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FILE

STATE OF OHIO
BEFORE THE
PUBLIC UTILITIES COMMISSION

CASE NO. 08-935-EL-SSO

IN THE MATTER OF THE APPLICATION OF OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY FOR AUTHORITY TO ESTABLISH A STANDARD SERVICE OFFER PURSUANT TO SECTION 4928.143, REVISED CODE, IN THE FORM OF AN ELECTRIC SECURITY PLAN

DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF NUCOR STEEL MARION, INC.

September 29, 2008

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission (NCUC). During my tenure at the NCUC, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the NCUC, I also served as a member of the

Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, policy, planning, and pricing issues involving firms that operate in energy markets. For example, I have prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts; and conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits and provided technical assistance in more than 100 proceedings before state and federal agencies as an expert in competitive market issues, regulatory policy, utility planning and operating practices, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission (FERC), the Government Accountability Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. Additional details of my educational and professional background are presented in the Appendix.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Nucor Steel Marion, Inc., which is located in Marion, Ohio. The Nucor facility—a large retail industrial consumer served by Ohio Edison Company—produces steel by recycling steel scrap in electric arc furnaces.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review and evaluate FirstEnergy's proposed Electric Security Plan (ESP). Given the limited time for review and analysis under the procedural schedule in this case (particularly in conjunction with my review of FirstEnergy's Market Rate Offer that was filed concurrently), I was asked to focus on the rate elements in (or missing from) FirstEnergy's ESP pricing mechanisms.[1]
2. Identify any major deficiencies in FirstEnergy's ESP rate options and pricing mechanisms, and suggest recommended changes.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed FirstEnergy's ESP filing presented in this case by its Ohio utility operating company subsidiaries—Ohio Edison, Toledo Edison, and Cleveland Electric Illuminating. I also reviewed responses to discovery in this case[2] and information available on web sites operated by FirstEnergy, the Commission, and the Midwest ISO (MISO). In addition, I reviewed FirstEnergy's Market Rate Offer (MRO) plan and related documents

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[1] My silence on other elements of FirstEnergy's ESP should not be construed as my implicit endorsement of them.

[2] FirstEnergy's responses to selected Nucor discovery requests are included in Exhibit DWG-1.

submitted in Case No. 08-936-EL-SSO and its 2007 competitive bidding proposal (CBP) and related documents in Case No. 07-796-EL-ATA.[3]

Q. WHY ARE THE MRO AND THE 2007 COMPETITIVE BIDDING PROPOSAL RELEVANT IN THIS CASE?

A. These cases provide some context in which to evaluate the ESP. The MRO is a benchmark against which the ESP can be judged with respect to which plan is most beneficial to customers, while the 2007 CBP case provides useful benchmarks against which to evaluate FirstEnergy's proposed ESP rate options.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. FirstEnergy's ESP combines a plan to acquire electric supply resources from its affiliate FirstEnergy Solutions (FES) with pricing mechanisms designed to recover the costs of those resources. The ESP also includes transmission and distribution services and associated rates and riders for standard service offer (SSO) customers. Because FirstEnergy's SSO supply will come from the same source as it does today (that is, the operating companies' affiliate generation supplier), in many ways the ESP represents a continuation of the status quo—albeit with a substantial increase in generation supply costs. However, with respect to the pricing of generation services, the ESP's pricing mechanisms and rate options raise serious concerns regarding:

[3] Excerpts from FirstEnergy's filing in the 2007 case are presented in Exhibits DWG-2 and DWG-3.

- Interclass cost subsidies and unreasonable customer rate impacts created by not reflecting identifiable class-specific cost differentials in generation rates.
- Proper incentives for interruptible and time-of-day customers to control peak demands and energy use in high-cost peak periods.
- Negative impacts on economic development and retention of manufacturing jobs stemming from the large rate increases to industrial customers.
- Non-cost-based impediments to customer shopping.

2. According to FirstEnergy, large industrial customers served at transmission voltages will likely see first-year price increases more than three times greater than the average increase for all customers. Increases for some large interruptible customers are likely to be significantly greater.
3. FirstEnergy's ESP generation rates ignore well-recognized cost differences to serve class-specific loads. Under FirstEnergy's proposal, all classes are charged the same volumetric time-of-use (TOU) generation rate[4] differentiated only by service voltage. The blended supply cost that serves as the basis for these prices is derived from the cost of capacity and energy purchased from FES to meet system requirements. Notwithstanding FirstEnergy's proposed uniform ESP generation rates, the actual average cost of generation capacity and energy to meet class-specific loads would be lower (*ceteris paribus*) for classes with higher load factors and primarily off-peak usage.

[4] This rate—Rider GEN—excludes applicable transmission and ancillary service charges, which will be recovered through Rider TAS. TOU pricing periods include seasonal and time-of-day (TOD) periods.

Such cost and rate differences are explicitly identified in FirstEnergy's market price projections,[5] were implicitly recognized in FirstEnergy's 2007 CBP proposal,[6] and have traditionally been recognized by this Commission is setting rates. Retail rates currently in effect reflect these class-specific cost differences, even though the operating companies' generation supply is now provided by FES under a wholesale power contract. If the ESP is adopted, FES will continue supplying generation services to the operating companies under a new wholesale contract. Simply changing the contract terms under which generation services are provided does not change the class-specific cost differences that exist today and will exist after January 1, 2009. Moreover, FirstEnergy has offered no justification for ignoring these class-specific cost differences by charging a uniform generation rate.

Despite compelling evidence that its generation costs vary by class of service, FirstEnergy ignores class-specific cost differences in pricing ESP generation service, and unfairly penalizes higher load factor and primarily off-peak (for example, street lighting) customers through the uniform volumetric generation rates.[7] As a result, FirstEnergy's ESP prices implicitly allocate excessive generation supply costs to these classes—for example, classes served at transmission voltages and street lighting customers. Such interclass subsidies can and should be removed from the ESP prices, particularly when they result from large, unjustified rate increases for industrial customers that are important for Ohio's economic well-being.

[5] *See* the direct testimony of FirstEnergy witness Scott T. Jones at Exhibits 3, 4, and 8.
[6] *See* Exhibits DWG-3 and DWG-4.
[7] FirstEnergy indirectly address this issue for street lighting customers through a credit in Rider EDR.

4. By offering interruptible rate options, FirstEnergy properly recognizes the potential benefits of interruptible service in reducing its customers' total costs for generation and transmission services, enhancing system reliability, and potentially reducing fuel costs for firm-service customers. However, several elements of the proposed interruptible options are problematic—for example, the proposed low interruption credits, bundled emergency and economic interruption options, unlimited economic interruptions, and determination of interruptible demand.
5. FirstEnergy's proposed time-of-rate options and demand measurement approach for transmission customers can and should be improved to reflect cost causation more accurately and send proper price signals.
6. FirstEnergy's has proposed several non-bypassable charges that should be carefully scrutinized to identify and eliminate non-cost-based charges that may impede the development of competitive retail markets. A good example is FirstEnergy's proposed Rider MDS (Minimum Default Service Rider).

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission require FirstEnergy to:

1. Modify its ESP as described in my testimony. As I discuss in detail later, multiple improvements in FirstEnergy's ESP rates are necessary to ensure that they provide proper incentives for customers to control peak demands and use electricity efficiently, reasonably reflect generation cost differentials of serving different

types of customers (thereby reducing the likelihood of interclass subsidies), and promote economic development.

2. Revise Rider GEN such that the ESP generation rates properly reflect class-specific cost differences.[8] I describe my recommended approach to achieve this objective later in my testimony.

3. Revise interruptible Riders ELR and OLR as follows:
   - Create stand-alone options within each rider that permit customers to choose to be subject to emergency (reliability) interruptions, economic interruptions, or both in response to cost-based incentives applicable to each option.
   - Set the emergency interruption option credit at $7.50 per kW-month, and the economic interruption credit at $2.60 per kW-month.
   - Define Realizable Curtailable Load to reflect a customer's monthly peak demand used to calculate billing demand instead of the customer's historical average demand during selected summer hours as FirstEnergy proposes.
   - Set reasonable limits (I recommend 250 hours annually) on the allowable hours of economic interruptions.

4. With respect to FirstEnergy's proposed time-of-day rates, modify the 16-hour summer weekday peak period to include two separate pricing periods—for example, peak and shoulder pricing periods. (Winter peak hours and all off-peak hours would remain as proposed by FirstEnergy.)

5. Determine billing demands for transmission customers on the basis of 60-minute integrated demands instead of 30-minute demands as FirstEnergy proposes.

[8] Changes to Rider GEN would also require corresponding adjustments in Rider GPI (Generation Phase-in Rider).

6. Modify the ESP rates as necessary to remove impediments (for example, Rider MDS) to competitive energy markets.

CLASS-SPECIFIC COST DIFFERENCES

Q. DO THE PROPOSED ESP RATES HAVE DISPARATE RATE IMPACTS ON CUSTOMER CLASSES?

A. Yes. According to FirstEnergy, most customer classes will get only moderate (5 percent or less) first-year rate increases under its proposed ESP rates. However, large industrial customers served under transmission Rate GT and most lighting customers will get significant rate increases. For example, as shown in Table 1 below, transmission customers will get increases ranging from about 14 percent to nearly 34 percent. The estimated increases are understated for some customers. For example, increases may approach or exceed 50 percent for some transmission customers served under interruptible rates. As I discuss in more detail later, I do not believe that such increases are cost-based. Instead, in my opinion, the disparate increases for transmission customers are attributable in large part to the method FirstEnergy has chosen to set generation rates.

Table 1. Proposed ESP Rate Increases (%): 2009

	FirstEnergy Company		
Class	OE	CEI	TE
RS	2.38	6.17	5.73
GS	2.53	4.77	(6.92)
GP	5.33	2.23	(10.27)
GSU	8.69	1.74	(14.88)
GT	19.63	13.50	33.83
POL	2.46	26.29	16.17
STL	11.53	17.20	1.92
TRF	12.38	21.33	(25.66)
Total	5.23	5.26	6.96

Source: FirstEnergy ESP, Schedule 1A; CEI Contracts excluded

Q. WHY ARE THE RATE INCREASES SO DISPROPORTIONATE FOR TRANSMISSION AND LIGHTING CUSTOMERS?

A. In my opinion, a primary reason is that FirstEnergy has not properly reflected the cost of generation capacity in developing ESP rates for customer classes. As a result, high load factor (transmission) and primarily off-peak classes (lighting) get disproportionate rate increases under the ESP.

Q. HOW IS THE COST OF GENERATION SERVICE REFLECTED IN THE ESP RATES?

A. FirstEnergy proposes to recover its cost of resources purchased from FES primarily through Rider GEN (Generation Service Rider). Rider GEN (as proposed) is a uniform volumetric TOU generation rate[9] differentiated by service voltage. It reflects the blended supply cost derived from the cost of capacity and energy products that FirstEnergy purchases from FES to meet system requirements.

Q. DOES RIDER GEN ACCURATELY REFLECT COST DIFFERENCES TO SERVE CLASS-SPECIFIC LOADS?

A. No. Except for voltage adjustments, the ESP generation rates ignore any class-specific differences in the cost of serving FirstEnergy's SSO customers.[10] That is, with the exception of voltage differentials, the ESP generation rates make no effort to recognize cost differences to serve specific classes (for example, loads characterized by timing, duration, and

[9] As I noted earlier, Rider GEN excludes applicable transmission and ancillary service charges, which will be recovered through Rider TAS. TOU pricing periods include seasonal and TOD periods.

[10] FirstEnergy's ESP generation rates reflect time-of-use (season and time-of-day) MISO cost differences—not class cost differences—that FirstEnergy uses to weight its uniform generation rate.

load factor differences). By implicitly assuming a uniform blended cost to serve all loads, FirstEnergy has ignored market realities, Commission precedent, and its own CBP pricing proposals in 2007. The result is a set of ESP generation rates that create interclass subsidies and large rate increases for selected classes.

Q. DO THE TOU PRICE DIFFERENTIALS REFLECT CLASS-SPECIFIC COST DIFFERENCES?

A. No. In developing TOU price differentials for Rider GEN, FirstEnergy assumes a uniform average annual cost per MWh for each year in the ESP (for example, $75 per MWh in 2009). FirstEnergy then uses a non-class-specific locational marginal price (LMP) weighting scheme to develop TOU price differentials. Under this weighting scheme, the weight derived for a particular period (for example, summer on-peak hours) equals the ratio of the average LMP for that particular period in 2006-2007 to the total average LMP for those 2 years.[11] While this weighting scheme may be reasonable in setting TOU price differentials, it does not address class-specific generation cost differences.

Q. HOW DO YOU KNOW THAT CLASS-SPECIFIC GENERATION COST DIFFERENCES EXIST?

A. In reaching this conclusion, I have relied on information that can be either reasonably inferred based on expert judgment or empirically observed. For example, notwithstanding FirstEnergy's uniform ESP generation rates, we can reasonably infer that the average cost of purchased capacity and energy to meet class-specific loads is lower (*ceteris paribus*) for classes with higher load factors and classes with primarily off-peak usage. This inference is the same whether one looks at the issue in the context of a

[11] *See* the direct testimony of FirstEnergy witness Kevin Warvell at 9:18-10:8 and Schedule 5a at 7.

traditional cost-of-service study or an analysis of competitively priced generation products. The reason is simple—the fixed cost of capacity to serve higher load factor customers is spread over more kWh, resulting in a lower average cost. Moreover, with respect to off-peak loads, capacity costs to serve such loads approach zero, again resulting in a low average cost of generation products for off-peak customers. With respect to information that can be empirically observed, FirstEnergy's estimates of 2009 market-rate offers clearly shows that the cost of generation services varies by class or type of customer.[12]

Q. HAS THE COMMISSION TRADITIONALLY RECOGNIZED LOAD FACTOR AND OFF-PEAK USAGE IN ALLOCATING COSTS AND SETTING RATES?

A. Yes. In allocating costs and setting rates, this Commission—as well as most regulatory commissions with which I am familiar—has traditionally recognized the lower average cost of generation and transmission to serve higher load factor classes compared to lower load factor classes, and the lower cost of serving off-peak consumption relative to on-peak consumption. This logical result simply reflects recovery of fixed generation costs over more kWh for higher load factor classes, and the significantly lower cost of off-peak generation. In its ESP, FirstEnergy will be buying both capacity and energy from FES—its current supplier—not from alternative suppliers in a competitive market. In other words, nothing changes with respect to FirstEnergy's current generation supply except that a new wholesale contract (with higher costs) will be put in place with FES for the 3-year ESP term.

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[12] *See* the direct testimony of FirstEnergy witness Scott T. Jones at Exhibits 3, 4, and 8.

Q. IS THIS CASE DIFFERENT FROM SETTING RETAIL RATES FOR A DISTRIBUTION UTILITY THAT BUYS WHOLESALE FULL-REQUIREMENTS SERVICE FROM A SUPPLIER TO MEET ITS GENERATION NEEDS?

A. No. Power purchased under a full-requirements wholesale contract would typically be assigned to customer classes on a traditional cost-of-service basis. This case is no different, despite the option for customers to shop for an alternative generation services supplier. (Customers could also shop when FirstEnergy's current retail rates were set.) FirstEnergy did not present a cost-of-service study in this case that would identify class-specific cost differences for generation service. However, I recommend that principles of traditional ratemaking not be completely abandoned simply because FirstEnergy's has proposed a uniform generation charge to recover its FES supply costs. Reasonable methods to identify and assign class-specific generation costs are available and should be used.

Q. DID THE OPERATING COMPANIES REFLECT CLASS-SPECIFIC COST DIFFERENCES IN RATES FILED IN THE 2007 CBP CASE?

A. Yes. In the 2007 CBP case, FirstEnergy proposed two auction alternatives: a load class approach and a slice-of-system approach. Under the load class approach, FirstEnergy proposed class-specific rates to recover generation costs to serve each rate class within a major load class. (*See* Exhibit DWG-2.) Under the slice-of-system approach (which is most comparable to this case), FirstEnergy proposed a pricing mechanism that reflected the Commission's traditional recognition of the lower average cost of generation and transmission to serve higher load factor classes. (*See* Exhibit DWG-3.) That is, in both CBP approaches, FirstEnergy recognized class-specific cost differences for generation services. Yet in the current ESP case, FirstEnergy has abandoned its 2007 position and opted instead to set uniform ESP rates for all classes differentiated only by TOU and voltage. As a result, FirstEnergy's voltage-differentiated TOU prices effectively allocate excessive supply costs to higher load factor classes (for example, classes served at transmission voltages) and to primarily off-peak classes—for example, street lighting customers. Unless FirstEnergy's ESP pricing proposal is corrected, higher load factor and off-peak classes will bear a disproportionate and unfair share of the costs of FirstEnergy's generation purchases from FES. Such interclass subsidies can and should be removed from the ESP prices.

Q. HOW SHOULD THE ESP RATES BE MODIFIED TO REFLECT THESE CLASS-SPECIFIC COST DIFFERENCES?

A. The most readily available, reasonable, and straightforward method to address this problem is the approach that FirstEnergy proposed for its slice-of-system CBP rates in 2007. (*See* Exhibit DWG-3.) I recommend that the Commission require FirstEnergy to use this approach to set its class-specific ESP generation rates that can then be adjusted to reflect FirstEnergy's TOU and voltage differentials. Moreover, because it recommended this approach in 2007, I do not see how FirstEnergy can now credibly argue that the approach is unreasonable for setting class-specific ESP generation rates.

Q. HOW SHOULD YOUR RECOMMENDED METHOD BE IMPLEMENTED?

A. In its 2007 CBP case, FirstEnergy developed class allocation factors (CAFs) to convert the blended competitive bid price to an SSO rate for each load class. The CAFs were based on the ratio of each load class' historical average SSO generation and transmission rate to the historical average SSO rates for all classes. The CAFs by load class are shown in Table 2 below. These CAFs should be the first adjustment to

FirstEnergy's proposed uniform ESP generation rate ($75 per MWh in 2009), followed by the TOU and voltage adjustments. If CAFs for additional classes are necessary, then FirstEnergy should be required to develop them consistent with the approach it used in 2007.

Table 2. Load Class Allocation Factors

Class	CAF
RS	1.000
GS	1.252
GP	0.900
GSU	0.800
GT	0.769

Source: FirstEnergy 2007 CBP filing, Exhibit C2.

To illustrate this method, assume FirstEnergy's uniform generation rate is $0.075 per kWh in 2009. For residential customers, the CAF-adjusted generation rate would be $0.075 per kWh (1.000 times $0.075 per kWh). Similarly, for GT transmission customers, the CAF-adjusted generation rate would be $0.0577 per kWh (0.769 times $0.075 per kWh). All CAF-adjusted rates would then be further adjusted using the TOU weights and voltage differentials developed by FirstEnergy.

INTERRUPTIBLE RATES

Q. DO THE ESP RATES PROVIDE INCENTIVES FOR CUSTOMERS TO CONTROL PEAK DEMANDS AND USE ELECTRICITY EFFICIENTLY?

A. Yes. However, the incentives are limited, and must be strengthened and improved—particularly with respect to incentives in the proposed interruptible and time-of-day rate options.

Q. WHAT IS INTERRUPTIBLE OR NONFIRM SERVICE?

A. Interruptible service is a separately identifiable nonfirm utility product that allows a supplier to interrupt or curtail customer loads when reliability is impaired.[13] Interruptible load enables a supplier to maximize the value of existing capacity resources and to avoid acquiring new capacity resources. The available supply of interruptible service depends on the relationship between available power supply resources and firm service demands. That is, if firm demands command all available power supply resources, the supply of interruptible service falls to zero. When firm demands are significantly less than available resources, the supply of interruptible service is significantly greater. Many utilities—including those in Ohio—have offered interruptible rate options for years.

Q. CAN INTERRUPTIBLE RATES REDUCE BUSINESS AND FINANCIAL RISKS FOR ENERGY-INTENSIVE CUSTOMERS?

A. Yes. Some customers are willing and able to interrupt loads in exchange for lower electricity prices. For electricity-intensive manufacturing customers such as Nucor that can interrupt their manufacturing processes, lower electricity prices afforded by interruptible rates help reduce their financial and business risks by making their products more cost-competitive. Moreover, including interruptible rates in the ESP recognizes not only the role such rates can play in economic development and job retention, but also the potential benefits of interruptible service in enhancing system reliability and reducing all customers' costs for generation and transmission services.

[13] Some interruptible programs also provide credits for customers that interrupt for economic reasons—for example, when the market price or the supplier's marginal energy cost exceeds a specified level.

Q. DO INTERRUPTIBLE LOADS PROVIDE TANGIBLE BENEFITS?

A. Yes. Interruptible load can and should be a significant element of any utility's demand-response programs. Interruptible load has long been recognized as a means to reduce generating and transmission capacity requirements and a substitute for such ancillary services as spinning and operating reserves. Interruptible load expands the range of resources available to meet contingencies, lowers customer costs, and can even be used to mitigate price volatility and curb potential market power problems. In addition, interruptible load can create environmental benefits when used to displace fossil generation during peak periods—thereby reducing greenhouse gas emissions.

Interruptible load can also be used in wholesale markets to reduce prices and price volatility. For example, market-clearing prices fell by \$100-\$200/MWh on a peak day in August 2006 in the Midwest ISO when interruptible load was used in response to a call for demand reductions.[14] Various states—including Ohio—have also initiated efforts to increase and expand demand-response programs. Furthermore, properly designed interruptible programs can be an integral part of efforts by Ohio utilities to meet peak demand reduction targets established by SB 221.

Q. DOES THE MIDWEST ISO CURRENTLY OFFER TESTED AND ROBUST DEMAND-RESPONSE PROGRAMS?

A. No. The Midwest ISO's demand-response programs are neither well-developed nor robust. For example, the Midwest ISO has no formal capacity market and its ancillary services market—in which interruptible loads may play an important role in providing operating reserves—is not scheduled to start until later this year.

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[14] Federal Energy Regulatory Commission Staff Report, *2007 Assessment of Demand Response and Advanced Metering* at 6-7 (September 2007).

Q. EVEN IF ROBUST INTERRUPTIBLE PROGRAMS WERE AVAILABLE IN MISO, SHOULD THE COMMISSION RELY EXCLUSIVELY ON SUCH PROGRAMS?

A. No. The Commission cannot and should not rely on the Midwest ISO to fulfill the need for effective and robust demand-response programs. Retail interruptible programs regulated by the Commission can be important in meeting legislated targets for peak load reductions. In addition, states should not defer to regional transmission organizations the exclusive role for developing and implementing interruptible and other demand response programs that can address local capacity and reliability problems. This position is supported by a recent national study that cited the need for retail demand-response programs to compete with and potentially displace supply-side peaking resources.[15]

Q. SHOULD INTERRUPTIBLE RATES BE PART OF THE ESP RATE OPTIONS?

A. Yes. Interruptible rates are critical to meet the broad demand response policy objectives outlined in SB 221, as well as the specific peak demand reduction targets for utilities under Section 4928.66(A)(1)(b) of the Revised Code. To promote these policy objectives and targets, the Commission should ensure that FirstEnergy's ESP rates include at least two stand-alone interruptible rate options:

- Emergency or reliability option under which a customer is required to interrupt or curtail load during a system emergency when service reliability to firm customers is endangered.
- Economic interruption option under which a customer can elect either to interrupt load, or not interrupt and pay market

[15] Nicole Hopper, Charles Goldman, Ranjit Bharvirkar and Dan Engel, Lawrence Berkeley National Laboratory, *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response* at 11 (May 2007).

prices for the nonfirm load that remains on-line during the hours of a called economic interruption.

Customers should be allowed to take service under either or both of these interruptible rate options.

Q. DOES THE ESP INCLUDE SUCH INTERRUPTIBLE RATES?

A. Yes. However, the emergency and economic interruption options are not offered as stand-alone choices for current and new interruptible customers. FirstEnergy's proposed interruptible rate options are:

- Rider OLR (Optional Load Response Rider), which is available to new and existing customers that agree to interrupt load during an Emergency Curtailment Event.
- Rider ELR (Economic Load Response Program Rider), which is available to existing interruptible customers and requires both emergency and economic interruptions with a buy-option. During an Economic Buy Through (EBT) Option Event, a customer may continue to purchase energy at a price that reflects the adjusted day-ahead MISO LMP.[16]

The proposed monthly credit for both interruptible rates is $1.95 per kW-month of predetermined Realizable Curtailable Load (RCL).

Q. HAVE YOU IDENTIFIED NECESSARY IMPROVEMENTS TO THE PROPOSED ESP INTERRUPTIBLE RATES?

A. Yes. Several adjustments would significantly improve the interruptible rate options in the ESP. In particular, I recommend:

[16] Rider ELR lists existing interruptible rates whose customers are eligible for service under Rider ELR. This list omits the General Service Interruptible Electric Arc Furnace Rate (Original Sheet No. 29), which should be added to the list of eligible rates. In addition, FirstEnergy's proposed Rider EDR also improperly omits Rate 29 from the applicability section of its interruptible credit provision. FirstEnergy has agreed with this correction. (*See* Exhibit DWG-1, FirstEnergy's response to Nucor 1-19.) This omission should be corrected in the Commission-approved version of Rider EDR.

- Modifying Riders ELR and OLR to include stand-alone emergency (mandatory) and economic (voluntary) interruption options. That is, a customer served under Rider ELR or Rider OLR would be required to interrupt only during a called emergency interruption, and could voluntarily opt to be subject to economic interruptions in exchange for an additional credit.
- Changing the definition of RCL in Riders ELR and OLR to reflect the difference between a customer's monthly peak demand and contract firm load.
- Setting the emergency interruptible credit in Riders ELR and OLR at $7.50 per kW-month.
- Setting the economic interruption credit in Riders ELR and OLR at $2.60 per kW-month.
- Limiting economic interruptions under Riders ELR and OLR to no more than 250 hours annually.

I will discuss each recommendation in more detail.

Q. WHY SHOULD EMERGENCY AND ECONOMIC BUY-THROUGH BE STAND-ALONE OPTIONS IN RIDERS ELR AND OLR?

A. The two options should be stand-alone because they represent separately identifiable products that have different purposes and underlying values. Emergency (or capacity) interruptions allow a supplier to avoid capacity costs, and are used to maintain system reliability for firm customers. In contrast, economic interruptions are typically used to displace high-cost—but available—energy, assuming a customer chooses to interrupt instead of buying through the interruptions at above-average prices. As I discuss later, because load interruptions for emergency and economic conditions create different value streams for suppliers, they should be sold as separate, stand-alone products. There is no inherent economic or engineering justification for requiring the products to be sold on a bundled basis.

By offering the emergency and economic buy-through options as separate programs, customers can determine whether they are interested in and want to participate in either or both programs. For example, some customers may have loads suited for short-notice emergency interruptions, while others may have loads more suitable for responding to economic interruptions. In either case, my recommended improvements are likely to increase customer acceptance of and participation in both rate programs.

Q. HOW IS A CUSTOMER'S RCL DEFINED IN RIDERS ELR AND OLR?

A. FirstEnergy defines RCL, which is calculated annually, as the difference between an interruptible customer's contract firm load and average hourly demand (AHD) during the hours of 12 noon to 6:00 p.m. EDT in the preceding months June-August.[17]

Q. SHOULD A CUSTOMER'S MONTHLY INTERRUPTIBLE CREDIT BE BASED ON THE RCL AS DEFINED IN THE ESP?

A. No. A customer's RCL should reflect the difference between the customer's *monthly* peak demand—not historical average demand—and contract firm load. This approach is consistent with:

- Requiring an interruptible customer served under Rider OLR and/or Rider ELR to reduce ***actual*** (not average) demand down to contract firm load during a called emergency event.
- Setting buy-through charges under Rider ELR to reflect the difference between ***actual*** (not average) load and contract firm load during each hour of the buy-through event.

[17] The measurement period excludes holidays and hours of emergency and economic interruptions.

In addition, FirstEnergy's definition of RCL ignores its responsibility to serve customer peak demands whenever they occur—not arbitrarily defined average demands that understate the firm capacity and energy requirements that FirstEnergy avoids with interruptible load. FirstEnergy's definition mistakenly assumes that it achieves these avoided cost savings only when interruptible load—maximum demand less firm demand—is on-line and available for interruption. Because of its obligation to serve maximum firm customer demands whenever they occur, FirstEnergy realizes these savings even if interruptible load is not on-line during all hours of its RCL-defined summer peak period. As a result, the monthly credit paid to an interruptible customer should reflect the difference between the customer's monthly peak demand—not historical average demand—and contract firm load.

Q. WILL CUSTOMERS BE ENCOURAGED TO USE ELECTRICITY MORE INTENSIVELY DURING SUMMER PEAK HOURS IF THE RCL IS BASED ON AVERAGE DEMAND IN SELECTED SUMMER PEAK HOURS?

A. Yes. Defining the RCL as FirstEnergy proposes sends an improper price signal to interruptible customers by encouraging them to use more electricity during high-cost summer peak hours. Basing RCL on average demands encourages Rider ELR and OLR customers to use electricity more intensively during summer peak hours to increase their average demands—thereby effectively increasing the level of interruptible credits they receive. Since FirstEnergy will not be acquiring capacity to serve these customers because they must interrupt during emergency conditions,[18] the definition of RCL should not encourage them to shift energy use to super-peak hours in the summer.

[18] *See* FirstEnergy Reply Comments, Case No. 07-796-EL-ATA, at 50 (October 12, 2007). This excerpt from the Reply Comments is presented in Exhibit DWG-4.

Q. HAVE THE OPERATING COMPANIES PROPOSED CONSISTENT DEMAND MEASURES FOR THE RCL AND TRANSMISSION BILLING DEMAND?

A. No. Transmission costs—including ancillary and congestion costs—will be recovered through Rider TAS from demand-metered customers on the basis of billing demands—that is, each customer's maximum noncoincident demand during each billing month. FirstEnergy suggests that it selected this approach to be consistent with the calculation of distribution billing demands. (*See* Exhibit DWG-1, Nucor 1-22.e.) Consistency also demands that payments for transmission services and credits for interruptible loads be based on the same measure—customer peak billing demands.

Q. SHOULD THE INTERRUPTIBLE PROGRAM CREDIT BE HIGHER THAN $1.95 PER KW?

A. Yes. Several factors indicate that the credits proposed in FirstEnergy's ESP interruptible rates should be much higher. Moreover, there is no fundamental economic reason why the emergency and economic interruption credits should be the same.

Q. WHAT SHOULD BE THE BASIS FOR THE EMERGENCY INTERRUPTIBLE CREDIT?

A. With respect to the emergency program, the credit should generally reflect the long-run marginal cost of peaking capacity (including reserves and adjusted for losses) and incremental transmission capacity costs that can be avoided because of the interruptible load. FirstEnergy's proposed ESP credit of $1.95 per kW—which is not supported by any detailed analysis—

conservatively implies a peaking capacity cost around $150 per kW.[19] This estimate is well below the current cost of new peaking capacity, which has risen substantially in recent years.[20] In addition, the ESP credit is less than the $2.40-$3.40 per kW range for emergency curtailment credits that FirstEnergy identified in 2007,[21] and also well below the Department of Energy's recent avoided cost estimate of more than $6 per kW for peaking capacity.[22]

Q. WHAT DO YOU RECOMMEND?

A. I recommend setting the emergency interruptible credit using the Department of Energy's recent avoided cost estimate of $75 per kW-year. This estimate reflects an independent assessment of the long-run avoided cost of peaking capacity. Conservatively adjusting this estimate to reflect avoided reserve capacity and losses indicates that the emergency

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[19] This estimate assumes an annual cost of $23.40 per kW (12 x $1.95) divided by an assumed carrying charge of 15 percent. Avoided reserve, transmission, and energy (including losses) costs are not included in this estimate.

[20] *See*, for example, Marc W. Chupka and Gregory Basheda, *Rising Utility Construction Costs: Sources and Impacts*, (2006). This report by the Brattle Group noted that:

> Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years. (report at 7)
>
> Over the period of 2000 to 2006,...the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006. (report at 8)

[21] *See* Exhibit DWG-4.

[22] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* at 74 (2006). The DOE report states:

interruptible credit should be set around $91 per kW-year—or $7.50 per kW-month.[23]

I consider the DOE estimate conservative for two reasons. First, as I noted earlier, the cost of new peaking generation has increased substantially in recent years. (The DOE report relies on a 2004 estimate) Second, despite potential transmission benefits, the DOE estimate does not include any avoided cost of transmission.

Q. SHOULD SHORT RUN MARKET PRICES FOR CAPACITY BE USED TO SET INTERRUPTIBLE CREDITS?

A. No. As noted earlier, long run avoided costs are the appropriate measure on which to base interruptible credits. Short run market prices fluctuate to reflect current market conditions for existing generating capacity, while long-run avoided costs reflect the cost of adding new capacity to meet demand growth. Basing interruptible credits on short-run market prices is similar to relying solely on the spot market to meet future energy needs—both approaches increase customer risks via unstable and unpredictable prices. Relying on spot markets is wonderful as long as excess supply exists and prices are low. However, when generation supply becomes scarce, short-run market prices can far exceed the cost of new capacity that cannot be added for several years. Large interruptible customers need and want price (that is, credit) stability and predictability in exchange for

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Demand response programs designed to reduce capacity needs are valued according to the marginal cost of capacity. By convention, marginal capacity is assumed to be a "peaking unit," a generator specifically added to run in relatively few hours per year to meet peak system demand. Currently, peaking units are typically natural gas turbines with annualized capital costs on the order of $75/kilowatt-year (kW-year). [$75/12 = $6.25 per kW-month]

[23] ($75 * 1.15)/0.95 = $90.79 per kW-year ($7.57 per kW-month). This calculation assumes that interruptible load avoids not only capacity needed to serve the load, but also capacity needed to provide a 15-percent reserve margin and losses of 5 percent. (This value ignores any avoided transmission and incremental fuel cost savings.) I have included adjustments for reserves and losses to reflect capacity requirements to serve end-use customers. Since these requirements can

making the capital and operating cost commitments necessary to participate in an interruptible program. Basing interruptible credits on short-run market prices of generating capacity is definitely not the way to provide that needed price stability and predictability.

Q. WHAT VALUE IS IMPLIED BY THE OPERATING COMPANIES' PROPOSED ESP ECONOMIC INTERRUPTION CREDIT?

A. The implied value of economic interruptions in Rider ELR is zero. Recall that both Rider ELR and OLR require mandatory emergency interruptions with a $1.95 per kW-month credit. Rider ELR contains no additional credit for economic interruptions—thereby implying that FirstEnergy places no value on such interruptions. (If the Commission agrees and finds that economic interruptions provide no value, they should be removed from Riders ELR and OLR.)

Q. IS THIS RESULT CONSISTENT WITH THE COMPANIES' PAST STATEMENTS REGARDING ECONOMIC INTERRUPTIONS?

A. No. In late 2007, FirstEnergy indicated that the value of the economic interruption credit should reflect market prices (LMPs), with the credit netting to zero if a customer bought through all economic interruptions. On the basis of this position, FirstEnergy indicated that the economic interruption credit should range between $1.60-$2.60 per kW.[24]

Q. WHAT SHOULD BE THE BASIS FOR THE ECONOMIC INTERRUPTIBLE CREDIT?

A. With respect to the economic interruption program, this credit should, at a minimum, reflect the expected avoided cost of energy displaced by interruptible load (for example, day-ahead MISO LMPs). This value

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be avoided by interruptible load, the credit for interruptions should include the relevant capacity cost savings—including savings offsets for reserves and losses.

[24] *See* Exhibit DWG-4. .

should be converted to a per kW credit and applied to the customer's RCL. Because of time constraints, I have chosen to rely on FirstEnergy's 2007 estimates of the value of economic interruptions. Therefore, I recommend setting the economic interruption credit in Riders ELR and OLR at $2.60 per kW-month—the upper end of FirstEnergy's estimated $1.60-$2.60 per kW range in 2007. In my opinion, this is a conservative estimate given the dramatic rise in fuel prices and LMPs in 2008.

Q. DOES THE PROPOSED RIDER ELR HAVE ANY LIMITS ON THE HOURS OF ECONOMIC INTERRUPTIONS?

A. No. Under Rider ELR, FirstEnergy can call an economic interruption during any 3-hour Market Premium Condition—that is, whenever the MISO LMP exceeds the applicable kWh net charges in Riders GEN and GPI. This definition implies that the potential hours of economic interruptions cannot be determined with certainty, thereby exposing interruptible customers to little or no financial benefit under the economic buy-through program.

Q. WILL THIS UNCERTAIN INTERRUPTION EXPOSURE DISCOURAGE CUSTOMERS FROM CHOOSING THE ECONOMIC INTERRUPTION OPTION?

A. Yes. Exposing customers to an indeterminate number of economic interruptions severely limits their ability to control power costs and increases their risk of unanticipated electricity cost fluctuations each year.

Q. SHOULD THE HOURS OF ECONOMIC INTERRUPTIONS BE LIMITED?

A. Yes. The hours should be limited to those that correspond to the highest cost hours in MISO. I recommend limiting economic interruptions under Rider ELR to 250 hours annually. From January through August 2008, day-ahead LMPs in MISO for the FirstEnergy hub exceeded $120 per MWh in 238 hours. (See Table 3 below.) If economic interruptions were limited to 250 hours annually, my analysis indicates that FirstEnergy would be able to call economic interruptions to reduce consumption during many of the highest cost hours in MISO while still encouraging customers to choose the economic interruption option in Rider ELR.

Table 3. MISO Day-Ahead LMPs - 2008 YTD

	Applicable Hours	
LMP	>= Target LMP	Avg LMP
$100	472	$127
$110	329	$137
$120	238	$145
$130	181	$151
$140	132	$157
$150	81	$165

Q. COULD THE LIMIT BE SET AT A DIFFERENT LEVEL?

A. Yes. However, some reasonable limit is necessary. Additional analyses are required to identify the likely number of 3-hour Market Premium Conditions, estimate the cost differential between the LMPs and a customer's net generation costs, and determine the likely number of interruptions at which total buy-through costs match expected economic interruption credits. FirstEnergy has not provided such analyses in its ESP. Absent further analyses, I recommend a 250-hour limit.

Q. HAVE YOU PREPARED TEMPLATES THAT INCLUDE THE PROPOSED INTERRUPTIBLE RATE MODIFICATIONS YOU HAVE RECOMMENDED?

A. Yes. Exhibit DWG-5 is a template for Rider ELR that incorporates my recommended changes, while Exhibit DWG-6 includes my recommended changes for Rider OLR.

TIME-OF-USE RATES

Q. DO THE ESP RATES ALSO INCLUDE TIME-OF-DAY OPTIONS?

A. Yes. As I noted earlier, FirstEnergy's ESP generation rates reflect both seasonal and time-of-day price differentials. FirstEnergy has also proposed an experimental dynamic peak pricing rate for residential customers. Time-differentiated rates that reflect diurnal cost variations provide better price signals to which customers can respond. Without time-of-day pricing, consumers see uniform prices each hour despite the fact that the cost of electricity varies significantly by time of day. Non-time-differentiated price signals lead to inefficient investment and consumption decisions regarding electricity. In addition to promoting efficient investment and consumption decisions, time-of-day rates would significantly enhance the demand-response elements of FirstEnergy's ESP rates.

Q. HOW WERE THE TIME-OF-USE PRICE DIFFERENTIALS SET?

A. As I noted earlier, FirstEnergy used a weighting scheme that reflects the ratio of the average LMP for a particular period in 2006-2007 (for example, summer on-peak hours) to the average LMP for those 2 years.[25]

[25] *See* the direct testimony of FirstEnergy witness Kevin Warvell at 9:18-10:8 and Schedule 5a at 7.

Q. SHOULD THE PROPOSED TOU RATES BE IMPROVED?

A. Yes. I recommend modifying the proposed 16-hour summer weekday peak period to include two separate pricing periods—for example, peak and shoulder pricing periods. Under FirstEnergy's ESP, the summer and winter daily peak periods are identical: 16 hours, Monday – Friday, 6:00 a.m. – 10:00 p.m., excluding holidays. The breadth of these peak periods significantly restricts customers' flexibility in shifting electricity use to lower-cost hours—particularly in summer months. FirstEnergy provides no empirical justification for selecting a 16-hour daily peak period. I recommend, at a minimum, requiring FirstEnergy to split the proposed 16-hour summer daily peak into two periods based on an analysis of hourly LMPs in MISO.[26] Rate differentials for these two new pricing periods should be set using the same general approach that FirstEnergy used in setting the differentials in all of its TOD rates.

OTHER ISSUES

Q. DO YOU HAVE COMMENTS REGARDING OTHER ELEMENTS OF THE ESP?

A. Yes. I have comments regarding the calculation of billing demand in the ESP rates and FirstEnergy's proposed Rider MDS. In particular, I recommend that the Commission reject FirstEnergy's proposed:

- Billing demand provisions for transmission (Rate GT) customers. Monthly billing demand for such customers should reflect the higher of a customer's maximum 60-minute demand during system peak hours as determined by the Commission, or the Contract Demand as specified in FirstEnergy's proposed ESP rates.

[26] In FirstEnergy's proposed experimental dynamic peak pricing program for residential customers, the summer peak period is 11:00 a.m. – 5:00 p.m., Monday – Friday, excluding holidays. All other summer hours are off-peak.

- Rider MDS. This rider is not cost-based and will hinder the development of competitive markets for retail generation services.

Q. HOW IS BILLING DEMAND CALCULATED IN THE ESP RATES FOR TRANSMISSION CUSTOMERS?

A. FirstEnergy has proposed calculating monthly billing demand in Rate GT as the greater of 100 kVA, the customer's highest 30-minute demand (kVA), or contract demand (equal to 60 percent of a customer's expected, typical monthly peak load).

Q. DO YOU AGREE WITH THE PROPOSED BILLING DEMAND PROVISIONS?

A. No. I recommend determining billing demands for transmission customers on the basis of 60-minute integrated demands instead of 30-minute demands as FirstEnergy proposes. FirstEnergy's 30-minute measurement period differs from the 60-minute measurement period used by the Midwest ISO and other wholesale markets. This creates a load-management problem for customers—particularly certain manufacturers—buying competitive generation service as they try to manage loads on both a 60-minute and 30-minute basis during the same 60-minute period. For example, under a situation with different demand-measurement periods for generation and distribution services, it would be possible during any 60-minute period for an Ohio Edison Rate GT customer's loss-adjusted distribution service demand to exceed the customer's generation demand. Such a situation adds nothing but unnecessary complexity for manufacturers served at high voltages as they try to manage loads during production cycles.

Q. WHAT IS RIDER MDS?

A. Rider MDS is a $0.01 per kWh non-bypassable charge that applies to shopping customers served by an alternative supplier.[27] The charge is allegedly designed to recover generation-related administrative and hedging costs for SSO service.

Q. SHOULD RIDER MDS BE APPROVED?

A. No. FirstEnergy has not adequately explained the basis for the proposed charge, much less demonstrated that it is necessary and cost-based. (*See* Exhibit DWG-1, Nucor 1-8.) As a result, it should not be approved. Any non-cost-based, non-bypassable charge—especially one as large as Rider MDS—will hinder the development of competitive markets for retail generation services by putting alternative suppliers at a significant competitive disadvantage.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING NON-BYPASSABLE CHARGES?

A. Yes. I recommend that the Commission carefully scrutinize all of FirstEnergy's proposed non-bypassable charges and eliminate any that are not directly attributable to costs caused by shopping customers. Shopping customers should only be required to pay those costs that are reasonably attributable to them.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

[27] FirstEnergy asserts that the $0.01 per kWh charge is also embedded in Rider GEN. *See* the direct testimony of FirstEnergy witness Kevin T. Warvell at 10:16 – 12:4.

STATE OF OHIO
BEFORE THE
PUBLIC UTILITIES COMMISSION

CASE NO. 08-935-EL-SSO

IN THE MATTER OF THE APPLICATION OF
OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY FOR AUTHORITY TO ESTABLISH A STANDARD SERVICE OFFER PURSUANT TO SECTION 4928.143, REVISED CODE, IN THE FORM OF AN ELECTRIC SECURITY PLAN

EXHIBITS TO THE
DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF NUCOR STEEL MARION, INC.

September 29, 2009

EXHIBIT DWG-1

FIRSTENERGY'S RESPONSES TO SELECTED NUCOR DISCOVERY REQUESTS

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the *Form of an* Electric Security Plan.

RESPONSES TO REQUEST

Nucor Set 1-4 Refer to page 9, lines 6-1 3 of Mr. Blank's testimony:

(a) Why do the Companies propose to spend up to $5 million annually, and not some different amount, from 2009 through 2013 for energy efficiency and demand side management activities?

(b) Explain in detail what energy efficiency and demand side management activities the Companies intend to fund with these amounts.

(c) Why do the Companies propose to spend up to $5 million annually, and not some different amount, from 2009 through 2013 for economic development and job retention?

(d) Explain in detail what economic development and job retention programs and activities the Companies intend to fund with these amounts.

(e) Are the Companies actually committing to spend $5 million each year on each of the above activities, or some amount between zero and $5 million?

(f) Explain in detail how the Companies propose for the Commission to oversee these expenditures.

(g) Identify and provide all documents that refer or relate to the energy efficiency and demand-side management funding proposal and the Companies' decision to offer it.

(h) Identify and provide all documents that refer or relate to the economic *development and job retention* funding proposal and the Companies' decision to offer it.

Response: (a) The annual commitment of up to $5 million from 2009 through 2013 represents the amount that the Companies propose to spend without recovery on energy efficiency and demand side management activities as part of the comprehensive ESP package. The amount is based on management judgment and is provided to recognize and advance the *long-term* policies of Am. Sub. SB 221.

(b) The Companies have not determined how the energy efficiency and demand side management funds will be used.

(c) The annual commitment of up to $5 million from 2009 through 2013 represents the amount that the Companies propose to spend without recovery on economic development and job retention as part of the comprehensive ESP package. The amount is based on management judgment and is provided to recognize and advance the long-term policies of

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

Am. Sub. SB 221.

(d) The Companies have not determined how the economic development and job retention funds will be used.

(e) The Companies agree to spend up to *$5 million annually for energy efficiency and* demand side management activities and up to $5 million annually for economic development and job retention for the years 2009 through 2013.

(f) There is no proposal in the ESP regarding Commission oversight of these expenditures.

(g) No such documents exist.

(h) No such documents exist.

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

Nucor Set 1-6 Referring to proposed Rider GEN:

(a) In providing generation service, will the Companies or their affiliates be providing reliable generation capacity to meet retail customer demands?

(b) Explain the answer to (a) above in detail.

(c) If the answer to (a) above is yes: (i) identify the generation units that will be used to provide generation capacity; and (ii) provide an estimate of the cost of generating capacity (both on a per kW and total basis).

(d) Provide workpapers and all other analyses and documents showing the derivation of the answer to part (c) above.

(e) Identify and provide all documents that show that generation capacity will be provided under Rider GEN in order to ensure reliable service to the Companies' retail customers.

Response:

a) Yes.
b) ***The Companies or their affiliates will need to meet the MISO long-term Adequacy Requirements: NOTE: This response is based upon Midwest ISO filings with the Federal Energy Regulatory Commission ("FERC") on December 27, 2007, and June 25, 2008 in docket ER08-394, as amended by subsequent filings to comply with FERC orders.*** The Midwest ISO proposes to implement long-term Resource Adequacy Requirements ("RAR") effective with an initial capacity planning year beginning June 1, 2009. Under that proposal, the RAR that will be applicable to load-serving entities ("LSEs") in the Midwest ISO, including the Ohio Operating Companies, will be determined by the Midwest ISO annually via a technical analysis considering factors including, but not limited to, Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources, LSEs' forecasted Demand uncertainty, system operating reserve requirements, transmission congestion, external firm capacity sales and available transmission import capability. The planning reserve margin for each LSE will then be determined based upon the probabilistic analysis of being able to reliably serve each LSE's demand for each month of the capacity resource planning year

Under the Midwest ISO proposal, an LSE will conform with RAR in accordance with Module E of the Midwest ISO TEMT by demonstrating to the Midwest ISO that it has sufficient generation capacity resources to meet its forecasted demand for the applicable planning period, plus the planning reserve margin established either by the Midwest ISO or by the state having jurisdiction over the LSE.

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

The applicable section in proposed revisions to Module E of the Midwest ISO tariff, section 69.3.7.a, states:

> "...The LSE's Financial Settlement Charge for a given month shall be the product of the number of MW-months that an LSE is capacity deficient pursuant to Section 69.3.6c for such month and CONE value."

Section 69.3.8.a. sets the Cost of New Entry ("CONE") value at

> "...$80,000 per MW-month for the initial Planning Year, subject to modification by the Transmission Provider and the IMM (Independent Market Monitor)."

c) (i) The attached file Nucor DR-06 Attachment 1.xls, lists the capacity commitments of the existing assets that would be committed under the plan. As noted, at this time there is no net demonstrated capability value. All of the MW's associated with the listed units and purchases, as well as the capacity listed in Attachment D (when completed), are committed to the operating companies' retail load obligation. The operating companies will not have other commitments for wholesale sales or CRES sales.; (ii) If Nucor is requesting the cost of procuring generation capacity on an annual basis then please refer to the response to Nucor 1-10.

d) Please see response to Nucor 1-10.

e) Please see b) above.

Case No. 08-935-EL-SSO
Nucor DR 6 Attachment 1

Module E Filing				Unit NDC		
Plant Name	July	August		Plant Name	July	August
Sumpter	85	85		Sumpter	85	85
Sumpter	85	85		Sumpter	85	85
Sumpter	85	85		Sumpter	85	85
Sumpter	85	85		Sumpter	85	85
Astabula	244	244		Astabula	244	244
Bayshore1	136	136		Bayshore1	136	136
Bayshore2	138	138		Bayshore2	138	138
Bayshore3	142	142		Bayshore3	142	142
Bayshore4	215	215		Bayshore4	215	215
Burger 3	94	94		Burger 3	94	94
MadRiver	25	25		MadRiver	30	30
MadRiver	0	0		MadRiver	0	0
MadRiver	25	25		MadRiver	30	30
MadRiver	0	0		MadRiver	0	0
Davis Besse	879	879		Davis Besse	893	893
Eastlake1	132	132		Eastlake1	132	132
Eastlake2	132	132		Eastlake2	132	132
Eastlake3	132	132		Eastlake3	132	132
Eastlake4	240	240		Eastlake4	240	240
Eastlake5	597	597		Eastlake5	597	597
Eastlake6	24	24		Eastlake6	29	29
Edgewater2	19	19		Edgewater2	24	24
Edgewater3	19	19		Edgewater3	24	24
Lakeshore1	245	245		Lakeshore1	245	245
Mansfield1	830	830		Mansfield1	830	830
Mansfield2	830	830		Mansfield2	830	830
Mansfield3	830	830		Mansfield3	830	830
Perry1	1246	1245		Perry1	1269	1269
Sammis ED	13	13		Sammis ED	13	13
Sammis 1	180	180		Sammis 1	180	180
Sammis 2	180	180		Sammis 2	180	180
Sammis 3	180	180		Sammis 3	180	180
Sammis 4	180	180		Sammis 4	180	180
Sammis 5	300	300		Sammis 5	300	300
Sammis 6	600	600		Sammis 6	600	600
Sammis 7	600	600		Sammis 7	600	600
Stryker	17	17		Stryker	18	18
BayshoreCT	16	16		BayshoreCT	17	17
BayshoreCT	0	0		BayshoreCT	0	0
West Lorain	49.5	49.5		West Lorain	50	50
West Lorain	7.5	7.5		West Lorain	10	10
West Lorain	49.5	49.5		West Lorain	50	50
West Lorain	7.5	7.5		West Lorain	10	10
West Lorain	85	85		West Lorain	85	85
West Lorain	85	85		West Lorain	85	85
West Lorain	85	85		West Lorain	85	85
West Lorain	85	85		West Lorain	85	85
West Lorain	37	37		West Lorain	85	85
Lakeshore CT	4	4		Lakeshore CT	4	4
Burger CT	6.3	6.3		Burger CT	6	6
Burger CT	0.7	0.7		Burger CT	1	1
Burger4	156	156		Burger4	156	156
Burger5	156	156		Burger5	156	156
Richland1	11	11		Richland1	14	14
Richland2	11	11		Richland2	14	14
Richland3	11	11		Richland3	14	14
Richland4	112	112		Richland4	130	130
Richland5	112	112		Richland5	130	130
Richland6	112	112		Richland6	130	130
OVEC	461	461		OVEC	461	461
	11,424	11,423			11,605	11,605

* Module E filed capacity reflects summer derates

** Effective June 1, 2009 capacity will no longer be represented as installed capacity but rather will reflect Unforced capacity values
- MISO analysis is still on-going regarding final decision to use a 3 year average for eFOR or a 1 year average.

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Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

Nucor Set 1-7 Referring to proposed Rider GEN:

(a) Do the proposed generation charges include capacity costs?

(b) Explain the answer to part (a) in detail.

(c) If the answer to part (a) is yes, provide a quantification of the capacity costs included in the proposed generation charges (on both a per kW and per kwh basis). Identify and provide any workpapers and related documents showing how the quantification was developed.

(d) In calculating the proposed generation charges, did the Companies use class allocation factors reflecting the different peak demands and load factors of the various customer classes?

(e) If the answer to part (d) is no, explain in detail why not.

(f) In calculating the proposed generation charges, did the Companies use class allocation factors reflecting the same factors (e.g., the ratio of the class historical average generation and transmission rates to the system) proposed in the Companies' slice of system competitive bid process rate template proposed last year?

(g) If the answer to part (f) is no, explain in detail why not.

(h) Explain in detail the Companies' view as to how to best address the differences in class demand and usage characteristics in establishing generation rates for the Companies' retail service.

(i) Did the Companies consider incorporating more seasonalltime differentiation into the proposed generation rates, such as critical peak period pricing?

(j) Explain the answer to part (h) in detail, including the reasons for such decision.

(k) If a critical peak period pricing component were to be included in the Companies' proposed rates, explain in detail how the Companies would propose that it be designed.

(l) Identify and explain in detail all differences between the method used by the Companies in developing proposed Rider GEN in this case and the method the Companies proposed last year to convert the Blended Competitive Bid Price into a retail rate under the slice of system competitive bid proposal. In particular, explain in detail why a

Case No. 08-935-EL-SSO
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different method is being proposed in this case.

Response:

a) Yes.
b) A detailed response to this question can be found in the testimony of Kevin Warvell.
c) There is no quantification of the generation capacity costs that is included in generation charges. There is a market value of Designated Network Resources, which is referred to in response to Nucor 1-10.
d) No.
e) Costs are a function of market energy prices. The proposed base generation rates for the ESP are energy prices which are differentiated on a voltage and seasonal basis. Also, the Companies have proposed an optional time of use energy rate.
f) No.
g) See response to (e) above.
h) The Companies used rates differentiated by voltage and seasonal factors as well as optional time-of-use rates.
i) The Companies have proposed a critical peak pricing pilot for residential customers.
j) Please see response to (h) immediately above.
k) Based upon historical day ahead LMP for the FirstEnergy load zone.
l) Comparisons of and differences between the Companies' current proposal and that which was proposed in Case No. 07-796-EL-ATA are irrelevant to this proceeding.

Nucor Set 1
Witness: Warvell

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

Nucor Set 1-8 Referring to the 1 cent / kWh minimum default service charge contained in proposed Rider GEN and Rider MDS:

(a) Explain how this charge was derived.

(b) Provide all workpapers and calculations used to derive the proposed charge.

(c) Identify and provide all other documents that refer or relate to this charge.

Response:

a) The 1.0 cent per kWh non-bypassable Minimum Default Service Charge addresses the risks involved in hedging 60 million MWh of POLR load and is neither cost-based nor the result of an analytic study.
b) There are no workpapers or calculations used to derive the minimum default service charge contained in proposed Rider GEN and Rider MDS.
c) Please see the Companies filing for all documents that refer or relate to the minimum default service charge contained in proposed Rider GEN and Rider MDS.

Nucor Set 1
Witness: Hussing

Case No. 08-935-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 In the Form of an Electric Security Plan.

RESPONSES TO REQUEST

Nucor Set 1-9 Explain in detail why customers that avoid DSEI or DSE2 charges pursuant to Rider DSE are precluded from taking service under Rider RAR.

Response: Customers that avoid DSE1 or DSE2 charges pursuant to Rider DSE are precluded from taking service under Rider RAR pursuant to proposed Ohio Administrative Code rules. Chapter 4901:1-38 of proposed Ohio Administrative Code rules, Case No. 08-777-EL-ORD, governs customer options provided by both riders RAR and DSE. Section 4901:1-38-07 (D) of these proposed rules states the following: "No customer shall be provided incentives from more than one schedule or arrangement approved by the commission pursuant to this chapter." Thus a customer can take service under the RAR or avoid the charges per the terms of the DSE rider, but cannot receive the benefit from both.

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RESPONSES TO REQUEST

Nucor Set 1-10 Refer to page 22, lines 15-17 of Mr. Warvell's testimony. Regarding the $64lMW/day price utilized to calculate the $1.95/kw/ month curtailable credit:

(a) What is the basis for the $64/MW/day price?

(b) Does this $64/MW/day price represent short run or long run avoided capacity costs? Explain the answer in detail.

(c) Has this $64/MW/day price been adjusted for or reflect avoided losses, planning reserve margins, etc.? Explain the answer in detail.

(d) Explain in detail how the credits in the Companies' existing interruptible rates were developed.

(e) Did the Companies consider any other ways to value capacity aside from the market value of MISO designated network resources?

(f) Is capacity only sold on a "bilateral" basis in MISO?

(g) If the answer to part (f) is no, describe in detail by type of capacity transaction how capacity is sold in MISO.

(h) Identify and provide all workpapers, studies, reports and analyses (including all Excel workbooks and worksheets with all links and formulas intact) that underlie and/or support the $64/MW/day price and the $1.95/kw/month curtailable credit.

(i) Has the Company conducted or obtained any other analyses (formal or informal) of the value of interruptible load or curtailable load in the past 3 years?

(j) If the answer to part (i) is yes, indicate the person(s) or entity that conducted each study or analysis and describe each such analysis in detail, including the methodology and results.

(k) If the answer to part (i) is yes, identify and provide all studies, analyses, workpapers and related documents.

(l) Identify and provide all analyses of the avoided cost of capacity by or for the Companies in the past 3 years.

(m) Identify and provide all analyses of the avoided cost of energy by or for the Companies in the past 3 years.

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RESPONSES TO REQUEST

Response:

a) The $64/MW/day price reflects the estimated market price for DNR (Designated Network Resource) for calendar year 2009.
b) See response to a) above.
c) There are no Transmission losses to reflect in the DNR price, since MISO includes these losses in the LMP. Planning reserve margin has not been included in the price.
d) The interruptible credit for a 100% load factor customer in Ohio Edison's tariff sheet No. 73 was originally developed in the mid 1980's and was based upon the "up to" value for generation capacity in wholesale agreements. The interruptible credit for lower load factor customers in these tariffs was based upon a proration. Any other interruptible credits in other tariffs or contracts entered into by the Companies were a product of a bilateral negotiation between the specific Company and the customer.
e) No. The market is the only way to value DNR in a year where DNR is being bought and sold on a routine basis.
f) Yes.
g) N/A
h) Please see Schedule 5s of Volume 3 of the filing.
i) The Companies have not conducted or obtained any other analyses for the capacity value of interruptible load over the last three years.
j) N/A
k) N/A
l) The Companies have not performed any analyses of the avoided cost of capacity in the past 3 years..
m) The Companies have not performed any analyses of the avoided cost of energy in the past 3 years.

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<u>RESPONSES TO REQUEST</u>

Nucor Set 1
13 Referring to economic interruptions and economic buy-through programs in general:

a. Explain in detail why there are no economic interruption options offered for customers other than under proposed Rider ELR (which only applies to existing interruptible customers).

b. Explain in detail the benefits from economic interruption programs to the Companies and/or system and identify and provide all documents that refer or relate to these benefits.

c. Are the system benefits from economic interruption programs limited to existing interruptible customers or could benefits be derived from new customers agreeing to economic interruptions? Explain the answer in detail.

d. Are the system benefits from economic interruption programs limited to customers that also agree to emergency/reliability interruptions or could benefits be derived from customers agreeing to economic interruptions but not emergency/reliability interruptions? Explain the answer in detail.

e. What value (or credit) per kW would the Companies place on an economic interruption and buy-through program exclusive of any reliability or emergency interruption features? Explain in detail (including any workpapers) how to determine such value.

f. *Identify and provide all related documents.*

g. Identify the economic carrying charge the Companies use to evaluate the costs and benefits of interruptible load. Identify and provide all components of the carrying charge, and show its derivation in Excel format with all links and formulas intact.

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RESPONSES TO REQUEST

Response:

a) Rider ELR is available for customers currently on the Companies' existing interruptible tariffs or a special contract containing interruptible provisions and approved by the Commission before July 31, 2008. In addition, Rider OLR is designed with the same general terms and conditions as Rider ELR, but applies to emergency interruptions and is available to new participants as well as existing customers. Rider ELR is designed to be utilized with the interruptible credit provision of the Economic Development Rider (EDR). These customers are currently subject to Economic Buy Through Option Events and this concept is incorporated into Rider ELR. Rider OLR is designed for use with new interruptible customers/load as an interruptible credit that recognizes customers are only subject to interruption in an emergency curtailment event, and are not subject to Economic Buy Through Option Events or the interruptible credit provision of Rider EDR.
b) There are no benefits to the Companies or the transmission system from economic buy through opportunities presented to customers.
c) Please see b) immediately above.
d) Please see b) immediately above.
e) There is no value to the Companies for economic buy through opportunities.
f) Not applicable
g) Not applicable

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RESPONSES TO REQUEST

Nucor Set 1
14 Referring to economic interruption features of proposed Rider ELR:

a. Please confirm that once an Economic Buy Through Event (EBT) has been called, the EBT will end as of the beginning of the first hour that the MISO LMP no longer exceeds the otherwise applicable per kWh net charges set forth in Rider GEN and Rider GPI (i.e., the first hour when a Market Premium Condition no longer exists).

b. Provide an estimate (or range if a specific number is not available) and analysis of the likely number of hours EBTs are expected to be called per year under the plan.

c. Provide an estimate of the energy cost avoided per kW of demand as a result of EBTs.

d. Identify the specific per kWh price(s) that the MISO LMP has to exceed to create a Market Premium Condition.

e. Are the applicable MISO LMPs for determining the Market Premium Condition and the EBT prices the Day-Ahead LMPs?

f. Did the Companies consider or evaluate a possible limit on the number of hours subject to EBTs?

g. Explain the answer to part (f) in detail and identify and explain any options considered.

h. In the Companies' view, what would be a reasonable limit on the number of hours subject to EBTs?

Response:

a) The EBT will end as of the beginning of the first hour that the MISO LMP no longer exceeds the otherwise applicable per kWh net charges set forth in Rider GEN and Rider GPI.
b) An estimate and analysis of the likely number of hours EBTs are expected to be called per year cannot be provided.

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RESPONSES TO REQUEST

c) An estimate of the energy cost avoided per kW of demand as a result of EBTs cannot be provided.
d) In order to create a Market Premium Condition, the MISO LMP has to exceed the otherwise applicable per kilowatt-hour net charges set forth in the Company's Generation (Gen) and Generation Phase-In (GPI) riders. Note these prices vary by voltage level served and by season.
e) The MISO Day-Ahead LMPs for the FE load zone are the basis for determining a market Premium Condition.
f) No.
g) The Economic Buy Through Event is proposed to be the same as the existing tariffs where there is no limit to the number of hours subject to EBTs.
h) It is the Companies' view that there should be no limit on the number of hours subject to EBT. However, if there was to be one, the credit provided to these customers via Rider EDR should be lowered proportionately. In addition, the Companies note that there is no such limit on the number of hours a credit is applied to the customer's bill for being on the program.

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RESPONSES TO REQUEST

Nucor Set 1
15 Regarding the standby charges of 1.5 cents/kWh in 2009, 2.0 cents/kWh in 2010 and 2.5 cents/kWh in 2011 contained in proposed Rider PSR:

a. Explain in detail how these charges were derived.

b. Identify and provide all documents, workpapers, and calculations underlying the proposed charges. Include in your response all Excel workbooks and worksheets (with all links and formulas intact) used in the derivation and calculation of the standby charges

Response: The Companies did not perform an analytical study to develop the proposed standby charge of \$15/MWH in 2009, \$20/MWH in 2010 and \$25/MWH in 2011. The basis for the charge is an evaluation that if customers switch to an alternative supplier and desire to return to the Companies at the SSO base generation rate, the Companies need to make that reservation and plan for that eventuality in advance. Implementation of the standby charge is recognition that providing protection from market prices, and the volatility associated with market pricing, imposes a significant cost and risk on the Companies. This charge, which customers may choose to not pay, recognizes that cost and risk. For payment of the charge, the Companies offer to stand ready to serve retail customers, at any time, who have switched to an alternative supplier but then desire to return to retail generation service provided by the utility at a stabilized SSO base generation price for a fixed period of time.

Nucor Set 1
Witness: Warvell

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RESPONSES TO REQUEST

Nucor Set 1
16 Explain in detail the different types of risk the 1 cent/kWh minimum default service charge contained in proposed Rider GEN and Rider MDS and the standby charges contained in proposed Rider PSR are intended to mitigate.

Response: Please see the responses to Nucor 1-8 and Nucor 1-15 regarding the different types of risk the minimum default service charge and the standby charges are intended to mitigate.

Nucor Set 1
Witness: Warvell

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RESPONSES TO REQUEST

Nucor Set 1
17 If a customer that switches to an alternative supplier may:(i) elect to pay the standby charge under Rider MDS, then pay the base SSO generation price if it returns to the SSO, or (ii) elect not to pay the standby charge, but then pay the full market price for retail generation if it returns to the SSO, why is the 1 cent/kWh minimum default service charge contained in proposed Rider GEN and Rider MDS necessary?

Response: Rider MDS is applicable only to customers who shop and is non-bypassable. All retail customers are obligated to pay the minimum default service charge regardless of whether they are shopping (through payment of Rider MDS) or taking retail generation service from the Companies (where the minimum default service charge is a part of the base generation charge).

Nucor Set 1
Witness: Warvell

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RESPONSES TO REQUEST

Nucor Set 1
18 Explain in detail the purpose behind the restriction in proposed Rider ELR and Rider OLR that customers on these riders may not participate in any other load curtailment program, including DSM programs offered by MISO. Identify and provide all related documents that underlie and/or support the proposed restriction.

Response: Customers need to choose between the two options because it is not practical to administer two programs that seek similar results such as a tariff-based rider and a MISO program for the same customer. MISO currently offers a voluntary emergency demand response program. Since both Riders ELR and OLR require a customer to interrupt in an emergency, it would be "double counting" for a customer to participate/benefit from both the Companies' Rider and the MISO program. A customer does have the option of taking firm service from the Companies and then participating in a MISO program.

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RESPONSES TO REQUEST

Nucor Set 1
19 Regarding the Companies' statements that all existing interruptible customers (as of July 2008) will be entitled to service under Rider ELR:

a. Please confirm that interruptible customers currently on Rate 29 will be eligible for proposed Rider ELR and the Interruptible Credit Provision of proposed Rider EDR.

b. If the Companies cannot confirm the statement in part (a), explain in detail why Rate 29 customers are not eligible.

c. Would the Companies agree to modify proposed Rider ELR and Rider EDR to list Rate 29 as one of the applicable existing interruptible rates?

Response:

a. Rate 29 customers will be eligible for proposed Rider ELR and the Interruptible Credit Provision of proposed Rider EDR.

b. N/A

c. The Companies will modify the proposed Rider ELR and Rider EDR to list Rate 29 as one of the applicable existing interruptible rates

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RESPONSES TO REQUEST

Nucor Set 1
22 Regarding Rider TAS:

a. Explain in detail the allocation method utilized by the Companies to allocate transmission, ancillary services and related costs to customer classes.

b. Explain in detail how the Companies pay for transmission service to provide retail service in Ohio, including:

i. Do the Companies pay based on demands?

ii. Are the demands NCP or CP demands?

iii. When do these demands occur (and when did they occur historically over the past two years)?

iv. What demand measurement period is used (60-minute, 30-minute of some other measurement period)?

v. Identify and provide a copy of the applicable FERC tariff under which the Companies pay for transmission service.

c. Provide the same information as requested in part (b) for ancillary services.

d. Explain in detail why the Companies propose to use 30-minute customer maximum demands for billing transmission and/or ancillary services.

e. Explain in detail why the Companies do not propose to utilize on-peak demands for billing transmission and/or ancillary services.

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RESPONSES TO REQUEST

Response:

a. The allocation methodology utilized by the Companies to allocate transmission, ancillary services, and related costs to the customer classes is described in detail in the direct testimony of Kevin Warvell.

b. The responses below assume that the term "transmission" refers to the MISO charge "Network Integration Transmission Service" (NITS).

i. NITS is a demand-based charge.

ii. The billing demand is coincident to the maximum demand for the month for the FE control area, which would be non coincident with other MISO control area peak demands, and non coincident to the MISO peak demand

iii. The transmission billing demand used by MISO is set each month. History is as follows:

Month	Date	Hour Ending (EST)
Jan-06	01/18/06	19
Feb-06	02/08/06	19
Mar-06	03/02/06	20
Apr-06	04/05/06	10
May-06	05/30/06	15
Jun-06	06/22/06	14
Jul-06	07/31/06	14
Aug-06	08/01/06	15
Sep-06	09/08/06	14
Oct-06	10/23/06	19
Nov-06	11/02/06	19
Dec-06	12/07/06	19
Jan-07	01/30/07	19
Feb-07	02/05/07	20
Mar-07	03/06/07	20
Apr-07	04/05/07	10
May-07	05/31/07	15
Jun-07	06/26/07	16
Jul-07	07/10/07	14
Aug-07	08/24/07	15
Sep-07	09/06/07	16
Oct-07	10/08/07	16

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RESPONSES TO REQUEST

Nov-07	11/29/07	19
Dec-07	12/17/07	19
Jan-08	01/24/08	19
Feb-08	02/11/08	20
Mar-08	03/04/08	19
Apr-08	04/03/08	10
May-08	05/30/08	13
Jun-08	06/09/08	15
Jul-08	07/17/08	16

iv. A 60-minute demand measurement period is used.

v. The Companies pay for transmission under the MISO tariff filed with FERC which can be found at : http://www.midwestiso.org/publish/Document/2b8a32_103ef711180_-75b10a48324a?rev=95

c. The responses below assume that the term "ancillary services" refers to MISO Schedules 3, 5, and 6, and that the MISO ancillary services market is up and running on or before January 1, 2009.

i. Schedules 3, 5, and 6 are energy-based charges.

ii. Not Applicable

iii. Not Applicable

iv. Not Applicable

v. See above response to b. v.

d. Please see response e) immediately below.

e. The Companies did not propose to utilize on-peak demands for billing transmission and/or ancillary services for the following reasons: 1) so that a customer only has one billing demand per month, making transmission billing demands consistent with distribution billing demands, 2) to encourage customers to control their demand such that all FE transmission and distribution facilities are better utilized to the benefit of all customers 3) to address problems with power quality created by customers end use devices.

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RESPONSES TO REQUEST

Nucor Set 1
23 Explain in detail why proposed Rider CCA applies to interruptible customers. Identify and provide any documents that refer or relate to this matter.

Response: Please refer to the Companies' response to Nucor Set 1 - 11

EXHIBIT DWG-2

EXCERPT FROM FIRSTENERGY CASE NO. 07-796-EL-ATA: EXHIBIT C1

Competitive Bid Process by Load Class
Rate Template and Reconciliation Mechanism

Introduction

This document provides a description of the manner in which the Blended Competitive Bid Price of a load class is converted into a retail rate (Rate Template) and the methodology for determining a Reconciliation Mechanism. The methodologies described are generally applicable to each load class at each of the three Ohio operating companies, Ohio Edison (OE), Toledo Edison (TE) and Cleveland Electric Illuminating (CEI), except, as further discussed below. A Rate Template unique to CEI is necessary for the period January 1, 2009 until the time there is full recovery of Regulatory Transition Charges.

OE, TE and CEI will implement retail tariffs, developed through the Rate Template, that will recover the Standard Service Offer (SSO) Revenue Requirements. SSO Revenue Requirements are equal to the payments to SSO suppliers for purchased power plus the Companies' costs for providing SSO Generation Service.

A reconciliation rider will be implemented to ensure that the Companies recover the amount of the Companies' SSO Revenue Requirements. Under the terms of the reconciliation rider, revenues received by OE, TE and CEI to cover SSO Revenue Requirements will be reconciled quarterly to recover or refund the difference, including appropriate interest, between the Companies' SSO Revenue Requirements and revenues received from SSO customers during the quarterly reconciliation period.[1]

A subgroup of customers will be handled separately under this alternative, which introduces the need for an additional rider. Details related to this are included in the Revenue Variance section of Exhibit C-1.

Tariffs associated with the Competitive Bid Process by Load Class Rate Templates and Reconciliation Mechanisms are contained in Exhibit D-1.

Rate Template - General

The Rate Template is used to convert the Blended Competitive Bid Price to a retail rate, which will be referred to as the Standard Service Offer Generation Charge (SSOGC). The solicitations in the Competitive Bid Process for generation supply will result in nine different clearing prices for the Residential and General Service - Small load classes and six different clearing prices for the General Service - Large load class. For each class, the clearing prices will be averaged using the number of tranches purchased at each price as weights to obtain a Blended Competitive Bid Price. The SSOGC for each load class (SSO Load Class Charge) will be determined by dividing each class' Blended Competitive Bid Price by 1 minus the load class specific distribution loss factor, expressed as a percentage of the power supply. The class specific result will then be adjusted to incorporate the Seasonal Application Factor (SAF), and in addition, if appropriate, the Time-Of-Day Application Factor (TAF), as well as the Commercial Activity Tax (CAT) to arrive at the SSOGC. There is a temporary modification to this process for CEI which is described in the Rate Template - CEI section below.

[1] SSO Revenues, also referred to as SSO Generation Services revenues, include revenues from the SSOGC as well as the reconciliation rider, Rider GEN-R, and will be adjusted to exclude revenues for the Commercial Activity Tax (CAT) and interest.

The SAF for each load class is as follows:

	Seasonal Application Factor	
	Summer	Winter
RS	1.328	0.885
GS, POL	1.251	0.906
GP, GSU, GT	1.219	0.919

For qualifying customers, there will be a Time-of-Day option available. Customers served under this option will have an SSOGC that, in addition to the SAF, incorporates a Time-of-Day Application Factor (TAF). The TAF for each class is as follows:

	Time-Of-Day Application Factor			
	On-Peak		Off-Peak	
	Summer	Winter	Summer	Winter
RS	1.316	1.281	0.659	0.731
GS, POL	1.282	1.237	0.612	0.688
GP, GSU, GT	1.344	1.285	0.638	0.704

On-Peak time shall be 6:00 a.m. to 10:00 p.m. EST, Monday through Friday, excluding holidays. Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Off-Peak shall be all other hours.

Summer and winter periods will be consistent with the Company's Electric Service Regulations, Section VI.I.

Rate Template - CEI for the period January 1, 2009 to May 31, 2009 (est.)

For the period January 1, 2009 until approximately May 31, 2009, the SSOGC for CEI will be calculated by individual rate block. This modification is necessary because CEI's current tariffs will extend until all Regulatory Transition Costs are recovered[1]. The individual current tariff generation, rate stabilization, and transmission charges for each rate block will be summed. The results will be multiplied by the ratio of the Adjusted Competitive Bid Price, adjusted for Seasonal Application Factors and Commercial Activity Tax (CAT), to the overall average generation and Rate Stabilization Charge (RSC), by season, in cents per kWh.

[1] This recovery is expected to be complete by May 31, 2009. Refer to paragraph 5 of the Companies' Application filed September 9, 2005 in Case No. 05-1125-EL-ATA.

Competitive Bid Process by Load Class
Rate Template and Reconciliation Mechanism

Rate Template – Formula

Below are Rate Template Formulas used to develop the SSOGC:

$SSOGC_i = \{[AP_i / (1 - DL_i)] \times SAF\} \times [1 / (1 - CAT)]$, rounded to the fifth decimal place.

where i is Residential, General Service - Small, or General Service - Large

$SSOGC_i$	=	Standard Service Offer Generation Charge for Class I
AP_i	=	Blended Competitive Bid Price for Class i
DL_i	=	Distribution Losses for Class i, in percentage of power supply
SAF	=	Seasonal Application Factor
CAT	=	Commercial Activity Tax, in percentage

Rate Template – CEI Formula for period January 1, 2009 to May 31, 2009 (est.)

$SSOGC_n = [SSOGC_i / (g + RSC + T)_i] \times (g + RSC + T)_n$

where i is Residential, General Service - Small, or General Service - Large

$SSOGC_n$	=	Standard Service Offer Generation Charge for Rate Block n
$SSOGC_i$	=	Standard Service Offer Generation Charge for Class i
$(g + RSC + T)_i$	=	Overall average generation, RSC, and transmission charge for Class i
$(g + RSC + T)_n$	=	Generation, RSC, and transmission for rate block n

Competitive Bid Process by Load Class
Rate Template and Reconciliation Mechanism

Rate Template - Calculation Examples

Residential Load Class

Assume:

Blended Competitive Bid price	\$60.00 / MWh
Distribution loss percentage	6.28%
CAT rate	0.156%
Winter seasonal application factor	0.885

then,

60.00 / (1 -.0628) = \$64.02	Adjusted Competitive Bid Price
times 0.885	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
\$ 56.75 per mWh or 5.675¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

General Service -Small Load Class

Assume:

Blended Competitive Bid price	\$60.00 / MWh
Distribution loss percentage	6.28%
CAT rate	0.156%
Winter seasonal application factor	0.906

then,

60.00 / (1 -.0628) = \$64.02	Adjusted Competitive Bid Price
times 0.906	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
\$ 58.09 per mWh or 5.809¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

General Service - Large Load Class

Assume:

Blended Competitive Bid price	\$60.00 / MWh
Distribution loss percentage	0.68%
CAT rate	0.156%
Winter seasonal application factor	0.919

then,

60.00 / (1 -.0068) = \$60.41	Adjusted Competitive Bid Price
times 0.919	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
\$ 55.60 per mWh or 5.560¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

Standard Service Offer Generation Charge Reconciliation Mechanism

The Companies, by load class, will recover from customers the total amount of SSO Supply costs, which will be referred to as Standard Service Offer (SSO) Revenue Requirements. The SSO Revenue Requirements are equal to payments to SSO Suppliers for purchased power plus the Companies' costs for providing SSO Generation Service. Costs for providing SSO Generation Service will include: (1) actual expenses necessary to conduct the competitive solicitation less any recovery of these costs in the tranche fees; (2) a working capital adjustment accounting for the fact that revenues received by the Companies for SSO Supply expenses lag the actual payment by the Companies to the SSO Suppliers for such power supply requirements[1]; (3) labor and benefit costs for employees managing the Companies' power supply activities and (4) actual uncollectible expense amounts related to SSO Generation Service. SSO Revenues will be reconciled quarterly to recover or refund the difference between SSO Revenue Requirements and the revenues (excluding revenues related to recovery of the Commercial Activity Tax and interest) from SSO customers. The over/under recovery, calculated on a load class basis, will be collected or refunded two months later through a Standard Service Offer Generation Charge (SSOGC) Reconciliation Rider, Rider GEN-R.

The reconciliation will be done on a quarterly basis by load class and the first reconciliation amount will be based on the first three months of 2009. The reconciliation amount will be billed to SSO customers via Rider GEN-R beginning sixty days after the end of the quarter. The difference between SSO Revenue Requirements and the SSO Revenues received, plus interest calculated at the embedded cost of debt, is not determinable for a given quarter until the subsequent month, therefore the SSOGC Reconciliation Charge on Rider GEN-R will be on a two month lag. As a result, the SSOGC Reconciliation Charge will be zero for the period January 1, 2009 through May 31, 2009. The SSOGC Reconciliation Charge will be calculated each quarter in the following manner:

1. Sum the amounts paid to SSO Suppliers[2] with the Company's costs to provide SSO Generation Service to determine the SSO Revenue Requirement.
2. Sum the SSOGC revenues billed during the revenue month (Billed SSO Revenues).[3]
3. Calculate applicable Commercial Activity Tax Revenues associated with the SSOGC Revenues.
4. Calculate the interest recovery component of the SSO Revenues.
5. Calculate a preliminary Over/Under Recovery by subtracting the SSO Revenue Requirement from the Billed SSO Revenues (less the Commercial Activity Tax and interest recovery).
6. If there is a phase-in of residential generation rates, the attendant deferred expense and related revenues will be subtracted from the preliminary Over/Under Recovery to calculate the final Over/Under Recovery.
7. On a monthly basis throughout the quarter, calculate the balance subject to interest by adding the previous month's balance (which is equal to the final over/under

[1] If the conversion from current tariff charges for generation service to the SSOGC is implemented on a service rendered basis there will be an additional working capital component consisting of the interest on the difference between the cash outlay for purchased power for January 2009 and the cash received from customers for service rendered in January 2009.
[2] Payments to SSO Suppliers will exclude the portion of the payment that relates to Street and Traffic Lighting customers as well as special contract accounts.
[3] Billed SSO Revenues include only SSO load served by successful competitive solicitation bidders and includes SSOGC revenues as well as any billed GEN-R rider revenues. The billed SSO Revenues would exclude SSOGC revenues from Street and Traffic Lighting customers as well as any generation related revenue for special contract accounts.

recovery balance plus the interest balance) amount to one half the current month's final over/under recovery.

8. Calculate the applicable interest by multiplying the balance subject to interest by the interest rate divided by 12.
9. Determine the current month's reconciliation amount by adding the interest to the final over/under recovery for the month.
10. For each calendar quarter, calculate the reconciliation charge by dividing the current reconciliation amount for the quarter by the forecasted SSO retail kWh excluding street, traffic lighting and special contracts for the quarter for which the reconciliation charge will be in effect and dividing this result by 1 minus the CAT.

The SSOGC Reconciliation Charge calculated in the preceding steps may be a positive or negative value and will be applied to SSO customer kWh usage (excluding street, traffic lighting and special contracts) beginning sixty days after the end of the quarter.

See Table 1 for an example of the SSOGC reconciliation mechanism.

<u>Revenue Variance:</u>

Certain customers will be billed for generation service at a rate different than the SSOGC for their load class which results in the Companies' SSO Generation Service revenue being less than the SSO Revenue Requirements. This includes customers on rate schedules STL and TRF, customers participating in the Optional Load Response Program ("OLRP"), special contract customers, and residential customers if there is a phase-in of residential generation rates. The Companies will recover this difference between revenue and expenses (referred to as revenue variance) from all customers, excluding STL, TRF and special contract customers ("RVR Rider customers"), through Rider RVR.

Rider RVR will recover the revenue variance for customers on rate schedules STL and TRF and the revenue variance for customers participating in the Optional Load Response Program. Rider RVR will also recover 50% of the difference between the revenue received from special contract customers for generation service and the expense incurred in purchasing the electricity. Each company's RVR Rider charge is calculated in two steps. The first step results in the same value for each company and is equal to the aggregated revenue variance (excluding the special contract variance) of the three companies divided by the estimated aggregated retail kWh of RVR Rider customers. The second step adds a component that is equal to an individual company's special contract variance divided by the estimated retail kWh of the individual company's RVR Rider customers. If there is a residential phase-in, there will be a third component of the RVR Rider charge to recover the deferred amounts and applicable interest.

This rider will be updated annually, to be effective each June 1 and will include a reconciliation component. This reconciliation is for the sole purpose of reconciling recovery under the estimated Rider RVR value and the actual revenue variance.

An example of the calculation of Rider RVR is shown below[1]:

RVR Sample Calculation (Illustrative)

STL &TRF Revenue Variance

Retail mWh	CEI	170,325	
	OE	150,091	
	TE	52,367	
	Total	372,783	
Total mWh		372,783	
Estimated Price ($/mWh)		$ 30.00	[2]
STL & TRF Revenue		$ 11,183,489	
SSOGC Equivalent Price		$ 64.12	[2]
SSOGC Equivalent Revenue		$ 23,902,844	
STL & TRF Revenue Variance		$ 12,719,355	
Retail mWh paying for the STL & TRF Revenue Variance		53,556,103	mWh
		$ 0.24	RVR Factor per mWh (STL & TRF Component)

Optional Load Response Program Revenue Variance:

Retail mWh paying for the OLRP Revenue Variance	53,556,103	mWh
OLRP Revenue Variance	≈ $ 10,000,000	
	$ 0.19	RVR Factor per mWh (OLRP Component)

CEI Contracts Revenue Variance in Total:

CEI Extended Contracts Rev.	$ 83,293,444	
SSOGC Equivalent Revenue	$ 173,858,202	
CEI Ext. Contracts Rev. Variance	$ 90,564,758	
50% of Contract Rev. Variance	$ 45,282,379	
Retail mWh for CEI RVR Rider customers	16,891,139	mWh
	$ 2.68	RVR Factor per mWh (CEI Special Contract Component)

[1] The example is illustrative only. While not specifically shown in the example, Rider RVR will include a reconciliation component which recovers or refunds the difference between actual revenue recovery for the revenue variance and the actual revenue variance.

[2] As indicated in Rider GEN, there is no seasonal component for the $30/mWh charge. For illustrative purposes therefore, no seasonal component is built into this illustrative example.

TABLE 1

ILLUSTRATIVE EXAMPLE
Competitive Bid Process by Load Class
Reconciliation Mechanism
Sample Residential Calculation of Reconciliation Rider

	Jan-09	Feb-09	Mar-09	Reconciliation 1	Apr-09	May-09	Jun-09	Reconciliation 2
Projected SSO Revenue Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	1,753,000,000	1,527,000,000	1,463,000,000	4,743,000,000	1,248,000,000	1,214,000,000	1,479,000,000	3,941,000,000
Actual SSO Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	1,753,253,640	1,527,091,510	1,463,320,860	4,743,666,010	1,247,619,310	1,214,391,040	1,478,801,640	3,940,811,990
Payment to Supplier From Invoice	$101,356,466	$88,281,923	$84,595,310	$274,233,701	$72,125,496	$70,204,552	$119,951,452	$262,281,500
Program Costs	$10,000	$10,000	$10,000	$30,000	$10,000	$10,000	$10,000	$30,000
Total SSO Revenue Requirements	$101,366,466	$88,291,923	$84,605,310	$274,263,701	$72,135,496	$70,214,552	$119,961,452	$262,311,500
Billed SSOGC Revenue from Report of Electric Sales (Excl RVR Rider)	$99,491,280	$86,657,336	$83,038,565	$269,187,180	$70,798,223	$68,912,630	$125,922,981	$265,633,834
GEN-R Rider Revenue	$0	$0	$0	$0	$0	$0	$1,720,989	$1,720,989
Commercial Activity Tax	$153,206	$135,186	$129,540	$419,932	$110,446	$107,604	$199,125	$417,074
Interest Recovery	$0	$0	$0	$0	$0	$0	$13,344	$13,344
SSO Cost Recovery	$99,338,074	$86,522,150	$82,909,024	$268,767,248	$70,687,778	$68,805,126	$127,431,503	$266,934,406
Preliminary Over (Under) Recovery	($2,030,395)	($1,769,773)	($1,696,285)	($5,496,453)	($1,447,718)	($1,409,426)	$7,470,050	$4,612,907
Residential Deferral	$0	$0	$0	$0	$0	$0	$0	$0
Final Over (Under) Recovery	($2,030,395)	($1,769,773)	($1,696,285)	($5,496,453)	($1,447,718)	($1,409,426)	$7,470,050	$4,612,907
Cumulative Final Over (Under) Recovery	($2,030,395)	($3,800,167)	($5,496,453)		($6,944,170)	($8,353,596)	($883,546)	
Balance Subject to Interest	($1,015,197)	($2,920,357)	($4,667,988)	($8,603,642)	($6,263,329)	($7,723,218)	($4,731,522)	($18,718,068)
Interest	$5,076	$14,602	$23,340	$43,018	$31,317	$38,616	$23,658	$93,590
Cumulative Interest	$5,076	$19,678	$43,018		$74,334	$112,950	$136,608	
Current Month's Reconciliation Amount	($2,035,471)	($1,784,374)	($1,719,625)	($5,539,470)	($1,479,034)	($1,448,042)	$7,446,393	$4,519,316
SSOGC Reconciliation Charge on Rider GEN-R				$0.001164				($0.001156)
Interest Charge (Included in Reconciliation Charge)				$0.000009				$0.000024

Embedded Cost of Debt	6.00%
Commercial Activity Tax Rate	0.156%

ILLUSTRATIVE EXAMPLE
Competitive Bid Process by Load Class
Reconciliation Mechanism
Sample Residential Calculation of Reconciliation Rider

TABLE 1

	Jul-09	Aug-09	Sep-09	Reconciliation 3	Oct-09	Nov-09	Dec-09	Reconciliation 4
Projected SSO Revenue Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	1,709,000,000	1,580,000,000	1,245,000,000	4,534,000,002	1,285,000,000	1,384,000,000	1,698,000,000	4,367,000,000
Actual SSO Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	1,709,479,000	1,579,490,870	1,244,980,950	4,533,950,820	1,284,261,710	1,383,623,190	1,697,609,680	4,365,494,580
Payment to Supplier From Invoice	$138,662,505	$128,118,754	$71,972,970	$338,754,329	$74,243,811	$79,987,948	$98,139,663	$252,371,422
Program Costs	$10,000	$10,000	$10,000	$30,000	$10,000	$10,000	$10,000	$30,000
Total SSO Revenue Requirements	$138,672,505	$128,128,754	$71,982,970	$338,784,329	$74,253,811	$79,997,948	$98,149,663	$252,401,422
Billed SSOGC Revenue from Report of Electric Sales (Excl RVR Rider)	$145,565,630	$134,496,875	$70,648,505	$350,711,010	$72,877,557	$78,515,966	$96,333,671	$247,727,217
GEN-R Rider Revenue	$1,989,621	$1,838,515	($1,439,780)	$2,387,345	($1,486,049)	($1,600,538)	($4,886,144)	($7,872,731)
Commercial Activity Tax	$230,185	$212,683	$107,966	$550,833	$111,371	$119,966	$143,126	$374,466
Interest Recovery	$15,419	$14,255	$29,770	$59,444	$30,727	$33,094	$40,602	$104,422
SSC Cost Recovery	$147,308,648	$136,108,451	$69,070,979	$352,469,078	$71,249,411	$76,762,366	$91,563,799	$239,576,578
Preliminary Over (Under) Recovery	$8,636,042	$7,979,698	($2,911,992)	$13,709,749	($3,004,400)	($3,235,579)	($8,585,864)	($12,825,844)
Residential Deferral	$0	$0	$0	$0	$0	$0	$0	$0
Final Over (Under) Recovery	$8,636,042	$7,979,698	($2,911,992)	$13,709,749	($3,004,400)	($3,235,579)	($8,585,864)	($12,825,844)
Cumulative Final Over (Under) Recovery	$7,752,497	$15,732,194	$12,820,203		$9,815,803	$6,580,223	($5,641)	
Balance Subject to Interest	$3,297,867	$11,589,248	$14,065,155	$28,952,270	$11,038,633	$7,861,460	$2,911,431	$21,809,626
Interest	$16,489	$57,946	$70,326	$144,761	$55,183	$39,307	$14,557	$109,048
Cumulative Interest	$153,097	$211,044	$281,369		$336,553	$375,860	$390,417	
Current Month's Reconciliation Amount	$8,619,553	$7,921,762	($2,982,317)	$13,558,987	($3,059,583)	($3,274,887)	($8,600,421)	($12,934,891)
SSOGC Reconciliation Charge on Rider GEN-R				($0.002701)				$0.003252
Interest Charge (Included in Reconciliation Charge)				$0.000029				$0.000040

Embedded Cost of Debt	6.00%
Commercial Activity Tax Rate	0.156%

EXHIBIT DWG-3

EXCERPT FROM FIRSTENERGY CASE NO. 07-796-EL-ATA: EXHIBIT C2

Slice Of System Competitive Bid Process
Rate Template and Reconciliation Mechanism

Introduction

This document provides a description of the manner in which the Blended Competitive Bid Price is converted into a retail rate (Rate Template) and the methodology for determining a Reconciliation Mechanism. The methodologies described are generally applicable to each of the three Ohio operating companies, Ohio Edison (OE), Toledo Edison (TE) and Cleveland Electric Illuminating (CEI), except, as further discussed below. A Rate Template unique to CEI is necessary for the period January 1, 2009 until the time there is full recovery of Regulatory Transition Charges.

OE, TE and CEI will implement retail tariffs, developed through the Rate Template, that will recover the Standard Service Offer (SSO) Revenue Requirements. SSO Revenue Requirements are equal to the payments to SSO suppliers for purchased power plus the Companies' costs for providing SSO Generation Service.

A reconciliation rider will be implemented to ensure that the Companies recover the amount of the Companies' SSO Revenue Requirements. Under the terms of the reconciliation rider, revenues received by OE, TE and CEI to cover SSO Revenue Requirements will be reconciled quarterly to recover or refund the difference, including appropriate interest, between the Companies' SSO Revenue Requirements and revenues received from SSO customers during the quarterly reconciliation period.[1]

A subgroup of customers will be handled separately under this alternative, which introduces the need for an additional rider. Details related to this are included in the Revenue Variance section of Exhibit C-2.

Tariffs associated with the Slice of System Competitive Bid Process Rate Templates and Reconciliation Mechanisms are contained in Exhibit D-2.

Rate Template - General

The Rate Template is used to convert the Blended Competitive Bid Price to a retail rate, which will be referred to as the Standard Service Offer Generation Charge (SSOGC). The solicitations in the Competitive Bid Process for generation supply will result in twelve different clearing prices. The clearing prices will be averaged using the number of tranches purchased at each price as weights to obtain a Blended Competitive Bid Price. The SSOGC for each load class (SSO Load Class Charge) will be determined by multiplying the Blended Competitive Bid Price by a factor based on the ratio of each load class' historical average SSO Generation and Transmission Rate to the average of all historical SSO Generation and Transmission Rates, with all rates converted to a wholesale equivalent. These load class results will be referred to as the Class Allocation Factors (CAF) which are shown below.

RS	=	1.000
GS	=	1.252
GP	=	0.900
GSU	=	0.800
GT	=	0.769

[1] SSO Revenues, also referred to as SSO Generation Service revenues, include revenues from the SSOGC as well as the reconciliation rider, Rider GEN-R, and will be adjusted to exclude revenues for the Commercial Activity Tax (CAT) and interest.

After the application of the CAF, the results are adjusted to account for distribution losses by dividing by 1 minus the appropriate distribution loss factor, in percentage of power supply. The class specific result will then be adjusted to incorporate the Seasonal Application Factor (SAF), and in addition, if appropriate, the Time-Of-Day Application Factor (TAF), as well as the Commercial Activity Tax (CAT) to arrive at the SSOGC. There is a temporary modification to this process for CEI which is described in the Rate Template - CEI section below.

The SAF for each load class is as follows:

	Seasonal Application Factor	
	Summer	Winter
RS	1.328	0.885
GS, POL	1.251	0.906
GP	1.231	0.917
GSU	1.230	0.909
GT	1.208	0.925

For qualifying customers, there will be a Time-of-Day option available. Customers served under this option will have an SSOGC that, in addition to the SAF, incorporates a Time-of-Day Application Factor (TAF). The TAF for each class is as follows:

	Time-Of-Day Application Factor			
	On-Peak		Off-Peak	
	Summer	Winter	Summer	Winter
RS	1.316	1.281	0.659	0.731
GS, POL	1.282	1.237	0.612	0.688
GP	1.321	1.266	0.624	0.694
GSU	1.331	1.273	0.627	0.700
GT	1.358	1.298	0.650	0.710

On-Peak time shall be 6:00 a.m. to 10:00 p.m. EST, Monday through Friday, excluding holidays. Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Off-Peak shall be all other hours.

Summer and winter periods will be consistent with the Company's Electric Service Regulations, Section VI.I.

Rate Template - CEI for the period January 1, 2009 to May 31, 2009 (est.)

For the period January 1, 2009 until approximately May 31, 2009, the SSOGC for CEI will be calculated by individual rate block. This modification is necessary because CEI's current tariffs will extend until all Regulatory Transition Costs are recovered[1]. The individual current tariff generation, rate stabilization, and transmission charges for each rate block will be summed. The results will be multiplied by the ratio of the Adjusted Competitive Bid Price, adjusted for Seasonal Application Factors and Commercial Activity Tax (CAT), to the overall average generation and Rate Stabilization Charge (RSC), by season, in cents per kWh.

Rate Template - Formula:

Below are Rate Template Formulas used to develop the SSOGC:

$SSOGC_i = \{[(AP \times CAF_i) / (1 - DL_i)] \times SAF\} \times [1 / (1 - CAT)]$, rounded to the fifth decimal place.

$SSOGC_i$	=	Standard Service Offer Generation Charge for Class i
AP	=	Blended Competitive Bid Price
DL_i	=	Distribution Losses for Class i, in percentage of power supply
CAF_i	=	Class Allocation Factor for Class i
SAF	=	Seasonal Application Factor for Class i
CAT	=	Commercial Activity Tax, in percentage, for Class i

Rate Template – CEI Formula for period January 1, 2009 to May 31, 2009 (est.)

$SSOGC_n = [SSOGC_i / (g + RSC + T)_i] \times (g + RSC + T)_n$

$SSOGC_n$	=	Standard Service Offer Generation Charge for Rate Block n
$SSOGC_i$	=	Standard Service Offer Generation Charge for Class i
$(g + RSC + T)_i$	=	Overall average generation, RSC, and transmission charge for Class i
$(g + RSC + T)_n$	=	Generation, RSC, and transmission for rate block n

[1] This recovery is expected to be complete by May 31, 2009. Refer to paragraph 5 of the Companies' Application filed September 9, 2005 in Case No. 05-1125-EL-ATA.

Rate Template - Calculation Examples

RS Load Class

Assume:

Blended Competitive Bid price	$60.00 / MWh
CAF	1.000
Distribution loss percentage	6.28%
CAT rate	0.156%
Winter seasonal application factor	0.885

then,

[(60.00 x 1.000) / (1 -.0628)] = $64.02	Adjusted Competitive Bid Price
times 0.885	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
$56.75 per mWh or 5.675¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

GS, POL Load Classes

Assume:

Blended Competitive Bid price	$60.00 / mWh
CAF	1.252
Distribution loss percentage	6.28%
CAT rate	0.156%
Winter seasonal application factor	0.906

then,

[(60.00 x 1.252) / (1 -.0628)] = $80.15	Adjusted Competitive Bid Price
times 0.906	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
$72.73 per mWh or 7.273¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

Rate Template - Calculation Examples (Cont'd)

GP Load Class

Assume:

Blended Competitive Bid price	$60.00 / mWh
CAF	0.900
Distribution loss percentage	2.91%
CAT rate	0.156%
Winter seasonal application factor	0.917

then,

[(60.00 x 0.900) / (1 -.0291)] = $55.62	Adjusted Competitive Bid Price
times 0.917	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
$51.08 per mWh or 5.108¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

GSU Load Class

Assume:

Blended Competitive Bid price	$60.00 / mWh
CAF	0.800
Distribution loss percentage	0.10%
CAT rate	0.156%
Winter seasonal application factor	0.909

then,

[(60.00 x 0.800) / (1 -.0010)] = $48.05	Adjusted Competitive Bid Price
times 0.909	Incorporate SAF
times (1 / (1-.00156))	Incorporate CAT
$43.74 per mWh or 4.374¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

Rate Template - Calculation Examples (Cont'd)

GT Load Class

Assume:

Blended Competitive Bid price	$60.00 / mWh
CAF	0.769
Distribution loss percentage	0.00%
CAT rate	0.156%
Winter seasonal application factor	0.925

then,

[(60.00 x 0.769) / (1 -.0000)] = $46.14	Adjusted Competitive Bid Price
times 0.925	Incorporate SAF
times (1 / (1-.00156))	*Incorporate CAT*
$42.75 per mWh or 4.275¢ per kWh	Standard Service Offer Generation Charge (SSOGC)

Standard Service Offer Generation Charge Reconciliation Mechanism

The Companies, in aggregate, will recover from customers the total amount of SSO Supply costs which will be referred to as Standard Service Offer (SSO) Revenue Requirements. The SSO Revenue Requirements are equal to payments to SSO Suppliers for purchased power plus the Companies' costs for providing SSO Generation Service. Costs for providing SSO Generation Service will include: (1) actual expenses necessary to conduct the competitive solicitation less any recovery of these costs in the tranche fees; (2) a working capital adjustment accounting for the fact that revenues received by the Companies for SSO Supply expenses lag the actual payment by the Companies to the SSO Suppliers for such power supply requirements[1]; (3) labor and benefit costs for employees managing the Companies' power supply activities and (4) actual uncollectible expense amounts related to SSO Generation Service. SSO Revenues will be reconciled quarterly to recover or refund the difference between SSO Revenue Requirements and the revenues (excluding revenues related to recovery of the Commercial Activity Tax and interest) from SSO customers. The over/under recovery will be collected or refunded two months later through a Standard Service Offer Generation Charge (SSOGC) Reconciliation Rider, Rider GEN-R.

The reconciliation will be done on a quarterly basis and the first reconciliation amount will be based on the first three months of 2009. The reconciliation amount will be billed to SSO customers via Rider GEN-R beginning sixty days after the end of the quarter. The difference between SSO Revenue Requirements and the SSO Revenues received, plus interest calculated at the embedded cost of debt, is not determinable for a given quarter until the subsequent month, therefore the SSOGC Reconciliation Charge on Rider GEN-R will be on a two month lag. As a result, the SSOGC Reconciliation Charge will be zero for the period January 1, 2009

[1] If the conversion from current tariff charges for generation service to the SSOGC is implemented on a service rendered basis there will be an additional working capital component consisting of the interest on the difference between the cash outlay for purchased power for January 2009 and the cash received from customers for service rendered in January 2009.

through May 31, 2009. The SSOGC Reconciliation Charge will be calculated each quarter in the following manner:

1. Sum the amounts paid to SSO Suppliers[1] with the Company's costs to provide SSO Generation Service to determine the SSO Revenue Requirement.
2. Sum the SSOGC revenues billed during the revenue month (Billed SSO Revenues).[2]
3. Calculate applicable Commercial Activity Tax Revenues associated with the SSOGC Revenues.
4. Calculate the interest recovery component of the SSO Revenues.
5. Calculate a preliminary Over/Under Recovery by subtracting the SSO Revenue Requirement from the Billed SSO Revenues (less the Commercial Activity Tax and interest recovery).
6. If there is a phase-in of residential generation rates, the attendant deferred expense and related revenues will be subtracted from the preliminary Over/Under Recovery to calculate the final Over/Under Recovery.
7. On a monthly basis throughout the quarter, calculate the balance subject to interest by adding the previous month's balance (which is equal to the final over/under recovery balance plus the interest balance) amount to one half the current month's final over/under recovery.
8. Calculate the applicable interest by multiplying the balance subject to interest by the interest rate divided by 12.
9. Determine the current month's reconciliation amount by adding the interest to the final over/under recovery for the month.
10. For each calendar quarter, calculate the reconciliation charge by dividing the current reconciliation amount for the quarter by the forecasted SSO retail kWh excluding street, traffic lighting and special contracts for the quarter for which the reconciliation charge will be in effect and dividing this result by 1 minus the CAT.

The SSOGC Reconciliation Charge calculated in the preceding steps may be a positive or negative value and will be applied to SSO customer kWh usage (excluding street, traffic lighting and special contracts) beginning sixty days after the end of the quarter.

See Table 1 for an example of the SSOGC reconciliation mechanism.

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[1] Payments to SSO Suppliers will exclude the portion of the payment that relates to Street and Traffic Lighting customers as well as special contract accounts.

[2] Billed SSO Revenues include only SSO load served by successful competitive solicitation bidders and includes SSOGC revenues as well as any billed GEN-R rider revenues. The billed SSO Revenues would exclude SSOGC revenues from Street and Traffic Lighting customers as well as any generation related revenue for special contract accounts.

Revenue Variance

Certain customers will be billed for generation service at a rate different than the SSOGC for their load class which results in the Companies' SSO Generation Service revenue being less than the SSO Revenue Requirements. This includes customers on rate schedules STL and TRF, customers participating in the Optional Load Response Program ("OLRP"), special contract customers, and residential customers if there is a phase-in of residential generation rates. The Companies will recover this difference between revenue and expenses (referred to as revenue variance) from all customers, excluding STL, TRF and special contract customers ("RVR Rider customers"), through Rider RVR.

Rider RVR will recover the revenue variance for customers on rate schedules STL and TRF and the revenue variance for customers participating in the Optional Load Response Program. Rider RVR will also recover 50% of the difference between the revenue received from special contract customers for generation service and the expense incurred in purchasing the electricity. Each company's RVR Rider charge is calculated in two steps. The first step results in the same value for each company and is equal to the aggregated revenue variance (excluding any special contract variance) of the three companies divided by the estimated aggregated retail kWh of RVR Rider customers. The second step adds a component that is equal to an individual company's special contract variance divided by the estimated retail kWh of the individual company's RVR Rider customers. If there is a residential phase-in, there will be a third component of the RVR Rider charge to recover the deferred amounts and applicable interest.

This rider will be updated annually, to be effective each June 1 and will include a reconciliation component. This reconciliation is for the sole purpose of reconciling recovery under the estimated Rider RVR value and the actual revenue variance.

An example of the calculation of Rider RVR is shown below[1]:

RVR Sample Calculation (Illustrative)

STL &TRF Revenue Variance			
Retail mWh	CEI	170,325	
	OE	150,091	
	TE	52,367	
	Total	372,783	
Total mWh		372,783	
Estimated Price ($/mWh)		$ 30.00	2
STL & TRF Revenue		$ 11,183,489	
SSOGC Equivalent Price		$ 80.28	2
SSOGC Equivalent Revenue		$ 29,927,017	
STL & TRF Revenue Variance		$ 18,743,528	
Retail mWh paying for the STL & TRF Revenue Variance		53,556,103	mWh
		$ 0.35	RVR Factor per mWh (STL & TRF Component)
Optional Load Response Program Revenue Variance:			
Retail mWh paying for the Revenue Variance		53,556,103	mWh
OLRP Revenue Variance		≈ $ 10,000,000	
		$ 0.19	RVR Factor per mWh (OLRP Component)
CEI Contracts Revenue Variance In Total:			
CEI Extended Contracts Rev.		$ 83,293,444	
SSOGC Equivalent Revenue		$ 136,950,480	
CEI Ext. Contracts Rev. Variance		$ 53,657,036	
50% of Contract Rev. Variance		$ 26,828,518	
Retail mWh for CEI RVR Rider customers		16,891,139	mWh
		$ 1.59	RVR Factor per mWh (CEI Special Contract Component)

[1] The example is illustrative only. While not specifically shown in the example, Rider RVR will include a reconciliation component which recovers or refunds the difference between actual revenue recovery for the revenue variance and the actual revenue variance.

[2] As indicated in Rider GEN, there is no seasonal component for the $30/mWh charge. For illustrative purposes therefore, no seasonal component is built into this illustrative example.

ILLUSTRATIVE EXAMPLE
Slice Of System Competitive Bid Process
Reconciliation Mechanism

TABLE 1

		Jan-09	Feb-09	Mar-09	Reconciliation 1	Apr-09	May-09	Jun-09	Reconciliation 2
2	Projected SSO Revenue Month kWh (Excluding STL, TRF, Special Contracts,								
3	and HPS rider customers)	3,673,000,000	3,365,000,000	3,654,000,000	10,692,000,000	3,509,000,000	3,634,000,000	3,753,000,000	10,896,000,000
4									
5	Actual SSO Month kWh (Excluding STL, TRF, Special Contracts,								
6	and HPS rider customers)	3,672,636,240	3,365,118,630	3,654,488,900	10,692,443,770	3,509,479,880	3,633,903,960	3,752,874,460	10,896,258,270
7									
8	Payment to Supplier From Invoice	$206,556,050	$189,250,368	$205,524,217	$601,330,634	$198,129,651	$205,154,083	$297,275,843	$700,559,577
9	Program Costs	$10,000	$10,000	$10,000	$30,000	$10,000	$10,000	$10,000	$30,000
10	Total SSO Revenue Requirements	$206,566,050	$189,260,368	$205,534,217	$601,360,634	$198,139,651	$205,164,083	$297,285,843	$700,589,577
11									
12	Billed SSOGC Revenue from Report of Electric Sales (Excl RVR Rider)	$207,609,566	$190,215,619	$206,572,470	$604,397,656	$198,375,736	$205,408,893	$297,646,072	$701,429,700
13	GEN-R Rider Revenue	$0	$0	$0	$0	$0	$0	($693,997)	($693,992)
14	Commercial Activity Tax	$323,871	$296,736	$322,253	$942,860	$309,466	$320,438	$463,244	$1,098,146
15	Interest Recovery	$0	$0	$0	$0	$0	$0	($5,178)	($5,178)
16	SSO Cost Recovery	$207,285,695	$189,918,883	$206,250,217	$603,454,795	$198,066,270	$205,088,455	$296,493,015	$699,647,739
17									
18	Preliminary Over (Under) Recovery	$719,646	$658,514	$716,001	$2,094,161	($73,381)	($75,628)	($792,828)	($941,838)
19	Residential Deferral	$0	$0	$0	$0	$0	$0	$0	$0
20	Final Over (Under) Recovery	$719,646	$658,514	$716,001	$2,094,161	($73,381)	($75,628)	($792,828)	($941,838)
21	Cumulative Final Over (Under) Recovery	$719,646	$1,378,160	$2,094,161		$2,020,780	$1,945,151	$1,152,323	
22									
23	Balance Subject to Interest	$359,823	$1,050,702	$1,743,213	$3,163,736	$2,078,239	$2,009,100	$1,584,918	$5,667,257
24	Interest	($1,799)	($5,254)	($8,716)	($15,769)	($10,366)	($10,048)	($7,925)	($28,336)
25	Cumulative Interest	($1,799)	($7,053)	($15,769)		($26,135)	($36,180)	($44,105)	
26									
27	Current Month's Reconciliation Amount	$721,445	$663,768	$724,717	$2,109,930	($63,015)	($65,583)	($784,904)	($913,502)
28	SSOGC Reconciliation Charge on Rider GEN-R				($0.000185)				$0.000068
29	Interest Charge (Included in Reconciliation Charge)				($0.000001)				($0.000003)
30									
31									
32									
33									
34	Embedded Cost of Debt	6.00%							
35	Commercial Activity Tax Rate	0.156%							

TABLE 1

ILLUSTRATIVE EXAMPLE
Slice Of System Competitive Bid Process
Reconciliation Mechanism

	Jul-09	Aug-09	Sep-09	Reconciliation 3	Oct-09	Nov-09	Dec-09	Reconciliation 4
Projected SSO Revenue Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	3,849,000,000	3,826,000,000	3,586,000,000	11,261,000,000	3,821,000,000	3,430,000,000	3,535,000,000	10,586,000,000
Actual SSO Month kWh (Excluding STL, TRF, Special Contracts, and HPS rider customers)	3,849,274,920	3,825,624,210	3,585,854,210	11,260,653,370	3,620,550,110	3,429,534,840	3,535,433,040	10,585,517,990
Payment to Supplier From Invoice	$304,912,001	$303,030,637	$202,441,408	$810,384,046	$203,616,538	$192,873,061	$198,828,653	$595,317,253
Program Costs	$10,000	$10,000	$10,000	$30,000	$10,000	$10,000	$10,000	$30,000
Total SSO Revenue Requirements	$304,922,001	$303,040,637	$202,451,408	$810,414,045	$203,625,538	$192,883,061	$198,838,653	$595,347,253
Billed SSOGC Revenue from Report of Electric Sales (Excl RVR Rider)	$305,290,714	$303,407,013	$202,692,848	$811,390,575	$204,654,057	$193,858,789	$199,842,757	$598,353,603
GEN-R Rider Revenue	($711,744)	($707,491)	$308,446	($1,110,789)	$311,456	$295,027	$457,674	$1,064,158
Commercial Activity Tax	$475,143	$472,211	$316,682	$1,264,036	$319,748	$302,877	$312,469	$935,092
Interest Recovery	($5,311)	($5,279)	($9,553)	($20,143)	($6,645)	($9,137)	($8,417)	($28,200)
SSO Cost Recovery	$304,109,138	$302,232,591	$202,694,164	$809,036,892	$204,655,413	$193,858,077	$199,997,379	$598,510,869
Preliminary Over (Under) Recovery	($812,863)	($808,047)	$242,757	($1,378,153)	$1,029,875	$975,016	$1,158,726	$3,163,617
Residential Deferral	$0	$0	$0	$0	$0	$0	$0	$0
Final Over (Under) Recovery	($812,863)	($808,047)	$242,757	($1,378,153)	$1,029,875	$975,016	$1,158,726	$3,163,617
Cumulative Final Over (Under) Recovery	$939,460	($468,587)	($225,830)		$804,045	$1,779,061	$2,937,787	
Balance Subject to Interest	$789,998	($24,408)	($306,931)	$458,656	$930,919	$1,331,710	$2,391,922	$4,054,551
Interest	$3,950	($122)	($1,535)	$2,293	$1,865	$6,659	$11,960	$20,273
Cumulative Interest	($40,155)	($40,277)	($41,812)		($40,157)	($33,499)	($21,539)	
Current Month's Reconciliation Amount	($816,813)	($807,925)	$244,291	($1,360,446)	$1,028,220	$968,357	$1,146,767	$3,143,344
SSOGC Reconciliation Charge or Rider GEN-R				$0.000129				($0.000297)
Interest Charge (Included in Reconciliation Charge)				$0.000009				$0.000003

Embedded Cost of Debt	6.00%
Commercial Activity Tax Rate	0.156%

EXHIBIT DWG-4

EXCERPT FROM FIRSTENERGY REPLY COMMENTS, CASE NO. 07-796-EL-ATA

FILE

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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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On behalf of Ohio Edison Company,
The Cleveland Electric Illuminating Company,
and The Toledo Edison Company

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

EXHIBIT DWG-5

RECOMMENDED RIDER ELR

RIDER ELR
Economic Load Response Program Rider

APPLICABILITY:

This Economic Load Response Program Rider ("Program") is available to customers taking service under the Company's general service tariffs served at primary voltages or higher voltages provided that the customer meets all of the following five conditions at the time of initiation of service under this Rider and on a continuing basis thereafter (i) the customer took service under the Company's interruptible tariffs set forth below as of July 31, 2008; (ii) the customer can successfully demonstrate to the Company that it can reduce its instantaneous measured load to a pre-established contract Firm Load (as defined below) within ten minutes of notification provided by the Company without the need of a generator. A customer may intend to use a generator to reduce its usage to or below its Firm Load, but if the generator does not start, the customer must still reduce its usage to or below its Firm Load. Failure of a customer to reduce its usage to or below its Firm Load shall result in the consequences listed in the Emergency Curtailment Event Section herein; (iii) the customer executes the Company's standard Program contract; (iv) the customer is taking generation service from the Company under the Generation Service Rider (GEN); and (v) the customer is not participating in any other load curtailment program, including without limitation a demand response program offered by the Midwest Independent Transmission System Operator, Inc. ("MISO") or any other independent system operator.

Interruptible Rider – General Service Large and High Use Manufacturing	Original Sheet No. 73
Interruptible Rider – Metal Melting Load	Original Sheet No. 74
Interruptible Rider – Incremental Interruptible Service	Original Sheet No. 75
General Service – Interruptible Electric Arc Furnace Rate	Original Sheet No. 29

RATES:

In addition to any other charges under any other rate schedules applicable to customer's service, customers participating in the Program shall also pay the charges and receive the credit set forth below:

Charges:

Program Administrative Charge $150.00 per month

EBT Charge:

If Customer elects in its contract to be subject to Economic Buy Through Events as defined below, dDuring such an event ~~an Economic Buy Through Option Event (as defined below)~~, the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an EBT Charge, which is calculated for each hour of the event as follows:

EBT = (AL x MPD) x (1 + LAF) x ([1/(1 – CAT)]

Where:

AL = the customer's actual hourly load during an Economic Buy Through Option Event that exceeds the customer's pre-established contract Firm Load.

MPD = the market price differential, which shall be calculated by subtracting the customer's otherwise applicable total generation related per kilowatt-hour charges set forth in the Company's tariffs from the MISO day ahead LMP for the period in which the Economic Buy Through Option Event occurred for each hour that results in a MPD greater than zero.

MISO LMP is the final Day Ahead Locational Marginal Price as defined and specified by MISO at the Commercial Pricing Node "FESR" (or its equivalent) during the applicable hour(s).

CAT = the Commercial Activity Tax rate (in decimal form) as established §5751.02 of the Ohio Revised Code.

LAF = Loss Adjustment Factor
3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

ECE Charge:

During an Emergency Curtailment Event (as defined below), the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any hour during such event shall be assessed an ECE Charge which is calculated for each hour of the event as follows:

ECE = (AL x MISO LMP x 300%) x (1 + LAF) x ([1/(1-CAT)]

Customer may receive Emergency Curtailment or Economic Buy Through Program Credits, or both, as set forth below, depending on the Customer's election in its contract to participate in the Emergency Curtailment or Economic Buy Through options or both under this Rider.

Emergency Curtailment Program Credit ("ECPC"):

Customers taking service under this Rider who agree to be subject to Emergency Curtailment Events shall receive a monthly Program Credit which shall be calculated as follows:

ECPC = RCL x $7.50~~1.95~~/kW/month

Where:

RCL is the ~~predetermined~~ Realizable Curtailable Load, which shall be calculated by ~~the Company once per year for each customer by~~ subtracting the customer's contract Firm Load from its Measured Demand each month as defined in the underlying rate schedule applicable to customer. ~~Average Hourly Demand ("AHD"). For purposes of this Rider, the AHD shall be the greater of 1) customer's average load during the hours of noon to 6:00 pm EDT on non-holiday weekdays during the months of June through August, excluding actual hours of any Emergency Curtailment Events occurring during the historical calculation period or 2) customer's average load during the hours of noon to 6:00 pm EDT on non-holiday weekdays during the months of June through August, excluding actual hours of any Emergency Curtailment Events and any Economic Buy Through Option Events that the customer was subject to occurring during the preceding 12 month period. The RCL shall not exceed the amount of a customer's billing demand in excess of the contracted Firm Load on a monthly basis. The customer shall be provided written notice each year by the Company of the value of the RCL at least thirty (30) days in advance of the effective date of the RCL.~~

Economic Buy Through Program Credit ("EBTPC"):

Customers taking service under this Rider who agree to be subject to Economic Buy Through Events shall receive a monthly Program Credit which shall be calculated as follows:

EBTPC = RCL x $2.60/kW/month

Where:

RCL is defined as set forth above.

OTHER PROVISIONS:

A. Firm Load

For purposes of this rider, "Firm Load" shall be that portion of a customer's electric load that is not subject to curtailment. A customer may request a reduction to its contract Firm Load no more than once in any twelve month period. The Firm Load may be reduced to the extent that such reduction is consistent with other terms and conditions set forth in this Rider. Any such change in Firm Load shall be applied beginning with the customer's January bill immediately following the year in which the change has been approved by the Company, provided that advance written request is provided to the Company no less than thirty (30) days prior to the effective billing month of the change. The Company may increase the Firm Load at any time if the Company, at its sole discretion, determines the Firm Load is at a level that the customer fails to demonstrate that they can reach. The Company shall promptly notify the customer of any such change.

B. Load Response Program Contract

Customers taking service under this optional rider shall execute the Company's standard Program contract which, among other things, will establish the Customer's Firm Load.

C. Metering

The customer must arrange for interval metering consistent with the Company's Miscellaneous Charges, Tariff Sheet 75.

D. Emergency Curtailment Event

Upon no less than ten minutes advance notification provided by the Company, a customer taking service under this rider that opts to be subject to Emergency Curtailment Events must curtail all load above its Firm Load during an Emergency Curtailment Event consistent with the Company's instructions. For purposes of this rider, an Emergency Curtailment Event shall be one in which the Company, a regional transmission organization and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area.

During the entire period of an Emergency Curtailment Event, the customer's actual measured load must remain at or below its Firm Load with such load being measured every clock half hour. A customer's actual measured load shall be determined using the greater of the customer's highest lagging kVa or highest kW during the Emergency Curtailment Event.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds its contract Firm Load, the Company may disconnect the customer from the transmission system for the duration of the Emergency Curtailment Event, at the customer's expense. The Company shall not be liable for any direct or indirect costs, losses, expenses, or other damages, special or otherwise, including, without limitation, lost profits that arise from such disconnection.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds 110% of its Firm Load, the customer shall be subject to all four (4) of the following: (i) forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred; (ii) pay the ECE Charge set forth in the Rates section of this Rider; (iii) pay the sum of all Program Credits received by the customer under the Program during the immediately preceding twelve billing months which shall include credits from this Rider and the Generation and Economic Development Credit Rider; and (iv) the Company's right, at its sole discretion, to remove the customer from the Program for a minimum of 12 months.

If at any time during the Emergency Curtailment Event a customer's actual measured load is greater than 100% and less than or equal to 110% of its Firm Load during the Emergency Curtailment Event, the customer shall forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred and shall pay the ECE Charge set forth in the Rates section of this Rider.

In the event of any conflict between the terms and conditions set forth in this Rider and other service reliability requirements and/or obligations of the Company, the latter shall prevail.

E. Economic Buy Through Option Event

Upon no less than a 90 minute advance notification provided to the customer, the Company shall call an Economic Buy Through Event ("EBT") when a "Market Premium Condition" exists for at least three (3) consecutive hours during any day. A Market Premium Condition is defined as a *point in time that the MISO LMP exceeds the otherwise applicable per kilowatt-hour net charges set* forth in the Company's Generation (GEN) and Generation Phase-In (GPI) riders. In response to an EBT, the customer that opts to be subject to EBTs may curtail usage or buy-through subject to the EBT charge set forth above.

F. Notification

Customers served under this Rider shall be provided notification of Economic Buy Through Option Events and Emergency Curtailment Events by the Company. Customers shall be provided clock times of the beginning and ending of these events, except the Emergency Curtailment Event notification may be stated such that customers must curtail their actual measured load to its Firm Load in 10 minutes from the time the notification is issued. Receipt of curtailment notifications shall be the sole responsibility of the customer.

Notification of an interruption Economic Buy Through Option Event and Emergency Curtailment Event consists of an electronic message issued by the Company to a device or devices such as telephone, facsimile, pager or email, selected and provided by the customer and approved by the Company. Two-way information capability shall be incorporated by the Company and the customer in order to provide confirmation of receipt or notification messages. Operation, maintenance and functionality of such communication devices selected by the customer shall be the sole responsibility of the customer.

G. Term

This rider shall become effective for service rendered in January 2009, and shall expire with service rendered through December 31st, 2011.

A customer may terminate its participation in the Program upon no less than twelve (12) months advance written notice to the Company. Except as otherwise provided in this rider, a qualifying customer may return to the Program at any time after a hiatus from the program of at least one (1) year.

H. Conditions

Payment by the customer of all charges herein is a condition of service under this Economic Load Response Program Rider.

RIDER ELR
Economic Load Response Program Rider

ADDENDUM TO THE CONTRACT FOR ELECTRIC SERVICE

This Addendum, effective __________________, 20___, establishes the following additional terms and conditions that are to be part of the Contract for Electric Service, dated __________________ for the Customer premises at ____________________________________ (the "Service Contract").

1. Customer has elected to participate in the Company's Economic Load Response Program ("Program") set forth in Company's Economic Load Response Program Rider included in Company's standard Tariff, P.U.C.O. No. 11 ("Tariff"), as amended from time to time (hereinafter "ELR rider"). Customer acknowledges that the terms and conditions of the Program are supplemental to, and do not replace, those set forth in the rate schedules and riders identified in the Service Contract. In addition the Customer makes the following elections: (a) Customer [elects/does not elect] to participate in the Emergency Curtailment option and (b) Customer [elects/does not elect] to participate in the Economic Buy Through option.

2. For purposes of participating in the Program, Customer's Firm Load, as that term is defined in the ELR rider, shall be ___________________________. This Firm Load may be altered, consistent with the terms of the ELR rider.

3. If applicable, the execution of the Service Contract and this Addendum supersedes the terms and conditions of any other interruptible or curtailment program under which Customer takes service at the time of executing this Addendum, rendering any terms and conditions of any such program null and void.

4. This Addendum (but not the Service Contract) shall automatically terminate if Customer no longer takes service under the ELR rider, or if the ELR rider terminates consistent with its terms.

Ohio Edison Company (Company)	____________________________________ (Customer)
By:______________________________	By:______________________________
Its:______________________________	Its:______________________________
On:______________________________	On:______________________________

EXHIBIT DWG-6

RECOMMENDED RIDER OLR

RIDER OLR
Optional Load Response Program Rider

APPLICABILITY:

This Optional Load Response Program Rider ("Program") is available to any customer taking service under the Company's general service tariffs served at primary voltages or higher voltages provided that the customer meets all of the following five conditions at the time of initiation of service under this Rider and on a continuing basis thereafter (i) the customer has at least one megawatt of Realizable Curtailable Load ("RCL"); (ii) the customer can successfully demonstrate to the Company that it can reduce its instantaneous measured load to a pre-established contract Firm Load (as defined below) within ten minutes of notification provided by the Company without the need of a generator. A customer may intend to use a generator to reduce its usage to below its Firm Load, but if the generator does not start, the customer must still reduce its usage to or below its Firm Load. Failure of a customer to reduce its usage to or below its Firm Load shall result in the consequences listed in the Emergency Curtailment Event Section herein; (iii) the customer executes the Company's standard Program contract; and (iv) the customer is taking generation service from the Company under the Generation Service Rider (GEN) or the Market Rate Provision of the Power Supply Reservation Rider (PSR); (v) the customer is not participating in any other load curtailment program, including without limitation a demand response program offered by the Midwest Independent Transmission System Operator, Inc. ("MISO") or any other independent system operator. This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

RATES:

In addition to any other charges under any other rate schedules applicable to customer's service, customers participating in the Program shall also pay the charges and receive the credit set forth below.

Charges:

Program Administrative Charge: $150.00 per month

EBT Charge:

If Customer elects in its contract to be subject to Economic Buy Through Events as defined below, during such an event, the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an EBT Charge, which is calculated for each hour of the event as follows:

EBT = (AL x MPD) x (1 + LAF) x {[1/(1 – CAT)]}

Where:

AL = the customer's actual hourly load during an Economic Buy Through Option Event that exceeds the customer's pre-established contract Firm Load.

MPD = the market price differential, which shall be calculated by subtracting the customer's otherwise applicable total generation related per kilowatt-hour charges set forth in the Company's tariffs from the MISO day ahead LMP for the period in which the Economic Buy Through Option Event occurred for each hour that results in a MPD greater than zero.

MISO LMP is the final Day Ahead Locational Marginal Price as defined and specified by MISO at the Commercial Pricing Node "FESR" (or its equivalent) during the applicable hour(s).

CAT = the Commercial Activity Tax rate (in decimal form) as established §5751.02 of the Ohio Revised Code.

LAF = Loss Adjustment Factor

3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

ECE Charge:

During an Emergency Curtailment Event (as defined below), the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an ECE Charge which is calculated for each hour of the event as follows:

ECE = (AL x MISO LMP x 300%) x (1 + LAF) x ([1/(1-CAT)]

Where:

AL = the customer's actual hourly load during an Emergency Event that exceeds the customer's pre-established contract Firm Load

MISO LMP is the final Day Ahead Locational Marginal Price as defined and specified by MISO at the Commercial Pricing Node "FESR" (or its equivalent) during the applicable hour(s).

CAT = the Commercial Activity Tax rate (in decimal form) as established in §5751.02 of the Ohio Revised Code.

LAF = Loss Adjustment Factor
3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

Customer may receive Emergency Curtailment or Economic Buy Through Program Credits, or both, as set forth below, depending on the Customer's election in its contract to participate in the Emergency or Economic Curtailment Program options or both under this Rider.

Emergency Curtailment Program Credit ("ECPC")

Customers taking service under this Rider who agree to be subject to Emergency Curtailment Events shall receive a monthly Program Credit which shall be calculated as follows:

PC = RCL x $7.50~~1.96~~/kW/month

Where:

RCL is the ~~predetermined~~ Rrealizable Ccurtailable Lload, which shall be calculated by the Company once per year for each customer by *subtracting the* customer's contract Firm Load from its Measured Demand each month as defined in the underlying rate schedule applicable to customer. ~~Average Hourly Demand ("AHD"). For purposes of this Rider, the AHD shall be the greater of 1) customer's average load during the hours of noon to 6:00 pm EDT and non-holiday weekdays during the months of June through August, excluding actual hours of any Emergency Curtailment Events occurring during the preceding 12 month period. The RCL shall not exceed the amount of a customer's billing demand in excess of the contracted Firm Load on a monthly basis. The customer shall be provided written notice each year by the Company of the value of the RCL at least thirty (30) days in advance of the effective date of the RCL.~~

Economic Buy Through Program Credit ("EBTPC"):

Customers taking service under this Rider who agree to be subject to Economic Buy Through Events shall receive a monthly Program Credit which shall be calculated as follows:

EBTPC = RCL x $2.60/kW/month

Where:

RCL is defined as set forth above.

OTHER PROVISIONS:

A. Firm Load

For purposes of this Rider, "Firm Load" shall be that portion of a customer's electric load that is not subject to curtailment. A customer may request a reduction to its contract Firm Load no more than once in any twelve month period. The Firm Load may be reduced to the extent that such reduction is consistent with other terms and conditions set forth in this Rider. Any such changes in Firm Load shall be applied beginning with the customer's January bill immediately following the year in which the change has been approved by the Company, provided that advance written request is provided to the Company no less than thirty (30) days prior to the effective billing month of the change. The Company may increase the Firm Load at any time if the Company, at its sole discretion, determines the Firm Load is at a level that the customer fails to demonstrate that they can reach. The Company shall promptly notify the customer of any such change.

B. Load Response Program Contract

Customers taking service under this optional rider shall execute the Company's standard Program contract which, among other things, will establish the Customer's Firm Load.

C. Metering

The customer must arrange for interval metering consistent with the Company's Miscellaneous Charges, Tariff Sheet 75.

D. Emergency Curtailment Event

Upon no less than ten minutes advance notification provided by the Company, a customer taking service under this rider that opts to be subject to Emergency Curtailment Events must curtail all load above its Firm Load during an Emergency Curtailment Event consistent with the Company's instructions. For purposes of this rider, an Emergency Curtailment Event shall be one in which the Company, a regional transmission organization and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area.

During the entire period of an Emergency Curtailment Event, the customer's actual measured load must remain at or below its Firm Load with such load being measured every clock half hour. A customer's actual measured load shall be determined using the greater of the customer's highest lagging kVa or highest kW during the Emergency Curtailment Event.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds its contract Firm Load, the Company may disconnect the customer from the transmission system for the duration of the Emergency Curtailment Event, at the customer's expense. The Company shall not be liable for any direct or indirect costs, losses, expenses, or other damages, special or otherwise, including, without limitation, lost profits that arise from such disconnection.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds 110% of its Firm Load, the customer shall be subject to all four (4) fo the following: (i) forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred; (ii) pay the ECE Charge set forth in the Rates section of this Rider; (iii) pay the sum of all Program Credits received by the customer under the Program during the immediately preceding twelve billing months which shall include credits from this Rider and the Generation and Economic Developent Credit Rider; and (iv) the Company's right, at its sole discretion, to remove the customer from the Program for a minimum of 12 months.

If at any time during the Emergency Curtailment Event a customer's actual measured load is greater than 100% and less than or equal to 110% of its Firm Load during the Emergency Curtailment Event, the customer shall forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred and shall pay the ECE Charge set forth in the Rates section of this Rider.

In the event of any conflict between the terms and conditions set forth in this rider and other service reliability requirements and/or obligations of the Company, the latter shall prevail.

E. Economic Buy Through Option Event

Upon no less than a 90 minute advance notification provided to the customer, the Company shall call an Economic Buy Through Event ("EBT") when a "Market Premium Condition" exists for at least three (3) consecutive hours during any day. A Market Premium Condition is defined as a point in time that the MISO LMP exceeds the otherwise applicable per kilowatt-hour net charges set forth in the Company's Generation (GEN) and Generation Phase-in (GPI) riders. In response to an EBT, the customer that opts to be subject to EBTs may curtail usage or buy-through subject to the EBT charge set forth above.

F~~E~~. Notification

Customers served under this Rider shall be provided notification of Economic Buy Through Option Events and Emergency Curtailment Events by the Company. Customers shall be provided clock times of the beginning and ending of these events, except the Emergency Curtailment Event notification may be stated such that customers must curtail their actual measured load to its Firm Load in 10 minutes from the time the notification is issued. Receipt of curtailment notifications shall be the sole responsibility of the customer.

Notification of an Economic Buy Through Option Event and Emergency Curtailment Events consists of an electronic message issued by the Company to a device or devices such as telephone, facsimile, pager or email, selected and provided by the customer and approved by the Company. Two-way information capability shall be incorporated by the Company and the customer in order to provide confirmation of receipt of notification messages. Operation, maintenance and functionality of such communication devices selected by the customer shall be the sole responsibility of the customer.

G~~F~~. Term

This rider shall become effective for service rendered in January 2009 ~~and shall expire with service rendered through December 31st, 2011~~.

A customer may terminate its participation in the Program upon no less than twelve (12) months advance written notice to the Company. Except as otherwise provided in this rider, a qualifying customer may return to the Program at any time after a hiatus from the Program of at least one (1) year.

H~~G~~. Conditions

Payment by the customer of all charges herein is a condition of service under this Optional Load Response Program Rider.

RIDER OLR
<u>Optional Load Response Program Rider</u>

ADDENDUM TO THE CONTRACT FOR ELECTRIC SERVICE

This Addendum, effective ________________, 20___, establishes the following additional terms and conditions that are to be part of the Contract for Electric Service, dated __________________ for the Customer premises at ___________________________________ (the "Service Contract").

1. Customer has elected to participate in the Company's Optional Load Response Program ("Program") set forth in Company's Optional Load Response Program Rider included in Company's standard Tariff, P.U.C.O. No. 11 ("Tariff"), as amended from time to time (hereinafter "OLR rider"). Customer acknowledges that the terms and conditions of the Program are supplemental to, and do not replace, those set forth in the rate schedules and riders identified in the Service Contract. <u>In addition the Customer makes the following elections: (a) Customer [elects/does not elect] to participate in the Emergency Curtailment option and (b) Customer [elects/does not elect] to participate in the Economic Buy Through option.</u>

2. For purposes of participating in the Program, Customer's Firm Load, as that term is defined in the OLR rider, shall be __________________________. This Firm Load may be altered, consistent with the terms of the OLR rider.

3. If applicable, the execution of the Service Contract and this Addendum supersedes the terms and conditions of any other interruptible or curtailment program under which Customer takes service at the time of executing this Addendum, rendering any terms and conditions of any such program null and void.

4. This Addendum (but not the Service Contract) shall automatically terminate if Customer no longer takes service under the OLR rider, or if the OLR rider terminates consistent with its terms.

Ohio Edison Company (Company)	______________________________ (Customer)
By:____________________________	By:____________________________
Its:____________________________	Its:____________________________
On:____________________________	On:____________________________

APPENDIX

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory commissions in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2008), on behalf of CMC Steel Alabama, Nucor Steel Birmingham, and Nucor Steel Tuscaloosa, re energy cost recovery.

2. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-08-10 (2008), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.

3. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re energy security plan proposal.

4. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 08-936-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re market rate offer proposal.

5. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 35269 (2008), on behalf of Texas Cities, re jurisdictional allocation of system agreement payments.

6. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43374 (2008), on behalf of Nucor Steel and Steel Dynamics, Inc., re alternative regulatory plan.

7. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 34800 (2008), on behalf of Texas Cities, re affiliate transactions.

8. Commonwealth Edison Company, before the Illinois Commerce Commission, Docket No. 07-0566 (2008), on behalf of Nucor Steel Kankakee, Inc., re cost-of-service and rate design issues.

9. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 07-0551-EL-AIR *et al.* (2008), on behalf of Nucor Steel Marion, Inc., re cost-of-service and rate design issues.

10. Appalachian Power Company dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 06-0033-E-CN (2007), on behalf of Steel of West Virginia, Inc., re power plant cost recovery mechanism.

11. Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership, before the Public Utilities Commission of Texas, PUC Docket No. 34077 (2007), on behalf of Nucor Steel - Texas, re acquisition of TXU Corp. by Texas Energy Future Holdings Limited Partnership.

12. Arkansas Oklahoma Gas Company, before the Arkansas Public Service Commission, Docket No. 07-026-U (2007), on behalf of West Central Arkansas Gas Consumers, re gas cost-of-service and rate design issues.

13. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-07-08 (2007), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.

14. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1056 (2007), on behalf of the General Services Administration, re demand-side management and advanced metering programs.

15. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2007-229-E (2007), on behalf of CMC Steel-SC, re cost-of-service and rate design issues.

16. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9092 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.

17. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1053 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.

18. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32907 (2006), on behalf of Texas Cities, re hurricane cost recovery.

19. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32710/ SOAH Docket No. 473-06-2307 (2006), on behalf of Texas Cities, re reconciliation of fuel and purchased power costs.

20. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 060001-EI (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and purchased power cost recovery.
21. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-05-0816 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
22. PacifiCorp (dba Rocky Mountain Power), before the Utah Public Service Commission, Docket No. 06-035-21 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re rate design issues.
23. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2006-2-E (2006), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
24. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31544/ SOAH Docket No. 473-06-0092 (2006), on behalf of Texas Cities, re transition to competition rider.
25. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-05-28 (2006), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
26. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
27. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050001-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and capacity cost recovery.
28. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31315/ SOAH Docket No. 473-05-8446 (2005), on behalf of Texas Cities, re incremental purchased capacity cost rider.
29. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050045-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
30. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 05-042-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re power plant purchase.
31. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.

32. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and interruptible rate issues.

33. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.

34. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.

35. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-11 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re time-of-day rate design issues.

36. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.

37. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.

38. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.

39. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.

40. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

41. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

42. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.

43. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribune*, *Billings Gazette*, *Montana Standard*, *Helena Independent Record*, *Missoulian*, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicle*, the Montana Newspaper Association, *Miles City Star*, *Livingston Enterprise*, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.
44. Louisville Gas & Electric *et al.*, before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.
45. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.
46. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.
47. FPL Group *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.
48. Entergy Mississippi, Inc., *et al.*, before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.
49. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.
50. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.
51. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.
52. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.

53. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.

54. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.

55. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.

56. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.

57. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.

58. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

59. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

60. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

61. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

62. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.

63. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.

64. Central Hudson Gas & Electric Corporation *et al.*, before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.
65. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
66. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
67. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
68. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
69. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
70. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.
71. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.
72. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.
73. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

74. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

75. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.

76. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.

77. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.

78. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.

79. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

80. Carolina Power & Light Company, *et al.*, Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

81. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.

82. West Penn Power Company, *et al.*, v. State Tax Department of West Virginia, *et al.*, Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.

83. Carolina Power & Light Company, *et al.*, Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.

84. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.

85. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.

86. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.

87. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.

88. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.

89. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.

90. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.

91. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.

92. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.

93. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.

94. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.

95. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.

107. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
108. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
109. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.
110. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
111. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 869 (1988), on behalf of Peoples Drug Stores, Inc., re cost of service and rate design.
112. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.
113. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.
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139. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.

140. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing testimony was served upon the following parties of record or as a courtesy, via U.S. Mail postage prepaid, express mail, hand delivery, or electronic transmission, on September 29, 2008.

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