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Douglas E. Hart
Attorney at Law

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VIA FAX
Ms. Renee Jenkins
Public Utilities Commission of Ohio
Docketing Division
180 E. Broad Street, 11th Floor
Columbus, OH 43215

Re: *In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct A Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service,* Case No. 10-2586-EL-SSO

Dear Ms. Jenkins:

Please find attached the Initial Brief of the Greater Cincinnati Health Council, which is thirty (30) pages in length, to be filed in this proceeding by fax. The original and twenty copies will be sent by overnight delivery. As indicated on the Certificate of Service, all parties will be served copies by e-mail.

Very truly yours,

Douglas E. Hart

Enclosure

441 Vine Street Suite 4192 Cincinnati, Ohio 45202
Ph: (513) 621-6709 Fax: (513) 621-6981
dhart@douglashart.com

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.	Case No. 10-2586-EL-SSO

INITIAL BRIEF OF THE GREATER CINCINNATI HEALTH COUNCIL

Douglas E. Hart (0005600)
441 Vine Street, Suite 4192
Cincinnati, OH 45202
(513) 621-6709
(513) 621-6981 fax
dhart@douglasehart.com

Attorney for The Greater
Cincinnati Health Council

January 27, 2011

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I. INTRODUCTION

On November 15, 2010, Duke Energy Ohio ("Duke" or "the Company") filed an application for a standard service offer ("SSO") pursuant to Revised Code § 4928.141. The application sought approval of a market rate offer ("MRO") in accordance with § 4928.142. The Company is currently providing service to its customers in accordance with an Electric Security Plan ("ESP") approved by the Commission in late 2008, which terminates on December 31, 2011.[1] The Company provides its own full requirements power to supply generation service to its retail generation customers. In its application, the Company proposes an MRO whereby it would conduct a descending clock auction to procure supply for a portion of its SSO electric generation service beginning January 1, 2012 to retail electric customers who do not purchase electric generation service from a CRES provider. Duke is requesting that the Commission approve a plan to transition to 100% market rate generation service in 29 months.

In its application, Duke presented a proposed competitive bid process ("CBP") under which bidders would offer to provide SSO supply in tranches, each consisting of one percent of total company load (Co. Ex. 1 at 11). The Company's proposal utilizes a slice-of-system approach. The total amount of SSO supply to be procured would be divided into equal tranches, with each tranche representing a fixed percentage of the Company's SSO hourly load. Tranches would be full requirements, load following. Bidders would bid through a descending clock (reverse auction) format. As proposed by Duke, the initial MRO competitive solicitation would procure ten percent of the total SSO load for the 17 month period from June 1, 2012, through May 31, 2014 (Co. Ex. 1 at 7; Co. Ex. 4 at 4). In the second year, Duke proposes that twenty

[1] *See In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan*, Case No. 08-920-EL-SSO, et al., Opinion and Order (December 17, 2008).

percent of its SSO load would be procured through the CBP. After the first two years, beginning June 1, 2014 and each year thereafter, Duke proposes that one hundred percent of its SSO load would be procured through the auction. Once a winning bid price is known, a rate conversion process would be used to convert the bid price into retail rates to be blended with Duke's current ESP prices to formulate the generation price paid by the Company's retail electric customers (Co. Ex. 4 at 4). This plan would require that, in the third year of the MRO, eighty percent of the total power requirements of Duke's SSO load would be bid out, evenly divided between one, two and three year contracts. (Application, Attachment B).

II. APPLICABLE LAW

Revised Code § 4928.14 requires electric distribution utilities to provide consumers with an SSO, which may consist of an MRO or an ESP. An SSO serves as the utility's default standard service offering for customers who do not shop. The law allows utilities to apply for either an MRO, an ESP, or both simultaneously. Duke Energy Ohio chose to file only an MRO plan in this case and has expressly chosen not to pursue an ESP option, despite Staff comments suggesting that it do so. Once an MRO is approved, an electric utility may never go back to an ESP.[2] Therefore, it is important that the Commission be extremely careful in its review of the application in determining whether an MRO is appropriate, as it is an irrevocable decision.

Revised Code § 4928.142 authorizes electric utilities to file an MRO, whereby retail generation pricing will be based, in part, upon the results of a CBP. The statute sets forth specific requirements that the utility must meet. The Commission also has rules for SSO applications that must be satisfied before an SSO plan may be approved.[3] In determining

[2] R.C. § 4928.142(F).
[3] Ohio Admin. Code Chapter 4901:1-35.

whether an MRO meets the statutory and rule requirements, the Commission must read them together with the state energy policies set forth in § 4928.02, which guide the Commission in its implementation of § 4928.142(A) and (B).[4] It is the policy of the state to, *inter alia*:

> (A) ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;
>
> (B) ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs;
>
> * * *
>
> (E) encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language;
>
> (F) ensure that an electric utility's transmission and distribution systems are available to a customer-generator or owner of distributed generation, so that the customer-generator or owner can market and deliver the electricity it produces;
>
> * * *
>
> (H) ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates;
>
> (I) ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power;[5]

III. ARGUMENT

A. <u>Duke's Proposed MRO Does Not Comply With the Statutory and Rule Requirements Governing Blending.</u>

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[4] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service*, Case No. 08-936-EL-SSO, Opinion and Order (Nov. 25, 2008).
[5] Revised Code § 4928.02.

Duke's proposed blending schedule cannot be approved at this time. Revised Code § 4928.142(D) requires an MRO to start with a minimum five-year initial blending period:

> 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.

Similarly, Commission Rule 4901:1-35-03(2)(j) requires that the application state how the Company would satisfy blending requirements for the first five years of the MRO.

It is undisputed that Duke owned operating electric generation facilities that had been used and useful in Ohio on July 31, 2008, making it subject to the blending provision. (Tr. III, p. 650). Duke has requested that the first year of its MRO be extended by five months to a 17 month period, so that the anniversary date would coincide with the June 1 PJM planning year. Assuming the Commission accepts that proposal, the "first year" under Duke's plan would be January 1, 2012 through May 31, 2013. Year two would be June 1, 2013 through May 31, 2014, year three would be June 1, 2014 through May 31, 2015, and so forth. According to R.C. § 4128.142(D), the applicable blending rates must be ten percent in the first year, not more than twenty percent in the second year, thirty percent in the third year, forty percent in the fourth year, and fifty percent in the fifth year. Duke's application fails to comply with this.

Despite the various testimonies that opine on the meaning or intent of the blending provisions in R.C. § 4128.142(D) and (E), interpretation of the statute is a question of law. Even Duke agrees. (Tr. I, p. 60). The first place to look to determine the intent of the statute is its own language. (Tr. I, p. 25). Words and phrases are to be read in context and construed according to the rules of grammar and common usage.[6] If a statute is ambiguous, determination of the intent of the legislature may also consider the circumstances under which the statute was enacted, the legislative history and the administrative construction of the statute.[7]

There has been much debate in this case about whether the stated blending percentages are fixed amounts or maximums, whether the Commission may vary from them and, if so, when. All of these questions are answered by the plain language of the statute and are further illuminated by the legislative history of § 4128.142.

What became R.C. § 4128.142 was first introduced through Senate Bill 221. As originally introduced and passed by the Senate as Sub. S.B. 221 on October 31, 2007, the bill had no blending requirement.[8] The legislation was substantially revised when introduced into the House. At that time a blending requirement was introduced that required the competitively bid portion of the standard service offer to be "not less than ten per cent of the load in year one and not less 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."[9] This version of the legislation would have established ***minimum*** blending percentages, i.e., the competitively bid prices had to be *at least* the stated percentages in each year. This explains the purpose of the second sentence: the Commission would have had to set the specific percentages for each year, as the statute would have only established minimums. Sub. S.B. 221 also first introduced the first version of what would become § 4928.142(E).

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[6] Revised Code. § 1.42.
[7] Revised Code. § 1.49(B), (C), (F).
[8] http://www.legislature.state.oh.us/bills.cfm?ID=127_SB_221_PS.
[9] http://www.legislature.state.oh.us/bills.cfm?ID=127_SB_221_PH.

The language of § 4928.142(D) would be changed several more times before it actually became law. The 2008 budget bill, H.B. 562, made a major change to the blending requirement when it abandoned the concept of minimum blending percentages and instead established fixed blending percentages of ten to fifty percent in each of the first five years of an MRO, except year two, where twenty percent became a *maximum*:

> (D) The first application filed under this section by an electric distribution utility that, as of ~~the effective date of this section~~ 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 ~~and~~, not ~~less~~ 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.[10]

The argument over whether the percentages in years three, four and five were intended to be fixed percentages or maximums is settled by reviewing interim amendments to H.B. 562 that were considered but rejected. The Senate attempted to add language to R.C. § 4928.142(D) to clarify that the stated percentages would be maximum amounts for each individual year:

> (D) The first application filed under this section by an electric distribution utility that, as of ~~the effective date of this section~~ 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 ~~and~~, not ~~less~~ more than twenty per cent in year two, not more than thirty per cent in year three, not more than forty per cent in year four, and not more than 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.[11]

However, the insertion of the words "not more than" before each percentage was rejected by the Conference Committee before the bill became law.

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[10] http://www.legislature.state.oh.us/BillText127/127_HB_562_EN_N.html.

[11] http://www.legislature.state.oh.us/BillText127/127_HB_562_PS_N.html.

What we can conclude from the plain language of the statute and its legislative history is that an MRO application *must* use blending percentages of exactly ten percent in year one, thirty percent in year three, forty percent in year four and fifty percent in year five. The Commission has discretion to set a blending percentage of up to a maximum of twenty percent in year two.

This brings us to R.C. § 4928.142(E), which provides a mechanism for the Commission to adjust the blending percentages prospectively. Several controversies have been raised with respect to the interpretation of § 4928.142(E), including the meaning of "beginning in the second year of a blended price," "notwithstanding any other requirement of this section," "prospectively," and "to mitigate the effect of an abrupt or significant change." Parties have debated when the Commission can adjust the blending percentages, whether they may be adjusted up or down, and for what reason. The plain language is clear that the Commission may *not* consider any adjustments to the blending schedule until the beginning of the second year of blending, which under Duke's proposal would be June 1, 2013.

There are numerous pointers to this result in the statute and legislative history. The first is the plain language of the statute itself. "Beginning in the second year of a blended price" sets a clear point at time when the consideration may begin. "Beginning" means "the point at which something begins."[12] "In the second year" indicates that the point in time is in the future, not now. Had the General Assembly intended for the Commission to have the ability to select a different blending schedule than is established in § 4928.142(D) at the outset of an MRO, the various amendments back and forth of the blending requirements in various versions of Sub. S.B. 221 and H.B. 562 would make no sense. The General Assembly would have addressed that directly in § 4928.142(D) by giving the Commission discretion to set any of the blending

[12] http://www.merriam-webster.com.

percentages at the outset, not to wait until the second year. The only year over which there is any initial discretion is the second year (and then the discretion is limited to a range of zero to twenty percent). Previous versions of the language had alternated between making the blending percentages minimums and maximums, but the General Assembly finally settled on language that established *fixed* percentages for all but year two.

Grammatically, the placement of the phrase "[b]eginning in the second year" at the head of the sentence indicates that it modifies the phrase "the commission may," identifying the time at which the Commission may act. It does not control when alterations would take effect. That work is done by the word "prospectively." Duke's interpretation that the Commission may alter the blending percentages today, to be effective beginning in the second year, would make the word "prospectively" superfluous.

It is significant that § 4928.142(D) gives the Commission discretion over the blending percentage for the second year at the outset, but not for any other year. This provision permits the Commission to look forward one year, but no further, upon initial consideration of an MRO application and allows it to *slow* the blending down if it foresees that a twenty percent blending requirement would be inappropriate at that time. Beginning *in the second year*, the Commission has authority to vary from the theretofore *fixed* thirty, forty and fifty percent blending rates in years three, four and five (and potentially extend it into years six through ten). The Commission would have more current information about market conditions at that point in time in order to make a better decision. (Tr. V, p. 1076).

This concept is reinforced by the Commission's own Rule 4901:1-35-11(C), which requires an electric utility operating under an MRO with a blending period to file an annual report. Among the many matters to be reported, the utility must address the rates it projects will be charged to customers under the continuation of the plan. Specifically, "[t]he projected blended phase-in rates shall be compared in the annual report to the existing blended phase-in rates."[13] This dovetails with R.C. § 4928.142(E) and explains how the Commission would determine whether an abrupt or significant change in the blended rate is expected and provide the Commission with an opportunity to make an adjustment.

Perhaps the most important language in § 4928.142(E) is the phrase "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." This language establishes the purpose for which the Commission may alter the percentages *specified* in § 4928.142(D). It requires an analysis of the prices that would result from the percentages specified in § 4928.142(D). If the Commission would find that continuing to follow the specified blending percentages would lead to "an abrupt or significant change" in the SSO price, then it may change the blending schedule prospectively to *mitigate* any effect of such change.

The word "mitigate" is also important. "Mitigate" means "to cause to become less harsh," or "to make less severe or painful."[14] So, the purpose of making any future change to the pre-established blending schedule must be to reduce the amount of change in prices that would otherwise result from the existing blending schedule.

Even assuming that Duke and its supporters are correct that the Commission could *consider* an alteration to the blending schedule now (which it cannot), and assuming theoretically that the blending percentages could be adjusted either up or down (an upward adjustment to the blending rate would only mitigate a rate change if market rates declined

[13] Rule 4901:1-35-11(C)(7).
[14] www.merriam-webster.com.

relative to ESP rates, the opposite of the trend that Duke projects), and even assuming that adjustments could be made either for the benefit of customers *or* Duke (all implications from the context appearing that the concern was the effect of rates on customers), Duke has *still* not justified the blending schedule that it proposes in this case. GCHC will leave it to other parties to debate these points for now, as it turns out they are all irrelevant under the circumstances. The Commission should also decline to rule on that debate, as any opinion would be advisory and unnecessary to reach the right result. Even resolving all doubt on those issues in Duke's favor, its own evidence defeats its request to accelerate the move to full market rates.

The premise of Duke's attempt to accelerate blending to a 100% market rate after only twenty-nine months is that market prices and its legacy ESP will converge in approximately 2014, thereby negating any further need for blending. That entire argument is inherently illogical and completely at odds with the statutory language. Consider Duke's evidence.

Duke witness Judah Rose offered projections of expected retail prices for electric generation through 2014. No other witness in this case has offered any price projections. GCHC is certainly not suggesting that Mr. Rose's projections should be accepted. It must be remembered that the same witness offered a virtually identical future price analysis in Case No. 08-920-EL-SSO on behalf of Duke that predicted that market prices in 2001 would be higher than the ESP prices then requested by Duke. (Tr. I, p. 149). Mr. Rose predicted that market prices in 2011 would be well above Duke's ESP price right now. We all know how that projection turned out, which is largely why Duke finds itself today with retail generation prices that are well above market rates. (Tr. I, p. 150). For all we know, Mr. Rose's projections may be equally wrong (in either direction) with respect to 2014 prices. In any event, for purposes of testing Duke's hypothesis, let's assume Mr. Rose is right this time.

Mr. Rose projects that Duke's legacy ESP price, including all existing riders that Duke proposes to fold into the single Rider GEN rate will be 7.34 cents per kWh in 2012, 2013 and 2014. After extensive analysis, much the same as was done in Case No. 08-920-EL-SSO, Mr. Rose projects comparable retail market prices of 5.82, 6.34 and 7.17 cents per kWh in 2012, 2013 and 2014, respectively. Using the prescribed ten percent blending rate in year one and the maximum twenty percent blending rate in year two, Mr. Rose projects blended MRO prices of 7.19 and 7.14 cents per kWh in 2012 and 2013, respectively. Mr. Rose did not project a blended price for 2014 using the prescribed thirty percent blending rate for year three. However, Duke witness Wathen confirmed that blending the projected legacy ESP price and Mr. Rose's projected 2014 retail market price using thirty percent would yield a blended rate of 7.22 cents per kWh. (Tr. III, p. 659). Using Mr. Rose's projected market prices, the results would be a decrease in year one from Duke's legacy ESP price of 2%, a decrease in year two of 0.1%, and an increase in year three of 1.1%. (Tr. III, p. 660).

For the Commission to alter the blending percentages from the fixed thirty percent in year three, it would first have to find that an anticipated 1.1% increase in Duke's SSO price that would otherwise result from applying the thirty percent blending rate would be "an abrupt or significant change." R.C. § 4928.142(E). Duke makes no effort to demonstrate that such a small increase would be "abrupt or significant." In fact, Mr. Wathen agreed that Duke's past rate increases in 2009, 2010 and 2011 of approximately 2% per year were not unreasonable and that he "wouldn't characterize it as abrupt or significant." (Tr. III, p. 653-55). If a 2% increase in 2009, 2010 and 2011 was not "abrupt or significant," a 1.1% rate change in 2014 is not.

Remarkably, Duke is not contending that there would be an abrupt or significant change in its SSO price absent its alteration proposal. Instead, Duke contends that *its* proposal would not allow an abrupt or significant change. But, that is not the statutory standard for altering the blending schedule. Any number of different blending proposals might result in no abrupt or significant change in the resulting prices, but the prerequisite for modifying the pre-established percentages is that *the pre-established percentages* would result in an abrupt or significant price change. Duke makes no pretense that they would. Hence, it has failed to establish the predicate event necessary to request the Commission to alter the blending schedule. It is irrelevant whether the Commission may consider altering the blending schedule at the outset (as opposed to waiting until the second year of blending) or whether the Commission may alter the fixed blending rates upward or downward. Accepting all of Duke's testimony and projections as true, the prerequisite for diverging from the statutory blending schedule has not been established.

Mr. Wathen contended on cross-examination that the "significant" event that would justify a variance in favor of Duke was the predicted convergence of Duke's legacy ESP price and the retail market price. (Tr. III, p. 623-25, 643). But the statute is not triggered by a "significant event" (even assuming the convergence of prices is of any significance), only a "significant change" and, then, only a significant change to the resulting blended price. The evidence in this case is that, if Mr. Rose's projections hold true, there would be no significant difference between the blended price at thirty percent and a 100% percent market price. (Tr. I, p. 149). In fact, it is this *lack* of a difference between the two that Duke uses to argue in favor of ending blending in year three. (Tr. I, p. 124). That makes no sense under § 4928.142(E).

Even if it could do so, a decision now to allow Duke to go to 100% market pricing in year three would not be prudent. Duke contends that once the Commission allows 100% market pricing, it cannot go back. (Tr. I, pp. 142-43, 152). Duke even contends that the Commission cannot retreat from any given blending percentage, even one less than 100%, once it has been approved. (Tr. I, p. 145). At the same time, Duke makes no forecast of prices past 2014 (Tr. I, p. 125), although it expects the trend in prices to continue *upwards* after 2014. (Tr. I, p. 140). While, by definition, there would be no significant difference between blending according to the statutory schedule and 100% market pricing while the prices remain close (Tr. I, pp. 124, 148), there could be significant differences if the prices do not remain converged. That is the very reason why the Company must wait until evidence is available that the statutorily mandated fixed blending percentages will result in an "abrupt or significant" change in price.

Duke's desire to go to a 100% market rate in year three is not because blending would no longer be relevant. Nor is it out of altruism for customers to give them lower rates.[15] Duke has stated its intent to transfer its generation assets out of the regulated company and to take advantage of higher market prices in the future and not be restricted to the legacy ESP price. (Tr. I, p. 26; Tr. III, p. 631). Duke's testimony plainly states that it objects to the ESP price because, when the market price is below the ESP price, Duke is vulnerable to shopping and, when the market price is above the ESP price, it cannot raise its rates to take advantage of the increase. To be realistic, Duke is not hampered by an inability to *lower* its prices to meet the market. First, it could have, but has not, proposed lowering its rates. It claims it met resistance when it suggested doing that in the past (Tr. I, p. 68; Tr. III, p. 632), but Duke has not adequately explained why it did not pursue that further. The only parties that would logically object to Duke lowering its rates would be competitive suppliers who can use Duke's rates as

[15] Duke's customers have the ability to shop if market rates are below ESP rates. Late in the hearing, Duke raised the point that PIPP customers, are not eligible to shop to a CRES, asserting that the right to shop does not benefit them, but lower Duke rates would. (Tr. V, pp. 960-61). This is a red herring, as PIPP customers do not pay the actual amount of their energy bills. Instead, they pay a percentage of their income, which is the same, regardless of the retail rates that Duke charges. The other examples, customers with arrearages of certain amounts or duration, are only precluded from shopping because they did not pay their bill, a restriction that Duke has itself imposed by tariff.

umbrellas to price under. In any event, Duke has been selling its excess generation service at market prices. (Tr. II, p. 388; Tr. III, p. 627; Tr. IV, p. 777). Having several options to adapt to low market prices (lowering its own rates, selling into the wholesale market, and selling power to its own affiliate (Tr. IV, p. 780)), it is apparent that the reason for Duke's market rate proposal is its desire to follow the market price upwards when prices exceed its legacy ESP price. (Tr. IV, pp. 747-48, 778, 793-94). And that is exactly why consumers need the protection of the statute blending schedule in § 4928.142(D).

B. Cost Adjustments Pursuant to § 4928.142(D).

In the event the Commission approves Duke's proposal to go to full market pricing in 29 months (which it should not), Duke proposes to freeze Rider GEN and not make the quarterly adjustments described in R.C. §4928.142(D). (Tr. III, p. 592). While Duke is free to forgo increases in rates due to changes in costs, its proposal would also remove the Commission's authority to make downward adjustments if costs go down. (Tr. I, p. 66). Duke may be willing to "make a bet" with the Commission on where future cost adjustments might go during the 29 month period (Tr. III, p. 668), but the Commission should be more circumspect. For example, if Duke incorporates 4th Quarter 2011 PTC-FPP and PTC-AAC costs into the base generation rate, the amounts for that quarter may not be representative of average costs over a longer term. (Tr. IV, p. 810). The Commission should not gamble, certainly not without requiring Duke to divulge all information that is has about future costs that would otherwise flow through the adjustments so that Duke is not acting on superior information not available to others.

C. All Riders That Collect Costs of Obtaining Generation Service Must Be Fully Bypassable.

Duke proposes a number of riders in this case. With the exception of two transmission riders, BTR and RTO, all of Duke's proposed riders involve the recovery of costs associated with generation costs. These include Riders GEN, MRO, SCR, AERR, UE-GEN and RECON. In addition, if Duke's proposal to shorten the blending period to 29 months is not accepted (which it should not be), Duke proposes Riders FPP and EIR to recover adjustments to the legacy ESP price permitted under R.C. § 4928.142(D). All of these riders are proposed to be fully by-passable except for Rider RECON and Rider SCR on certain conditions.

State energy policy set forth in R.C. § 4928.02 specifically addresses cross-subsidization of regulated and non-regulated services. It is the policy of the state to:

> Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates;[16]

This prohibits public utilities from using revenues from competitive generation service components to subsidize the cost of providing noncompetitive distribution service, or vice versa.[17] All generation-related charges should be avoidable by shopping customers.

Proposed Rider RECON would directly violate this state policy. Rider RECON is a true-up mechanism to recover or return any remaining balances in two legacy generation service riders that are currently bypassable. (Tr. III, p. 611). Rider RECON would recover costs of providing generation service from Duke distribution customers that do not take generation service from Duke. (Tr. I, p. 74). Accordingly, to avoid cross-subsidization, Rider RECON must be fully by-passable. (Tr. VI, p. 1136).

The Company proposes a cost recovery true-up reconciliation mechanism (Rider SCR), designed primarily to reconcile the difference due to rate design between what is paid to

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[16] Revised Code § 4928.02(H).

[17] *Migden-Ostrander v. Pub. Util. Comm.*, 102 Ohio St.3d 451, 2004-Ohio-3924, 812 N.E.2d 955, ¶ 4; *Elyria, supra*, ¶¶ 47-58.

suppliers who participate in the competitive auction and what is collected from Duke SSO customers. In addition, the Company proposes that Rider SCR be used to recover certain incremental expenses associated with the implementation of the CBP, including the independent third party and any consultant hired by the Commission. The Company proposes that Rider SCR become unavoidable if it exceeds five percent of the SSO generation rates.

The Company argues that, if customers are allowed to shop and avoid such charges, there would be a shrinking pool of customers from which to recover such cost. While this may be theoretically possible, it is doubtful that it would ever occur, particularly if blending progresses at the statutory pace and not Duke's accelerated schedule. (Duke Ex. 16, p. 20). Nevertheless, this risk does not justify recovering generation supply costs from shopping customers. All aspects of Rider SCR relate to generation. Thus, the Commission should find that Rider SCR should be avoidable for all customers who shop.

In addition to Ohio's energy policy, Duke's corporate separation plan prohibits subsidies between its regulated business and non-regulated business. (Tr. IV, p. 733). This means that the distribution business cannot subsidize the generation business. (Id.). Duke has not offered any means of reconciling its request to make Rider SCR conditionally bypassable with the clear terms of its own corporate separation policy. (Tr. IV, pp. 742-43). Any provisions in Rider SCR attributable to acquiring generation service should be fully by-passable. (Tr. VI, p. 1139).

At the very least, as suggested by Wal-Mart/Sam's witness Chriss with respect to Rider RECON, any recovery of Rider SCR from shopping customers should be limited to those who took generation supply from the Company during the time that the costs to be recovered in the SCR were incurred. (Wal-Mart/Sam's Ex. 1, p. 9). The Commission should prohibit Duke from assessing Rider SCR on any customer who left Duke SSO service before the quarter in which the rider would become non-bypassable.

If the Commission does entertain a scenario where Rider SCR could become non-bypassable, Mr. Wathen described a process whereby Duke would make application to the Commission to declare Rider SCR non-bypassable. (Tr. III, pp. 595-96). However, the tariff pages proposed by the Company do not contain any such procedure. The proposed tariff would render Rider SCR automatically non-bypassable if the 5% condition was met. (Tr. III, pp. 699-700). Duke should be required to amend the proposed tariff to require it to apply to the Commission for approval before making the rider non-bypassable.

D. The Commission Should Not Approve Riders BTR and RTO As Proposed.

Duke proposes to eliminate current Rider TCR and replace it with two new transmission riders, Rider TRO and Rider BTR. Currently, Rider TCR recovers MISO transmission costs and is bypassable. However, CRES providers are independently billed the same TCR charges, so it is, in effect, non-bypassable because all customers incur these costs, either directly through Duke or indirectly through their CRES provider. In its new proposal, Duke would divide transmission costs into two categories. Duke proposes that non-usage sensitive costs, including NITS, would go into Rider BTR and be non-bypassable. (Tr. III, p. 598). Rider RTO would include usage sensitive costs and be bypassable.

The Commission should not approve the manner in which Duke proposes that the amounts of Riders BTR and TCR would be established. As is described in Duke's application and various testimonies, Duke decided to withdraw from MISO and join PJM effective January 1, 2012. The exact cost of this RTO change is still unknown and is subject to great uncertainty, but the amounts at stake are significant. (Tr. II, p. 467, 471). It is not clear when, how, or by whom the costs to withdraw from MISO and join PJM will be established. Duke says it will negotiate with MISO to establish an exit fee and its responsibility for RTEP costs incurred while it was a transmission owning member of MISO. However, the resolution of those issues may have to be resolved through litigation either at FERC or elsewhere. It is further unclear to what degree a resolution between Duke and MISO will be incorporated into MISO tariff charges or whether there would be a financial settlement outside of a tariff. (Tr. III, p. 675).

Duke states that it is not seeking a prudence review of its MISO exit fees, MISO MTEP costs, PJM entrance fees, or PJM RTEP fees in *this* proceeding (Tr. III, p. 644). But what it is proposing would actually remove any role of the Commission in approving the recoverability of those costs in *any* proceeding. Duke proposes that any FERC approved RTO costs would automatically flow through one of its two new transmission riders. (Tr. III, p. 644-46). The proposed tariff page for Rider RTO was developed by red-lining existing Rider TCR, which currently only allows transmission costs that have been approved both by FERC and this Commission. Duke's proposal would strike the language requiring approval by this Commission and FERC to only provide for FERC approval of those costs. (Tr. III, pp. 678-78, 701). Similarly, the proposed tariff page for new Rider BTR would only require FERC approval of the costs to be flowed through that rider. (*Id.*)

GCHC is not requesting that the Commission conduct a prudence review of RTO costs in this proceeding, which would be premature. But GCHC believes the Commission should reject Duke's proposed tariff language because it would potentially foreclose any prudence review by the Commission in some other proceeding. GCHC recognizes that there are jurisdictional questions regarding the scope of the Commission's authority to review transmission costs.

However, this is not the proceeding in which to resolve those issues. Duke's proposed tariff would conclusively resolve them.

E. **The Proposed Rate Design Should Be Modified**

Commission Rule 4901:1-35-03(B)(2)(i) requires Duke to explain the rate structure and methodology that it has chosen to convert bid prices to retail rates. In addition, the policy of the state, as codified in § 4928.02(B), requires the Commission to ensure the availability of unbundled and comparable retail electric service that provides customers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs. Nothing in § 4928.142 diminishes the Commission's existing authority over rate design or duty to ensure the availability of reasonably priced electric service.

With regard to the generation rate design proposed in the MRO application, Duke has proposed tariffs for the competitively bid portion of the price that are based solely on per kilowatt hour (kWh) charges, as opposed to the existing tariffs which include demand charges. This change would cause high load factor customers to lose the relative price advantage that they currently have relative to low load customers. (Tr. III, p. 566). Duke has not demonstrated that its proposed rate design advances the state policies enumerated in § 4928.02, so the proposed rate design should not be adopted and approved by the Commission. The Commission should accept Kroger's request that the rate design include demand charges, rather than bill all charges as energy. (Kroger Ex. 1, pp. 12-17).

Duke proposes to allocate the capacity portion of the auction price to different customer classes on the basis of peak demand. The rate conversion process proposed by the Company to derive its retail rate is not an appropriate method to use because it is inconsistent with the rate conversion process used in Duke's ESP rates. The Company proposes to allocate capacity costs from the CBP auction prices using the 4 CP method. However, Duke's current ESP rates allocate capacity costs among customer classes using the 12 CP method. (Tr. III, pp. 577, 582). Duke witness Bailey testified that the 12 CP method passed FERC Test C for rate design and is consistent with how current Duke rates are calculated. (Tr. III, pp. 577-78). Duke should also use the 12 CP method to convert auction prices to retail rates.

F. <u>There Are Concerns Whether An MRO Is Appropriate At This Time.</u>

Section 4928.142(A)(1) requires that an MRO be determined through a CBP that provides for all of the following: an open, fair, and transparent competitive solicitation; a clear product definition; standardized bid evaluation criteria; oversight by an independent third party; and evaluation of submitted bids prior to selection of the least-cost bid winner or winners.

As stated at the outset, before approving an MRO, the Commission should ensure that it is consistent with state energy policy. Among those policies are to ensure effective competition and to protect consumers against market deficiencies and market power. The policies specified in § 4928.02 are more than mere statements of general policy objectives. Section 4928.06(A) imposes on the Commission a specific duty to "ensure the policy specified in section 4928.02 of the Revised Code is effectuated." The Ohio Supreme Court has held that the Commission may not approve a rate plan which violates the policy provisions of § 4928.02.[18] Accordingly, an electric utility can only be deemed to have met the statutory requirements of § 4928.142(A) to the extent that its proposed MRO is consistent with the policies set forth in § 4928.02. Among these critical policies are the requirements to ensure the availability of reasonably priced retail

[18] *Elyria Foundry Co. v. Pub. Util. Comm.*, 114 Ohio St. 3d 305, 2007-Ohio-4164.

electric service; ensure diversity of suppliers; and protect customers against unreasonable sales practices, market deficiencies, and market power.

1. Open, fair, and transparent competitive solicitation - § 4928.142(A)(1)(a).

The Commission must assure itself that the proposed reverse auction is an "open, fair and transparent competitive solicitation," and would result in the least-cost rate for consumers. Duke must demonstrate that the reverse auction format that it has proposed is the superior format to result in the lowest and best possible prices for consumers. Duke has offered no evidence of the level of participation that would be expected in such an auction. With all due respect to the results of the FirstEnergy auctions, which Duke has repeatedly referred to and assumed would be repeated in Duke's market, FirstEnergy is in a different market altogether. The proximity of non-Duke generation assets is different. The cost of transmission into the market is different. And, the capacity that is already committed to serving FirstEnergy's customer load is not available to bid in the Duke auction.

The Commission should ensure that the Company has adequately demonstrated that its market is truly competitive. And, the Commission should be sure that Duke and its affiliate, Duke Energy Retail Sales ("DERS") cannot unduly influence the market clearing price by virtue of Duke's concentration of generation ownership. If Duke has market power and the ability to control pricing, the auction result would not be a fair price that reflects effective competition.

As the basis for its contention that its market is competitive, Duke relies upon the statistic that approximately 60% of its wired customer load has elected to take generation service from a CRES supplier and that there are currently 13 CRES suppliers active in its market area. Duke Ex. 2, p. 8; Tr. I, pp. 232). When explored more closely, the 60% switching statistic is less impressive. The switching that has occurred is due to Duke's ESP price being set too high in relation to current market conditions. (Tr. I, pp. 71-72). Most of Duke's competitive loss has been to its own affiliate, DERS. Of the approximately 60% of Duke's retail load that has switched suppliers, approximately 60% has switched to DERS. (Tr. II, pp. 358, 381; Tr. IV, p. 776). Duke has bilateral supply agreements with DERS (Tr. II, p. 382), although it did not disclose their magnitude. That may mean as little as 24% of Duke's wired load is served by independent, unaffiliated CRES providers.[19]

Consider the scenario that could occur if Duke's proposal to go to 100% market rates in three years would be approved. It would be necessary to secure generation supply for 80% of Duke's customer load in a single auction. (Application, Attachment B). There is no evidence in this record that there is sufficient non-Duke generation supply available and willing to meet that supply requirement at prevailing market prices. Under the rules of the proposed reverse auction, the auction stops when all of the tranches up for bid in the auction are not fully subscribed at the same price. (Application, Attachment C, p. 18). Duke proposes to offer three products of various contract lengths at auction in 2013 for delivery in 2014 in tranches of 26% to 27% of its total load for each. Considering that as little as 24% of Duke's total load may be being supplied presently by independent generation, it is speculative that even one of the products offered for auction could be fully subscribed without participation by Duke generation. It is highly doubtful that any two of the products could be fully subscribed, and virtually certain that they could not all be fully subscribed without substantial participation by Duke (or whomever owns those assets if they are transferred pursuant to the application Duke has forewarned is coming). The import of all of this is that, under the auction format proposed by Duke, it may have the market

[19] In point of fact, Duke has not demonstrated that the 24% of its customer load that does not take service from Duke or DERS is actually supplied by non-Duke generation, only that the CRES provider serving those customers is not DERS. Those independent CRES providers could be obtaining some generation supply from Duke through the MISO market.

power to artificially stop the auction early, thereby securing a higher clearing price than would occur under competitive conditions.

Duke's effort to persuade the Commission in its Application that it and its affiliate do not have market power is based on two facts: that DERS has only recently acquired more than a nominal portion of the retail market, and that the Company has an approved corporate separation plan. (Application, p. 16). Neither assertion provides much comfort in the context in which market power is relevant here. Duke considers its legacy generation assets to be a non-regulated business (Tr. II, p. 356). While it has "functionally" separated the generation business from the regulated distribution business, the same management operates the generation business and the DERS CRES business. (Tr. II, p. 356, 380-81; Tr. IV, pp. 769-70). The Duke corporate separation plan does not address business relationships between the generation side of Duke's business and DERS. (Tr. IV, p. 740). Duke and DERS have entered into bilateral supply contracts that they consider secret and the terms of which remain undisclosed. (Tr. II, p. 381-84, 417-24). The bidding rules do not prohibit the Duke generation business and DERS from affiliating with each other in the auction as long as it is disclosed.[20]

A reverse auction format allows a bidder holding a significant concentration of the generation to strategically withhold some of its generation to ensure a higher price. (Tr. I, p. 195; Tr. II, pp. 402-04). The state of the record in this proceeding demonstrates a high risk of a significant concentration of generation available for bidding under the control of Duke. Therefore, the Commission should carefully consider whether the reverse auction format will

[20] The communications protocols would treat Duke's merchant generation business as a separate affiliate, such that Duke personnel working on the auction process could not share information with the generation side of the business, but nothing prevents the generation business and the retail business from sharing information. (Application, Attachment E, p. 2, § 3.1).

protect customers from the potential of Duke to exercise market power and provide for an open, fair, and transparent competitive solicitation pursuant to § 4928.142(A)(1).

2. Clear product definition - § 4928.142(A)(1)(b)

According to the application, the product is designed to be a full requirements SSO supply which will be provided for a specified term by the winning bidders. Thus, the product includes all energy and capacity, resource adequacy requirements, i.e., capacity associated with planning reserve requirement, transmission service, and ancillary services.

In the FirstEnergy MRO case, the Commission found that a slice-of-system approach did not provide the required clear product definition. The design proposed by Duke is substantially similar. It requires bidders to bid on a product and to assume the obligation to do whatever it takes to supply Duke's retail load, subject to whatever requirements PJM might put in place. Potential bidders will bid on tranches defined as load-following, but the quantities of power they will have to provide are largely undefined and unpredictable. While each tranche is nominally one percent of SSO load, the actual amount of power a successful bidder will have to provide may vary widely. The Commission should carefully compare the approach taken by Duke to what it rejected in the FirstEnergy MRO to ensure that the statutory standard is satisfied.

One of Duke's justifications for proposing an MRO instead of an ESP is that if finds it unreasonable for the Company to bear the standby risk of potentially having to serve customers who decide to switch to a CRES supplier and return to SSO service. Because Duke currently supplies only about 40% of its wired load under its ESP rates, there is a wide range of possible demand that bidders could have to service if shoppers returned to SSO service. Duke's "slice-of-system" approach to the auction shifts that standby risk to third-party bidders, who would assume the same uncertainty and risk that Duke wishes to avoid. (Tr. II, pp. 229-30, 390-92; Tr.

IV, p. 779-80). This is a risk that the market would have to quantify (Tr. I, p. 37), which would undoubtedly be embedded into the auction price. (Tr. II, pp. 231, 392).

3. Alternative Procurement Options

Commission Rule 4901:1-35-03(B)(2)(m) requires an applicant to discuss 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. Duke's application really only discusses the alternative of a sealed bid auction as contrasted with the descending clock auction. Duke gave short shrift to active portfolio management and RFPs, concluding with no analysis that the former approach was inconsistent with the General Assembly's intent and the latter did not have the benefits of the auction process. (Application, p. 29). Clearly, the Commission wanted applicants to consider all alternatives, specifically identifying active portfolio management as an alternative to consider. By summarily dismissing that process based on its view of legislative intent flies in the face of the Commission's own assessment of that intent in promulgating its rules. By not even considering active portfolio management, Duke has not established that its CBP would achieve the lowest and best price for consumers. Nor has Duke analyzed the alternative of obtaining blocks of wholesale power in fixed load quantities, rather than full requirements service, which would remove significant quantitative supply risk from bidders.

FirstEnergy did not demonstrate that its proposal was superior to making forward purchases of a clearly defined quantity and flowing through, via a reconciliation adjustment, the net result of any short-term power purchases and sales needed to match load. The Commission should carefully assess what, if anything, is different about Duke's approach. As a result, the

Commission should closely consider whether Duke has analyzed all reasonable alternative methods of obtaining generation supply.

IV. CONCLUSION

Duke's plan to accelerate the blending period and go to 100% market rates in 29 months should be rejected. Duke's attempt to make any generation cost riders non-bypassable should be rejected. Duke's attempt to evade Commission review of any MISO exit or MTEP fees, or duplicate PJM realignment or RTEP fees should be rejected. Duke's rates design should be modified to incorporate demand charges.

In addition, the Commission should conduct a thorough analysis of competitive conditions, the impact on competition of the switch from MISO to PJM, Duke's market power over generation facilities, whether the slice-of-system auction approach provides a clear product definition, and alternative procurement systems before approving the reverse auction concept or an MRO. The Commission should carefully compare Duke's MRO application to the FirstEnergy application that was not approved to determine if Duke's plan suffers from any of the same defects.

Respectfully submitted,

Douglas E. Hart (0005600)
441 Vine Street, Suite 4192
Cincinnati, OH 45202
(513) 621-6709
(513) 621-6981 fax
dhart@douglasehart.com

Attorney for The Greater
Cincinnati Health Council

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Initial Brief of the Greater Cincinnati Health Council has been served to the parties listed below by electronic delivery this 27th day of January 2011.

Amy B. Spiller
Elizabeth Watts
Rocco O. D'Ascenzo
Duke Energy Business Services, Inc.
139 Fourth Street, 25 Atrium II
P.O. Box 960
Cincinnati, OH 45202-0960
Amy.spiller@duke-energy.com
Elizabeth.watts@duke-energy.com
Rocco.dascenzo@duke-energy.com

Samuel C. Randazzo
Joseph C. Oliker
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215
sam@mwncmh.com
joliker@mwncmh.com

Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
777 North Capitol Street, NE
Suite 401
Washington, DC 20002-4292
rweishaar@mwn.com

David C. Rinebolt
Colleen L. Mooney
Ohio Partners for Affordable Energy
231 West Lima Street
Findlay, OH 45839-1793
drinebolt@aol.com
cmooney2@columbus.rr.com

David F. Boehm
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OH 45202
dboehm@bkllawfirm.com
mkurtz@bkllawfirm.com

John W. Bentine
Mark Yurick
Chester, Wilcox & Saxbe, LLP
65 East State Street, Suite 1000
Columbus, OH 43215-4213
jbentine@cwslaw.com
myurick@cwslaw.com
mwhite@cwslaw.com

William Reisinger
Nolan Moser
Trent A. Daugherty
Ohio Environmental Council
1207 Grandview Avenue, Suite 201
Columbus, OH 43212-3449
will@theoec.org
Nolan@theoec.org
trent@theoec.org

Mark A. Hayden
FirstEnergy Service Company
76 South Main Street
Akron, OH 44308
haydenm@firstenergycorp.com

Cynthia Fonner Brady
Senior Counsel
Constellation Energy Resources, LLC
550 W. Washington St., Suite 300
Chicago, IL 60661
Cynthia.brady@constellation.com

M. Howard Petricoff
Stephen M. Howard
Vorys, Sater, Seymour and Pease LLP
52 East Gay Street
P.O. Box 1008
Columbus, OH 43216-1008
mhpetricoff@vorys.com
smhoward@vorys.com

Ann M. Hotz
Kyle L. Verret
Jody M. Kyler
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, OH 43215-3485
hotz@occ.state.oh.us
Verrett@occ.state.oh.us
kyler@occ.state.oh.us

Barth E. Royer
Bell & Royer Co., LPA
33 South Grant Avenue
Columbus, OH 43215-3927
barthroyer@aol.com

Michael D. Dortch
Kravitz, Brown & Dortch, LLC
65 East State Street, Suite 200
Columbus, OH 43215
mdortch@kravitzllc.com

David A. Kutik
Jones Day
901 Lakeside Avenue
Cleveland, OH 44114
dakutik@jonesday.com

Grant W. Garber
Jones Day
525 John H. McConnell Blvd.
Suite 600
Columbus, OH 43215-2673
gwgarber@jonesday.com

Thomas J. O'Brien
Terrence O'Donnell
Matthew W. Warnock
Bricker & Eckler LLP
100 South Third Street
Columbus, OH 43215
tobrien@bricker.com
todonnell@bricker.com
mwarnock@bricker.com

John H. Jones
Steven L. Beeler
Assistant Attorneys General
Public Utilities Section
180 East Broad Street, 6th Floor
Columbus, OH 43215-3793
John.jones@puc.state.oh.us
Steven.beeler@puc.state.oh.us