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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company For Approval of a Competitive Bidding Process For Standard Service Offer Electric Generation Supply, Accounting Modifications Associated With Reconciliation Mechanism and Phase-In And Tariffs for Generation Service	))))))))	Case No. 07-796-EL-ATA Case No. 07-797-EL-AAM

OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY'S
REPLY COMMENTS

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The Cleveland Electric Illuminating Company,
and The Toledo Edison Company

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OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY'S REPLY COMMENTS

Come now Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company ("Companies") and hereby respectfully file their Reply Comments in accordance with Commission Entries in this proceeding. For the reasons more fully set forth below, the Commission should approve the Companies' request for a competitive bidding process (CBP) consistent with the reply comments set forth below.

I. Executive Summary

In 1999, the Ohio General Assembly enacted SB3, which changed the regulatory landscape for electric utilities in Ohio by making retail generation service competitive. Since that time, the Companies have focused on preparing for the challenges of competitive markets by changing their business, investment and operating strategies to comply with Ohio laws.

The Companies believe customers should not be denied the advantages of choice and the ability to obtain the best generation price in competitive markets. With competitive markets, customers receive economically meaningful price signals and the resulting efficiencies can produce real cost savings. In addition, competitive markets for electricity, like any other market, drive innovation, efficiency and investment. Customer access to these markets, therefore, is in the best interests of customers and Ohio's economy.

A. *Electricity Markets*

Contrary to current rhetoric and self-serving contentions, Ohio is part of a robust regional wholesale electricity market through both the MISO and PJM regional transmission organizations ("RTOs"). MISO alone has over 300 market participants including nearly 70 generators and 170,000 MW of connected generation capacity within its footprint. And this market is robust - clearing some $2.3 billion in energy transactions every month, translating into some 60 million MWh's.[1] These RTOs are responsible for administering spot electricity markets, and for ensuring reliability across much of the country. These markets have resulted in better price and cost transparency, and provide motivation for sound investments where needed. Since 1999, more than 7,500 MW of generating capacity have been added in Ohio alone.[2]

[1] This is over 12 times the average monthly usage by customers located in the Companies' service areas.

[2] On page 10 of its comments, Staff goes on at great lengths describing what it "observes" is a lack of investment in base load capacity in Ohio, viewing this as a negative reflection on the market. This view reflects an implicit assumption that there was a need for base load capacity during this period. It does not recognize the 'effective' capacity added to the market realized from the decreases in realized forced outage rates of existing generating plants, nor does it seem to consider the capacity additions resulting from uprates of existing generating plants. (Note: FirstEnergy subsidiaries have added or will add approximately 279 MW of baseload

The markets operated by these RTOs are overseen by independent market monitors - which are in place to police the behavior of market participants and to devise solutions to optimize the performance of markets - as well as the Federal Energy Regulatory Commission ("FERC") to ensure transparency, fair competition, and an absence of market manipulation. Studies show that wholesale competition resulted in over $34 billion in savings for residential customers across the country over seven years - - concrete proof that markets and robust competition are providing substantial benefits to electricity consumers. In sum, the competitiveness of the markets administered by RTOs is both well recognized and fully documented.

The full development of retail markets will follow once wholesale market prices are reflected in the prices for standard service offer generation. Generation pricing was first administratively determined in 1999, with current rates set in 2004. It is unrealistic to expect pricing for generation will never increase or that prices from three years ago are still reasonable today. As is well known, the costs of generation inputs have increased since then. It would be equally unrealistic is to expect competitive retail suppliers to enter a market where they are compelled to compete against pricing that has not kept up with the market.

Parties in this proceeding argue that the ownership of generation facilities in the FirstEnergy zone within the MISO market is highly concentrated and that FirstEnergy Solutions ("FES"), which they dub the largest generator, has market power and will abuse that market power to extract higher prices in the auction. This line of reasoning

capacity from 2005 to 2008 through capacity upgrades at existing generating plants, all of which was cost justified against the market, not by assuming cost recovery through regulated rates. Additionally, in that same period FirstEnergy has contracted for over 200 MW of intermittent wind generation.)

assumes that the relevant market area for generation supply is the FirstEnergy zone, an assumption that is simply not correct. These parties are looking at the wrong market area. The appropriate area that must be reviewed in analyzing competitive markets would include all or parts of both MISO and PJM footprints.

In the case of MISO, all generating facilities located in the FirstEnergy zone must compete directly with all bids from all other generators in MISO to generate electricity. There is no basis in which generating facilities owned or controlled by FES are in a privileged position.

Because of the geographic location and the integrated nature of the transmission grid, it is also relatively straightforward for generators located in the adjacent portions of PJM also to provide a physical supply of electricity to meet load requirements in the FirstEnergy zone.

The relevant physical supply market that must be analyzed to make determinations about competitive markets is much broader in scope than the FirstEnergy zone. Concerns expressed about the concentration of ownership of generation facilities within that particular zone are simply not meaningful for determining whether competitive results are achieved in either the spot or forward wholesale markets.[3]

B. <u>Competitive Bid Process</u>

Clearly, a vital market is in place and as such, there is a blueprint and foundation that will provide for further development of competitive markets as contemplated by

[3] Those concerned about this matter should refer to the 2006 Midwest ISO State of the Market Report (full text), issued by the Market Monitor Dr. David B. Patton in May 2007, particularly in the segment "Competitive Assessment", starting on page 85.

SB3. The Companies have detailed a well-balanced competitive bid process for electric generation service that is the best possible option for customers who do not select an alternative supplier.

The Companies no longer own or control generation assets. Therefore, the Companies must purchase generation from the market in order to provide a standard service offer to retail customers in 2009 and beyond.

The generating assets formerly owned by the Companies participate in large, vibrant wholesale markets and are delivering competitive prices. In fact, under the Companies' proposal, customers would receive the benefits of these wholesale markets since the Companies would simply be passing through market-based prices without profiting from the transaction.

Through this proposal, the Companies would seek the lowest prices possible for SSO power supply and pass these competitive, wholesale prices on to customers while incorporating mechanisms that encourage supplier participation and robust competition. Several specific features of the CBP will produce tangible customer benefits. First, the Companies would use a staggered, multi-year bid process to minimize customers' exposure to price volatility in the electricity market. In other states, prices were often set by a single auction, which only reflected the best price available at that time. Second, features such as optional time-of-day and hourly pricing to help customers take advantage of the best possible prices while the discipline of the market will send more economically meaningful price signals. Third, the Companies provide for market-driven programs that encourage energy efficiency, demand response and the use of advanced energy resources. Lastly, the Companies' proposal provides the PUCO the option to phase-in increases if the residential customer class experiences a change in average total price of more than 15%.

C. *Myth v. Reality*

Amidst all the stories about substantial price increases in Maryland and Illinois that followed 10 years of price freezes, there are the untold stories of larger and more dramatic increases in 'regulated' states that have occurred throughout that period – for example, the 45% increase in Florida, 53% increase in Washington and 57% increase in Wisconsin. In fact, prices have increased at essentially the same pace in regulated and unregulated states over the past 10 years.[4]

As the current state administration and other experts have observed, price increases cannot be avoided in either regulated or unregulated states. However, it is clear that competitive markets, over time, will produce the lowest price for customers. The basic economic theory that well-functioning competitive electricity markets yield the greatest benefits to consumers in terms of price, investment and innovation applies to all markets and is widely accepted among the nation's leading economists.[5] In fact, contrary to the myth that competitive wholesale energy markets lead to higher retail prices, numerous studies have shown that wholesale competition has reduced cost for millions of retail energy consumers. Importantly, the well-documented precipitous

[4] *Restructuring Revisited – What we can learn from retail-rate increases in restructured and non-restructured states*; Public Utilities Fortnightly, June 2007

[5] Open Letter to Policymakers, June 26, 2006 – Paul L. Joskow, Professor of Economics and Director of the Center for Energy and Environmental Policy research, MIT; Alfred E. Kahn, Robert Julius Thorne Professor of Political Economy Emeritus, Cornell University; William W. Hogan, Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University; Peter Cramton, Professor of Economics, University of Maryland; Howard J. Axelrod, President, Energy Strategies, Inc.; Vernon L. Smith, President,

increase in fuel costs over the past several years would have had a greater impact on retail prices under the old, regulated monopoly regime. Price increases to consumers in a competitive market have been construed as a flawed market but nothing could be further from the truth.

For reasons set forth in these reply comments, other parties' concerns reflect a fundamental misunderstanding of both the current market arrangements and of the nature of the process proposed in the Companies' Application. The unavoidable conclusion is that competitive wholesale markets for electric power **are** transparent and vibrant, and sufficiently developed and mature to support the competitive bidding proposal offered by the Companies.

In sum, the Companies' competitive bid process proposal reflects the competitive goals of the Ohio General Assembly, and provides for Commission pre-approval, oversight and evaluation of the process. The Companies proposal will bring the benefits of wholesale competition to customers who do not choose a competitive alternative and will help foster the continued evolution of the competitive retail electric market - and therefore should be approved as filed.

II. Introduction

On July 10, 2007, the Companies filed for approval of a competitive bidding process ("CBP") designed to procure supply for generation service for the Companies' retail customers who do not purchase generation service from a competitive supplier beginning January 1, 2009.

International Foundation for Research in Experimental Economics; David W. DeRamus, Ph.D., Partner, Bates White, LLC; Gary L. Hunt, President, Global Energy Advisors

Several intervening parties, and the PUCO Staff, filed comments on the Companies' proposal – both for and against certain aspects of the proposal. However, few parties put forth detailed comments objecting to central or fundamental aspects of the competitive bidding proposal itself. Instead, most commentators focused on spurious contentions about the competitiveness of the market from which power supply would be procured. Yet, when considering the facts and evidence, the inescapable conclusion is that wholesale markets for electric power are transparent and very active. These markets are sufficiently developed and competitive to assure benefits for Ohioans, rather than relying on the throw-back of cost plus regulations and as a result, the competitive bidding proposal requested by the Companies should be supported. Both the MISO and PJM regional transmission organizations are fully capable of supporting competitive procurement, and prospective bidders have the sophistication and wherewithal to supply retail customers in Ohio through the proposed process.

A. *Staff Comments*

Staff concludes "neither retail nor wholesale electricity market[s] have developed sufficiently to warrant confidence in a CBP process that relies on the fairness and efficiency of those markets", and hence recommends rejection of the proposed CBP process.

Staff's conclusions are premised on an apparent fundamental misunderstanding of critical market principles, discussed in detail later in these comments. Staff's unstated definition of "competitive" relates to the expected level of prices, rather than whether competition is actually taking place in the market. That is to say, Staff's concern relates to the potential that prices from a properly conducted auction in a competitive marketplace may produce a price that some do not like, as opposed to whether competition actually and objectively exists in the procurement and supply of power to the Companies.

Since the inception of utility "restructuring" in the 1990s, there have been fundamental changes in the wholesale power markets, particularly in the two market areas, of which Ohio makes up a small part. Those changes have resulted in the introduction of independent regional transmission organizations to host, organize and ensure competitive wholesale markets in which retail electric distribution companies may purchase power. The result of these market enabling developments is the ability today to support dramatically increased power volumes traded with transparency and clarity, significant improvements in performance efficiency by generators, and thousands of megawatts in generating capacity being added to the grid. That vibrant wholesale market provides the foundation for the Companies' proposed competitive bidding process. This process will in turn result in just and reasonable market-based retail generation prices for the Companies' retail customers in the form of a standard service offer - against which competitive retail suppliers may compete for business, thereby allowing customers to choose their electric generation as required by state policy in Ohio expressed in Revised Code Chapter 4928.

The Companies encourage the Commission to review the two auction processes it has previously approved for the Companies. (See Commission Orders and Entries in Case Nos. 04-1371-EL-ATA and 05-936-EL-ATA) In both cases, Staff participated fully in procurement process design and implementation and utilized an independent reviewer to oversee the process in addition to the independent auction manager. The bid process mechanics previously approved by the Commission combined with the Companies' experience in other competitive power supply procurement processes outside of Ohio have been the basis for what has been proposed in this case, with two primary improvements. The first is to conduct a series of solicitations during the year, procuring supplies with laddered durations, features which are designed to reduce price volatility and other risks relative to accessing the market at a single point in time. The second is to provide the Commission with the choice of two separate means to take CBP prices to POLR customers, each of which provides the Commission substantial opportunity to maintain specific public policy objectives. In addition, other recommended process modifications focus on alternative means for customers to take advantage of market opportunities that may better meet their circumstances. The Companies submit that the competitive bidding process proposed is a reasonable means of providing a market-based standard service offer to customers, as required by R.C. 4928.14.

III. Market-Based Retail Generation Rates are Required and Markets are Sufficiently Competitive to Support the Competitive Bidding Proposal

Numerous parties (OEG p. 1, NOPEC p. 4, NUCOR p. 9 and OPAE p. 4) assert that the Companies' affiliate, FirstEnergy Solutions, has market power and will abuse that market power to artificially inflate the clearing prices resulting from the CBP. Their basic position is that FE Solutions dominates the market in Northeast Ohio. Staff is also concerned about the ability of competitive wholesale and retail markets to support the Companies' competitive bid process. As Staff's comments generally address all the competitive issues raised by the other parties, the response of the Companies to these issues will primarily respond to Staff's comments.

First, the Companies agree that Staff is asking relevant questions. The comments and conclusions, however, reflect an erroneous definition of the relevant scope of the market, reflect a lack of understanding of the different relationships between the spot and forward markets, and fly in the face of conclusions reached by FERC and the Market Monitoring Units of the RTOs. The CBP is designed to bring to consumers the competitive prices available in the wholesale market, i.e., the Companies have not requested a profit margin be added to the price derived from the CBP. The difference with Staff is that, while Staff is "uncertain" as to the competitiveness of wholesale markets and basically concludes there is no market for electricity, the Companies and others have demonstrated through these reply comments that there is *no doubt* that such markets exist, are competitive, are producing competitive prices, and are sufficiently developed and to support the CBP requested by the Companies.

A. <u>PUCO Staff Recommendation to Reject the Application due to the Alleged Lack of Effective Competition is Inconsistent with Current Law</u>

The PUCO Staff filed comments in this proceeding stating in its view that there does not exist a competitive market for electricity sufficient to satisfy them, therefore the Commission should reject the Companies' Application on this basis alone. This recommendation is, however, not consistent with law, and therefore must be rejected.

The substantive aspects of the Staff's allegations that there is no competitive markets are addressed elsewhere in these reply comments. But the threshold issue that must be addressed is whether the Commission may reject a competitive bidding process solely because the PUCO Staff holds the view that no competitive market exists. The answer, of course, is no.

R.C. 4928.14 requires that retail generation service be market-based. The Legislature determined in R.C. 4928.03 that retail generation service is competitive. If the Commission over time came to believe that retail generation service was not competitive, R.C. 4928.06 provided a means for the Commission to express its concerns or findings to the Legislature. The Legislature may then consider the PUCO's concerns and determine whether to change the statutory requirement that retail generation service is competitive. To date, no such change in law has been enacted, therefore retail generation service must be priced on a market basis, notwithstanding the PUCO Staff's disagreement with the Legislature and the law.

The PUCO Staff may have the luxury of making recommendations that are directly at odds with the requirements of R.C. 4928.14, but the Companies and the Commission do not. Despite what debate may be underway at the Legislature, the Companies, as well as the Commission, must follow the law as it currently exists, not based upon speculation as to changes that may take place at some future date. It would be imprudent and irresponsible for the Commission to simply ignore the law and reject the Companies otherwise proper filing, thereby jeopardizing the provision of electric service to customers. A competitive bidding process is specifically identified by R.C. 4928.14 as a means of providing market-based retail generation service to customers. Similar competitive bidding processes have been approved twice before by the Commission as just and reasonable. Neither of these prior approvals made any reference to an "effective competition" test for a very simple reason - there is no requirement in the statute that an "effective competition" test be imposed on and passed by electric utilities before they can offer market-based generation. Market-based retail generation service is required by law. The Commission cannot now arbitrarily reject the Companies' filing because the electricity markets did not pass a test created from thin air solely by the PUCO Staff and completely outside the scope of R.C. 4928.14. Failure to adopt a market-based generation rate is not an option for the Commission, regardless of the Staff's erroneous views about the existence of a market.

B. *Markets Are Competitive*

Staff states in its view that retail markets have failed and compounds that mistake by further concluding that such failure of retail markets in Ohio reflects the failure of wholesale markets to discipline prices to reasonable levels. Staff further states that given the large load that must be served in the Companies' service territories, the Commission should direct the Companies to demonstrate that the wholesale market on which it will rely for electricity is sufficiently competitive, despite the fact that no such demonstration is required in or contemplated by Revised Code Chapter 4928.

These concerns, along with those of other parties who claim that FES will abuse market power in Northeast Ohio, reflect a fundamental misunderstanding of both the current market arrangements and the nature of the product proposed to be bid in the CBP.

Prior to the establishment of, and the Companies' participation in, the MISO RTO, it would indeed have been more difficult for an entity other than FES to serve a large quantity of load in Northeast Ohio. Such an entity would have needed to rely on remote generation, arrange for a variety of transmission arrangements, buy or provide balancing services, and been subject to imbalance penalties. If wholesale competition occurred under this construct, serving all or substantially all of the Companies' load without access to the generation of FES, would indeed be difficult. However, with the advent of MISO and the wholesale markets it maintains, this is no longer the case and the claim that FES dominates the market is an anachronism.

C. MISO Administers Multiple Product Markets

MISO administers several distinct markets for serving load in MISO. First is the energy market. MISO has both Locational Marginal Price (LMP) based spot energy markets and day-ahead energy markets. MISO has a Commercial Pricing (CP) point for load in the Companies' zone. A supplier can balance its energy requirement and can acquire the energy needed to serve load by purchasing energy in the MISO energy markets. These markets are subject to FERC jurisdiction and review. They are monitored by the MISO market monitor and FERC's market oversight group. The FERC assures that there is not excessive concentration in the energy market and that the market is not manipulated. MISO further has in place specific procedures to mitigate local market power in the energy market should it arise. Hence, potential standard service offer (SSO) suppliers can balance or rely for supply on the MISO spot energy market in which FES clearly has no market power.

D. No Concern That Congestion Costs or Generation Concentration Will Affect Markets

Prices for energy in the FE Zone could theoretically differ from prices elsewhere in MISO as a function of congestion. The historic data clearly show, however, that prices for the FE Zone are very similar to prices at the Cinergy Hub and are not materially affected by congestion. (See Figure 1 and Table 1). Hence, potential SSO suppliers will be purchasing energy produced throughout MISO, not simply the FE Zone. As Staff notes in its comments, forward energy prices will reflect spot energy prices. The Companies agree. This means that because spot energy prices are formed in a MISO-wide market where there is no significant concentration of generation ownership and where FES owns less than 8% of the total generation, forward prices for energy that reflect spot prices will also be unaffected by any market power that FES supposedly has. Potential SSO suppliers, i.e., CBP bidders, will be able to hedge energy obligations by purchasing standard products for energy forwards at liquid trading hubs. In fact, the MISO Cinergy hub is among the most liquid forward trading points in North America. An SSO supplier can arrange a competitive energy supply by purchasing a combination of forward products at the Cinergy hub, supplemented by spot purchases from the MISO LMP market at the FE zone. No market power exists for energy and FES would have no competitive advantage. Such fears are unfounded.

E. Market Power Concern is Premised on Confusion of Spot Market and Forward Market

Part of the concerns expressed over the potential exercise of market power by FES appears to stem from confusing the physical spot markets administered by MISO with the forward market, which would be accessed through the procurement process proposed by the Companies. While spot and forward markets are interrelated in very important ways, the differences between them are important. Spot markets provide price transparency to all market participants, establishing for all to see the value at which the physical demand for electricity is satisfied. Knowledge of these prices is a critical reference set for both buyers and sellers in forward markets and in a sense constrains or controls the price expectations in the forward markets. Keep in mind the Companies proposed procurement process is a process for accessing the forward electricity market. A fundamental premise of the Companies' plan is that sole reliance on the spot market for their power supply to SSO customers would result in SSO pricing which would be intolerably volatile and unacceptably risky to customers.

F. *MISO Capacity Obligations Need Not Be Deliverable in FE Load Zone*

MISO has certain capacity obligations. Most significantly on a daily basis, MISO load-serving entities must be able to point to generation facilities that are deliverable to the MISO footprint in an amount equal to their daily peak. ***However, they need not actually supply energy from the identified facilities***. Further, the generation only needs to be deliverable *to MISO* and need not be deliverable *to the FE zone* or to any specific location in MISO. MISO has certified over 170,000 MW as qualified for delivery to MISO.[6] Hence, suppliers can obtain capacity from a variety of sources, less than 8% of which are controlled by FES. FES has no dominance with respect to capacity and no advantage in the auction in this regard.

[6] This is almost 15 times the 11,500 MW the Companies seek to source in the CBP.

G. MISO Ancillary Services Remain Cost-Based Unless FERC has determined a competitive market exists

MISO also administers ancillary services markets. These markets consist of market-based and cost-based markets. Ancillary service markets are the last to become market-based and can only be such when the FERC determines that the market for the specific ancillary service is competitive. Hence, if an ancillary service is market-based, the FERC has already determined that market power does not affect the particular ancillary service. Therefore, FES cannot dominate the ancillary services market. Further, ancillary service costs in total represent only a small fraction, under \$2/MWH[7] of load served, compared to the cost of energy, therefore any issue that may arise in that market would not be a sufficient reason to reject the Companies' CBP proposal.[8]

H. FERC, MISO, and the Market Monitor Assure Competitive Markets

Certain comments reflect a lack of awareness of the roles of FERC and the RTOs independent Market Monitoring Units in assessing and ensuring the competitiveness of the wholesale market. Under FERC regulations, all entities with market-based rate authority are required to periodically file with FERC to demonstrate their lack of market power.[9] FERC employs a set of quantitative tests to determine if market power exists, and if so, will require remediation measures to either remove the incentive or capability to exercise market power. FES, the entity which seems to have

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[7] Equivalent to 0.20¢/kWh, about 4% of today's total generation price.
[8] The ancillary services under consideration by MISO to be served at market, rather than cost-based prices include regulation, spinning reserve and supplemental reserve services.
[9] See 18CFR35.37(2)(1). As a "Category 2 Seller" FES is obligated to submit a market power analysis every 3 years.

drawn the most attention from commentators, supplied the required filing at FERC - most recently in 2006 - and FERC concluded FES did not have market power.

For the sake of argument, if one were to incorrectly assume FES possesses market power, and if one were to further incorrectly assume FES exercised such market power in the spot market, then one must deal with MISO's Market Monitoring Unit. Under MISO's tariffs and agreements, the Market Monitoring Unit is charged with continually analyzing and monitoring the behavior of all market participants and to impose immediate mitigation measures. The commenting parties assert that the Market Monitoring Unit is not capable of fulfilling its responsibilities. Such assertions reflect an unawareness of the conclusions reached by the MISO Market Monitor in the 2006 State of the Market Report, which stated in part:[10].

I. Overall, we found that the market performed competitively in 2006

II. . . electricity prices in Midwest ISO markets declined in 2006 by nearly 20 percent when compared to average Midwest ISO prices in 2005. We attribute the decline primarily to lower fuel prices.

III. Midwest ISO electricity markets facilitates the use of the lowest-cost supplies to meet real-time demand for energy, while respecting reliability requirements for reserves and preventing power flows on the network from exceeding transmission constraints.

IV. The markets produce Locational marginal prices ("LMPs") that reflect the marginal system cost of serving load at each location on the network. . . . these prices not only provide transparent price signals that promote efficient operation of the system in the short term, they also facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions.

V. MISO day-ahead and real-time energy markets provide substantial benefits to the region through efficient daily commitment of economic generation resources; employment of least-cost re-dispatch options to permit greater utilization of the transmission system, and provision of

[10] 2006 State of the Market Report – Midwest ISO, Prepared by Midwest ISO Independent Market Monitor, David B. Patton, Ph.D. – Potomac Economics, May 2007

transparent economic signals to guide short- and long-run decisions by market participants.

VI. Overall concentration of generation ownership within the Midwest ISO is low.

VII. To the extent that transmission constraints within the Midwest ISO cause a particular supplier to be a pivotal supplier within a sub-region, market power mitigation measures have protected consumers.

VIII. The Independent market monitor is in place to police the market and mitigate the effects of anticompetitive conduct, if any. Conduct warranting mitigation includes physical and economic withholding of generation, uneconomic production, and uneconomic bids or virtual transaction. Market Monitor can also propose mitigation measures for location market power resulting from transmission congestion.

I. Staff's Desire to Indefinitely Maintain RSP Pricing is Unrealistic

Staff also observes that the prices offered in rate stabilization plans by Ohio electric utilities have proved to be more reasonable than those offered by entities operating under market forces. One factor that must be considered in this regard is that the RSPs were established beginning in 2004. Prices in the February 2004 New Jersey BGS Auction were about 5.5 cents per KWH and prices in the February 2005 New Jersey BGS Auction were about 6.5 cents reflecting escalation in power and natural gas markets. Given the historic differences in price between Ohio and New Jersey, competitive markets at the time of the RSP were producing results in line with the RSP prices. In 2004, the Companies conducted their first auction. While the price resulting from the auction exceeded the RSP price, it was not disproportionate to the RSP price. In summary, contemporaneous competitive procurements have produced prices similar to the RSP prices. More recent procurements have produced higher prices precisely because these prices reflect increases in natural gas and power prices. It would be unrealistic to think that RSPs developed today would not also increase. Staff errs in drawing conclusions from a comparison of the 2004 RSP to more recent competitive procurements. Staff's conclusion also serves to illustrate the point made earlier. The objection to the CBP does not come from valid and supportable objections to the competitiveness of the underlying market or the process proposed, but from an aversion, based upon speculation, that the results of actually obtaining a market price will exceed current RSP pricing levels.[11]

Staff further observes that a vibrant retail market has not developed even for those customers who use large amounts of electricity. This is solely a function of the fact that RSP prices, which were reasonably favorable relative to the market when set, fell below rising market prices over time. It is not reasonable to expect that a retail market would flourish in that situation. If prices for SSO are market-based more retail competition will develop.

J. <u>Hedging Opportunities for Winning Bidders Assure Competitiveness of the CBP</u>

The CBP product is full requirements. Bidders and suppliers can hedge through standard energy products at the Cinergy hub, can balance and buy energy in the MISO spot market, face little congestion cost, can access capacity from over 170,000 MW deemed deliverable by MISO, and can purchase ancillary service from markets only when FERC has found there is no market power abuse for that service. Bidders and suppliers have access to a fully competitive and monitored wholesale market and no entity including FES dominates the market.

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[11] Recall that the RSP price also provided for periodic increases to reflect changes from the 2002 baseline fuel cost. The supervening RCP price included a small portion of the then-experienced fuel cost increase, and authorized deferral of any remaining increase for later

In a sense, the spot market is the supply source of last resort. A seller in the forward market can always source their supply in the spot market or, depending on their individual risk tolerance, they can decide to hedge their forward positions in order to reduce the uncertainty or risk associated with the financial outcomes of their forward position. The individual participants in the forward market are driven to enter hedging transactions by their individual risk tolerances, not by a need to source physical power as the actual physical power can always be obtained in the physical spot market.

The specific forward hedging activities by suppliers will be as varied as the number of participants in the market. Some suppliers, such as those that own generation assets can view those assets as their hedge position. They can sell the electricity from their assets to the spot market and purchase their physical supply from the spot market. In fact, with transparent spot markets, the physical location of the asset relative to the load being supplied is not critical as long as suppliers can adequately assess the spot price differentials between the location of their assets and their load obligations. Other suppliers will use their positions or business transactions in other commodity markets to hedge their forward obligations in electricity. Futures contracts in natural gas and oil may be used. Further still, it is entirely possible that some companies will enter into forward electricity contracts as the hedge for their other business transactions.[12]

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recovery from customers. The amount expected to be deferred exceeds $400 million through the end of the RSP pricing period.

[12] Individual customers, aggregators or other customer organizations have been , and are very able to continue to be, very active in entering bilateral contracts with interested sellers in order to establish supply conditions that are more appropriate for them the conditions the POLR supplier must meet. These bilateral arrangements are just as much a forward market process as is anything suppliers can enter.

Pricing in the forward market is a combination of expectations for future spot prices (constrained by knowledge of actual, historical spot prices) intertwined with individual risk tolerances and hedging strategies. Therefore, an assertion of market power should also include an assessment of the supply and demand of the hedging instruments which can be accessed by potential bidders in the proposed procurement process. Unfortunately, commentators rely instead on a sort of "everybody knows" argument. The fact of the matter is not everybody knows, and fact "repetition does not transform a lie into a truth".[13]

Spot market data shows no market manipulation. The existence and exercise of market power is fundamentally an empirical issue. If wholesale pricing in the FirstEnergy zone was currently being influenced or manipulated by anyone, one would expect to observe anomalies in the observed spot prices relative to pricing characteristics of other locations. Yet even a cursory review of actual spot pricing data reveals no obvious anomalies with the pricing in the FirstEnergy zone.

Figure 1 displays the weekly average of the actual hourly LMPs observed for the FirstEnergy zone, the PJM West Hub and the Cinergy Hub during the period July 1, 2006 through June 30, 2007. These latter two pricing points are the two most liquid electricity locations in the country. As is visually obvious, prices at all three locations display the same characteristics. Numerically, the correlation values shown in Table 1 convey similar information. The correlation number may be interpreted as a measure of the direction of change in two data series. A correlation value of 100% means the two series always move in the same direction at the same time. A value of negative 100% means the two series always move in opposite directions and a value of 0% means the

[13] Franklin D. Roosevelt, October 26, 1939 radio address

series move in random directions, relative to each other. The high correlations between the FirstEnergy zone prices and the hub prices means when the market goes up, prices in the FirstEnergy zone go up. When the market goes down, prices in the FirstEnergy zone go down. If market power was being exercised within the FirstEnergy zone, the pricing in that zone would display different characteristics than pricing in the market in its totality – and it doesn't – an indication that no market power is being exercised.

Figure 1

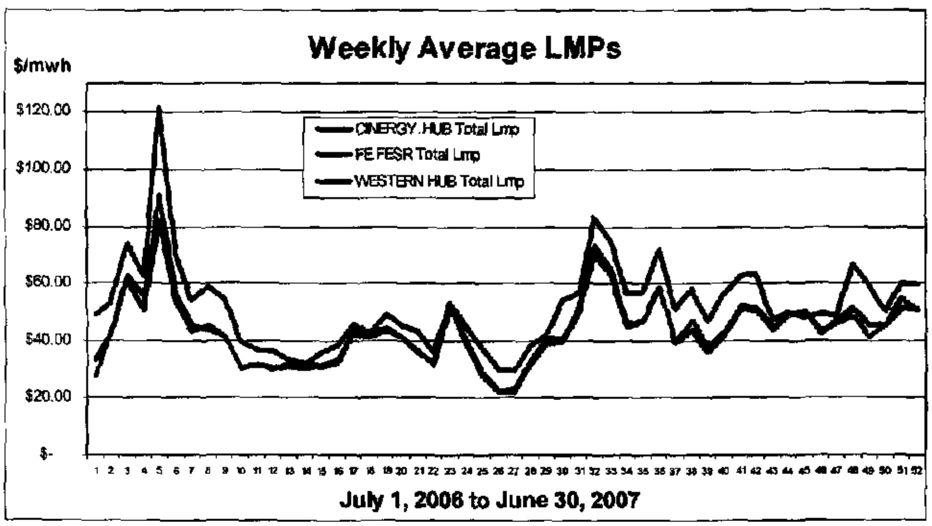

Table 1

Monthly Average LMPs $/MWh			
	Cinergy Hub	FE Zone	PJM West Hub
Jul-06	$49.64	$50.59	$62.16
Aug-06	$51.87	$53.97	$71.90
Sep-06	$30.60	$31.02	$36.07
Oct-06	$34.46	$35.41	$38.37
Nov-06	$39.20	$39.42	$44.25
Dec-06	$34.59	$35.38	$40.49
Jan-07	$36.48	$37.83	$43.69
Feb-07	$56.82	$58.61	$69.05
Mar-07	$44.47	$45.75	$55.94
Apr-07	$47.73	$48.80	$56.64
May-07	$47.44	$46.63	$52.06
Jun-07	$48.72	$47.34	$57.79
Average	**$43.41**	**$44.14**	**$52.27**
Correlations with FE Zone	98.73%	100.00%	86.85%

IV. Single Price Auction Mechanisms Produce Equitable Results

Staff criticizes the use of single price auctions in the context of the MISO spot energy market. (Staff p. 9-12). Essentially, Staff implies that paying all energy suppliers based on the cost or bid of the last supplier overpays many suppliers relative to cost. Staff does not however provide any explanation as to how it would organize an energy market that was not a single clearing price market. Nor does Staff explain how generators using technology with higher capital but lower energy costs recover capital costs if they did not receive the clearing price, but were paid based solely on their own variable costs. The notion of a single market-clearing price is fundamental to many robustly competitive markets for various types of commodities, including other types of energy products. The issue of a single clearing-price auction was examined in 2001 by a blue ribbon panel of four independent and distinguished economists, and their conclusions hold as true today as they did then. Those economists, Dr. Alfred Kahn, Dr. Peter Cramton, Dr. Robert Porter and Dr. Richard Tabors issued a Blue Ribbon Panel Report entitled, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" in January 2001. In this report, these economists studied this issue in the context of a recommendation for California's electricity market to shift from uniform pricing to pay-as-bid, and dismissed the presumption that such a change would be beneficial. They concluded that - "In sum, our response is that the expectation behind the proposal to shift from uniform to as bid pricing—that it would provide purchasers of electric power substantial relief from the soaring prices of the electric power, such as they have recently experienced—is simply mistaken. In our view it would do consumers more harm than good."

This issue has been examined in the context of other markets including the US Treasury debt market. In 1992, the US Treasury adopted a uniform-price auction format, which had been suggested by several academics as an alternative format that would lead to lower financing costs. A study by Malvey and Archibald provided empirical support for the contention that in a uniform-price auction, participants will bid more aggressively than in a pay-as-bid approach. These authors conclude that uniform-price auctions have reduced the costs of financing the Federal debt and have led to a broader distribution of auction awards. On the basis of these empirical studies, the Treasury decided in October 1998 to extend the uniform-price format to all auction offerings.[14] The Treasury Auctions deal with volumes that dwarf even electric supply auctions. If a uniform price auction became the standard for such a large and scrutinized auction, there is no reason to doubt that it would be suitable for electric spot markets such as MISO and it is reasonable for the CBP to rely on such markets.

V. Retail Markets

OEG (p. 1-6) and Staff (p.2-6) assert that the retail market in Ohio is not competitive, pointing to the current lack of active offers by retail marketers, as the basis for this assertion. From this observation Staff concludes that the Commission should not approve the Companies' CBP plan.

A fundamental flaw in the Staff's assertion is, however, readily apparent. Specifically, the existence of rate caps on the Standard Service Offer prices during the past seven years, a period in which raw production costs have risen dramatically, has effectively meant that alternative suppliers had no reasonable expectation of making money, and in fact were assured of losing money with virtual certainty if they actively entered the market. This is not however to say that retail competition is in any sense precluded in Ohio. Indeed, during the initial years of the market development period, there was significant shopping by the Companies' customers. The reality is that the only impediment to the emergence of alternative suppliers has been the regulatory imposed below market retail prices.

Moreover, it is critically important to note that the merits of the Companies' proposal of using a bidding process to secure its wholesale power is not dependent on

[14] See Malvey, P. and Archibald, C., Uniform Price Auctions – Update of the Treasury Experience, Office of Market Finance, United States Department of the Treasury, October 1998.

the presence of an existing vibrant retail market. If the Companies secure wholesale power through the CBP for its SSO customers, those customers will be assured competitively determined retail prices even absent alternative providers at the retail stage. Specifically, wholesale power will have been secured through a competitively determined bidding process and any retail stage mark ups, which the Companies have not requested, are determined by ongoing regulation by the PUCO. Thus, having the option for retail stage competitors to emerge and solicit retail customers affords an added layer of comfort but is not necessary to assure competitive pricing in the purchase and sell of the SSO product.

Furthermore, on page 2 of its comments, Staff references a series of statistics about the level of third party supply in Ohio. As is demonstrated by Staff's own reports, the vast bulk of third party shopping in Ohio has been in the Companies' services areas. A much more telling statistic to use would be the number of customers shopping as opposed to the number of *kilowatthours* shopping. That is because, as the Staff well knows, the vast majority of the largest users in the Companies' service areas are served under special contracts where the price is and has been substantially below market. Those customers, whose usage comprises over 15% of the Companies total sales, were never going to shop as long as their contracts remained in force. And those customers continued to press for their contracts to be extended for as long as possible.

The PUCO reports shopping metrics in a report entitled "The Ohio Retail Electric Choice Programs, Report of Market Activity". The August 2005 report, covering the period January 2003 through July 2005, contains detailed customer shopping data for December 2004 for the Companies.

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and Kenneth D. Garbade and Jeffrey F. Ingber

Every customer segment had high levels of shopping. More than one million customers were shopping. The Companies' records identify that over 670,000 customers, or 62% of shoppers, were being supplied by non-affiliated CRES suppliers at that time.

TABLE 2

Switch Rates to Alternative Suppliers--December 2004	*Residential*	*Commercial*	*Industrial*	*Total*
Total Number of Customers				
CEI	656,990	77,257	2,204	736,451
OE	919,375	106,292	960	1,026,627
TE	261,838	35,225	258	297,321
Total	1,838,203	218,774	3,422	2,060,399
Customers served by the utility				
CEI	202,753	19,005	1,664	223,422
OE	612,749	66,670	614	680,033
TE	135,092	16,830	198	152,120
Total	950,594	102,505	2,476	1,055,575
Customers served by Third-party suppliers				
CEI	454,237	58,252	540	513,029
OE	306,626	39,622	346	346,594
TE	126,746	18,395	60	145,201
Total	887,609	116,269	946	1,004,824
% of customers served by Third-party suppliers				
CEI	69%	75%	25%	70%
OE	33%	37%	36%	34%
TE	48%	52%	23%	49%
Total	48%	53%	28%	49%

Inexplicably, Staff concludes, at the bottom of page 2, that a vibrant retail market has not developed. In reviewing the Staff's charts, the more appropriate conclusion is that *a very vibrant market had in fact developed*, but that the amount of consumption served by third party suppliers dropped significantly at the end of 2005. Would that not lead then to an evaluation of the reason for the drop, i.e., why did the competitive suppliers leave the market so abruptly? Perhaps Staff would have discovered that customers could no longer save money by shopping, since the fixed prices for POLR service promulgated by the Commission, coupled with increased market prices, did not allow any margin for suppliers to offer a better price unless they served customers at a loss.

That does not mean the market did not develop; history shows that it in fact did develop. What it does mean is that the regulatory process thwarted retail competition. But prices for generation are going to rise because the inputs to produce that generation have dramatically increased. As has been demonstrated, a concern over rising prices does not equate to the Companies' proposed CBP being unjust or unreasonable.

VI. Proposed 75% Volume Cap

Some parties (OEG p. 1, NOPEC p. 4, NUCOR p. 9, OPAE p. 4) believe that the proposed limit of 75% on the volume that any one supplier can win is too high.[15] These parties also appear to assume that only one supplier could possibly bid for the proposed 75%. The Ohio Partners for Affordable Energy, for instance, state: "The Companies' affiliates are clearly destined to be the principal bidders at the auction and the probable winners of 75% of the volume." Parties assume that this single supplier is the Companies' affiliate FirstEnergy Solutions and they view this limit as an admission that competitive markets have failed to develop. Nothing could be further from the truth.

[15] In the two previous CBP processes approved by the Commission for the Companies, the load cap was set at 67%. In this proceeding the load cap was increased in recognition of the successful implementation of the MISO energy markets as discussed previously in these reply comments.

The assumption that only FE Solutions would be capable of targeting volumes of 20-30 tranches is unfounded. The Companies put forward their proposal on the basis of experience with procurement of standard service offer type supply in various jurisdictions. This experience clearly shows that a variety of different types of entities, and not just owners of a portfolio of generation assets, bid and win to serve the load of standard service offer customers. These entities include a variety of energy marketers and traders, with and without generation assets, as well as financial entities. These entities are sophisticated market participants that are willing and able to competitively provide price-risk management service and to assemble the portfolio of wholesale products necessary to offer the full-requirements product being proposed. It is typical in these solicitations to attract twenty bidders or more. Table 3 shows the number of bidders publicly reported over the past five years in other jurisdictions. There is no reason to believe that volumes of 20 or 30 tranches are beyond the reach of many of these entities. In fact, in the 2004 CBP, FE Solutions did not participate in the auction process. In the same auction, Constellation was the winning bidder for 65 tranches and Morgan Stanley was the winning bidder for 17 tranches.[16] Each tranche represents approximately 100 MW of load. In New Jersey, as provided in Table 3, seventeen different suppliers currently serve customers on standard service offer load. Two are serving over 25 tranches, and three more are serving between 10 and 24 tranches. (The New Jersey tranches are also 100 MW). These figures represent tranches that these entities *have actually won* - this means that these entities had likely initially targeted higher volumes and were limited to winning these tranches through the competition during the bidding process. Similarly, in Illinois, five entities won the

[16] NERA Post Auction Report, Case No. 04-1371-EL-ATA, filed April 27, 2006.

equivalent of 20 tranches, including Morgan Stanley and JP Morgan Ventures, both entities having no generation assets in the region and being strong financial entities. Again, these figures relate to the entities that won these volumes and there is every reason to believe that an even wider pool of potential bidders were able and willing to target larger volumes in these bidding processes.

Table 3

Major Procurements 2004 - 2007

Year	Jurisdiction	# of Bidders	# of Winners
2007	New Jersey[1]	20	16
2007	Pennsylvania (PPL)[2]	7	n/a
2007	Pennsylvania (PPL)[2]	9	n/a
2006	Delaware[3]	11	6
2006	Maryland[4]	13	10
2006	New Jersey[1]	16	12
2006	Illinois[5]	21	16
2005	Maryland[4]	18	8
2005	New Jersey[1]	25	11
2004	Maryland[4]	25	14
2004	New Jersey[1]	26	14

Notes/Source

1) http://www.bgs-auction.com/bgs.auction.prev.asp
2) Number of winners not provided; http://www.pplelectric.com/Business+Partners/Provider+of+Last+Resort/
3) http://www.pepcoholdings.com/remphi/derfp/dplrfp-overview.aspx
4) The Commission Staff's Report/Observations on the Standard Offer Service Bidding Process and Results for 2006, 2005, and 2004
5) The September 2006 Illinois Auction Post-Auction Public Report of the Staff.

The Companies put forward a 75% limit on the volume bid not in acknowledgment of the failure of the competitive market, as alleged by certain commentators. To the contrary, such a limit explicitly recognizes the breadth of the possible competition in the competitive bidding process and the ability of a wide variety of entities to compete at these levels.

Some parties (OEG p. 1, NOPEC p. 4, NUCOR p. 9, OPAE p. 4) believe that the proposed limit of 75% on the volume that any one supplier can bid and win is too high because it does not sufficiently promote the diversity of winning suppliers or because it may lead to anti-competitive results. As discussed above, the Companies expect diversity in winning suppliers given the interest from a broad spectrum of entities that past competitive procurements for standard offer service have attracted in other jurisdictions. It is accurate that a 75% limit only forces two different suppliers to win tranches. However, given that there are multiple solicitations, for there to be two suppliers of the standard service offer load requires one to believe that of the multiple entities expected to participate, only two entities would win in a given solicitation, and that the same entities would win again in the two or three other solicitations conducted in a given year. Given the expected pool of potential suppliers, this defies logic. Diversity in winning suppliers will naturally occur as a result of the diverse pool of interested suppliers and the multiple solicitations being conducted.

The load cap – or the limit on the number of tranches that a bidder can bid and win – is one of the measures proposed by the Companies to enhance and favor the competitiveness of the auction. This load cap serves as a limit on the number of tranches that any one bidder bids and controls, which limits the influence that any one bidder has on the outcome. Parties appear to assume that this is the only measure proposed to promote the competitiveness in the CBP. This is absolutely not the case. The load cap is only one of the competitive safeguards being proposed.

The auction rules include a comprehensive set of rules to ensure that each bidder bids independently, and that there is no coordination among the bidders. Bidders will be required to certify their adherence to these rules as part of the application process. The auction rules provide for the possibility to reduce the auction volume if interest in the solicitation is less than expected. This reduction in volume ensures a sufficient number of tranches bid per tranche needed, and fosters a competitive bidding environment. Should tranches be removed from one or more solicitations and not filled during a given competitive bidding process, the power supply for such tranches would be obtained pursuant to the contingency plans described in Exhibit I of the original CBP filing. This ensures that suppliers know that they must bid in one of the solicitations in order to be able to serve load for the Companies' SSO customers and promotes participation in the CBP. All these measures work together to promote competition in each and every solicitation, and to lead to prices that are consistent with market conditions.

VII. Long-term Supply Contracts Provide More Stable Prices

OEG (p. 8) and Direct Energy Services, LLC. (p. 14 – 17) both assert that the 29 and 41 month delivery periods[17] are too long, opining the longer the length of the term

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[17] In the initial 2009 CBP power supply for 17, 29 and 41 month delivery periods will be procured. Because the delivery period begins January 1, 2009 the seemingly unusual number of months for each period is required in order to sync future CBPs with MISO planning years

of commitment by suppliers the higher their bid price in the CBP will be because longer time periods necessarily come with higher risk premiums. Direct Energy, to its credit and somewhat unique among the commentators also proposes an alternative – the Companies should only procure power a month ahead of when it is needed with the SSO rate changing monthly.

These comments appear to be based on the false belief that wholesale prices for longer time periods are always higher than wholesale prices for shorter time periods. This is simply not true. At any point in time, forward prices reflect the collective views of market participants regarding fundamental determinants of supply and demand, transient influences such as disruptions in fuel supplies due to weather, strikes, potential political changes, and so forth. At different points in time, these influences will drive short term prices higher than long term prices and sometimes result in short term prices lower than long term prices. One only needs to look at forward prices during the Fall of 2005 to observe a period during which long term prices were below short term prices. All that can be said with certainty is that at any point in time market prices for different future time periods will be different. This simple market reality, as opposed to the aforementioned erroneous belief, is why OEG's and Direct's position on this issue should be rejected.

The Companies feel strongly that the interests of customers who choose to receive standard service offer generation service are best protected by a procurement process which blends out the price volatility which will always be present in the wholesale market. The Companies' plan does exactly this. By securing a portion of the

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which begin June 1 of each year. After the 2009 CBP, the subsequent CBPs will have a uniform 36 month delivery period.

required power supply through multiple solicitations and in each solicitation securing supply for staggered delivery periods, the inevitable fluctuations in wholesale market prices will be smoothed out, providing SSO customers with a stable price.

VIII. Companies Proposed Treatment of Demand Charges is Reasonable

Both IEU (p. 6) and OCC (p. 2) take issue with the proposed elimination of demand charges from the retail rate design and propose a reinstatement of demand charges. OCC recommends reinstatement only for large customers. Notably, neither party explains exactly how this is to be done.

Traditionally, a regulated utility would design rates with customer charges, demand charges and energy charges. Customer and demand charges were designed to recover the revenue requirement created by expenses which were viewed as fixed, meaning the level of the expense did not change appreciably with changes in energy consumption, while energy charges were designed to recover those expenses which fluctuated directly as a result of changes in consumption. In the past, the Companies owned generation assets which represented the bulk of a utility's rate base and which spawned large fixed costs for the utility – depreciation expense, interest expense, property tax, etc. It was entirely appropriate for the utility's retail rates to reflect demand charges. But with Ohio's adoption of Senate Bill 3 and competitive retail generation service, this traditional world was forever altered and this traditional approach to rate design is simply inappropriate for today's circumstances.

The Companies do not produce their own power nor do they own generation assets. They do not incur fixed generation expenses. Their generation expense today and in the future will be entirely variable, it will increase or decrease as a function of energy consumption by SSO customers. The Companies' proposal reflects this fact and proposes that revenue requirements stemming from purchased power expense incurred by the Companies be recovered through energy charges in retail rates.

If the Commission were to adopt the position of either IEU or OCC, then the issue of the level of the demand charge must be dealt with. What will be the expense or cost used to determine the charge? Will the Commission designate some arbitrary portion of the Companies purchased power expense for recovery through demand charges? Will such an approach provide economically efficient price signals to consumers in order to achieve the beneficial aspects of demand charges portrayed by IEU and OCC? Or will such an approach further distance the price signals to consumers from the underlying market determinations further thwarting the full development of a competitive retail market?

IX. The Proposed Bidding Format is Preferable to Sealed Bid/RFP

The OEG, IEU and OPAE appear to be against the use a descending clock format (an auction), seeming to prefer a sealed bid RFP. In fact, IEU's comments are confusing as they point to alleged unsuccessful results for auctions, but erroneously attribute such unsuccessful results for auctions to states such as Delaware, Maryland and Texas. Delaware and Maryland used a sealed bid process, i.e. the process preferred by IEU. Texas has no organized procurements of any type for standard offer type service. Hence, it is unclear if IEU is actually against the specific proposal made by the Companies or just broadly against any type of competitive procurement by the

Companies whether done through a descending clock format or a sealed bid RFP.[18] The Companies believe that the bidding format proposed is a strong feature of their proposal that has many advantages for customers over the use of a sealed bid RFP.

The descending clock format is referred to as a multiple round process because suppliers get aggregate information each round about the amount of total supply bid in the previous round. Suppliers can revise their bids and re-adjust their bidding strategies on that basis. This is in contrast to a sealed-bid, single-round RFP, where suppliers must make all decisions regarding their bids and their strategies before submitting their proposals, and where bids are generally evaluated without bidders having the flexibility to revise their offers in light of new market information. For example, a bidder that had formed expectations before the auction about the final price may well find that this price has been reached while there is still excess supply -- perhaps substantial excess supply left in the auction. The bidder will realize that the rest of the market has assessed future market conditions differently or has been able to assemble their portfolio of products to fulfill the full-requirements obligations more cheaply. This bidder would be able to re-align its expectations in light of the judgment of the rest of the market or to revise its business plan so as to attempt to cut costs to be able to compete.

The ability of open auctions to deliver valuable information to bidders, and the flexibility that bidders have to re-adjust their bids in light of new information lead to important economic benefits. Bidders face less uncertainty than in an RFP process as the flexibility to re-adjust bids takes away most of the guesswork in bidding that is

[18] In this regard OEG points to Mon Power's Ohio sealed bid procurement as allegedly more successful than other procurements, but seems to attribute that to Mon Power's small size more

present in an RFP. When bidders face less uncertainty and guesswork, bidders have more confidence and tend to bid lower, leading directly to better prices for customers.

An additional economic benefit of the descending clock format, and of multiple round processes in general, is that suppliers can switch their bids from one product to another during the course of bidding when several related products are included in the same solicitation - as in the case under either procurement alternative proposed by the Companies. This switching means that any price differentials among the different products – the different terms and/or different rate classes – will be determined by market forces. If a gap in prices opens up, say with the 17-month price higher than the 29-month price, and this gap is not supported by the market's assessment of differences in costs or risks between the products, bidders would switch their bids, in this case from the 29-month product to the 17-month product. As more supply is bid on the 17-month product, its price would tick down faster than the price in the 29-month product, closing the gap and re-aligning relative prices in a rational manner in accordance with the market's assessment. In general, the bidding format includes a natural mechanism to determine prices among the different products that are consistent with the market. [19]

An RFP process would not have the advantages of an open auction. A sealed bid process presents bidders with more uncertainty, as it does not provide information to bidders on the basis of which they can revise their bids. A sealed bid process forces bidders to guess in preparing their bids as it does not typically provide bidders flexibility to adjust their bidding strategy and revise their business plan. If multiple products are

than to the format of the procurement.

involved, a sealed bid procurement process may lead to significant pricing inefficiencies (when compared to a descending clock auction), as this process does not permit effective arbitrage between products with excessive price differences. Under a sealed bid process, bidders need to decide in advance which customer classes or service term lengths they want to supply. In an open multi-round auction, such as a descending clock auction, suppliers can instead switch efficiently between customer classes and service term lengths based on the existing price differences between these products. For this reason, a sealed bid process does not necessarily select the most efficient providers, or promote the best match of product to supplier.

Despite these advantages of the descending clock format, OEG argues that the Companies' proposed bidding format will not produce a price that reflects market competition. OEG acknowledges that - "In theory, a reverse auction may result in competitive prices if there are numerous potential suppliers and no market dominance. But in the real world of Northern Ohio there is no basis to believe those circumstances exists." As explained above, the relevant market is not Northern Ohio. With the advent of MISO, capacity and energy from throughout MISO and beyond can be used to provide the Companies SSO load. Hence, OEG's attack on the reverse auction, which is solely predicated on the Companies affiliate owning the generation divested by the Companies - is irrelevant. Capacity and energy from a much broader geographic area than Northeast Ohio can serve and/or hedge SSO load.

OEG also alleges that the provision of indicative bids will risk manipulation by communicating indicative offers prior to the auction. OEG is clearly wrong. Only the CBP Manager and PUCO Staff will have access to indicative bids. Bidders will not know each other's indicative bids and the Companies will not know. It is apparent that OEG criticized the Company's proposal without even bothering to take the time to understand the proposal.

Finally, both OEG and IEU attack the open auction by pointing to the Illinois experience. That attack is based entirely on unverified press reports. In that auction, prices for ComEd and Ameren were very similar (within $2 MWH[20]). (See: The September 2006 Illinois Auction, Post-Auction Report Public Report of the Staff) (Illinois Staff Report page 6). For most residential customers of those utilities, prices had been *reduced* in 1997 by up to 20%. Following the auction, prices rose 21% for Commonwealth Edison, 37% for Illinois Power, 36% for CIPS and 53% for CILCO. Common sense indicates that if virtually the same auction price produces a rate increase of 21% for one utility and 53% for another utility, the 53% rate increase is not a result of the auction, but a result of a very low starting rate. (Illinois Staff Report). Further, the rate increases from the 1997 pre-reduction level were less than 3% for Commonwealth Edison, 10% for Illinois Power, 29% for CIPS and 45% for CILCO. Again, these are all based on virtually identical auction prices, indicating that the percent increase figure on rates is not very meaningful. (Illinois Staff Report) In real or purchasing power adjusted terms, *rates actually fell* for two of the four utilities. On an inflation adjusted basis, prices decreased 22% for Commonwealth Edison, decreased 11% for Illinois Power, rose 5% for CIPS and rose 18% for CILCO. (Page v. of v. of the Illinois Staff Report). Again it was virtually identical auction prices that produced a decline of 22% in inflation adjusted rates for Commonwealth Edison and an increase of

[20] Equivalent to 0.20¢/kWh

18% for CILCO, indicating that pre existing rate levels, not the auction, were the source of any increases. OEG misrepresents the results of the Illinois Auction. It relies solely on press reports for information as opposed to available official documents such as the Public Report of the Illinois Staff. OEG reports increases in one excerpt as ranging from "25 to 100 percent" (page 3) and in the only other reference to Illinois rates notes that the reverse auction "pushed rates up 55%...". (Page 4). As the source document was not provided, it is impossible to know if the information deleted and characterized by the ellipsis also noted that this was an extreme increase affecting only one utility that served 5% of Illinois customers and that in fact as a result of the Illinois Auction, inflation adjusted prices declined for 84% of the residential customers in Illinois. In any case, OEG has relied on press reports as opposed to reliable original documents. OEG's comments distort the results of the Illinois Auction and mislead the PUCO.

The Illinois Staff Report also makes the following observations with respect to the September 2006 reverse auction:

- Staff and the Commission's Auction Monitor, Boston Pacific Company, had full access to all elements of the Illinois Auction. ... Staff found that the auction was conducted in transparent, equitable and highly efficient manner, consistent with both the Commission orders in the Procurement Dockets and the auction rules. (Page iii.)
- In the view of Staff and the Auction Monitor, the auction was competitive. There were 21 registered bidders in the Illinois Auction and 16 of them were winning bidders. (Page iii.)
- The winning prices for the small to medium customers were in line with Staff's expectations. (Page iv.)

In summary, OEG's attack on the Companies' proposal based on alleged issues with the Illinois Auction ignores the objective evidence concerning that event.

X. The Repetitive Procurement Process Benefits Customers

Staff states that - "Procurement processes that repeat over and over again invite gaming. Suppliers can gain significant knowledge about one another's bidding strategies, inviting tacit collusion." (Staff p. 12) This assertion by Staff is not applicable to the Companies' proposal.

First, Staff simply assumes suppliers are able to gain significant knowledge about one another's bidding strategies. This is not the case. Under the proposed bidding process, bidders are provided information to reduce their uncertainty and solicit the best (i.e., lowest) bids. This information is the number of bidders registered in the process, the aggregate level of supply intended to be bid, and in each round of the bidding, the supply bid in aggregate in the previous round. A supplier is given absolutely no information regarding another supplier. A supplier does not know the intended bid volumes of any other suppliers, does not know the bids of any other supplier, and does not hold information regarding the bidding strategy of any other supplier. The assertion that suppliers will gain valuable knowledge about each other's strategies through the CBP is false. This proclamation ignores the structure of the auction, the rules regarding association and confidential information, as well as the provisions for which information is released to suppliers in confidence and which information is not provided to other suppliers. This assertion also ignores not only the measures to prevent collusion within the CBP but also antitrust laws specifically aimed at collusion and bid rigging. If it were true that a repeated procurement process is an invitation to tacit collusion, it would also be an invitation to the severe penalties for such action that exist under the relevant laws.

Second, it is completely unclear what type of procurement process would meet the burden of not being "repeated over and over again". Inherently, bidding and market interactions are repeated. Wholesale market participants meet and transact in wholesale markets every day. Procurement processes in other states are repeated, sometimes yearly, sometimes more often. A one-time procurement process, in which all power supply would be procured for all future generations of SSO customers from now until eternity is incomprehensible. Such processes inherently must be repeated. If Staff simply meant to say that it believes somehow the risk of collusion increases significantly between holding one solicitation and three, there is simply no evidence that this would make any difference. This is especially true since, as argued above, suppliers do not gain knowledge of each other's bidding strategies. Absent any such evidence, the advantage of not exposing customers to the volatility of short term markets and to average such market conditions over several solicitations clearly outweighs the unfounded concern expressed by Staff. This advantage is a strong feature of the Companies' proposal that directly benefits customers. This feature should be retained absent any evidence that holding three solicitations present more risk of an anti-competitive outcome than holding a single solicitation per year.

XI. The Proposed Contingency Plan is Complete and Flexible

The OCC (p. 18 -19) suggests that the PUCO should have additional oversight on the implementation of the contingency plan proposed by the Company in the event that a supplier defaults on their supply obligations after all solicitations have been conducted for power supply during a specific period of time. OCC recommends the

Companies should secure replacement power through a competitive bid or if not practical, then at a price below the spot price until a competitive bid can be conducted. OCC's suggestions reflect a misunderstanding of the contingency being addressed and does not reflect a consideration of the timing which may occur. This can best be understood with some examples.

Assume the 2009 CBP, which has the last solicitation scheduled to occur in November 2008, and further, assume that a winning supplier makes it known it will not be honoring its commitments on December 28, 2008. Clearly, in such circumstances, conducting a competitive bid for power to begin flowing January 1, 2009 is not practical. Further, it is unrealistic to expect a supplier to agree to be "willing to supply the power at less than MISO administered markets zonal spot prices until FirstEnergy can obtain supplies from a competitive bid." (OCC p. 19). A supplier could always make more money by simply selling its power to the MISO administered spot market.

As another example, assume a supplier makes it known on January 14, 2009 it will not be honoring its commitments beginning at midnight. In this contingency, the Companies have no reasonable alternative in the short term - other than to procure replacement power in the MISO spot market until a determination has been made to either offer the defaulted tranches back to the remaining suppliers or re-bid this amount at a later date.

It is impossible, *a priori*, to anticipate every potential contingency which may occur and the specific circumstances which will prevail at that time. The Companies proposed contingency plans, as described in Exhibit I of the original CBP filing, provides for an appropriate degree of flexibility necessary to appropriately react to the specific circumstances associated with any contingency which may occur and should be approved by the Commission. Moreover, in the interest of building greater visibility to contingency plan selection and the circumstances surrounding a particular default(s), the Companies agree to meet with the PUCO Staff in the event of a supplier default as soon as reasonably possible, to discuss the Companies' contingency plan selection rationale and the factors underlying the default event.

XII. Revenue Variance Rider (RVR)

While certain parties outright object to the Revenue Variance Rider (RVR), other parties seem confused about its function. As clearly stated in the Companies' application on Exhibit C1 at page 6 and Exhibit C2 at page 8, the RVR is for the sole purpose of reconciling recovery under the estimated RVR and the actual revenue variances as explained on the above referenced pages. The RVR has nothing to do with the under collection that NOAC refers to on page 5 of their comments, and which they state would be recovered in the RVR. Such under collection, if it did exist, would be recovered in the Standard Service Offer Generation Charge Reconciliation Rider, Rider GEN-R. Also, NOPEC at page 7 states that bad debt expense will be collected through the RVR. Again, as pointed out in the Companies' application, the RVR does not include any component for bad debt. Rather, as pointed out on Exhibit C1 and C2 on pages 5 and 6 respectively, uncollectible expense amounts related to SSO Generation Service are recovered in Rider GEN-R.

XIII. Slice of System - Class Allocation Factor

While the Companies' Application is clear at paragraph 29 that the Class Allocation Factor is simply based on historical rate relationships, some parties seem to have the belief that the Class Allocation Factors somehow represents cost relationships. NUCOR at page 14 of its comments, states that the Class Allocation Factor combined with the Seasonal Application Factor and Time-of-Day Application Factor are "intended to reflect the costs associated with serving each customer class". Exhibit C2 of the Companies' application reinforces paragraph 29 of the Companies' application that the Class Allocation Factor does not reflect cost relationships, but rate relationships between classes.

XIV. Avoided Costs for Slice of System Alternative

Under the proposed slice of system approach, the Commission has the ability to allocate the cost of the market-based generation supply as it deems appropriate. For example, as indicated in the Companies' filing, one such approach would be to continue the class-wise relationship of today's generation charges. If that occurs, and the avoidable cost or shopping credit is set equal to the Commission-determined cost allocation, the likelihood increases that the class paying a larger share of the market price will see an avoidable cost higher than what a third party supplier would offer in a shopping scenario. The incentive would for customers in this class to shop, with the result that the "larger share" of the market-based generation supply not being available as part of the utility's revenue stream. This will leave the utility with insufficient funds from generation revenue to pay the cost of generation supply.

Some parties (Integrys para. D., NUCOR p. 15 and SEL p. 7) have taken the position that the avoided costs under the slice of system approach should be set equal to the SSOGC, and not to the lesser of the SSOGC or the costs avoided by the Companies. Acceptance of the position of these parties will be counterproductive, as the end result will be that customers with lower indexed rates will remain on POLR service, and those with higher indexed rates will shop, such that the resulting generation revenues will be insufficient to pay for the cost of the purchased power supply. As that shortfall of revenue continues to grow and be added to the reconciliation mechanism, the generation cost for remaining customers will continue to increase, along with the avoidable cost for those customers. As the avoidable cost increases, more customers will shop at continually higher prices until, taken to the extreme, all customers shop at extremely high prices and the integrity of future competitive bid processes is fully undermined and compromised.

Limitation of the avoidable cost to the lesser of the SSOGC or the costs avoided by the Companies, as proposed by the Companies, permits the Commission to achieve specified rate design goals as part of the procurement process, which opportunity does not exist to the same extent under the load class arrangement.

XV. Hourly Price Generation Service

OCC (p. 9 -10) suggests that under the Slice of System alternative, restrictions should be imposed on the ability of customers to choose to participate in the Hourly Price Generation Service.

The Companies see no need for the Commission to unnecessarily restrict customer choices in this manner. As proposed by the Companies, a customer who selects the Hourly Price Generation Service must provide twelve months notice in order to return to the utilities' fixed price service. The Companies will make available, in the data room accompanying each solicitation, aggregate data providing bidders with the information necessary to assess potential volume and load shape impacts.

If the OCC's concern stems from the potential for customers to switch from fixed price service to hourly priced service, the Companies believe the concern is without a basis. First, the Companies have offered an hourly priced service for a number of years and there are very few customers who have selected this option. Second, the Companies have regulated affiliates in other states which only offer to specific customer groups an hourly priced service. The experience has been customers shop, choosing alternative retail suppliers who offer them fixed price service. Based on real experience, the Companies do not expect active switching by customers between the hourly and fixed price service offerings.

XVI. Load Response Program

Several parties provided suggested changes to the Load Response Program. OCC p. 13 suggests the economic buy through provisions of the program should be eliminated; a change in the proposed price threshold for an economic buy through event; and the Companies should specify the amount of the program credit. OEG endorses the program as a "good idea" (OEG p. 12) but suggests numerous refinements including establishing a working group (presumably to develop more refinements); the Companies should specify the amount of the program credit; more than 400,000 kW of load should be able to participate; and the Companies should offer a menu of terms and conditions from which customers could select. Constellation New Energy opines the Companies should specify the program credit.

The range of comments – from OCC suggestions to make the program more restrictive to OEG's request for a broader program providing for more customer choice, may be a good indication the Companies' proposal has achieved something of a middle ground between differing perspectives.

In proposing the Load Response Program, the Companies sought to provide its larger customers with a program which, while different than currently effective interruptible contracts and tariffs, is similar to a service offering to which some customers have become accustomed to receiving from the Companies. Yet, the Companies realize the 'menu of choices' requested by OEG, can be offered by any number of competitive suppliers, and the Companies have no desire or intent to actively compete with these suppliers. The proposed program was designed to establish a safety net for customers who desire an interruptible service in the event they cannot obtain the exact type of interruptible service they seek from the competitive retail market or the interruptible programs to be offered by MISO.

Several parties suggest the Companies proposed Load Response Program is deficient because the Companies did not provide a numerical value for the program credit. The value of the program credit will be comprised of two components - a value for the emergency or mandatory curtailments and a value for the voluntary or economic buy through events. The emergency curtailment value will be based on the market value for capacity using observed transactions for the MISO capacity equivalent – designated network resources – and values for capacity in the relevant western portions of PJM as observable in the transparent PJM capacity market. The economic buy through value will be based on the actual, blended competitive bid price and based on design parameters will net to zero if a customer always buys through. With the program requiring mandatory interruptions for Emergency curtailments, suppliers will not have to provide capacity for the load participating in this program, i.e. they will avoid incurring the market cost of capacity, and the Companies propose to flow this benefit through to participating customers. It is the Companies' intent to make known an indicative value of the program credit in early Summer 2008, using then current market values for capacity and a final value when the actual blended clearing price is known. However, using current market values for capacity and historical LMP data, the Companies estimate the program credit to be within a range of $4.00 to $6.00 per kw/month comprised of $2.40 to $3.40/kw/month for the emergency curtailment value and $1.60 to $2.60 /kw/month for the voluntary economic buy through value.

XVII. Treatment of Special Contracts

As stated in the Companies' Application, with respect to CEI's special contract customers remaining after January 1, 2009, the Companies propose to recover 50% of the difference between the Standard Service Offer Generation Charge and the generation portion of the special contract rate, consistent with past treatment, through a non-bypassable charge paid by all other CEI customers via a separate rider. These contracts were entered into with Commission approval for various reasons including helping the state's economy through the addition or retention of jobs, increased tax revenues, both locally and at the state level, and spreading the Companies fixed costs over more kWh's thereby benefiting all customers. The Companies must include the load associated with special contracts (those still in effect past January 1, 2009) in the competitive bid process because the Companies do not have generation resources nor an agreement for the procurement of generation to serve load associated with special contracts beyond 2008.

Arguing that the Commission should reject the proposal to recover 50% of the difference between CEI's special contract rate and the SSO generation charge, OEG states that:

> CEI's special contracts were extended as a result of a Rate Certainty Plan ("RCP") Stipulation that was approved by the Commission. The Company received valuable consideration for its agreement to provide generation at the rates specified in those special contracts. The Company should not be allowed to unilaterally alter the terms of the settlement in the RCP case in this totally separate filing. The Company has provided no justification for this proposal and no compelling justification exists. The Company has already been paid for the CEI contract extensions in the RCP case. It should not be paid again here. (OEG at 10)

To the contrary, the Companies are in no way altering the terms of RCP Stipulation with this Application nor does the Application seek to change the obligations set forth in the RCP Stipulation or the individual contracts themselves. The filing of the Application did not abrogate the RCP Stipulation or argue a new interpretation of the Stipulation. In fact, the RCP Stipulation does not even speak to the issue of 'delta revenue' other than to state that special contracts under the RSP shall continue in effect until December 31, 2010 for CEI.

The compelling justification for this provision of the Application which OEG seeks is provided by longstanding Commission and Staff policy regarding special contracts and delta revenue. The Commission believes that a 50/50 split properly recognizes that both the company and its customers benefit from the company's policy of providing economic incentive rates to certain customers to retain load, encourage expansion, and attract new development in the company's service territory.[21] This same policy allows for the continuation of special contracts, which OEG claims are "critical to the economic well being of Northern Ohio".[22]

In fact, given a very similar set of circumstances, the Commission recently stated in the Entry for the Companies' previous Application for Approval of a Competitive Bid Process:[23]

> The Commission believes that the difference between the auction clearing price and the contract rates should be shared by FirstEnergy and the non-contract customers. On the one hand, FirstEnergy offered to extend the contracts beyond the market development period in the context of an emerging competitive environment for generation supply. FirstEnergy also extended these contracts as part of a settlement package in its ETP and RSP cases and for reasons that it believed were in their own interests. Although the Commission reviewed and approved the individual contracts pursuant to Section 4905.31 Revised Code, at the time when they were originally established, the individual contracts were not reviewed in the context of the subsequent extensions offered by FirstEnergy. On

[21] Case No. 95-299-EL-AIR, Staff Report at 104, "Staff policy recommends that both the benefits and the costs of economic recovery be shared equally by the customers and the company. Therefore, Staff recommends that half of the delta revenue deficiency due to economic development arrangements be borne by the utility and half be borne by the ratepayers." See also, Opinion and Order Case No. 95-299-EL-AIR at 17-18, In Commission concurrence with Staff treatment of special contracts, "Staff witness ... testified that the treatment of ... delta revenue in this case (50/50 split between customers and shareholders) was consistent with the staff's recommendations in prior cases that have been adopted by the Commission"; Case No. 89-1001-EL-AIR Opinion and Order at 40-41, "The staff recommended that the delta revenue deficiency be split evenly between the applicant and its customers as recognition that both the company and customers benefit from ... contracts through the retention of load, load growth, increased income, greater efficiency of facilities, retained and increased employment, and increased tax revenues associated with economic recovery initiatives ... the staff's recommendation is consistent with past Commission precedent that companies and ratepayers should share in the revenue deficiencies associated with economic incentive contracts ... The Commission finds that the staff's recommended treatment of the delta revenues in this proceeding is appropriate and should be adopted... The Commission believes that a 50/50 split properly recognizes that both the company and its customers benefit from the company's policy of providing economic incentive rates to certain customers to retain load, encourage expansion, or attract new development in the company's service territory."

[22] Case No. 03-2144-EL-ATA, Initial Brief of OEG at 3

23 Entry, Case No. 04-1371-EL-ATA at 23; Similarly set forth in Entry, Case No. 05-936-EL-ATA at 18.

> the other hand, the special contracts have been part of the ETP and RSP stipulations all along. And the Commission believes that the retention of these special contract customers on FirstEnergy's system has also benefited the non-contract customers (e.g., through the relatively high load factors of the special contract customers as a whole when compared to non-contract customers). We believe our decision to share the revenue difference reaches a fair result, given these competing considerations. Consequently, the Price Matrix should be redesigned to target a total of fifty percent of the difference between the auction-clearing price and the contract rates for recovery from the other customer classes. [emphasis added]

Further, the Companies were not "paid", as OEG claims, for CEI contract extensions in the RCP case. Special contracts were one issue of many in which the Companies agreed to extend contracts in an effort to bring prompt and fair resolution to the pending case. The process of extending special contracts through stipulated agreement, one which OEG itself supported by signing in support of the Stipulation, should not then be used to prevent implementation of longstanding Commission policy.

OCC states the proposal fails to establish a market-based standard service generation offer for CEI's special contracts; the non-bypassable recovery of delta revenue is a noncompetitive rate in violation of 4928.02(G), 4905.33 and 4905.35; and because the generation cost is being charged as a noncompetitive distribution rate, it is in violation of the Supreme Court's decision in *Elyria Foundry* (114 Ohio St. 3d 305); special rates are preferential and discriminatory in violation of 4905.33 and 4905.35; and the non-bypassable rate is noncompetitive and results in a subsidy in direct violation of 4928.14(A), 4928.02(G), 4928.07, 4905.33 and 4905.35 (see OCC 12-13).

OCC's contentions are flawed and lack validity in several respects. First, the statute specifically contemplates that special contracts are an exception to the unbundling process.[24]. The contracts at issue here are the same contracts that were in effect on the effective date of Senate Bill 3. The Companies cannot charge or pass-through a market-based standard service generation offer to CEI special contract customers or any other rate other than the rate agreed upon in the contract by the parties and approved by the Commission.

Secondly, recovery of delta revenue has always been non-bypassable in rates because special contracts have been deemed to benefit all customers as explained above. There is no violation of 4928.02(G) nor a violation of the holding in *Elyria Foundry* because recovery of delta revenues associated with generation will not be recovered through noncompetitive distribution rates. Recovery will occur through a non-bypassable charge, which process has been authorized by the Commission and the Ohio Supreme Court.[25] Furthermore, recovery of delta revenue does not involve an anti-competitive subsidy flowing from noncompetitive electric service to competitive electric service as described in 4928.02(G). There is no violation of 4905.33 or 4905.35 because the special contracts at issue and the RCP have already been approved by the Commission. As a result, the approved contracts and the recovery of delta revenue associated with the contracts have not been found to be in violation of 4905.33 or 4905.35. And, OCC's contention that the Application provides for a special rate that is preferential and discriminatory under the law is baffling. The nature of the charge itself is <u>non-bypassable</u>. How can a non-bypassable charge be discriminatory? Moreover,

[24] 4928.34(A)(6) "For the purposes of this division, the rate cap applicable to a customer receiving electric service pursuant to an arrangement approved by the commission under section 4905.31 of the Revised Code is, for the term of the arrangement, the total of all rates and charges effect under the arrangement."
[25] *Ohio Consumers' Counsel v. PUCO*, 111 Ohio St.3d 300 (Nov. 22, 2006); Case No. 03-0093-EL-ATA

recovery of delta revenue does not provide a rebate, special rate or free service as described in 4905.33. The approval of such a provision in the Application is reasonable and does not discriminate against customers served under tariff rates. Rather, keeping the existing special contracts, as filed and approved by the Commission under 4905.31 and subsequent rate plans, along with delta revenue recovery, fulfills the commitment to economic development in Ohio, load retention, and the new development that occurred.

XVIII. Distribution Rate Case - Case No. 07-551-EL-AIR

IEU argues that the Application is dependent upon completion of the pending distribution rate case (Case No. 07-551-EL-AIR), which it claims cannot be accomplished in the necessary timeframe to appropriately implement the CBP. Fortunately, this contention is not true as the competitive bid process itself is not dependent upon the distribution rate case. The bid process clearing price will be determined regardless of the outcome of the Companies' distribution rate case. The manner in which the generation price stemming from that bid process translates into a retail rate will depend in part on rate design to be applied to that generation pricing. However, the Commission would not have to approve or render a final decision on rate design in order to approve and implement the CBP. If the Commission were to approve the CBP Application but reject the proposed rate design changes in the distribution rate case, the Companies could either amend the current CBP Application to account for rate design changes or even retain the currently effective rate design. As a result, IEU's alleged interdependence among the two separate cases is misplaced. Further, IEU is an intervening party in the distribution rate case and will have an opportunity to opine on rate design issues over the normal course of the proceeding.

In sum, the nature of the competitive bid process is such that it must be filed and approved well ahead of time for power procurement reasons. Therefore, perfect procedural alignment of the two cases in terms of timing is unnecessary, and the Companies recommend the Commission approve the CBP without delay.

XIX. The Companies' Application is Complete

IEU contends that the Companies have not contemplated certain discrete practical details necessary in order to make a CBP work effectively. As an example, IEU further noted that the Companies had not considered whether winning bidders would be required to refund prices found excessive by FERC; what actions the State could take if a winning bidder defaults; how many bidders it would take for the CBP to be deemed effective; and the role or limits of the Commission's review.

Even while providing a detailed description of contingency plans in the Application, as a practical point, every possible contingency or potential circumstance cannot be incorporated into the Application. That is in fact why the Companies requested an ongoing review process – for the purposes of accounting for changes or changed circumstances not considered in the Application.

Furthermore, to the extent that FERC *may* take issue with the bid process clearing price, that is a FERC jurisdictional issue and cannot be incorporated by the Companies in the Application. To the extent that the State *could* take action if the winning bidder defaults and what those actions may be – is a matter to be left to the State for determination and again not one to be incorporated in the Application. Finally, determination of the role and limits of the Commission's review is a matter to be decided by the Commission itself and inappropriate for inclusion in the Application. Contrary to

IEU's contentions, the Companies' Application is well supported and comprehensive in detail.

XX. Street and Traffic Lighting Rates

For customers served under the Street and Traffic lighting schedules, the SSOGC will be the applicable generation charge for rate GS or 3.0¢ kWh, whichever is less. Governmental entities that participate in or take generation service through opt-out governmental aggregation for their governmental electric accounts are not eligible for this special pricing provision.

Several intervening parties have provided comments in opposition to this special pricing provision and/or its limited availability. The Companies proposed this special pricing provision in the Application due to the traditionally very low generation rates provided to street and traffic lighting customers. As a result, generation rates resulting from the competitive bid process have the potential of creating exceedingly large rate increases for cities, municipalities and communities alike.

Further, governmental entities that participate in or take generation service through opt-out governmental aggregation receive discounted generation service from alternative suppliers. These entities should not then receive special rates from suppliers for part of their load and special pricing for the remainder of the load from the Companies. While these communities typically have multiple accounts for electric service, they are viewed as a single customer for the purposes of aggregation. As a single customer, Commission approved supplier tariffs prohibit a customer from 'shopping' part of its load with an alternative supplier while taking default service from the utility for the other portion of its load.[26] Again, arguments that this provision of the Application is discriminatory and anti-competitive are misplaced. 4905.35(A) provides that utilities cannot give any person an "undue or unreasonable preference or advantage" or subject any person to any "undue or unreasonable prejudice or disadvantage." Undue discrimination occurs when differently-situated parties are treated similarly, or when similarly-situated parties are treated differently. This provision of the proposal is not unduly discriminatory because access to the special street and traffic lighting rate is not afforded differently to similarly-situated customers, when participation in a governmental aggregation program clearly is distinguishing. Because customers to whom this rate will be available are differently situated from those to whom it will not be available – for the reasons discussed above – this rate provision of the proposal is not discriminatory and nor anti-competitive.

XXI. Demand Response

Staff claims that the Companies have not yet complied with the Commission's Finding and Order in Case No. 05-1500-EL-COI ("EPACT Case"), to file tariffs offering time differentiated rates and meters to enable customers to respond to market prices. The Companies do not agree. As indicated in the Companies' April 26, 2007 filing in the EPACT Case, the Companies submitted numerous examples of time sensitive rates, including market based tariffs that are available to both commercial and industrial customers. These market based rate schedules are available for the stated purpose of testing customer responses to hourly price signals quoted by MISO. This market-based program offers customers the opportunity to manage their electric costs by shifting

[26] P.U.C.O. No. S-1, Electric Generation Supplier Coordination Tariff, Sect. VII.D

usage from higher price to lower price periods. Moreover, the CBP Application itself includes both hourly and On-Peak/Off-Peak tariff pricing programs that would provide all SSO customers -- industrial, commercial and residential -- the opportunity to purchase generation service that are linked to the energy market. In light of the foregoing, the Companies believe that they are, indeed, in compliance with the Commission's March 28, 2007 Order in the EPACT Case.

XXII. No Hearing is Required For Commission Action on the Application

The Application to establish the competitive bidding process was filed under R.C. 4909.18 as an ATA case, as required by Commission rules. No hearing is required under this statutory provision unless the Commission first finds that the Application may be unjust or unreasonable. If the Commission sets this matter for hearing based upon such finding, then the same statute requires the Commission to act upon the Application within six months of the filing date. The filing date of the Application was July 10, 2007, so if a hearing is scheduled by the Commission, an Opinion and Order ruling upon the Application must be issued no later than January 10, 2008.

As stated though, no hearing is required. A finding that the Application may be unjust and unreasonable must be based upon more than the Commission's belief that certain provisions of the Application need to be modified or deleted, or that certain new terms need to be added. This is not the first Application filed by the Companies seeking approval of a competitive bidding process. On two previous occasions, the Companies have filed similar proposals. The first was Case No. 04-1371-EL-ATA, and the second was Case No. 05-936-EL-ATA. Both of these proposals were approved by the

Commission and were utilized by the Companies to conduct the competitive bidding process. In both instances, the Commission made numerous changes to the Companies' initial proposal to address concerns of other parties to the proceeding and to address concerns raised by the Commission itself. In each case, these changes were implemented, through Commission order, by the Companies. Further, the instant Application was filed under the same rules and statutes as the two previous competitive bidding processes. No hearing was necessary in order for the Commission to render an Opinion and Order establishing a just and reasonable competitive bidding process, and no party challenged the Commission's decision to not conduct a hearing in the matter.

In this proceeding, several parties have requested that the Commission conduct a hearing in this matter. IEU, p. 3, NUCOR, p. 8, OEG, p.4. The primary reason cited by these parties to support their request for a hearing is their fear of the level of pricing that will be the outcome of the approved competitive bidding process. However, this does not make the competitive bidding process itself unjust or unreasonable. In fact, the Commission has already approved two similar competitive bid processes, as described above, without conducting a hearing and no party appealed the Commission's Order. The possibility that the price that results from a properly conducted competitive bidding process may not please all parties involved, which is itself based upon speculation about the market price of electricity at future points in time, is not a basis upon which the process itself may be declared unjust and unreasonable.

It is important that the Commission not be distracted by the request for an unnecessary hearing. Such procedural maneuvering will surely delay Commission action on the Application without adding to the substantive process. All interested parties have the opportunity to file initial and reply comments, and may file an Application for Rehearing of the Commission's order. Effective January 1, 2009, the Companies do not have a power supply secured to provide electric generation service to retail customers in their service territories. That power is to be provided through the competitive bidding process, as contemplated by R.C. 4928.14. In order to implement aspects of the Companies' proposal designed to stabilize the pricing resulting from the competitive bidding process, multiple bids over time during 2008 must be conducted in order to ensure the power flow commences on January 1, 2009. The Companies request that the Commission approve the mechanism necessary to make this happen, and a hearing is neither required nor desirable for this type of proceeding.

XXIII. Combining the Transmission Component and the Generation Component is Permissible Under Chapter 4928

The Companies proposed to have the winning bidders supply both transmission and generation service, and to combine the cost of both services into the competitive bid process. At this time, competitive retail electric suppliers are responsible for providing both the transmission and generation service in the pricing to customers. The primary purpose of this proposal was to align the offer from competitive retail electric suppliers with the pricing format customers would see resulting from the competitive bid process for standard service offer. This approach will reduce customer confusion and aid the customer in making an economic decision when deciding whether to shop or remain with the standard service offer.

Combining the generation and transmission components is also consistent with the Commission's approval of the Companies' two previous competitive bidding processes. In both of those cases, the Commission authorized the combining of the price for generation and components of the price for transmission. The instant proposal is in accord with those previous Commission orders, which no party appealed. Further, R.C. 4928.07 contemplates that the electric distribution utility may combine unbundled components to meet customer preferences. From a customer perspective combining the generation and transmission components together makes perfect sense. First, it will permit true apples-to-apples comparisons between the standard service offer from the Companies and the pricing from competitive suppliers. Second, it will simplify the bill for customers by reducing the number of line items and bill components. Finally, under the load class bidding approach and for most customers under the slice of system approach, the avoidable cost will equal the sum of the generation charge and the transmission charge, so whether the charges are shown separately or on a combined basis, the customer will avoid the same level of charges. Therefore, since the Companies' proposed approach will benefit customers through simplifying the bill and making shopping comparisons easier, and will not harm customers in any way, the Companies' proposal should be adopted.

If the Commission determines that combining the generation and transmission component is not palatable, the Commission can administratively designate a portion of the bid amount to constitute the transmission component, and that component may be billed as a separate line item on customers' bills. In either event, this aspect of the proposal does not form a basis for the Commission to reject the Companies' entire proposal, as suggested by IEU.

XXIV. The Outcome of a Properly Conducted Competitive Bidding Process is Just and Reasonable

R.C. 4928.14 requires that electric distribution utilities provide retail generation service to their customers in the form of a standard service that is market-based. The statute also specifically identifies a competitive bidding process to be one means of providing such market-based standard offer service. Under current law, there is no alternative to a market-based standard service offer and there is no test or other standard that must be met before such market-based pricing is implemented. Certain parties have suggested that if the pricing of a properly conducted competitive bidding process results in a price higher than they like, then such pricing is unjust and unreasonable in violation of R.C. 4909.18. OPAE at p. 3-4. Just the contrary, however, is true. Because R.C. 4928.14 requires that retail generation service be market-based, if the competitive bidding process is proper, then the outcome of the competitive bidding process is just and reasonable as a matter of law. Any argument that the pricing that results from a properly conducted auction is unjust and unreasonable simply because the pricing is higher than customers want must be rejected. If this were the standard, every price increase would be found to be illegal. Such was clearly not the intent of the legislature.

XXV. Phase-In Proposal

The Companies proposed that if the pricing from the competitive bidding process resulted in an increase for residential customers of greater than 15%, that the

Commission may phase in such an increase. The proposal contemplated that the amounts not initially collected by the Companies would be deferred and recovered over a three year period with a carrying charge. At least one party expressed concern that the proposal did not specify the level of the carrying charge. To alleviate concerns with this aspect of the proposal, the Companies would not object to the Commission specifying the carrying charge to be the long term cost of debt of each Company for the amounts deferred by that Company.

XXVI. Renewable Energy aspects of Proposal Should Not Be Expanded in Initial Year

The Companies proposed that one tranche (approximately 100 MW of Companies' load in the bid) be composed of renewable energy. This aspect of the filing was voluntary on the part of the Companies, i.e., at present there is no requirement that any amount of the power bid out be made of renewable power. The Companies proposed the renewable tranche as another step to test the market in Ohio for renewable power from suppliers. Because this is the first time such a renewable power tranche has been bid out as part of a competitive bidding process in Ohio, the Companies broadly defined what renewable resources may be included in the tranche. This approach was taken to fully test the entire continuum of the renewable power market to see where the interest may lie. Limiting the scope of renewable resources was purposefully avoided in hopes of attracting sufficient bids from all types of renewable power to fully subscribe the tranche, and to not favor one type of renewable power over another.

The OCC has recommended narrowing the definition of renewable resource for the bid, or in the alternative expanding the amount of renewable power to be bid, before it is known whether there is any interest in bidding for such power and what the cost of such power may be. The Companies believe that such narrowing of the definition or expanding the amount of renewable power in the initial bid should not be accepted by the Commission. If the renewable tranche is fully subscribed and proves to be administratively reasonable to implement with the other aspects of the bidding process, then it can be expanded in the future through the periodic reviews conducted by the Commission. The Companies' voluntary undertaking regarding renewable resources should not be expanded beyond the Companies' proposal, at least in the first year of the competitive bidding process.

XXVII. Conclusion

The foregoing comments clearly demonstrate that a transparent, robust and competitive market exists for electric generation sufficient to support the competitive bidding process proposed herein. Parties' and Staff's concerns about the level of pricing that may result from such competitive markets is not a basis for the Commission to adjudge the Companies' filing as unjust and unreasonable. The Commission cannot, as recommended by its Staff, simply choose to ignore the mandates of R.C. 4928.14 - - it must allow market-based retail generation service for customers. The Companies' proposed competitive bidding process is specifically contemplated in the statute as a means to provide such required market-based retail generation service to customers. The Companies request the Commission to approve its proposal as filed consistent with the foregoing comments.

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CERTIFICATE OF SERVICE

I hereby certify that a true copy of the *foregoing* Reply Comments was served by regular U.S. mail, postage prepaid, upon the following parties of record, this 12th day of October 2007.

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