utility, the Commission's order defines all aspects of the ESP including the optional aspects like the FAC mechanism. Appellant has not terminated its ESP. The scope and terms of the FAC proceeding are as the Commission has defined them.

The Commission has acted within the terms that it has defined for the FAC. The Commission was quite specific in this regard when it stated:

> AEP Ohio's claims are without merit as the Commission has not adjusted the baseline for the 2009 period as decided in the Companies ESP cases. Rather, the Commission, in this case, is engaging in a reconciliation and accounting which was explicitly contemplated by the ESP cases in future FAC proceedings. Otherwise, there would be no rationale for undertaking an annual audit. In this case, the Commission is making an accounting adjustment to recognize extraordinary events affecting 2009 costs such that the Companies 2009 real costs will be comparable to the proxy baseline selected in the ESP proceedings.

FAC Order at 13, Appellant's App. at 20. Lest there be any doubt or confusion, the Commission expressly rejected the claim that it was changing the terms of either the ESP order or the scope of the FAC:

> The scope and extent of the audit and the audit period were not revised or expanded as a result of the FAC order. As IEU-Ohio reasoned, the focus of the dispute in these proceedings is OP's [Ohio Power's] 2009 fuel costs. OP's 2009 fuel costs were not litigated in the first ESP proceedings and could not have been litigated because the 2009 fuel costs were not known at that time. The purpose of the FAC audit was to evaluate 2009 fuel and fuel-related costs and the prudency of the Companies' fuel transactions, including the true costs and accounting accuracy of the fuel transactions. AEP-Ohio's claims to the contrary are without merit.

Second Entry on Rehearing at 5, ¶ 15, Appellant's App. at 36. In short, the Commission did exactly what it had set out to do – that is, determine the real price of fuel.

Appellant presents several arguments that are mere red herrings. It argues that the Commission could not adjust the price of coal based on the value of the reserves that it received, as part of the overall consideration, because ratepayers have no ownership interest in those reserves. Ownership is of no relevance whatsoever. Ratepayers do not own the reserves just as they do not own the coal that the case is about. Appellant owns both the coal and the reserves. Again, the Commission made this quite clear:

> AEP-Ohio made similar arguments in its brief and again takes the opportunity to mischaracterize the FAC order. The FAC order does not imply or recognize any ratepayer ownership interest in the coal reserve. *We agree with AEP-Ohio that ratepayers do not earn or acquire an ownership interest* in the utility's assets as a result of paying for utility services. An ownership interest is not necessary for the Commission to order, as it did in the FAC order, the alignment of fuel costs with the benefits of AEP-Ohio's fuel contracts. For these reasons, we again reject AEP-Ohio's claims and deny the request for rehearing.

Second Entry on Rehearing at 11, ¶ 29, Appellant's App. at 42. Ownership had nothing to do with the case below.

The Commission's task was to determine the correct value of the coal to be collected from ratepayers. That had to be done with reference to the value of the reserves because the reserves were part and parcel of the transaction through which the Appellant obtained the coal.

Appellant tries to muddy the waters with a discussion of imprudence. Again, this has nothing to do with the case below. The Commission made no imprudence finding. The accounting adjustment ordered by the Commission is not a punishment for some imprudent business decision. In fact the settlement agreement is a prudent resolution of the problem that Appellant faced at the time. Although Appellant claims that an imprudence finding was necessary for the Commission to order an adjustment, this argument ignores the purpose of the FAC proceeding. The Commission reasoned:

> Despite AEP-Ohio's arguments to the contrary, it is not a condition precedent to reflecting the realized value of the Companies' fuel costs in the FAC, that the Commission find the settlement agreement imprudent. Pursuant to the requirements of division (B)(2) of Section 4928.143, Revised Code, to include the FAC mechanism as a part of the first ESP, AEP-Ohio was required to include "in the application any benefits available to the electric utility as a result of or in connection with such [FAC] costs including but not limited to profits from emission allowance sales and profits from resold coal contracts." The purpose of the FAC audit was to ensure and verify the FAC costs and expenses as well as to review the prudency of the Companies' transactions.

Second Entry on Rehearing at 7, ¶ 21, Appellant's App. at 38. Imprudence has no applicability to the case below.

As already discussed at length herein, the Commission's task below was to determine the real, economic price of the coal consumed during the audit period. As that coal was sourced through a transaction that occurred both before and during the audit period, the Commission correctly considered both aspects of the transaction. While Appellant asserts that the Commission changed the scope of the proceeding, all the commission really did was answer the question before it.

In sum, the Commission is in the best position to understand the scope of the proceeding that it established and defined. It was required to determine the real cost of coal used during the audit period and it did so. Appellant's arguments to the contrary are simply wrong.

CONCLUSION

The Commission set about determining the cost of fuel used to produce electricity during the audit period below. To do this the Commission needed to examine the transaction under which that coal was obtained. That transaction was a little complicated. Appellant had a contract that allowed it to purchase coal at below market prices. It renegotiated that contract and traded it for three things: a cash payment; undeveloped coal reserves in West Virginia; and a new, higher priced contract. Coal was received under that new, higher-priced contract during the audit period. Appellant wanted the Commission to only consider the higher-priced coal contract and ignore the rest of the transaction. Reality is what it is however and the Commission considered the actual transaction to determine the real cost of the coal. This is the correct economic approach, reflects correct accounting, and, frankly, is only sensible. To determine the price of anything, it is necessary to count everything that one gets and gives up to obtain that thing. That, quite simply, is what the Commission did below. It should be affirmed.

Respectfully submitted,

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing Merit Brief, submitted on behalf of appellee, the Public Utilities Commission of Ohio, was served by regular U.S. mail, postage prepaid, or hand-delivered, upon the following parties of record, this 28th day of December, 2012.

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APPENDIX

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4901:1-35-03 Filing and contents of applications.

Each electric utility in this state filing an application for a standard service offer (SSO) in the form of an electric security plan (ESP), a market-rate offer (MRO), or both, shall comply with the requirements set forth in this rule.

(A) SSO applications shall be case captioned as (XX-XXX-EL-SSO). Twenty copies plus an original of the application shall be filed. The application must include a complete set of direct testimony of the electric utility personnel or other expert witnesses. This testimony shall be in question and answer format and shall be in support of the electric utility's proposed application. This testimony shall fully support all schedules and significant issues identified by the electric utility.

(B) An SSO application that contains a proposal for an MRO shall comply with the requirements set forth below.

(1) The following electric utility requirements are to be demonstrated in a separate section of the standard service offer SSO application proposing a market-rate offer MRO:

(a) The electric utility shall establish one of the following: that it, or its transmission affiliate, belongs to at least one regional transmission organization (RTO) that has been approved by the federal energy regulatory commission; or, if the electric utility or its transmission affiliate does not belong to an RTO, then the electric utility shall demonstrate that alternative conditions exist with regard to the transmission system, which include non-pancaked rates, open access by generation suppliers, and full interconnection with the distribution grid.

(b) The electric utility shall establish one of the following: its RTO retains an independent market-monitor function and has the ability to identify any potential for a market participant or the electric utility to exercise market power in any energy, capacity, and/or ancillary service markets by virtue of access to the RTO and the market participant's data and personnel and has the ability to effectively mitigate the conduct of the market participants so as to prevent or preclude the exercise of such market power by any market participant or the electric utility; or the electric utility shall demonstrate that an equivalent function exists which can monitor, identify, and mitigate conduct associated with the exercise of such market power.

(c) The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any energy product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the competitive bidding process (CBP) is publicly available. The information may be offered through a pay subscription service, but the pay subscription service shall be available under standard pricing, terms, and conditions to any person requesting a subscription. The published information shall be representative of prices and changes in prices in the electric utility's electricity market, and shall identify pricing of on-peak and off-peak energy products that represent contracts for delivery, encompassing a time frame beginning at least two years from the date of the publication. The published information shall be updated on at least a monthly basis.

(2) Prior to establishing an MRO under division (A) of section 4928.142 of the Revised Code, an electric utility shall file a plan for a CBP with the commission. The electric utility shall provide justification of its proposed CBP plan, considering alternative possible methods of procurement. Each CBP plan that is to be used to establish an MRO shall include the following:

(a) A complete description of the CBP plan and testimony explaining and supporting each aspect of the CBP plan. The description shall include a discussion of any relationship between the wholesale procurement process and the retail rate design that may be proposed in the CBP plan. The description shall include a discussion of alternative methods of procurement that were considered and the rationale for selection of the CBP plan being presented. The description shall also include an explanation of every proposed non-avoidable charge, if any, and why the charge is proposed to be non-avoidable.

(b) Pro forma financial projections of the effect of the CBP plan's implementation, including implementation of division (D) of section 4928.142 of the Revised Code, upon generation, transmission, and distribution of the electric utility, for the duration of the CBP plan.

(c) Projected generation, transmission, and distribution rate impacts by customer class and rate schedules for the duration of the CBP plan. The electric utility shall clearly indicate how projected bid clearing prices used for this purpose were derived.

(d) Detailed descriptions of how the CBP plan ensures an open, fair, and transparent competitive solicitation that is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code.

(e) Detailed descriptions of the customer load(s) to be served by the winning bidder(s), and any known factors that may affect such customer loads. The descriptions shall include, but not be limited to, load subdivisions defined for bidding purposes, load and rate class descriptions, customer load profiles that include historical hourly load data for each load and rate class for at least the two most recent years, applicable tariffs, historical shopping data, and plans for meeting targets pertaining to load reductions, energy efficiency, renewable energy, advanced energy, and advanced energy technologies. If customers will be served pursuant to time-differentiated or dynamic pricing, the descriptions shall include a summary of available data regarding the price elasticity of the load. Any fixed load provides to be served by winning bidder(s) shall be described.

(f) Detailed descriptions of the generation and related services that are to be provided by the winning bidder(s). The descriptions shall include, at a minimum, capacity, energy, transmission, ancillary and resource adequacy services, and the term during which generation and related services are to be provided. The descriptions shall clearly indicate which services are to be provided by the winning bidder(s) and which services are to be provided by the electric utility.

(g) Draft copies of all forms, contracts, or agreements that must be executed during or upon completion of the CBP.

(h) A clear description of the proposed methodology by which all bids would be evaluated, in sufficient detail so that bidders and other observers can ascertain the evaluated result of any bids or potential bids.

(i) The CBP plan shall include a discussion of time-differentiated pricing, dynamic retail pricing, and other alternative retail rate options that were considered in the development of the CBP plan. A clear description of the rate structure ultimately chosen by the electric utility, the electric utility's rationale for selection of the chosen rate structure, and the methodology by which the electric utility proposes to convert the winning bid(s) to retail rates of the electric utility shall be included in the CBP plan.

(j) The first application for a market rate offer by an electric utility that, as of July 31, 2008, directly owned, in whole or in part, operating electric generation facilities that had been used and useful in this state shall include a description of the electric utility's proposed blending of the CBP rates for the first five years of the market rate offer pursuant to division (D) of section 4928.142 of the Revised Code. The proposed blending shall show the generation service price(s) that will be blended with the CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending will be accomplished. The proposed blending shall show all adjustments, to be made on a quarterly basis, included in the generation service price(s) that the electric utility proposes for changes in costs of fuel, purchased power, portfolio requirements, and environmental compliance incurred during the blending period. The electric utility shall provide its best current estimate of anticipated adjustment amounts for the duration of the blending period, and compare the projected adjusted generation service prices under the CBP plan to the projected adjusted generation service prices under its proposed electric security plan.

(k) The electric utility's application to establish a CBP shall include such information as necessary to demonstrate whether or not, as of July 31, 2008, the electric utility directly owned, in whole or in part, operating electric generation facilities that had been used and useful in the state of Ohio.

(l) The CBP plan shall provide for funding of a consultant that may be selected by the commission to assess and report to the commission on the design of the solicitation, the oversight of the bidding process, the clarity of the product definition, the fairness, openness, and transparency of the solicitation and bidding process, the market factors that could affect the solicitation, and other relevant criteria as directed by the commission. Recovery of the cost of such consultant(s) may be included by the electric utility in its CBP plan.

(m) The CBP plan shall include a discussion of generation service procurement options that were considered in development of the CBP plan, including but not limited to, portfolio approaches, staggered procurement, forward procurement, electric utility participation in day-ahead and/or real-time balancing markets, and spot market purchases and sales. The CBP plan shall also include the rationale for selection of any or all of the procurement options.

(n) The electric utility shall show, as a part of its CBP plan, any relationship between the CBP plan and the electric utility's plans to comply with alternative energy portfolio requirements of section 4928.64 of the Revised Code, and energy efficiency requirements and peak demand reduction requirements of section 4928.66 of the Revised Code. The initial filing of a CBP plan shall include a detailed account of how the plan is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include a discussion of how the state policy continues to be advanced by the plan.

(o) An explanation of known and anticipated obstacles that may create difficulties or barriers for the adoption of the proposed bidding process.

(3) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(4) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I) and (K) of section 4928.20 of the Revised Code.

(C) An SSO application that contains a proposal for an ESP shall comply with the requirements set forth below.

(1) A complete description of the ESP and testimony explaining and supporting each aspect of the ESP.

(2) Pro forma financial projections of the effect of the ESP's implementation upon the electric utility for the duration of the ESP, together with testimony and work papers sufficient to provide an understanding of the assumptions made and methodologies used in deriving the pro forma projections.

(3) Projected rate impacts by customer class/rate schedules for the duration of the ESP, including post-ESP impacts of deferrals, if any.

(4) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including, but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(5) Division (A)(3) of section 4928.31 of the Revised Code required each electric utility to file an operational support plan as a part of its electric transition plan. Each electric utility shall provide a statement as to whether its operational support plan has been implemented and whether there are any outstanding problems with the implementation.

(6) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I), (J), and (K) of section 4928.20 of the Revised Code.

(7) A description of the effect on large-scale governmental aggregation of any unavoidable generation charge proposed to be established in the ESP.

(8) The initial filing for an ESP shall include a detailed account of how the ESP is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include how the state policy is advanced by the ESP.

(9) Specific information

Division (B)(2) of section 4928.143 of the Revised Code authorizes the provision or inclusion in an ESP of a number of features or mechanisms. To the extent that an electric utility includes any of these features in its ESP, it shall file the corresponding information in its application.

(a) Division (B)(2)(a) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the automatic recovery of fuel, purchased power, and certain other specified costs. An application including such provisions shall include, at a minimum, the information described below:

(i) The type of cost the electric utility is seeking recovery for under division (B)(2) of section 4928.143 of the Revised Code including a summary and detailed description of such cost. The description shall include the plant(s) that the cost pertains to as well as a narrative pertaining to the electric utility's procurement policies and procedures regarding such cost.

(ii) The electric utility shall include in the application any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales and profits from resold coal contracts.

(iii) The specific means by which these costs will be recovered by the electric utility. In this specification, the electric utility must clearly distinguish whether these costs are to be recovered from all distribution customers or only from the customers taking service under the ESP.

(iv) A complete set of work papers supporting the cost must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative and other support of assumptions made in completing the work papers.

(b) Divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, authorize an electric utility to include unavoidable surcharges for construction, generation, or environmental expenditures for electric generation facilities owned or operated by the electric utility. Any plan which seeks to impose surcharge under these provisions shall include the following sections, as appropriate:

(i) The application must include a description of the projected costs of the proposed facility. The need for the proposed facility must have already been reviewed and determined by the commission through an integrated resource planning process filed pursuant to rule 4901:5-5-05 of the Administrative Code.

(ii) The application must also include a proposed process, subject to modification and approval by the commission, for the competitive bidding of the construction of the facility unless the commission has previously approved a process for competitive bidding, which would be applicable to that specific facility.

(iii) An application which provides for the recovery of a reasonable allowance for construction work in progress shall include a detailed description of the actual costs as of a date certain for which the applicant seeks recovery, a detailed description of the impact upon rates of the proposed surcharge, and a demonstration that such a construction work in progress allowance is consistent with the applicable limitations of division (A) of section 4909.15 of the Revised Code.

(iv) An application which provides recovery of a surcharge for an electric generation facility shall include a detailed description of the actual costs, as of a date certain, for which the applicant seeks recovery and a detailed description of the impact upon rates of the proposed surcharge.

(v) An application which provides for recovery of a surcharge for an electric generation facility shall include the proposed terms for the capacity, energy, and associated rates for the life of the facility.

(c) Division (B)(2)(d) of section 4928.143 of the Revised Code authorizes an electric utility to include terms, conditions, or charges related to retail shopping by customers. Any application which includes such terms, conditions or charges, shall include, at a minimum, the following information:

(i) A listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or promoting customer shopping for retail electric generation service. Such components would include, but are not limited to, terms and conditions relating to shopping or to returning to the standard service offer and any unavoidable charges. For each such component, an explanation of the component and a descriptive rationale and, to the extent possible, a quantitative justification shall be provided.

(ii) A description and quantification or estimation of any charges, other than those associated with generation expansion or environmental investment under divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, which will be deferred for future recovery, together with the carrying costs, amortization periods, and avoidability of such charges.

(iii) A listing, description, and quantitative justification of any unavoidable charges for standby, back-up, or supplemental power.

(d) Division (B)(2)(e) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for automatic increases or decreases in any component of the standard service offer price. Pursuant to this authority, if the ESP proposes automatic increases or decreases to be implemented during the life of the plan for any component of the standard service offer, other than those covered by division (B)(2)(a) of section 4928.143 of the Revised Code, the electric utility must provide in its application a description of the component, the proposed means for changing the component, and the proposed means for verifying the reasonableness of the change.

(e) Division (B)(2)(f) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the securitization of authorized phase-in recovery of the standard service offer price. If a phase-in deferred asset is proposed to be securitized, the electric utility shall provide, at the time of an application for securitization, a description of the securitization instrument and an accounting of that securitization, including the deferred cash flow due to the phase-in, carrying charges, and the incremental cost of the securitization. The electric utility will also describe any efforts to minimize the incremental cost of the securitization. The electric utility shall provide all documentation associated with securitization, including but not limited to, a summary sheet of terms and conditions. The electric utility shall also provide a comparison of costs associated with securitization with the costs associated with other forms of financing to demonstrate that securitization is the least cost strategy.

(f) Division (B)(2)(g) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions relating to transmission and other specified related services. Moreover, division (A)(2) of section 4928.05 of the Revised Code states that, notwithstanding Chapters 4905. and 4909. of the Revised Code, commission authority under this chapter shall include the authority to provide for the recovery, through a reconcilable rider on an electric distribution utility's distribution rates, of all transmission and transmission-related costs (net of transmission related revenues), including ancillary and net congestion costs, imposed on or charged to the utility by the federal energy regulatory commission or a regional transmission organization, independent transmission operator, or similar organization approved by the federal energy regulatory commission.

Any utility which seeks to create or modify its transmission cost recovery rider in its ESP shall file the rider in accordance with the requirements delineated in Chapter 4901:1-36 of the Administrative Code.

(g) Division (B)(2)(h) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for alternative regulation mechanisms or programs, including infrastructure and modernization incentives, relating to distribution service as part of an ESP. While a number of mechanisms may be combined within a plan, for each specific mechanism or program, the electric utility shall provide a detailed description, with supporting data and information, to allow appropriate evaluation of each proposal, including how the proposal addresses any cost savings to the electric utility, avoids duplicative cost recovery, and aligns electric utility and consumer interests. In general, and to the extent applicable, the electric utility shall also include, for each separate mechanism or program, quantification of the estimated impact on rates over the term of any proposed modernization plan. Any application for an infrastructure modernization plan shall include the following specific requirements:

(i) A description of the infrastructure modernization plan, including but not limited to, the electric utility's existing infrastructure, its existing asset management system and related capabilities, the type of technology and reason chosen, the portion of service territory affected, the percentage of customers directly impacted (non-rate impact), and the implementation schedule by geographic location and/or type of activity. A description of any communication infrastructure included in the infrastructure modernization plan and any metering, distribution automation, or other applications that may be supported by this communication infrastructure also shall be included.

(ii) A description of the benefits of the infrastructure modernization plan (in total and by activity or type), including but not limited to the following as they may apply to the plan: the impacts on current reliability, the number of circuits impacted, the number of customers impacted, the timing of impacts, whether the impact is on the frequency or duration of outages, whether the infrastructure modernization plan addresses primary outage causes, what problems are addressed by the infrastructure modernization plan, the resulting dollar savings and additional costs, the activities affected and related accounts, the timing of savings, other customer benefits, and societal benefits. Through metrics and milestones, the infrastructure modernization plan shall include a description of how the performance and outcomes of the plan will be measured.

(iii) A detailed description of the costs of the infrastructure modernization plan, including a breakdown of capital costs and operating and maintenance expenses net of any related savings, the revenue requirement, including recovery of stranded investment related to replacement of un-depreciated plant with new technology, the impact on customer bills, service disruptions associated with plan implementation, and description of (and dollar value of) equipment being made obsolescent by the plan and reason for early plant retirement. The infrastructure modernization plan shall also include a description of efforts made to mitigate such stranded investment.

(iv) A detailed description of any proposed cost recovery mechanism, including the components of any regulatory asset created by the infrastructure modernization plan, the reporting structure and schedule, and the proposed process for approval of cost recovery and increase in rates.

(v) A detailed explanation of how the infrastructure modernization plan aligns customer and electric utility reliability and power quality expectations by customer class.

(h) Division (B)(2)(i) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for economic development, job retention, and energy efficiency programs. Pursuant to this section, the electric utility shall provide a complete description of the proposal, together with cost-benefit analysis or other quantitative justification, and quantification of the program's projected impact on rates.

(10) Additional required information

Divisions (E) and (F) of section 4928.143 of the Revised Code provide for tests of the ESP with respect to significantly excessive earnings. Division (E) of section 4928.143 of the Revised Code is applicable only if an ESP has a term exceeding three years, and would require an earnings determination to be made in the fourth year. Division (F) of section 4928.143 of the Revised Code applies to any ESP and examines earnings after each year. In each case, the burden of proof for demonstrating that the return on equity is not significantly excessive is borne by the electric utility.

(a) For the annual review pursuant to division (F) of section 4928.143 of the Revised Code, the electric utility shall provide testimony and analysis demonstrating the return on equity that was earned during the year and the returns on equity earned during the same period by publicly traded companies that face comparable business and financial risks as the electric utility. In addition, the electric utility shall provide the following information:

(i) The federal energy regulatory commission form 1 (FERC form 1) in its entirety for the annual period under review. The electric utility may seek protection of any confidential or proprietary data if necessary. If the FERC form 1 is not available, the electric utility shall provide balance sheet and income statement information of at least the level of detail as required by FERC form 1.

(ii) The latest securities and exchange commission form 10-K in its entirety. The electric utility may seek protection of any confidential or proprietary data if necessary.

(iii) Capital budget requirements for future committed investments in Ohio for each annual period remaining in the ESP.

(b) For demonstration under division (E) of section 4928.143 of the Revised Code, the electric utility shall also provide, in addition to the requirements under division (F) of section 4928.143 of the Revised Code, calculations of its projected return on equity for each remaining year of the ESP. The electric utility shall support these calculations by providing projected balance sheet and income statement information for the remainder of the ESP, together with testimony and work papers detailing the methodologies, adjustments, and assumptions used in making these projections.

(D) The first application for an SSO filed after the effective date of section 4928.141 of the Revised Code by each electric utility shall include an ESP and shall be filed at least one hundred fifty days before the electric utility proposes to have such SSO in effect. The first application may also include a proposal for an MRO. First applications that are filed with the commission prior to the initial effective date of this rule and that are determined by the commission to be not in substantive compliance with this rule shall be amended or refiled at the direction of the commission. The commission shall endeavor to make a determination on an amended or refiled ESP application, which substantively conforms to the requirements of this rule, within one hundred fifty days of the filing of the amended or refiled application.

(E) Subsequent applications for an SSO may include an ESP and/or MRO; however, an ESP may not be proposed once the electric utility has implemented an MRO approved by the commission.

(F) The SSO application shall include a section demonstrating that its current corporate separation plan is in compliance with section 4928.17 of the Revised Code, Chapter 4901:1-37 of the Administrative Code, and consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. If any waivers of the corporate separation plan have been granted and are to be continued, the applicant shall justify the continued need for those waivers.

(G) A complete set of work papers must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative or other support of assumptions made in the work papers. Work papers shall be marked, organized, and indexed according to schedules to which they relate. Data contained in the work papers should be footnoted so as to identify the source document used.

(H) All schedules, tariff sheets, and work papers prepared by, or at the direction of, the electric utility for the application and included in the application must be available in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers. The electronic form does not have to be filed with the application but must be made available within two business days to staff and any intervening party that requests it.

4905.13 System of accounts for public utilities.

The public utilities commission may establish a system of accounts to be kept by public utilities or railroads, including municipally owned or operated public utilities, or may classify said public utilities or railroads and establish a system of accounts for each class, and may prescribe the manner in which such accounts shall be kept. Such system shall, when practicable, conform to the system prescribed by the department of taxation. The commission may prescribe the forms of accounts, records, and memorandums to be kept by such public utilities or railroads, including the accounts, records, and memorandums of the movement of traffic as well as of the receipts and expenditure of moneys, and any other forms, records, and memorandums which are necessary to carry out Chapters 4901., 4903., 4905., 4907., 4909., 4921., and 4923. of the Revised Code. The system of accounts established by the commission and the forms of accounts, records, and memorandums prescribed by it shall not be inconsistent, in the case of corporations subject to the act of congress entitled "An act to regulate commerce" approved February 4, 1887, and the acts amendatory thereof and supplementary thereto, with the systems and forms established for such corporations by the interstate commerce commission. This section does not affect the power of the public utilities commission to prescribe forms of accounts, records, and memorandums covering information in addition to that required by the interstate commerce commission. The public utilities commission may, after hearing had upon its own motion or complaint, prescribe by order the accounts in which particular outlays and receipts shall be entered, charged, or credited. Where the public utilities commission has prescribed the forms of accounts, records, or memorandums to be kept by any public utility or railroad for any of its business, no such public utility or railroad shall keep any accounts, records, or memorandums for such business other than those so prescribed, or those prescribed by or under the authority of any other state or of the United States, except such accounts, records, or memorandums as are explanatory of and supplemental to the accounts, records, or memorandums prescribed by the commission. The commission shall at all times have access to all accounts kept by such public utilities or railroads and may designate any of its officers or employees to inspect and examine any such accounts. The auditor or other chief accounting officer of any such public utility or railroad shall keep such accounts and make the reports provided for in sections 4905.14 and 4907.13 of the Revised Code. Any auditor or chief accounting officer who fails to comply with this section shall be subject to the penalty provided for in division (B) of section 4905.99 of the Revised Code. The attorney general shall enforce such section upon request of the public utilities commission by mandamus or other appropriate proceedings.

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.

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.

4928.143 Application for approval of electric security plan - testing.

(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) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) 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;

(ii) 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.