Large Filing Separator Sheet

Case Number: 08-935-EL-SSO

Date Filed: 7/31/2008

Section: 1 of 2

Number of Pages: 200

Description of Document: Volume 1a
Application and Testimony

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FILE

Case No. 08-935-EL-SSO

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
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

VOLUME 1a

Electric Security Plan Application

Testimony

Filing Date: July 31, 2008

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	**Case No. 08-____-EL-SSO**

APPLICATION

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Ohio Edison Company (hereinafter "OE"), The Cleveland Electric Illuminating Company (hereinafter "CEI"), and The Toledo Edison Company (hereinafter "TE", with OE, CEI, and TE, individually referred to as "Company" and collectively referred to as the "Companies"), by this Application request regulatory authority to establish a standard service offer ("SSO") pursuant to R.C. § 4928.141 to be effective for a three year period commencing January 1, 2009.[1] As their SSO, and pursuant to and consistent with the provisions of R.C. § 4928.143, the Companies propose to implement their comprehensive Electric Security Plan (hereinafter "Plan") designed to provide stable pricing of energy services for their customers, assure supplies of electricity, enhance distribution service, maintain and improve the existing distribution system, and promote economic development, job retention, energy efficiency and peak demand reduction within their service areas.

A brief review of the recent history of electric utility regulation helps put this Application in perspective. In 1999, Am. Sub. S.B. 3 restructured the Ohio model for the rendition of electric service, moving it from a vertically integrated utility responsible for providing all components of retail electric service under comprehensive cost-based regulation to a structure where the generation function was separated, removed from regulation, and expected to operate in an environment where customers would shop for their generation service from competitive suppliers. Comprehensive Electric Transition Plans ("ETP") for each of the utilities, including the Companies, were approved by the

[1] Although filed as "SSO" pursuant to R.C. 4928.143 and to the proposed Rules, we request that the proposal be considered as if filed pursuant to any other statutory authority and case designations as may be applicable to the scope of the proposals made herein. Notice of this filing, as well as the separate Application filed this day pursuant to R.C. § 4928.142, is being provided to the parties in the Companies' Rate Stabilization Plan and Rate Certainty Plan proceedings, as well as their recent base distribution rate case and competitive bid proceeding. Accompanying that notice are complete copies of both of those filings, provided in electronic form on two compact discs to assist the recipients in their expeditious review.

Commission and intended to effect the move to this new framework in five years. Importantly, during this five-year market development period, utility rates were frozen at levels that had been established in 1990 for OE and 1996 for CEI and TE, and the Companies transferred their operating generation plants to a competitive affiliate.

In the period that followed, the wholesale electricity markets began to experience price volatility suggesting the prospect that customers would experience abrupt increases in prices for electric service in 2006 with the expiration of the rate constraints imposed under the ETPs during the market development period. As a response to this development, the Rate Stabilization Plan ("RSP"), and, subsequently, the Rate Certainty Plan ("RCP") were proposed by the Companies and adopted by the Commission, with the effect of assuring customers of price stability and certainty through 2008.[2]

In light of the experience in other states where electricity price caps had been lifted, and with the expiration of the rate plans approaching in 2009, the concerns about customer exposure to rate shock in Ohio reemerged and brought a legislative response which ultimately emerged in the form of Am. Sub. S.B. 221. The concerns surrounding electricity prices, however, had not arisen in a vacuum, and the broad scope of this legislation also contemplated plans and initiatives in response to its enactment that would address a broad range of topics including enhancing reliability and performance of an aging delivery system, developing societal interest in promoting renewable energy sources, energy efficiency and demand response, and, importantly, advancing the economic interests of the state in terms of job retention and economic development.

As relevant here, Am. Sub. S.B. 221 makes available two mechanisms to address the issues of how generation supply (in the form of an SSO under R.C. § 4928.141) will

[2] Rate plans were adopted for other electric utilities in the state as well.

be made available to customers in Ohio in 2009. One, a Market Rate Offer ("MRO"), provides for a competitive bid process to establish a utility's price for the SSO (R.C. § 4928.142). The other, an Electric Security Plan ("ESP")[3] under R.C. § 4928.143, provides a much broader, more flexible approach which can address not only the supply of generation as part of an SSO, but also allow for the inclusion of various provisions in an overall package to address the broad range of concerns contemplated within the scope of Am. Sub. S.B. 221. Importantly, the legislation expressly confers the legal authority on the Commission to approve these kinds of arrangements[4] if the ESP, considered as a whole, is deemed more favorable to customers than the result that would be expected under the more narrowly focused MRO.

The Companies' Plan proposed here is just such a holistic approach intended to address a broad variety of concerns. First, importantly, the Plan addresses price issues and does so from several perspectives, including that: 1) it provides price stability over the Plan period; 2) it settles pricing and service arrangements for the totality of electric service, not just generation; and 3) it provides substantial flexibility for the Commission to manage overall price trends over the Plan period.

Key price related features of the Plan include:

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[3] The term "Plan", as used herein, is a reference to the Companies' specific proposal in this Application. The acronym "ESP" is used, generically, to refer to arrangements under authority of R.C. § 4928.143.

[4] Indeed the introductory phrase "Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary" preceding the remaining language of R.C. § 4928.143(B), is a mark of the legislative intent to empower the Commission to sanction arrangements that capture a broad range of beneficial expedients within the scope of an ESP. Similarly, the fact that the list of potential ESP provisions enumerated in R.C. § 4928.143(B)(2) is prefaced by "without limitation" also demonstrates the considerable breadth of authority intended to be granted to the Commission.

- Overall, increases in total customer rates – including generation, transmission and distribution – would be moderated to an average of 5.32% in 2009, 4.01% in 2010 and 5.99% in 2011.[5]
- The waiver of further RTC and Extended RTC charges for CEI customers (which otherwise would continue through 2010), alone a step conferring a direct savings to these customers of *over half a billion dollars*.
- A three-year standard service generation offer of 7.5 cents per kilowatt-hour (kWh) in 2009, 8.0 cents per kWh in 2010, and 8.5 cents per kWh in 2011 for customers who choose to receive generation service from their distribution company.
    - This increase in the price of generation service would represent an average increase in a customer's total bill of 0.06 percent in 2009, 4.01 percent in 2010, and 5.79 percent in 2011.
    - To minimize the impact on customers even further, the Plan also includes deferring for future recovery approximately 10 percent of the generation price during the three-year Plan period. The Plan also allows for these deferred costs to be securitized.
- For customers who switch to an alternative generation supplier – either individually or as part of a governmental aggregation group – the Plan provides an option to elect to waive standby charges. For customers, waiver of the standby charges would mean that should they return to the utility for generation service anytime during the Plan period, they would do so at SSO market pricing for generation.[6]
- Resolution of the increase requested in the pending distribution rate case and a commitment to keep distribution rates in place through 2013 (absent limited unforeseeable circumstances).

[5] Adjustments included in the Plan could cause the percentages to be higher or lower than set forth.

[6] Upon the return of non-governmental aggregation customers who elected not to pay the standby charge to the utility for generation service, while they remain generation customers of the utility, they will pay the higher of SSO market pricing or SSO pricing otherwise applicable to such customers.

- Similar to the existing transmission rider, recovery of transmission and transmission-related costs, including ancillary and congestion costs, through a bypassable rider that would be adjusted annually to reflect actual costs incurred by the Companies to serve customers.

In considering the aspects of the Plan which address just the provision of generation service, the Plan is more favorable to customers than would be the MRO alternative. Significantly, however, in addition to the generation component alone, the Plan also has numerous other elements, carefully integrated into a package which, taken in the aggregate, is *considerably* more favorable to customers than the MRO alternative.[7]

Important among these elements is service reliability. In this regard, features of the Plan include:

- A commitment to invest at least $1 billion in capital improvements in the Companies' energy delivery systems through 2013.
- The establishment of appropriate SAIDI performance targets designed with performance incentives for the Companies skewed to benefit customers and tied to a Delivery Service Improvement rider that would, in part, support efforts to ensure the Companies' and customers' expectations pertaining to distribution reliability are aligned. This rider would be adjusted up or down by up to 15 percent annually, based on meeting certain goals related to distribution reliability.

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[7] The importance of integration of all the Plan components is not to be overlooked. This Plan is presented as an entire package, designed not only to provide the customer benefits it embodies, but to assure the Companies' ability to follow through on these commitments. It will not work for there to be picking and choosing, selecting only customer benefits without adequately providing the Companies the components required for them to be able to address the risks incurred in going forward. It should be understood that this Plan is not presented as if by each Company so that it may be approved with respect to one, but not another. It is presented on behalf of all three Companies collectively and must be accepted with respect to all of them.

Recognizing the importance of energy efficiency and demand response initiatives, the Plan also provides for:

- Up to $25 million to support energy efficiency and demand response programs.
- $1 million toward an Advanced Metering Infrastructure pilot program to determine the potential for deployment of advanced technologies to support time-of-day pricing and other demand-response and energy-efficiency programs.
- A commitment to undertake a comprehensive study of energy delivery system enhancement, including Smart Grid technologies.

The economic challenges facing the State of Ohio were clearly a major concern in the deliberations over Am. Sub. S.B. 221. In recognition of these issues, the Plan provides:

- Up to $25 million for economic development and job retention programs.

Integral to the design of the Plan is an arrangement with FirstEnergy Solutions ("FES") for generation supply. Under such an arrangement, there would be additional features expected to add to the benefits customers realize under the Plan. These include

- 1000 MW capacity additions.
- Environmental remediation and reclamation of up to $45 million over the term of the Plan.

In recognition of the constricted time period available to have a long-term ESP or MRO[8] in place on January 1, 2009, this Plan provides for a severable Short Term ESP

[8] The Companies have also this date made an MRO filing pursuant to R.C. § 4928.142.

Standard Service Offer ("Short Term ESP"). The Short Term ESP will help ensure that customers have price certainty on November 14, 2008 so that they may make timely 2009 budgeting decisions and will also provide additional time for the Commission's consideration of the entirety of the Plan. It also provides a more measured MRO timeline should the long-term ESP not be approved or implemented, which should foster greater bidding participation and, therefore, lower prices to customers. The Short Term ESP is a separate provision of the Companies' Plan and is severable and contingent upon its approval by the Commission on or before November 14, 2008. The Short Term ESP does not provide all the benefits of the Companies' entire proposed Plan, but is designed to provide a reasonable mechanism for generation pricing to be available on January 1, 2009 and to provide the Commission, and other parties, additional flexibility as to timing.

As previously noted, the Companies are also filing an Application for approval of an MRO under authority of R.C. § 4928.142. While the Companies firmly believe that the Plan proposed herein is more favorable than an MRO alternative, the matter of generation supply beginning January 1, 2009 must be addressed in some manner as the Companies do not own generation nor do their employees currently have experience in wholesale purchases, an expertise that now resides in their competitive affiliate. If an acceptable solution cannot be reached through an ESP mechanism, under the statute, an MRO is the alternative.

A. Proposed Electric Security Plan

The above section highlights important features of the Companies' proposed Plan. What follows in this section is a more detailed, comprehensive description of all the provisions of the Plan which should be read together with, and in light of, the various

Attachments referred to herein and the other documents and materials filed herewith, including the supporting testimony. A complete listing of all these accompanying materials, which are incorporated by reference herein as a part of this Application, is attached as an Appendix.

1. RTC Waiver

a. The RTC charge for CEI, which recovers both RTC and Extended RTC balances, will be waived for customers on a service rendered basis on and after January 1, 2009. From and after such date, customers will not receive Transition Rate Credits.[9] The waiver of further RTC and Extended RTC charges for CEI customers, which would otherwise continue through 2010, is a substantial direct savings to customers of *over half a billion dollars*. While the significance of the amount of such customer savings cannot be overstated, the benefits conferred upon customers are considerable and long lasting.

2. Generation

a. Price stability and predictability in the pricing of retail generation service are two of the cornerstones of the balanced approach taken in the Companies' Plan. As part of their required generation supply and pricing proposal, the Companies have committed to fixed generation prices, balanced by certain limited exceptions, to formulate their SSO for the Plan period, 2009-2011. This balance will provide stability to better provide an opportunity to customers to plan their energy budgets and needs over the life of the Plan, while the potential for limited exceptions permits the fixed prices to

[9] Transition Rate Credits are those residential rate credits initially approved in the ETP case (Case No. 99-1212-EL-ETP) and further preserved in the RSP and RCP cases (Case Nos. 03-2144-EL-ATA and 05-1125-EL-ATA respectively). Such credit is $5.00 per month for residential customers of CEI and TE and $1.50 per month for OE residential customers and a reduction of the RTC charge of 23.3%, 12.8% and 11.4% for OE, CEI, and TE residential customers respectively.

be set at a lower level than otherwise could be achieved. The Companies offer a fixed generation price separately for 2009, 2010, and 2011, with each year's price being phased-in by means of generation phase-in credits, with recovery of the amounts represented by the phase-in credits over a period not to exceed ten years. Phasing in the SSO pricing yields a reduction in generation pricing greater than ten percent during the Plan period, thereby mitigating the impact upon customers as pricing is transitioned to more closely reflect market pricing.

b. In 2009, the average base generation price is 7.5 cents/kWh, but the charge paid by customers in 2009 will be the phased-in price of 6.75 cents/kWh, representing a reduction of ten percent due to the phase-in. In 2010, the average base generation charge will be fixed at 8.0 cents/kWh, with the phased-in price for that year being 7.15 cents/kWh, also reflecting a reduction in excess of ten percent. Finally, in 2011, unless the Commission has terminated the third year of the Plan, which termination must occur prior to January 1, 2010, the average fixed base generation charge shall be 8.5 cents/kWh, with the phased-in price for 2011 being 7.55 cents/kWh, and also reflecting a greater than 10% reduction. Generation charges and phase-in credits will be seasonally and voltage adjusted for all three years in retail tariffs.

c. Before addressing the details of the proposal to phase-in a portion of the base generation charges, it is important to understand that the base generation charge also includes components covering the minimum default service rider and the standby charges, both discussed in more detail below. Amounts associated with these two charges will not be deferred and are not part of the deferral referenced in this paragraph.

d. The base generation prices also include all of the costs associated with the Companies' renewable energy resource requirements during the Plan period, and/or the equivalent cost for renewable credits. Such renewable energy resources will be acquired in sufficient amounts to comply with the requirements of Am. Sub. S.B. 221, without additional charge for the duration of the Plan period. In addition to meeting the renewable energy requirements without additional cost to customers, during the Plan period, the Companies will also offer a Green Resource program, similar to that approved in Case No. 06-1112-EL-UNC, so that residential customers who desire to take steps above and beyond these requirements in support of renewable generation will have the option to do so through the purchase of renewable energy credits.

e. Through the use of the generation phase-in, customers will gradually be moved closer to market prices for retail generation as compared to going directly to full market pricing. The amounts constituting the phase-in discount will be deferred, with carrying charges, and collected through a rider. Alternatively, at the Companies' option, and with Commission approval, those deferrals and carrying charges may be securitized and recovered. In either case, the recovery may not exceed ten years and would be non-bypassable (except to certain governmental aggregation customers consistent with R.C. § 4928.20(I)). For accumulated deferred phase-in discounts in 2009 and 2010, interest shall be deferred on the accumulated deferred balance including accumulated deferred interest, and without reduction for accumulated deferred taxes, until securitization or until January 1, 2011 at the rate of 0.7083 per cent per month. Thereafter, until recovery, if the amounts are not securitized, interest shall be deferred on the unrecovered accumulated deferred balances including accumulated deferred interest net of accumulated deferred income taxes at a rate equal to each Company's annual weighted cost of long term debt as of December 31, 2010. For accumulated deferred phase-in discounts in 2011 as well as any phased-in Capacity Cost Adjustment amounts as described in paragraph A.2.o, interest shall be deferred on the accumulated deferred balance including accumulated deferred interest, and without reduction for accumulated deferred taxes, until securitization or until January 1, 2013 at the rate of 0.7083 per cent per month. Thereafter, until recovery, if the amounts are not securitized, interest shall be deferred on the unrecovered accumulated deferred balances including accumulated deferred interest net of accumulated deferred income taxes at a rate equal to each Company's annual weighted cost of long term debt as of December 31, 2012. The estimated level of deferrals and details of the recovery mechanism are set forth in Attachment A. If the deferred amounts are not securitized, the accumulated balances including accumulated deferred interest existing as of December 31, 2010 will be recovered through a rider to customer rates as a non-bypassable charge starting January 1, 2011 at an initial rate averaging $0.002009 per kWh. This rate will be adjusted in subsequent months according to the recovery mechanics set forth in Option 1 in Attachment A. If the deferred amounts are not securitized, the accumulated balances including accumulated deferred interest existing as of December 31, 2012 will be recovered through a rider to customer rates as a non-bypassable charge starting January 1, 2013 at a rate averaging $0.003252 per kWh. This rate will be adjusted in subsequent months according to the recovery mechanics set forth in Option 1 in Attachment A. Recovery of the deferred costs pursuant to the recovery mechanics in Attachment A shall remain in effect until the deferred costs, including accumulated deferred interest, have been fully recovered, but in no event beyond December 31, 2022. The cost recovery rider will be reconciled semiannually during the recovery period to assure timely recovery of the deferred balances according to the recovery mechanics in Option 1 in Attachment A.

f. The Companies have proposed the securitization option set forth in Attachment A, whereby the accumulated balance of deferred generation charges, together with the associated carrying charges and the related securitization transaction costs may be securitized on at least an annual basis pursuant to R.C. § 4928.143(B)(2)(f) and § 4928.144 and recovered over the period of securitization bonds not to exceed 10 years. The amounts securitized shall be recovered though a non-bypassable deferred generation cost rider to be paid by existing and future customers receiving service from the Companies' rate schedules except in the case of certain governmental aggregation customers as provided for in R.C. § 4928.20(I). However, if securitization is utilized, the annual debt service costs during the plan period shall be, at the Commission's option, either (a) added to customer rates and the phase in credit in 2009, 2010 and 2011 shall be increased by the same amount, or (b) added to customer rates without additional deferrals. In any event, no costs attributable to the standby charge as described in paragraph A.2.k. shall be included in the amounts of phase-in discounts in 2009, 2010, or 2011.

g. The Companies will include, in their initial securitization transaction application, if such filing is made, details of the type specified in paragraph (E) of Appendix B (Requirements for Electric Security Plans) to draft Rule 4901:1-35-03. Those details will include the description of the securitization instrument. These details are not known at this time, and if the final rules contemplate that such details should be included in this filing, the Companies respectfully request a waiver from such requirement until the time of the filing of the initial securitization transaction application.

h. The base generation charge described in paragraph A.2.b. above includes a non-bypassable minimum default service charge for generation and administrative service under the Plan equal to 1.0 cent per kWh as permitted by R.C. § 4928.143(B)(2)(d). Such charge shall be effective January 1, 2009 on a service rendered basis. This charge is designed to compensate the Companies for the costs and risks associated with committing to obtain adequate generation resources to supply the entire retail load of customers in their service territories, a recognition of the risk and costs of customers switching to retail generation service provided by alternative generation suppliers at any time and in any amounts, consistent with the terms of any then existing ESP or applicable Commission Rules.

i. During the duration of the Plan, the only adjustments to the base generation charges described above are: 1) to recover, commencing on January 1, 2009 on a reconcilable and service rendered basis until full recovery is achieved, increases in fuel transportation surcharges imposed by shippers in excess of a baseline level of $30 million in 2009, $20 million in 2010, and $10 million in 2011; 2) costs associated with new alternative energy/renewable type requirements (other than those required under Am. Sub. S.B. 221), new taxes and new environmental laws or interpretations of existing laws becoming effective after January 1, 2008[10] to the extent such costs exceed $50 million during the Plan period and are related to the generation assets of FirstEnergy Solutions

[10] Renewable energy resource requirements imposed by Am. Sub. S.B. 221 are excluded from this exception.

used to support this Plan[11]; and 3) an adjustment that applies to costs arising in 2011 to recover increased fuel costs[12] above the level of fuel costs incurred in 2010. Recovery of the amounts described in this paragraph A.2.i. will be pursuant to the terms of the riders set out in Attachment B.[13]

j. Since the Companies would otherwise bear the risk of customer non-payment for non-distribution service, a non -bypassable Non-Distribution Service Uncollectible Rider shall be established to recover non-distribution costs. Such rider, effective January 1, 2009 on a service rendered basis, shall be initially set at the average rate of .0403 cents per kWh (composite of all Companies), but shall thereafter be reconciled annually to reflect actual uncollectible non-distribution costs. Additionally, in order to provide for recovery of uncollectible expense associated with PIPP customers to the extent such expense is incurred by the Companies as a result of modification of state policy on or after July 31, 2008, a non-bypassable PIPP Uncollectible Rider shall be established to recover such expense. Such rider, applicable to all customers effective January 1, 2009 on a service rendered basis, shall be initially set at a rate of 0.00 cents per kWh, but shall thereafter be updated and reconciled on an annual basis.

k. In addition to the risk associated with customers choosing to shop for generation service is the risk of customers coming back to the utility during times of rising prices. In order to address this risk, the Plan establishes a standby charge as

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[11] As set out in paragraph A.2.n.

[12] With respect to the Plan, the fuel costs shall be deemed to be those of the generation assets owned or controlled by FirstEnergy Solutions or any of its subsidiaries and used to support this Plan as set out in paragraph A.2.n.

[13] For purposes of this section A.2.i. (and with respect to Attachment B, for purposes of both the "Fuel Transportation Surcharge, Environmental Control and New Taxes" and "Fuel Cost Adjustment" provisions), it shall be assumed that: 100% of the FES generation used in support of the Plan is used to provide service under the Plan; taxes refers to any new tax on FES or the Companies arising out of any generation related item (to be construed in the broader sense); and that costs, including fuel costs, refers to those of FES associated with the generation used to support the Plan.

permitted under R.C. § 4928.143(B)(2)(d). While Am. Sub. S.B. 221 provides that governmental aggregation groups may avoid such charge if they agree to pay market prices when they return to utility service, the Companies have broadened that concept. Under the Plan, an option available to all customers that switch to a competitive supplier for retail generation service, whether individually or as part of a governmental aggregation program, is that the customer may choose whether or not to pay a standby charge. The standby charge is therefore bypassable for all customers at their option. The charge is 1.5 cents/kWh in 2009, 2.0 cents/kWh in 2010, and 2.5 cents/kWh in 2011. If the shopping customer pays this charge each monthly billing period during the time period the customer is shopping, then the customer may return to the applicable Company SSO at the pricing level set forth above in paragraph A.2.b. for the remainder of the Plan or until the customer selects another competitive supplier, but the customer must remain with the Company and pay the SSO price for at least 12 consecutive months or the remaining term of the Plan, whichever is shorter. For aggregation customers who do not pay the standby charge in any month but who return to the utility for generation service, such customers will pay, as long as they are taking SSO service, the applicable Company SSO reflecting the market price for retail service for the duration of the Plan term as further described in Attachment C to this Application.[14] For purposes of applying this provision, any member of a household or any continuing business at the same location shall be considered the customer irrespective of the name on the account. The Companies may require verification before allowing any customer to receive SSO service at a location for which a competitive supplier has provided service.

[14] For non-aggregation customers who do not pay the standby charge in any month but who return to the utility for generation service, such customers will pay the higher of the SSO reflecting the market price for retail service or the otherwise applicable SSO price for the duration of the Plan term.

l. As a condition of entering into a contract with FES for generation service, the Companies will require FES to commit to adding 1000 MW of capacity from January 1, 2007 - December 31, 2011 through (i) new or upgrading existing generation, which may include renewable generation through contracts or otherwise; (ii) maintaining existing generation in service that would otherwise be shutdown pursuant to court order without installing environmental control equipment or repowering consistent with such order or decree; and/or (iii) additional generation. Such a commitment provides considerable benefit to the region and customers in the Companies' service territory in that building and adding generating capacity serves to alleviate the burden of capacity constraints and meet the growing electricity demand. Additional generation ensures that energy resources will meet the increasing demand of the region's existing and new industries, as well as the region's residential customers. Moreover, statewide concerns over the lack of generating capacity are significantly addressed with such a commitment that will help meet the region's long-term energy needs. Attachment D sets forth the resources proposed to meet the requirements of this section.

m. In addition, as part of the Companies' ongoing commitment to environmental stewardship and as part of the agreement between the Companies and FES, the Companies will require FES to support and/or undertake environmental remediation and reclamation of existing retired generating plants and/or manufactured gas plant sites located in Ohio which are owned by the Companies and for which the Companies bear a remediation obligation. FES will be required and obligated during the period January 1, 2009 through December 31, 2011 to cover up to a maximum of $15 million per year of such costs, and the Companies will endeavor to the extent possible to cause such remediation to occur during the Plan period.

n. Capacity purchases required to meet FERC, NERC, MISO or other applicable standards for planning reserve margin requirements for Ohio retail load of the Companies (recognizing that such standards may be subject to change during the Plan period) will be provided by FES and recovered under a rider, as a bypassable Capacity Cost Adjustment charge. More specifically, (i) capacity owned by FES in MISO - including OVEC, but excluding capacity owned by FES in PJM such as Beaver Valley and Seneca capacity, not used to supply hourly load requirements, will be made available to meet such planning reserve requirements; (ii) FES capacity at the Fremont station will be considered MISO capacity on the date it is placed in service; (iii) to the extent FES capacity as determined in (i) and (ii) above is insufficient to meet planning reserve requirements, FES will purchase such necessary installed capacity reserves; and (iv) the costs of capacity purchased to meet the planning reserve requirements for Ohio retail load for the Companies for the period May 1 through September 30 of each calendar year of the Plan will be recovered pursuant to the bypassable Capacity Cost Adjustment Rider. During all other periods of each calendar year, any capacity purchases by FES to meet planning reserve requirements shall not be recoverable.

o. The Commission may, at its discretion, elect to increase the generation rate phase-in amounts set forth in paragraph A.2.b. above, to the extent of any charges for planning reserves under the Capacity Cost Adjustment charge provided for in A.2.n above but only to the extent such charges exceed 1.5% of the then existing average annual total rates of the Companies. This provision of the Plan provides additional flexibility for the Commission to mitigate and defer generation price increases and allow for a more gradual transition to generation rates under the Plan.

3. Distribution

a. The Companies, pursuant to R.C. § 4928.143(B)(2)(h), include in this Plan provisions pertaining to their electric distribution service. Such provisions are designed to ensure customers' and the Companies' expectations are aligned and that the Companies are placing sufficient emphasis on and dedicating sufficient resources to the reliability of their distribution systems. These Plan provisions are as follows:

b. In order to resolve the Companies' Case No. 07-551-EL-AIR ("Distribution Case") currently pending before the Commission and to enhance rate stability, this Plan provides for new distribution base rates. Such rates shall be effective for OE and TE on a service rendered basis on and after January 1, 2009, and shall be effective for CEI on a service rendered basis on and after May 1, 2009. The annual distribution rate increase over the rates in effect at the time of filing the Companies' Distribution Case, based on test year determinants in that case, shall be as follows: $75 million for OE, $34.5 million for CEI, and $40.5 million for TE. Additionally, during the period January 1, 2009 through April 30, 2009, CEI shall be authorized to defer $25 million in distribution-related costs incurred, and such deferred amounts shall be added to the deferred distribution balance and recovered through the Deferred Distribution Cost Recovery Rider discussed below. This annual distribution rate increase represents a fraction of the amount originally filed in the Companies' Distribution Case. The discounted amount requested pursuant to this Plan balances the Companies' need to increase distribution charges, as the costs the Companies incur continue to increase, and customer petitions that the Companies attempt to mitigate distribution rate increases to the fullest extent possible.

c. The Companies commit pursuant to this Plan to forego seeking additional distribution base rate increases to be effective before January 1, 2014, except in a case of an emergency pursuant to the provisions of R.C. § 4909.16, or for new or increased taxes or as otherwise provided in this Plan (the "Rate Freeze"). The Companies are not precluded during this period, however, from implementing changes in rate design that are designed to be revenue neutral or any new service offering, both as approved by the Commission.

d. Under the Plan, the Commission will be deemed to have resolved the following Distribution Case issues accordingly: (i) establish the allowed rate of return on equity for each of the Companies at 10.5% which reflects the midpoint of Staff's recommendation in the Companies' Distribution Case, and the necessary accounting authority as filed by the Companies to effectuate the proposed distribution base rate increase; (ii) approval of the revenue distribution and rate design stipulation, as modified by Commission Staff to include a single-block residential rate structure; (iii) approval of the Companies' proposed tariffs, including certain Commission Staff modifications which were accepted by the Companies; and (iv) acknowledgement of an understanding that the Companies will continue to work with the Commission Staff to ensure Commission Staff is provided sufficient information to effectively continue its routine audits.[15]

[15] Recovery of post date certain deferral balances are not a part of the resolution of the Distribution Case but are handled pursuant to paragraph A.6.b. of the Plan and deferred fuel costs handled in A.6.d..

e. In recognition of the importance of the overall health and physical and financial sustainability of the distribution business and the need and the desire by all to assure the continued reliability of the distribution system, the Companies during the period January 1, 2009 through December 31, 2011 shall establish a Delivery Service Improvement ("DSI") rider. The DSI rider will help enable the Companies to manage the increasing costs of providing electric distribution service, the need to expend capital for equipment far earlier than before, the need to train new employees to replace retirees, the need to replace components of an aging distribution system, the importance of reliability, and the emergence of new technology, such as Smart Grid. The DSI rider shall be a non-bypassable distribution charge equal on average, prior to the annual adjustment described in paragraph A.3.f, to 0.2 cents per kWh in 2009 through 2011.[16]

f. In order to align customers' and the Companies' interests, the DSI rider will be subject to an upward or downward adjustment each annual period April 1 through March 31, starting in 2010, based on a performance band, set forth in Attachment E, which is tied to the Companies' SAIDI reliability performance. The Companies' SAIDI targets shall be 120 minutes (which represents the current target of OE and TE and a revised target for CEI). In addition, as described in Attachment E, a rear lot reduction factor will be applied to CEI's customer outage minutes. The performance band represents an asymmetrical range from 90 minutes to 135 minutes that is skewed to benefit customers. The annual adjustment DSI rider for performance shall not exceed 15% of the average DSI rider charge (in the aggregate for all Companies) in any calendar year and shall continue to be effective through December 31, 2013 in the same calculated

[16] For technical reasons, the DSI rider is actually effective through 2013, but its charge in 2012-2013 is 0.0 cents per kWh.

amount and reflected in distribution charges even though the DSI rider value would be zero. The DSI rider shall not be considered a contribution in aid of construction or be used in any determination of excessive earnings.

g. The Companies commit pursuant to this Plan to make capital investments in their distribution system[17] in the aggregate of at least $1 billion, during the period January 1, 2009 through December 31, 2013. Such commitment shall help ensure that during the Rate Freeze period sufficient capital is being spent to address distribution system improvements.

h. During the period January 1, 2009 through December 31, 2013, the Companies in the aggregate may defer the following: (a) storm damage expenses in excess of $13.9 million annually; (b) additional costs, including post-in-service carrying charges, resulting from any changes in line extension costs recovery (as compared to the Companies' proposed line extension program in the Distribution Case) as a result of rules and/or policies implemented pursuant to R.C. § 4928.151; and (c) depreciation, property tax obligations and post-in-service carrying charges (at the rate of 0.7083 percent per month) on gross plant distribution capital investments placed in service after December 31, 2008 and made to improve reliability and/or enhance the efficiency of the distribution system. A non-bypassable Storm Damage and Distribution Enhancement rider shall be established to recover the accumulated deferred balance (including accumulated deferred interest) commencing January 1, 2014 on a service rendered basis over approximately a 10-year period. Interest shall be deferred on such accumulated deferred balance, including accumulated deferred interest and without reduction for accumulated deferred income taxes, for the period January 1, 2009 through December 31, 2013 at the rate of

[17] The distribution system is everything below 69 kV.

0.7083 percent per month. From January 1, 2014 until recovery is complete, interest shall be deferred at a monthly rate equal to one-twelfth of the annual weighted average cost of long-term debt outstanding on December 31, 2013 for each of the Companies on the unrecovered balance (including accumulated deferred interest) net of accumulated deferred income taxes.

4. AMI, Smart Grid, Energy Efficiency, Demand Response, Economic Development and Job Retention

a. The Companies will conduct an AMI pilot program using advanced metering technology capable of displaying real time energy usage to approximately 500 individual residential customers – all as set forth in Attachment F. The Companies will not seek recovery for the first $1 million of the costs associated with the pilot. Any costs incurred above that amount will be recovered through the Companies' proposed Demand Side Management and Energy Efficiency rider.

b. The purpose of the AMI pilot is to determine whether a program that combines Summer time-of-day generation rates with real time energy usage information can effectively change customer behavior and energy consumption. The program will provide participating customers with the ability to lower energy costs by shifting and/or reducing electricity usage during peak and critical peak times to off peak times when demand for electricity and rates are lowest.

c. The Companies will offer Dynamic Peak Pricing for the program. Once participants in the study are selected, the Companies will choose a similar group of customers as a control group for comparison. The Companies will implement the program using advanced metering technology in conjunction with its existing technical resources such as communication, meter data management and billing systems. The pricing program will be offered on a voluntary basis to customers that the Companies have determined to have discretionary summer usage, such as air-conditioning. The data collected via the pilot program will provide information indicative of the target group's behavior to dynamic price signals and the availability of real-time usage information.

d. As an approach for reaching some consensus regarding the optimal design and implementation of AMI programs going forward, the Companies propose a collaborative process in which interested parties provide input on the AMI process as well as discuss the Companies' proposed AMI pilot program and work cooperatively with the Companies in potential AMI plan designs going forward. This approach significantly and effectively limits the amount of contested matters and leads to greater understanding of the issues. It also requires less regulatory intervention, as the parties work out most, if not all, of their differences outside of the regulatory proceeding. A collaborative process can be very effective in developing successful, cost-effective programs. The Companies therefore recommend that a small group of major stakeholders agree to enter into a collaborative process starting 60 days after the final order in this case whose purpose is to: discuss the Companies' proposed AMI pilot; analyze the potential for continued investment by the Companies in AMI; design potential programs on a comprehensive and cost-effective basis; and, if mutually decided, facilitate the implementation and cost recovery of such programs by the Companies.

e. The details of the process would be worked out among the key stakeholders that participate. The first task of the collaborative would be to establish the overall goals and objectives of the process. The Companies propose a six month process to develop and refine collaboratively with interested stakeholders potential program designs. This allows sufficient time for meaningful input from the stakeholders, and would allow the Companies sufficient time for evaluation. Following the last summer period during which it would be in place, the Companies will assess the results of the proposed AMI pilot program and consider the information provided as part of the collaborative to make a determination of whether such AMI implementation is cost effective and in the best interests of customers and the Companies. As a result of such determination, the Companies may file an AMI plan for Commission review and approval, which would include a cost recovery mechanism such as that proposed by Commission Staff in the Companies' Distribution Case.

f. The Companies also commit to undertake and complete a comprehensive Smart Grid study on or before December 31, 2009, as more fully described in Attachment E.

g. Recognizing the importance of energy efficiency and demand response programs, the Plan also provides for significant investment to support such initiatives. The Companies will commit to provide up to $5 million of investment each year from January 1, 2009 to December 31, 2013 for customer energy efficiency/demand side management improvements made on and after January 1, 2009. Such investment, up to $25 million over the duration of the Plan, will provide a significant incentive for customer implementation of such programs. Moreover, there will be no recovery of such costs for the Companies. Therefore, these initiatives will come at no additional cost to customers.

h. The economic challenges facing the State of Ohio were clearly a major concern in the deliberations over Am. Sub. S.B. 221. Therefore, in recognition of the importance of regional economic growth and development in the Companies' service territory and to help facilitate the state's effectiveness in the global economy, the Companies further commit up to an additional $5 million of investment each year during that same period for economic development and job retention activities. Such commitments, up to $25 million over the duration of the Plan, will be made without recovery of the investment in the Plan.

i. As a means of further encouraging economic development, including job creation and retention, capital investment, incremental and retained load, and incremental and retained benefits such as local and state tax dollars and employment from business opportunities, the Plan includes the establishment of Economic Development, Reasonable Arrangements, Demand Side Management and Energy Efficiency and the Delta Revenue Recovery riders. The Economic Development rider will promote gradualism, recognize the efficient use of electricity, and mitigate overall bill impacts to customers through a series of credits and charges. Lessons learned from other states show that it is desirable from the perspective of economic stability of a region to proactively address issues of disproportionate rate impact typically felt by those customers previously served on tariffs with below average rates. Mechanisms such as this help promote the economic vitality of the area served and thereby foster job retention and promote economic development. As a result of implementing such a rider, the rate impact on some customers, such as certain residential rate schedules of the Companies, will be cut in half. The sum of all the credits and charges in this rider is revenue neutral (i.e. charges equal credits) for the Companies and any differences shall be reconciled on a annual basis until recovery is achieved. The credit or charge also reflects differences in rate schedule prices from voltage-based costs. Credits, if any, will only be available to customers taking SSO generation service from the Companies. The charges under this rider are non-bypassable. The Reasonable Arrangements Rider provides the mechanism to administer certain tariff discounts pursuant to R.C. § 4905.31, R.C. § 4905.34, and under the Commission's proposed rules pursuant to 4901:1-38 – Reasonable Arrangements. To qualify for such treatment the customer must commit to certain energy efficiency improvements. The discounts associated with this Rider will be forfeited if a customer receiving the discount switches generation service to an alternative supplier. The Demand Side Management and Energy Efficiency rider will recover costs incurred by the Companies associated with energy efficiency, peak load reduction and demand side management programs, including recovery of lost distribution revenues resulting from implementation of such programs and any unrecovered DSM program costs from the Rate Certainty Plan. A Delta Revenue Recovery rider will be established to recover the difference in revenue from the application of rates in the otherwise applicable rate schedule and the result of any reasonable arrangement, governmental special contract, or unique arrangement approved by the Commission.

j. The Reasonable Arrangements Rider, the Delta Revenue Recovery rider and Demand Side Management and Energy Efficiency riders will continue after December 31, 2011 to the extent such riders are necessary to provide tariff discounts and to recover delta revenues for contracts approved by the Commission after January 1, 2008 and to recover energy efficiency and peak load reduction program costs.

k. As permitted by RC § 4928.143(B)(2)(i), the Economic Development Rider, the Delta Revenue Recovery rider and the Demand Side

Management and Energy Efficiency rider will be determined and allocated across all classes of customers of all the Companies, as the Companies are in the same holding company system.

5. Transmission

a. The Companies propose to implement a similar recovery mechanism for transmission costs as exists in the Companies' tariffs today, *i.e.*, recovery, through a reconcilable rider, of all transmission and transmission-related costs, including ancillary and congestion costs as well as new charges which are or may be imposed on or charged to the Companies by FERC or a regional transmission organization, independent transmission system operator, or similar organization (hereinafter, a regional transmission organization, independent transmission system operator or similar entity referred to as an "RTO") approved by FERC. Such transmission charges, including net congestion, and ancillary service charges, reflect applicable FERC-approved charges or rates. The Companies currently are located within the Midwest Independent Transmission System Operator ("MISO") RTO footprint and, as a result, the Companies currently incur these transmission charges under the MISO tariffs and agreements.

b. This rider mechanism is appropriate for the recovery of RTO transmission and ancillary service-related costs and congestion costs because these costs represent federally-approved rates for electric services the Companies obtain in interstate commerce that is regulated by the FERC. The Companies propose to recover only the costs of such services under the applicable RTO tariff(s) or agreement(s), and the proposed rider mechanism is the best way to ensure that they recover neither more nor less than those costs. It is important to note that the applicable RTO, not the Companies, controls the RTO tariffs and agreements and, as such, the RTO is the entity that frequently adjusts the charges for service under the RTO tariff agreements. The rider will be avoidable by retail customers who select an alternative supplier.

6. Legacy issues

a. Ratepayers have received the benefit of service rendered in prior periods the costs of portions of which have, with Commission approval, been deferred for future recovery. The recovery of the associated deferred balances is provided for in this section of the Plan.

b. A Deferred Distribution Costs Recovery Rider shall be established to recover the following: 1) the post-May 31, 2007,[18] unrecovered balances of distribution costs deferred under the Rate Certainty Plan (Case No. 05-1125-EL-ATA); 2) the deferred distribution-related costs incurred by CEI during the period January 1 through April 30, 2009 pursuant to paragraph A.3.b.; 3) the post-May 31, 2007 unrecovered balances of deferred transition taxes under the Electric Transition Plan (Case No. 99-1212-EL-ETP); and 4) the post-May 31, 2007 unrecovered balances of line extension deferrals pursuant to Case No. 01-2708-EL-COI. The amounts of such balances are set out, and the rider shall be established in the manner set forth, on Attachment G. The Deferred Distribution Costs Recovery Rider shall be effective January 1, 2011 on a service rendered basis. Interest shall be deferred on the accumulated deferred balances (including accumulated deferred interest): 1) for the period January 1, 2009 through December 31, 2010 at the rate of 0.7083 percent per month and without reduction for accumulated deferred income taxes; and 2) for the period January 1, 2011 until recovery is complete at a monthly rate equal to one-twelfth

[18] *May 31, 2007 is the date certain in the Companies' pending Distribution Case.*

of the weighted average book cost of long-term debt outstanding on December 31, 2010 for each of the Companies on the unrecovered balance net of accumulated deferred income taxes. The Deferred Distribution Costs Recovery Rider shall be non-bypassable.

c. Pursuant to its Finding and Order in Case No. 04-1931-EL-AAM, the Commission permitted the Companies to defer certain incremental transmission and ancillary service-related charges, with recovery of such deferrals authorized in Case No. 04-1932-EL-ATA. Under the Plan, recovery of such deferrals will continue, commencing January 1, 2009, and ending December 31, 2010, pursuant to a non-bypassable Deferred Transmission Costs Recovery Rider. The amounts and balances of such deferrals are set out, and the rider shall be established in the manner set forth, on Attachment G.

d. As part of the Companies' RSP as modified by the RCP, the Companies were authorized to defer and recover certain fuel costs above an established baseline. The Stipulation in the RCP case stated that recovery of these deferred fuel costs would occur as a part of the Companies' next distribution base rate proceeding, however the Supreme Court of Ohio ruled that deferred fuel costs could not be collected through distribution rates. Thereafter, the Companies, per the Commission's direction, filed an application on remand to establish the recovery mechanism for these deferred fuel costs. Prior to the enactment of Am. Sub. S.B. 221, the Commission allowed the current recovery of 2008 fuel expense that would have otherwise been deferred. However, recovery of the 2006 and 2007 deferred fuel expense and associated carrying charge is currently pending before the Commission in Case No. 08-124-EL-ATA *et seq.*, which proceeding has been continued to permit the resolution of the recovery mechanism for these deferred fuel costs to occur in this proceeding. As part of the Companies' Plan, the Companies will establish a non-bypassable rider to recover the accumulated deferred balance of these fuel costs as of December 31, 2008, including interest at each Company's annual weighted book cost of long-term debt as of June 30, 2008, over a period not to exceed 25 years. Based upon a 25-year recovery period, the recovery factor for each of the Companies will be as follows: Ohio Edison 0.0375 cents/kWh, CEI 0.0339 cents/kWh, and TE 0.0260 cents/kWh, which will be reconciled on an annual basis. Such rider will be effective commencing on January 1, 2009 on a service rendered basis.

7. Procedural Aspects

a. The filing of an ESP is required by R.C. § 4928.141. Under R.C. § 4928.143, the Commission has a maximum of 150 days to rule on the Companies' ESP application. R.C. § 4928.141 also permits the filing of an MRO under R.C. § 4928.142. The Companies have also filed an MRO, and the Commission has up to 90 days to rule upon that application. If the Commission does not approve the ESP as filed, or with modifications acceptable to the Companies within 150 days, the Companies could proceed immediately with their competitive bid under their approved MRO, retail generation pricing would then forever be established through a competitive bidding process as contemplated by R.C. § 4928.142(F), and the benefits of the ESP proposed by the Companies would not be realized.

b. As part of the process of the Commission's approval of an ESP, the Commission by order shall approve or modify and approve an application filed under division (A) of R.C. § 4928.143 if it finds that the ESP so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under an MRO.[19] R.C. § 4928.143(C)(1). The Company has submitted the testimonies of Mr. David M. Blank and Mr. Kevin Warvell in support of the fact that the ESP is more favorable than would otherwise be expected if retail generation pricing were set through a competitive bidding process. The conclusion of these testimonies is that the ESP taken in the aggregate is more beneficial than an MRO.

c. The Plan is presented, collectively, by all three Companies and its offer is conditioned on its acceptance in its totality with all of its provisions and accepted for all three Companies.

d. In the period during which this Plan is in effect, the determination of significantly excessive earned return on common equity pursuant to R.C. § 4928.143(F) shall be made as set forth in Attachment H. R.C. § 4928.143(E) and the determination contemplated thereunder is inapplicable to this Plan because the Plan duration is not greater than three years.

e. The term of this Plan is three years unless, after hearing, the Commission determines to terminate the Plan effective January 1, 2011. The duration of this Plan (including for purposes of determining the applicability of R.C. § 4928.143(E)) is the period during which the standard service offer provided by it is in effect, i.e., through December 31, 2011, which will be the termination date of the Plan unless, after hearing, the Commission by final Order issued not later than December 31, 2009, determines to terminate the Plan effective January 1, 2011. If such a decision is not rendered prior to such date, the Plan shall be authorized to continue through December 31,

[19] As the Companies do not own any operating electric generating facilities, the MRO would be for 100% of the SSO load.

2011. If the Commission terminates the Plan effective January 1, 2011, then also terminated as of that date are the Companies' 2011 obligations under paragraphs A.2.a., A.2.i., A.2.k., A.2.m. through A.2.o., A.4.i. (regarding the Economic Development Rider), A.5.a, A.5.b, and A.7.d. (except as to the final test required). Any and all provisions for reconciliation or recovery of deferral cost, however, shall survive termination until such recovery and reconciliation is complete.

f. The following provisions will survive termination of the Plan on December 31, 2011 (or after December 31, 2010 if the Commission terminates the Plan after two years pursuant to the provisions of paragraph A.7.e.): 1) paragraphs A.2.f. (relating to securitization), A.3.b. through A.3.d., A.3.f., A.3.g., A.3.h., A.4.a. through A.4.f. (to the extent that any implementation of such programs remain), A.4.i. (with respect to the Demand Side Management and Energy Efficiency Rider, Delta Revenue Recovery Rider, Reasonable Arrangements Rider, and, to the extent only of any recovery and reconciliation, the Economic Development Rider), A.7.d. (with respect to the final test required), A.7.h., A.7.i., and any and all provisions for reconciliation or recovery of deferral cost until such recovery and reconciliation is complete.

g. Upon the occurrence of any of the following: 1) if the Plan should terminate or if any of its provisions are modified or rejected as the result of a decision on appeal to any court of competent jurisdiction, 2) if the Companies do not accept a modification of the Plan made as result of a decision on appeal to any court of competent jurisdiction, or 3) in the event of any finding or determination adverse to any of the Companies regarding the significantly excessive earnings criteria of R.C. § 4928.143(F), then at the Companies' election and subject to such decisions, the Companies' obligations as identified in the fourth sentence of paragraph A.7.e. above shall immediately terminate, except as to any reconciliation or recovery of deferred costs which shall continue until such recovery and reconciliation is complete, and the provisions of paragraph A.7.f. shall continue. In addition, the following provisions shall also terminate: the Companies' obligations under A.1.a., A.2.l., A.3.c., A.3.f., A.3.g., and A.4.a. through A.4.h.

h. Should the market price to be paid by customers/aggregation groups be altered in a manner unacceptable to the Companies on any appeal or otherwise be unenforceable, then for such customers, the difference in the amount that would have been charged for market generation service and what they pay for service under their tariffed rate shall be considered a rate stabilization charge, the cost of which shall be spread across all customers and shall be non-bypassable.

i. Unless the Companies otherwise agree, the generation price effective upon termination of the generation prices under this Plan shall be determined pursuant to a competitive bid. The Companies will use the previously approved MRO process to conduct the competitive bid, as such process may be updated and modified by the Companies through a filing with the Commission. The Companies may also implement their approved MRO and conduct a competitive bid following the Commission's rejection of this Application, the Companies' express rejection of the Commission's modifications to the Plan proposed herein, or 150 days following the filing date hereof, all consistent with Am. Sub. S.B. 221. Except as otherwise provided in sections A.8.a-d., in the event the Commission does not approve the Plan as filed by

December 10, 2008, or such other date as the Companies may agree, the Companies may withdraw the Plan.

j. To the extent necessary, the terms and conditions of the Plan will be embodied in a wholesale power sales agreement between the Companies and FES, which agreement will contain wholesale pricing and necessary arrangements and will require FERC approval or a general affiliate waiver. The Plan is conditioned upon all necessary FERC approval of the agreement between FES and the Companies to carry out the terms and conditions of matters set forth herein.

8. Severable Short Term ESP SSO Pricing

a. In recognition of the constricted time period in which Am. Sub. S.B. 221 allows the Commission to act on an ESP application coupled with the fact that the Companies do not own generation nor do they currently have employees skilled in the purchase of wholesale power, and taking into account the aggressive schedule that implementation of the Companies' proposed MRO would require, the Companies propose a Severable Short Term ESP Standard Service Offer ("Short Term ESP") in addition to the longer term ESP Standard Service Offer described earlier in this Application (Paragraphs A.1.a. through A.7.j. of the Plan, hereinafter referred to as the "longer term ESP"). The Commission must choose whether to accept this Short Term ESP by November 14, 2008 or it is deemed withdrawn from the Plan. Approval of the Short Term ESP provides a number of substantial benefits to customers, the Commission and the Companies. These include:

- Customers obtain early price certainty for January 1, 2009.
- The Commission gains additional time for consideration of the longer term ESP.

- If the MRO is selected as the standard service offer, it provides for a more orderly competitive bid process.
- In the event the Commission makes modifications to the longer term ESP, the Companies secure adequate time to fully consider the PUCO ordered modifications.

b. By approving the Short Term ESP on or before November 14, 2008, the Commission will have established known rates that will be in effect on January 1, 2009, in the event that there is no approved ESP acceptable to the Companies within the 150 day period provided pursuant to Am. Sub. S.B. 221.[20]

c. The Short Term ESP provides the Commission until March 5, 2009 to act on the longer term ESP. During the term of the Short Term ESP, if the Commission approves the longer term ESP on or before March 5, 2009 or modifies the longer term ESP in a manner acceptable to the Companies, then the provisions of the longer term ESP (or modified longer term ESP if accepted by the Companies) will become effective seven days following Commission approval. If no action is taken on the longer term ESP by March 5, 2009 or if the Commission rejects the longer term ESP, the Companies will proceed to implement the competitive bid process under their MRO application and the following schedule:

- The procurement auction bidding will occur on April 8, 2009.
- The Short Term ESP rates would cease at the end of April 30, 2009.
- Power supply from successful bidders will commence on May 1, 2009.
- MRO rates will be effective for service rendered on May 1, 2009.

d. Except as otherwise provided in this paragraph, the Short Term ESP terms and conditions are those set forth in the longer term ESP. For the Short Term

[20] This Short Term ESP proposal is a separate ESP Standard Service Offer severable from the longer term ESP.

ESP, the average base generation rate shall be 7.75 cents/kWh and the average base generation rate charged to customers will be 6.75 cents/kWh with the difference being deferred for future recovery in the same manner as the base generation rate deferrals in the longer term ESP. The rate design for implementing Short Term ESP generation rates shall be the rate design proposed in the filed tariffs associated with the long-term ESP. In addition, the following provisions of the longer term ESP will not be applicable and are withdrawn for the term of the Short Term ESP: A.1.a., A.2.d. (as to Green Resources), A.2.l, A.2.m., A.3.c., A.3.g., A.4.a. through A.4.h. and A.4.i. (regarding the Economic Development Rider). The following terms shall survive the termination of the Short Term ESP: A.2.f. (relating to securitization), A.3.b., A.3.d., A.3.e., A.3.f., A.3.h., A.4.i. (with respect to the Demand Side Management and Energy Efficiency Rider, Delta Revenue Recovery Rider, Reasonable Arrangements Rider, and, to the extent only of any recovery and reconciliation, the Economic Development Rider), A.4.j., A.4.k., A.5.a., A.5.b., A.7.d. (relating to the final test required), A.7.h., and A.7.i., and any and all provisions for reconciliation or recovery of deferral cost until such recovery and reconciliation is complete.

B. Compliance with Draft Commission Rules

To the extent determined necessary by the Commission, the Companies will conform this Plan to any substantive requirements of rules adopted by the Commission pursuant to R.C. § 4928.143(A) or other applicable Revised Code sections. Conversely, if this Plan is inconsistent with the Commission's final rules, the Companies request waivers to the extent deemed necessary and the Commission's approval of this Plan shall constitute a waiver of any Commission rule that is inconsistent with or in conflict with the provisions of this Plan.

1. Appendix B Filing Requirements

(A) *ESP Description.* The Companies' Plan is set out herein, and further detailed in the attachments to this Application and accompanying testimony.

(B) *Financial Projections.* Pro forma financial projections of the Plan upon the utilities for the duration of the ESP are attached as Schedules 7a-c.

(C) *Projected Rate Impacts.* A projection of rate impacts by customer class/schedule for the duration of the Plan is attached as Schedules 1a-c.

(D) *Corporate Separation Plan.* As further described in the testimony of Mr. David M. Blank, the Commission approved the Companies' interim corporate separation plan by Opinion and Order issued on July 19, 2000 in Case Nos. 99-1212-EL-ETP *et al.* (the "ETP Order"). The Companies' corporate separation plan currently is in full force and effect and is in compliance with statutory and rule requirements.

(E) *Operational Support Plan.* The Companies' operational support plan was implemented as directed by the Commission in the ETP Order and related orders. There are no outstanding problems with the implementation.

(F) *Governmental Aggregation.* The Companies will continue to maintain systems necessary to account for customer participation in governmental aggregation programs. Implementation of division (J) of R.C. § 4928.20 is addressed through the payment of an optional standby charge described above in paragraph A.2.k. Implementation of division (I) of R.C. § 4928.20 is described in the testimony of Mr. David M. Blank.

(G) *Impact of Unavoidable Generation Charge on Large-Scale Governmental Aggregation.* As explained in the testimony of David M. Blank, the overall effect of the Plan's nonavoidable charges [21] is beneficial to customers served by large-scale aggregation groups, just as it is beneficial for all customers. The nonavoidable generation charges help provide the risk mitigation arrangements that are essential for the utilities to have the financial capacity to propose the Plan in its present form for the benefit of all customers. Such charges have no disproportionate effect on large scale governmental aggregation. In any event, the Commission may conduct a specific analysis by obtaining pricing and cost data from governmental aggregators and/or their suppliers. With respect to the deferred generation cost rider, pursuant to R.C. § 4928.20(I) it would only apply to governmental aggregation groups to the extent the electric load centers within the jurisdiction of the governmental aggregation as a group benefited from the phase-in of generation prices under the Plan.

(H) *State Policy.* This Application and the testimony of Mr. David M. Blank describe how the Plan seeks to be consistent with certain of the policies delineated in R.C. § 4928.02(A) through (N) within the time frame afforded by the Plan. However, Am. Sub. S.B. 221 does not impose a requirement that every Electric Security Plan application achieve the policy goals set forth in R.C. § 4928.02, and those policies can conflict in practice. Indeed, the Commission's standard in R.C. § 4928.143(C)(1) for reviewing an electric security plan is limited to one question: is the plan more favorable in the aggregate as compared to the expected results from a market-rate offer implemented

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[21] R.C. § 4928.20(K) directs the Commission to consider the effect on large-scale governmental aggregation of non-bypassable generation charges established by an electric security plan, except for those non-bypassable generation charges that relate to a cost whose deferral was authorized by the Commission prior to July 31, 2008.

under R.C. § 4928.142? If the Commission answers this question affirmatively, then the proposed Plan is not only consistent with the statute, but necessarily advances state policy.

Except to the extent a waiver is requested, the specific information requested on pages two through six of proposed Appendix B to Rule 4901:1-35-03 is provided above in the discussion of each specific feature of the Plan.

2. Additional Rule Requirements

(A) *Transmission Rider.* The Companies have attached to this Application all information required by proposed Rule 4901:1-36, which applies to an application for Commission approval of a transmission cost recovery rider.

(B) *Economic Development and Energy Efficiency Schedules.* Also attached is information required by proposed Rule 4901:1-38-03, which establishes a process for Commission approval of an economic development schedule applicable to new or expanding customers, and proposed Rule 4901:1-38-04, which establishes a process for approval of an energy efficiency schedule applicable to energy efficiency production facilities with loads not more than one thousand kilowatts.

C. Proposed procedure and timing

The Companies seek approval of the Plan by such date as will allow the approved Plan to go into effect on January 1, 2009. To accommodate the necessary lead times and to assure continued provision of service to customers on and after January 1, 2009, the Companies request a timely review of this Application and approval via issuance of a Commission Opinion and Order no later than December 10, 2008. In the alternative, with regard to the provisions of section A.8.a.-d. (the Short-Term ESP), those terms shall apply.

As the Commission is aware, the Companies must enter into an agreement with FES and/or other wholesale providers in order to obtain generation resources sufficient to satisfy its Plan commitments. The Commission's decision in this proceeding will determine whether FES will either continue to dedicate generation resources to the Company's Ohio customers or will use those resources to supply other *obligations*. Time is of the essence because the overall requirements to be served by FES, assuming an obligation to Ohio customers continues beyond 2008, are greater than the resources controlled by that company. Moreover, to the extent a Commission decision on this Application results in the Companies electing, or being required, to establish a market-rate offer through a competitive bidding process, the Companies will require sufficient lead time to satisfy the procedural requirements set forth in R.C. § 4928.142.

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company

By ______________________

Senior Vice President & CFO

By ______________________

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

VERIFICATION

STATE OF OHIO)
) ss.
COUNTY OF SUMMIT)

The undersigned, being first duty sworn, state that they have the authority to verify the foregoing Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (collectively, the "Companies") for authority to establish a standard service offer pursuant to R.C. § 4928.143 in the form of an electric security plan. Also, they state that they have read said Application and are familiar with the contents in support; and that all of the statements contained in said filing made on behalf of the Companies are true and correct to the best of their knowledge and belief.

Richard H. Marsh
Senior Vice President & CFO

Ohio Edison Company
The Cleveland Electric Illuminating Co.
The Toledo Edison Company

Edward J. Udovich
Assistant Corporate Secretary

Ohio Edison Company
The Cleveland Electric Illuminating Co.
The Toledo Edison Company

Sworn to and subscribed before me, a notary public, in and for said County and State, this 31st day of July, 2008.

Notary Public

Kathleen Anne Grant
Notary Public, State of Ohio
Resident of Summit County
My Commission Expires Nov. 8, 2009.

APPENDIX

ESP Application

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ATTACHMENT A

Base Generation Charges:

The Companies' Plan provides the following base charges for generation service:

January 1, 2009 – December 31, 2009	$0.07500 per kWh
January 1, 2010 – December 31, 2010	$0.08000 per kWh

Unless the Commission elects to terminate the third year of the Plan, the 2011 base charges for generation service shall be as follows:

January 1, 2011 – December 31, 2011	$0.08500 per kWh

The Companies would recover revenues collected pursuant to the implementation of the above rates on a service rendered basis. In order to moderate the impact on customers' rates, the Companies propose to phase-in the base generation charges to be implemented and to defer purchased power costs incurred equal to the reduced generation revenue recognized due to the reduced base charges as follows (per kWh):

	Reduction from Base Charges	Billed Rate
2009	$0.00750	$0.06750
2010	$0.00850	$0.07150
2011	$0.00950	$0.07550

Note: The 2011 reduction from base generation charges is not applicable if the Commission elects to terminate the third year of the Plan.

Generation Deferrals and Carrying Costs:

The Companies' Plan proposes to defer incurred purchased power costs equal to the amounts for which recovery has been delayed, estimated to be:

Year 2009	$429 million deferred; cumulative deferral $429 million
Year 2010	$488 million deferred; cumulative deferral $917 million
Year 2011	$553 million deferred; cumulative deferral $1,470 million

Note: The above amounts are estimated based upon projected sales levels. In addition to variation that may arise due to actual sales volume, these amounts could be increased if the Commission elects to increase the generation phase in amounts for charges for planning reserves under the Transmission and Ancillary Service Rider.

Estimated Generation Deferrals by Company (excluding carrying costs):

Year 2009 — $429 million deferred

OE	$198M
CEI	$150M
TE	$ 81M

Year 2010	$488 million deferred		
		OE	$226M
		CEI	$170M
		TE	$ 92M
Year 2011	$553 million deferred		
		OE	$257M
		CEI	$193M
		TE	$103M

Pursuant to the Companies' Plan, the Companies will defer carrying costs associated with the delayed recovery of incurred purchased power costs on the gross accumulated deferred balance, including accumulated deferred interest and without reduction for accumulated deferred income taxes, until securitization or until recovery begins if not securitized (January 1, 2011 for the 2009 and 2010 deferrals, and January 1, 2013 for the 2011 deferrals), at a monthly rate of 0.7083%. If not securitized, from the date recovery begins until completed, carrying costs will accrue on the unrecovered balance net of accumulated deferred income taxes at a monthly rate equal to each Company's weighted book cost of long-term debt as of December 31, 2010 for the 2009 and 2010 deferrals and December 31, 2012 for the 2011 deferrals.

Listed below are the two options available for recovery of the deferred costs through a non-bypassable Generation Phase-In Cost Charge Rider ("GPICC"). In the event that a securitization transaction fails to provide recovery of the deferred costs, for any reason, such deferred costs shall be recovered pursuant to Option One below.

Option One

Deferrals Recovery Overview:

If authorized by the Commission, the Companies will begin recovering the costs and carrying costs deferred pursuant to this generation rate increase phase-in effective with service rendered on and after January 1, 2011 through implementation of a GPICC averaging $0.002009 per kWh. Beginning on January 1, 2013 the GPICC is projected to increase to an average of $0.003252 per kWh. Beginning on January 1, 2021 the GPICC is projected to decrease to an average of $0.001243 per kWh.

Such GPICCs include recovery of carrying costs at a rate equal to each Company's weighted book cost of long-term debt projected as of December 31, 2010 and December 31, 2012 on the unrecovered balance net of accumulated deferred income tax. The rider shall remain in effect for each Company until the deferred costs, including carrying costs, have been fully recovered, but in no event shall the GPICC continue beyond December 31, 2022.

Deferrals Recovery Detail (GPICC per kWh):

	Ohio Average
January 1, 2011 – December 31, 2012	$0.002009
January 1, 2013 – December 31, 2020	$0.003252
January 1, 2021 – December 31, 2022	$0.001243

	2011 - 2012	2013 - 2020	2021 – 2022
OE	$0.001998	$0.003230	$0.001232
CEI	$0.002014	$0.003263	$0.001249
TE	$0.002029	$0.003287	$0.001258

The GPICC will be reconciled semiannually during the proposed recovery period to ensure timely recovery of the deferred balances. Following implementation of the initial GPICC, effective with service rendered on and after January 1, 2011, the GPICC will be revised each August 1 and February 1 to reconcile recovery through June 30 and December 31, respectively. The revised GPICC will be filed with the Commission by July 15 and January 15 to become effective for service rendered August 1 and February 1, respectively. The revisions will be made in a manner such that the projected semiannual unamortized deferred generation phase-in balances will be maintained.

Option Two

Securitization Transactions[1]:

The Companies shall have the option to securitize, at least on an annual basis, the accumulated balance of their respective deferred costs ("Regulatory Assets") associated with the phase-in of the standard service offer price under the Electric Security Plan ("ESP"), plus carrying charges and certain other costs (such portion of Regulatory Assets, carrying charges and other costs defined in more detail below, the "Generation Phase-In Costs"). Each year's Generation Phase-In Costs may be securitized in separate transactions referred to herein as "Securitization Transactions" as authorized by Sections 4928.143(B)(2)(f) and 4928.144 of the Ohio Revised Code, by issuing bonds with scheduled final maturities not to exceed ten years.

Securitization Recovery Overview:
If the Commission authorizes the securitization option, the Companies are authorized to begin recovering the costs and carrying costs deferred pursuant to this generation rate increase phase-in effective with service rendered on and after January 1, 2010 through

[1] If securitization is approved, the annual debt service costs during the Plan period shall be at the Commission's option either, (a) added to customer rates and the phase in credit shall be increased by the same amount or (b) added to customer rates without additional deferrals. The references to the GPICC are illustrative, and are subject to change due to many factors. The actual GPICC will be set at the time each bond issue is priced, among a series of potential bond issuances. The initial securitization charges will be set at the pricing of each bond issue and will be based upon the specific size of each issuance, the specific ongoing costs, and the structure and market pricing of the bonds.

implementation of a GPICC averaging $0.000893 per kWh. The Commission would then have the option to increase the phase-in adjustment to offset the $0.000893 per kWh. Beginning on January 1, 2011, the GPICC is projected to increase to an average of $0.002006 per kWh. The Commission would again have the option to increase the phase-in adjustment to offset the $0.002006 per kWh. Beginning on January 1, 2012, the GPICC is projected to increase to an average of $0.003376 per kWh. Starting with service rendered on and after January 1, 2020, the GPICC is projected to decrease to an average of $0.002483 per kWh. Beginning on January 1, 2021, the GPICC is projected to decrease to an average of $0.001370 per kWh. Such GPICC shall be sufficient to ensure timely payment of the Generation Phase-In Bonds (as defined below) and associated ongoing securitization costs. The GPICC shall remain in effect for each Company while any Generation Phase-In Bonds are outstanding, but in no event shall any such GPICC remain in effect beyond December 31, 2021.

The Generation Phase-In Bonds (as defined below) will be issued in one or more tranches consisting of fixed rate bonds and/or floating rate bonds depending on market conditions at or near the time of issuance. For the purpose of this securitization scenario, we utilized a 5.75% securitization bond rate with bond terms of 10 years and excluded securitization transaction costs. Additionally, the GPICC utilized in this securitization scenario assumes the Commission exercises the option to increase the phase-in credits for 2010 and 2011.

<u>Securitization Deferrals Recovery Detail</u> (GPICC per kWh):

	Ohio Average Securitization GPICC	Reduction for Phase-In Adjustment	Net Billed Rate
2010	$0.000893	$0.000893	$0.00
2011	$0.002006	$0.002006	$0.00
2012 - 2019	$0.003376	$0.000000	$0.003376
2020	$0.002483	$0.000000	$0.002483
2021	$0.001370	$0.000000	$0.001370

	OE Securitization GPICC	Reduction for Phase-In Adjustment	Net Billed Rate
2010	$0.000886	$0.000886	$0.00
2011	$0.001989	$0.001989	$0.00
2012 - 2019	$0.003346	$0.000000	$0.003346
2020	$0.002460	$0.000000	$0.002460
2021	$0.001357	$0.000000	$0.001357

	CEI Securitization GPICC	Reduction for Phase-In Adjustment	Net Billed Rate
2010	$0.000896	$0.000896	$0.00
2011	$0.002014	$0.002014	$0.00
2012 - 2019	$0.003391	$0.000000	$0.003391
2020	$0.002495	$0.000000	$0.002495
2021	$0.001377	$0.000000	$0.001377

	TE Securitization GPICC	Reduction for Phase-In Adjustment	Net Billed Rate
2010	$0.000906	$0.000906	$0.00
2011	$0.002036	$0.002036	$0.00
2012 - 2019	$0.003428	$0.000000	$0.003428
2020	$0.002522	$0.000000	$0.002522
2021	$0.001392	$0.000000	$0.001392

The Companies' securitization of Generation Phase-In Costs through the issuance of "Generation Phase-In Bonds" will occur in two stages.

First, the Commission's approval of this securitization framework as an element of the Companies' ESP authorizes the Companies to: (1) defer certain specified costs as Regulatory Assets pursuant to generally accepted accounting principles ("GAAP"); (2) impose, collect and receive a GPICC upon each of the Companies' existing and future distribution customers on a date and in an amount to be fixed by Commission Order for purposes of each Securitization Transaction; and (3) prepare for securitization of the Generation Phase-In Costs in a Securitization Transaction beginning during 2009 or the following year and at least on an annual basis thereafter during each year of the ESP or the following year.

Second, the Commission's approval of this securitization framework also creates and establishes a process pursuant to which the Companies may apply for, and the Commission will review and approve to the extent consistent with this securitization framework, the Companies' securitization of their Generation Phase-In Costs in a series of Securitization Transactions.

A separate Commission Order will authorize a securitization program for each Company (each, a "Generation Phase-In Financing Order"). Each Generation Phase-In Financing Order will set forth the process for the subsequent issuance of a series of Generation Phase-In Bonds, including the process and formulae for determining and certifying by Generation Phase-In Cost Certificates the actual and/or estimated Generation Phase-In Costs to be securitized on at least an annual basis, and the process for the preparation of draft and final Issuance Advice Letters setting forth the terms of each Securitization Transaction. As each Generation Phase-In Financing Order becomes effective pursuant to its terms (upon its acceptance by the Company), each Company may securitize in a Securitization Transaction the Generation Phase-In Costs set forth in the accompanying Generation Phase-In Cost Certificate. The Commission shall not have discretion to disallow a Commission-approved Securitization Transaction, but will retain discretion to correct computational or other manifest errors. Each Generation Phase-In Financing Order also will describe the methodology for adjusting or "truing up" the GPICC to ensure there will be sufficient funds to cover all costs associated with each Securitization Transaction on a timely basis.

Generation Phase-In Financing Orders:

1. Authorize the Companies or a parent or affiliate of the Companies to create one or more non-utility, special purpose entity (each, an "SPE"). Each SPE's separate legal existence will be maintained as long as any related Generation Phase-In Bonds are outstanding. In the unlikely event of a bankruptcy of any one of the Companies, the assets and liabilities of the SPE will remain separate from the bankruptcy estate of the Company. Each Company will make a capital contribution to the related SPE in an amount expected to be not less than 0.5% of the aggregate principal amount of the Generation Phase-In Bonds described below (or such other amount as may be required to obtain favorable tax treatment), which amount will be held by the SPE in a separate account.

2. Approve the process for determining and certifying the estimated amount of each Company's total Generation Phase-In Costs pursuant to each Generation Phase-In Cost Certificate for a specified period, including (a) principal and interest on the Generation Phase-In Bonds; (b) the costs incurred to issue Generation Phase-In Bonds, which include, but are not limited to, initial deposits to reserve and/or overcollateralization accounts and/or subaccounts, Company financial advisor fees, underwriting fees, legal fees, servicing set-up fees, rating agency fees, accountant's fees, SEC fees and trustee fees (the "Upfront Transaction Costs"); and (c) the costs of paying, refinancing, administering and servicing, credit enhancing and over-collateralizing the Generation Phase-In Bonds, plus any costs of corporate franchise and commercial activity taxes assessed on the GPICC and/or payable by the Companies and/or SPE (the "Ongoing Generation Phase-In Bond Costs").

3. Approve each GPICC and require that each GPICC remain in effect as necessary to provide for the timely payment and recovery of the full amount of Generation Phase-In Costs.

4. Authorize a series of Securitization Transactions involving the issuance of Generation Phase-In Bonds by the SPE in amounts to be set forth and described in final Issuance Advice Letters. Each Generation Phase-In Bond issue will have a scheduled final maturity of not more than 10 years and a final legal maturity of up to two years beyond the scheduled final maturity date of each class of Generation Phase-In Bonds. The Generation Phase-In Bonds will be issued in one or more tranches consisting of fixed rate bonds and/or floating rate bonds depending on market conditions at or near the time of issuance.

5. Authorize the Companies to sell, transfer or assign to the SPE, in exchange for an amount approximately equal to the net proceeds from the bond sale, the right to impose, charge, collect and receive the GPICC, which right shall be an intangible property right or irrevocable contract right that can be transferred and pledged as a perfected security interest under Ohio law (the "Generation Phase-In Property" or the "Generation Phase-In Rights"). The transfer of the Generation Phase-In Property or the assignment of the

Generation Phase-In Rights to the SPE will be structured so as to constitute a "true sale" or a "full and absolute assignment" pursuant to both federal and Ohio law.[2]

6. Direct that the GPICC is non-bypassable, to the maximum extent permitted by Ohio law, so that it is paid by existing and future distribution customers of the respective Companies in their Ohio service territories, regardless of energy supplier, and also will be paid by the customers of a successor electric distribution utility of one or more of the Companies to the extent such successor utility operates within the Companies' respective currently existing service territories.

7. Provide for (a) semi-annual "true-ups" of the GPICC to the extent GPICC collections are more or less than projected, to ensure that there will be sufficient funds to timely pay the Ongoing Generation Phase-In Bond Costs as well as no significant over-collections; and (b) "non-routine" true-ups of the GPICC, as well as more frequent true-ups near the end of the term of the bonds to ensure that GPICC collections are always sufficient to pay Ongoing Generation Phase-In Bond Costs on a timely basis.

8. Retain exclusive jurisdiction over all matters set forth in each Generation Phase-In Financing Order and mandate that, once each such Order becomes effective and final, neither the Commission nor the State of Ohio nor any other State entity may rescind or amend the terms of each such Order. Moreover, upon the issuance of each Generation Phase-In Cost Certificate, the Commission covenants and agrees, and, by virtue of R.C. § 4928.143(B)(2)(f), the State of Ohio and its agencies shall be deemed to have covenanted and agreed, that they shall not rescind or amend or revise the amount of Generation Phase-In Costs or in any way reduce or impair the value of the Generation Phase-In Property or Generation Phase-In Rights, except for purposes of approving true-ups as described above. Each Generation Phase-In Financing Order, Generation Phase-In Cost Certificate and final Issuance Advice Letter and all the rights thereunder shall become irrevocable upon them becoming effective and final under Ohio law and each shall not be impaired by the State of Ohio, as pledged by the Commission, and as deemed to have been pledged by the State of Ohio, to the maximum extent authorized by Ohio law and Article II, Section 28, of the Ohio Constitution.

9. To the extent authorized by then-existing Ohio law, direct that the Generation Phase-In Property shall constitute a vested presently existing property right, which will continuously exist as property for all purposes, only upon each Company's transfer and receipt of payment for the Generation Phase-In Property from the related SPE, regardless of whether the revenues and proceeds arising with respect thereto have accrued and notwithstanding the fact that the value of the property right may depend upon customers using electricity or the Servicer performing services. Each Company's Generation Phase-In Property will consist of the following three elements: (a) the irrevocable right to

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[2] For purposes of this Plan, the assumed structure for the Securitization Transaction is that each Company will create an SPE and will transfer its respective Generation Phase-In Property or Generation Phase-In Rights to that entity. The final structure of each Securitization Transaction, however, will be determined by the Companies at a later date based on input from the underwriters, rating agencies and other transaction participants and each Company shall have substantial flexibility in the structuring of a Securitization Transaction. The final terms of each Securitization Transaction will be set forth in the related final Issuance Advice Letter.

charge, collect and receive, and be paid from collections of, the GPICC; (b) all rights of each Company under the Generation Phase-In Financing Order, including, without limitation, all rights to obtain periodic adjustments of the GPICC; and (c) all revenues, collections, payments, money and proceeds arising under, or with respect to, the GPICC.

10. Alternatively, direct that the Generation Phase-In Rights shall constitute vested presently existing contract rights, which will continuously exist as irrevocable contract rights for all purposes, only upon each Company's transfer and receipt of payment for the Generation Phase-In Rights from the related SPE, regardless of whether the revenues and proceeds arising with respect thereto have accrued and notwithstanding the fact that the value of the contract right may depend upon customers using electricity or the Servicer performing services. Each Company's Generation Phase-In Rights will consist of the following three elements: (a) the irrevocable right to charge, collect and receive, and be paid from collections of, the GPICC; (b) all rights of each Company under the Generation Phase-In Financing Order, including, without limitation, all rights to obtain periodic adjustments of the GPICC; and (c) all revenues, collections, payments, money and proceeds arising under, or with respect to, the GPICC.

11. Authorize each Company to act as servicer, either on its own or through an affiliated entity or agent, with respect to the GPICC to be collected from each Company's respective customers. As servicer, each Company will receive an annual servicing fee, which will be an Ongoing Generation Phase-In Bond Cost. Each servicer will be responsible for, among other things, billing and collecting the GPICC and remitting such collections to the bond trustee at intervals designed to assure that the Generation Phase-In Bonds receive the highest possible credit ratings, given the legal structure of each Securitization Transaction. Moreover, each Company is authorized to covenant to and agree with its related SPE that it (the Company) will continue to provide electric distribution services to customers within the Company's service territory, and in the event there is a successor to the Company, to facilitate the successor providing such electric distribution services, as long as any Generation Phase-In Bonds are outstanding.

12. Authorize the Companies, if requested by underwriters, rating agencies or other transaction participants, to apply a portion of the GPICC to an "overcollateralization amount" which will be deposited into a separate subaccount to satisfy an overcollateralization schedule. The collection of the overcollateralization amount will be in addition to the collection of the principal (which will be collected in accordance with an amortization schedule) and interest payable on the Generation Phase-In Bonds, and the collection of the other Ongoing Generation Phase-In Bond Costs, all of which will be recovered through the GPICC.

13. Authorize each SPE to enter into an administration agreement with FirstEnergy Service Company ("FE Service"), an affiliate of the Companies, pursuant to which FE Service will perform ministerial services and provide facilities for each SPE so that it is able to perform such day-to-day operations as are necessary to maintain its existence and satisfy its obligations under the Securitization Transaction documents. FE Service will be paid an administration fee in an amount equal to its costs. The periodic costs associated with such fee will be included in the Ongoing Generation Phase-In Bond Costs for such period.

14. To the extent requested by the Companies in their Securitization Transaction application, make appropriate findings and provide approvals as necessary regarding, among other things, the reasonableness of the GPICC and any true-up mechanism, the total amount of recoverable Generation Phase-In Costs, the use of proceeds, the irrevocability of the order and related issues.

The foregoing Securitization Framework is similar to those used in other states where securitization has been used to recover a clearly-defined amount of costs, such as deferred power procurement costs, stranded costs and storm recovery costs. The Companies expect that the additional details of their securitization plan will be substantially similar to other outstanding utility securitizations.

The Securitization Transactions, if pursued, will be structured in such a way as to facilitate the highest ratings on the Generation Phase-In Bonds, given the legal structure of each Securitization Transaction. The decision of a Company to submit an application for and enter into Securitization Transactions, as opposed to pursuing an alternate form of financing, will take into account, among other things, net present value revenue requirements, mitigation of annual customer charges, and/or the impact on the Company's credit metrics or ratings. The documentation supporting each Securitization Transaction will make clear that the Generation Phase-In Bonds are not obligations of the State of Ohio and any of its agencies, including the Commission.

The Companies expect that the Generation Phase-In Bonds will be recorded in accordance with GAAP as long term debt on the balance sheet of the SPE for financial reporting purposes. To the extent each SPE is a wholly-owned subsidiary of the related Company, GAAP requires that such SPE be consolidated with the related Company for financial reporting purposes.

Therefore, each SPE's debt may appear on the consolidated balance sheet of the related Company in its financial statements filed with the Securities and Exchange Commission.

While each GPICC will be part of regulated rates charged to customers, for purposes of financial reporting to the Commission, each Company will exclude the SPE's debt from its capital structure and exclude interest on the Generation Phase-In Bonds and other ongoing costs from its regulated cost of service in any future base rate proceeding.

<u>Attachment B[1]</u>

<u>Fuel Transportation Surcharge, Environmental Control and New Taxes</u>

Applicable to any customer that takes electric service under the Company's Rate Schedules. The Fuel Transportation Surcharge and Environmental Control charge will be effective for service rendered beginning January 1, 2009.

This charge consists of three components. The first component recovers fuel transportation surcharge costs in excess of $30 million, $20 million, and $10 million annually for 2009, 2010, and 2011, respectively. The second component recovers any additional costs, in excess of $50 million during the Plan period, of complying with new requirements for renewable resources (other than required by Am. Sub. S.B. 221), new taxes, and new environmental laws or new interpretations of existing environmental laws that take effect after January 1, 2008. Additionally, the charge will include a reconciliation for the over/(under) collection of actual recoverable costs, including applicable interest.

The charges contained in this Rider shall be updated and reconciled on a quarterly basis. No later than December 1st, March 1st, June 1st and September 1st of each year, the Company shall file with the PUCO a request for approval of the rider charges which, unless otherwise ordered by the PUCO, shall become effective on a service rendered basis on January 1st, April 1st, July 1st and October 1st of each year.

This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

FUEL COST ADJUSTMENT

Applicable to any customer that takes electric service under the Company's Rate Schedules. The Fuel Cost Adjustment Rider charge will be effective for service rendered beginning January 1, 2011.

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[1] For purposes of both the "Fuel Transportation Surcharge, Environmental Control and New Taxes" and "Fuel Cost Adjustment" provisions of this Attachment B, it shall be assumed that: 100% of the FES generation used in support of the Plan is used to provide service under the Plan; that taxes refers to any new tax on FES or the Companies arising out of any generation related item (to be construed in the broader sense); and that costs, including fuel costs, refers to those of FES associated with the generation used to support the Plan.

This charge per kWh consists of two components. The first component recovers the cost of fuel excluding fuel transportation surcharge, emission allowance, fuel handling, disposal, lime, urea, and ammonia costs at plants currently owned or controlled by FirstEnergy Solutions, or a subsidiary thereof, (collectively referred to as "FES") in MISO (including Ohio Valley Electric Corp. ("OVEC") arrangements and Fremont when placed in service, but excluding plants located in PJM - Beaver Valley and Seneca,) in excess of those costs for 2010. Additionally the charge will include a reconciliation component for the over/(under) collection balance of actual recoverable costs, including applicable interest.

The charges contained in this Rider shall be updated and reconciled on a quarterly basis. No later than December 1st, March 1st, June 1st and September 1st of each year, the Company shall file with the PUCO a request for approval of the rider charges which, unless otherwise ordered by the PUCO, shall become effective on a service rendered basis on January 1st, April 1st, July 1st and October 1st of each year.

This Rider is not applied to customers during the period the customer takes electric generation service from a certified supplier.

Attachment C

STANDARD SERVICE OFFER MARKET PRICING FOR RETURNING CUSTOMERS

Applicable to all customers returning from an alternative supplier that did not pay the stand by charge, provided for in Rider PSR, each month they received retail generation service from an alternative supplier, and that return to the Company for generation service during the term of the Company's Electric Security Plan ("ESP") plan. The charge described below will replace avoidable standard service offer ("SSO") generation related charges that the returning customer would have otherwise paid had they paid the stand by charge each month ("standard SSO generation"). All other provisions, rates and terms of the otherwise applicable tariff shall apply including the Company's current transmission rider. All returning customers, except for returning governmental aggregation customers, will pay the greater of the otherwise applicable tariff price for standard SSO generation or SSO market prices.

The SSO market prices will be derived based on a quarterly forward wholesale on peak and off peak price multiplied by 160%. All returning government aggregation customers will be charged at SSO market prices based on a quarterly forward wholesale on peak and off peak price multiplied by 160%. The quarterly forward market price will be based on published broker quotes for the Cinergy Hub. This market price reflects the LMP associated with the node applicable to returning customers. The 160% multiplier will cover the market cost for generation capacity, renewable energy resources that may include renewable energy credits, serving a shaped load versus a flat load, taxes, distribution losses, administrative costs, the cost of supplying credit to participate in the RTO markets to acquire power, and all other pricing elements provided in R.C. 4928.20(J).

For purposes of applying this section, any member of a household or any continuing business at the same location shall be considered the customer irrespective of the name on the account. The Company may require verification before allowing any customer to receive standard SSO generation pricing at a location for which an alternative supplier has provided service during the term the ESP is in effect.

Attachment D

As a condition of entering into a contract with FES for generation service, the Companies will require FES to commit to adding 1000 MW of capacity from January 1, 2007 - December 31, 2011 through (i) new or upgrading existing generation, including renewable generation through contracts or otherwise; (ii) maintaining existing generation in service that would otherwise be shutdown by December 31, 2010;[1] and/or (iii) additional generation.

Projects Effective 1/1/2007& Expected Future Projects (2)

Resource	Effective Date	Capacity Change	Comments	Details
Installed Wind	Varies	145	Contract	Wind Generation currently in operation and under contract
Planned Wind	11/1/2008	70	Contract	Currently planned wind generation
		215		
Perry 1	1/1/2008	15	Unit Uprate	Feedwater flow accuracy improvement
Davis Besse	2008	12	Unit Uprate	Installation of Leading Edge Feedwater flow meters.
Sammis 6	Q3-2009	50	Unit Uprate	Increased output from higher efficiency (Dense Pack) Turbines
Sammis 7	Q1-2010	50	Unit Uprate	Increased output from higher efficiency (Dense Pack) Turbines
		127		
Mansfield 3	12/1/2007	30	Unit Uprate	Increased output from higher efficiency (Dense Pack) Turbine
Fremont Energy Center	2009	707	New Capacity	
		737		
		$\boxed{1079}$		

[1] Pursuant to court order without installing environmental control equipment or repowering consistent with such order
[2] Projects may be substituted with other projects to achieve the 1,000 MW commitment

Attachment E

Distribution Service Provisions

Delivery Service Improvement Rider:

As expressly stated in R.C. § 4928.143(B)(2)(h), an Electric Security Plan may provide for provisions regarding a utility's distribution service. Pursuant to such statutory authority, the Companies' Plan includes a Delivery Service Improvement ("DSI") rider. The DSI rider is not and shall not be considered a contribution in aid of construction or be used in any determination of significantly excessive earnings.

The DSI rider is expected to provide adequate resources to maintain healthy sustainable distribution utilities, and shall be effective for OE, TE and CEI on a service rendered basis on and after January 1, 2009. The DSI rider will ensure that customers' and the Companies' expectations are aligned and that the Companies are placing sufficient emphasis on and dedicating sufficient resources to energy delivery and reliability improvement as contemplated in R.C. 4928.143(B)(2)(h). In furtherance of such expectations the DSI rider shall be subject to SAIDI[1] performance adjustments set forth in the proposed tariffs.

The DSI rider is a non-bypassable distribution charge equal on average, prior to any SAIDI performance adjustment, to $0.0020 per kWh in 2009 through 2011, and shall be set at $0.0000 per kWh in 2012 through 2013. For the period 2012 through 2013 the DSI rider will remain in place to effectuate any SAIDI performance adjustments.

SAIDI Reliability Targets:

The SAIDI for each of the Companies shall be set at 120 minutes. The 120 minute SAIDI reliability target reflects the existing targets for OE and TE and establishes a new SAIDI target for CEI. The adjustment to CEI's SAIDI target more appropriately reflects the historical system performance, system design and service geography in the CEI service territory.

Development of Rear Lot Reduction Factor:

The logistical issues associated with crews getting their equipment to facilities on rear lot circuits (the need to manually bring poles and other equipment to such sites as opposed to the use of bucket trucks, and the number of obstructions at such sites including trees, fences, garages, etc.), creates service restoration times that are roughly double for these locations than otherwise experienced for circuits where facilities are located adjacent to streets. In an effort to establish a representative outage duration time which takes into account the challenges of rear lot construction, customer outage minutes will be

[1] system average interruption duration index

multiplied by a factor of .5 ("Rear Lot Reduction Factor") on such circuits where fifty percent or more of the premises are served by rear lot facilities.

Reliability Reporting Requirement:

For the purposes of this Plan and all reporting requirements pursuant to O.A.C. § 4901:1-10, each of the Companies' SAIDI targets will be calculated using the methodology which has been accepted by the Commission Staff as of the filing of this Plan, including that major storm exclusions are generally defined as events affecting 6% of customers in a 12-hour period. In addition, in the case of CEI, a Rear Lot Reduction Factor would be applied to customer outage minutes. The Commission's approval of this Plan shall constitute any waiver required for purposes of complying with the Ohio Administrative Code with respect to establishing and calculating, reliability indices and performance targets.

SAIDI Performance Band:

The Companies' 120 minute SAIDI targets shall be coupled with a reliability performance band between 90 minutes and 135 minutes during the period January 1, 2009 through December 31, 2013. In an effort to emphasize the importance of reliability performance to the Companies and to customers, the performance band will be subject to SAIDI financial adjustments associated with variance of actual performance that is outside the performance band. The Companies' Plan proposes the asymmetrical performance band, set forth in the proposed tariffs, that is skewed to benefit customers. The performance band is set to achieve top quartile performance in the industry, and thus a SAIDI financial adjustment that reduces the DSI rider does not represent, nor shall it be construed, as a punitive measure in response to inadequate service.

If any Company's respective and individually calculated SAIDI performance as reported on the Company's annual report filed pursuant to O.A.C. § 4901:1-10-10, which for CEI shall reflect the Rear Lot Reduction Factor, shall fall outside the performance band for the previously recorded calendar year such that SAIDI performance is higher than 135 minutes, then the DIS rider for that Company will be adjusted downward consistent with the amounts set forth in proposed tariffs. However, if a Company's SAIDI performance for the previously recorded calendar year is less than 90 minutes, then the DIS rider shall be adjusted upward consistent with the amounts set forth in the proposed tariffs. The annual adjustment schedule for the DSI rider for SAIDI performance is set forth in the proposed tariffs. Such adjusted amounts to the DSI rider charge, if any, shall occur on April 1st of each applicable year.

Smart Grid Study:

The Companies commit to undertake and complete a comprehensive Smart Grid study on or before December 31, 2009 (the "Study"). This Study will include an analysis of the Companies' electric distribution system and define a first estimate of the scope, logical sequence, and cost of the major investments necessary to implement Smart Grid technology. The main objective will be to identify and describe the specific initiatives necessary for each of the Companies to address a number of capacity, reliability, and operationally related challenges that impact each of the Companies' near-term and long-term performance.

This Study will serve as a planning document to recognize the key changes/upgrades that may be needed to deploy Smart Grid, frame potential solutions for further study, and present a first-level prioritization of key investments. As part of this Plan the Companies commit to bear the expense of this Study. The Companies believe this Study will provide substantial value to customers.

Attachment F

Residential AMI Pilot

FirstEnergy's Ohio utilities will conduct a 500 customer pilot program using advanced metering technology capable of displaying real time energy usage to individual residential customers.

The Companies will solicit customers to participate through direct mailing. The Companies will not seek cost recovery of the first $1 million in costs associated with the program. Any costs incurred above that amount will be recovered through the energy efficiency rider proposed in the ESP. Estimated costs are as follows: $500 per interval meter, $500 - $1,000 per installation of customer side usage information system, $25 per customer per year program incentive and $180 per customer per year in communication costs.

The purpose of the pilot is to determine whether a program that combines Summer time-of-day generation rates with real time energy usage information can effectively change customer behavior and energy consumption. The program will provide participating customers with the ability to lower energy costs by shifting and/or reducing electricity usage during peak and critical peak times to off peak times when demand for electricity and rates are lowest. Once participants in the study are selected, the Companies will choose a similar group of customers as a control group for comparison.

The pilot program will be in place for the term of the proposed ESP.

In addition, the Companies propose a collaborative process in which interested parties provide input on the AMI process as well as discuss the Companies' proposed AMI pilot program and work cooperatively with the Companies in potential AMI plan designs going forward. The Companies recommend that a small group of major stakeholders agree to enter into a collaborative process starting 60 days after the final order in this case whose purpose is to: discuss the Companies' proposed AMI pilot; analyze the potential for continued investment by the Companies in AMI; to design potential programs on a comprehensive basis; and, if mutually decided, to facilitate the implementation of such programs by the Companies to the extent that they are cost-effective.

The details of the process would be worked out among the key stakeholders that participate. The Companies propose a six month process to develop and refine collaboratively with interested stakeholders potential program designs. This allows sufficient time for meaningful input from the stakeholders, and would allow the Companies sufficient time for evaluation. Following the last summer period during which it would be in place, the Companies will assess the results of the proposed AMI pilot program and consider the information provided as part of the collaborative to make a determination of whether such AMI implementation is cost effective and in the best interests of customers and the Companies. As a result of such determination, the Companies may file an AMI plan for Commission review and approval, which would include a cost recovery mechanism such as that proposed by Commission Staff in the Companies' Distribution Case.

Rate Program Description:

Participants in the pilot program will be subject to generation rates that vary based upon time of use periods. The time of use Peak hours will be Monday through Friday 11:00 am to 5:00 pm, with all other hours being Non-Peak. The Peak price will be increased up to 12 times per year during Critical Peak conditions in the Summer. The Companies will provide day-ahead notification via e-mail, telephone and/or text message to the participant the day before a Critical Peak Day event. Upon notification of the Critical Peak Day, participants are encouraged to shift or decrease energy usage between the hours of 11:00 am and 5:00 pm to lower energy costs. Likewise, participants are encouraged to shift or decrease energy usage during Peak times on non-critical days. Participants will pay the otherwise applicable residential tariff rate during the non-Summer period.

Summer billing months:[1]

Time of Use Periods: (stated in Eastern Standard Time)

Time/Day	Category	Rate (per kWh)
11am – 5pm Monday through Friday, excluding Holidays (up to 12 times per year)	**Critical Peak**	**$0.220000**
11am – 5pm Monday through Friday, excluding Holidays	**Peak**	**$0.105095**
5pm – 11am Monday through Friday, Weekends, Holidays	**Non-peak**	**$0.052303**

The rates shown are net of the ESP's Generation Phase-In Credit

[1] The Summer Month Period is defined in the Companies' Schedule of Rates Sheet 4 Section VI.I.I

Attachment G

Attachment G will cover two separate Riders. Section I relates to the recovery of post date certain deferred balances with a distribution rider and Section II relates to the recovery of 2005 deferred transmission costs with a transmission rider.

SECTION I – DISTRIBUTION RIDER

Rider:

The Commission has determined that a non-bypassable adjustable distribution rider shall be established by The Cleveland Electric Illuminating Company (CEI), Ohio Edison Company (OE) and The Toledo Edison Company (TE) (Companies) to recover the deferred balances arising after the date certain (5/31/07) in the Distribution Rate Case No. 07-551-EL-AIR starting on January 1, 2011 on a service rendered basis.for the following deferral items:

	Recovery Period	Post Date Certain * Estimated Balances (in millions)
ETP Deferred Transition Taxes *	5 years	
OE		$ 37.5
CEI		$ 2.2
TE		$ 3.6
Deferred Line Extensions*	5 years	
OE		$ 17.7
CEI		$ 8.7
TE		$ 4.0
RCP Deferred Distribution *	25 years	
OE		$ 109.1
CEI **		$ 154.7
TE		$ 17.7

* December 31, 2008 for OE and TE and April 30, 2009 for CEI relate to the Post Date Certain estimated balances only.
** CEI post date certain estimated amount includes the additional $25 million of deferred distribution-related costs during the period January 1 through April 30, 2009 mentioned under paragraph A.3.b. in the Application.

Carrying Costs:

The Companies are also authorized to defer interest costs associated with the delayed recovery by applying a monthly rate of 0.7083% to the accumulated post-date certain deferrals (without reduction for accumulated deferred income taxes) through December 31, 2010, including accumulated deferred interest. The post date certain deferrals represent costs deferred from June 1, 2007 through December 31, 2008, including carrying charges as defined in the respective ETP, Line Extension and RCP cases. CEI's post-date certain deferrals also include $25 million for additional distribution-related costs authorized in the Electric Security Plan.

Deferrals Recovery:

The Companies are authorized to begin recovering the post-date certain deferrals and carrying costs effective with customer bills rendered on and after January 1, 2011 via the implementation of non-bypassable distribution riders referred to as the Deferred Distribution Costs Recovery Rider. Such riders include a return component equal to each company's annual weighted average cost of long-term debt outstanding on December 31, 2010, net of accumulated deferred income taxes. Any under/over recovery of Deferred Transition Taxes and Deferred Line Extensions will adjust the unamortized balance of the RCP Deferred Distribution costs. Listed below is a table showing recommended customer rates per kWh. These overall rates will be different based on proposed rate schedules and customer classes.

Starting Dates for Rates per kWh	Deferred Transition Taxes	Deferred Line Extension	Deferred Distribution	TOTAL Rider
OH Total Average				
January 1, 2011	$ 0.000189	$ 0.000134	$ 0.000328	$ 0.000651
January 1, 2016	-0-	-0-	$ 0.000328	$ 0.000328
OE:				
January 1, 2011	$ 0.000357	$ 0.000169	$ 0.000276	$ 0.000802
January 1, 2016	-0-	-0-	$ 0.000276	$ 0.000276
CEI:				
January 1, 2011	$ 0.000027	$ 0.000107	$ 0.000513	$ 0.000647
January 1, 2016	-0-	-0-	$ 0.000513	$ 0.000513
TE:				
January 1, 2011	$ 0.000073	$ 0.000095	$ 0.000114	$ 0.000282
January 1, 2016	-0-	-0-	$ 0.000114	$ 0.000114

The final rider rate on January 1, 2016 shall remain in effect for each Company until the Deferred Distribution costs and interest and any over/under recovery adjustments have been fully recovered (estimated to be at the end of 2035 and surviving the end date of the ESP.)

SECTION II – TRANSMISSION RIDER

Rider:

The Commission has determined that a non-bypassable transmission costs rider shall be established by the Companies on the estimated December 31, 2008 balance of the 2005 deferred transmission costs with a recovery period of 2 years beginning January 1, 2009. The estimated balances including interest as of December 31, 2008 by company are as follows (in millions):

OE	$ 23.4
CEI	$ 14.5
TE	$ 6.0

Attachment G

The estimated December 31, 2008 balances for the 2005 deferred transmission costs are the remaining incremental transmission and ancillary service-related charges including interest that were authorized by the Commission in Case No. 04-1931-EL-AAM to be recovered over a five-year period beginning January 1, 2006.

Deferrals Recovery:

The Companies are authorized to begin recovering the remaining 2005 transmission deferrals and carrying costs effective with customer bills beginning January 1, 2009, through the implementation of non-bypassable transmission riders referred to as the Deferred Transmission Costs Recovery Rider. Such riders include a return component equal to each company's monthly weighted average cost of long-term debt. The remaining transmission cost deferrals including accumulated interest will be recovered with these riders. The riders will remain in effect for each Company until the earlier of December 31, 2010 or until any over/under recovery adjustments have been fully settled.

Attachment H

Significantly Excessive Earnings Test

Following the conclusion of each year under the Plan, a significantly excessive earnings test for each electric utility will be performed. The test will be comprised of the following:

i) If the ROE, recognizing an adjustment for differences in capital structure, for each electric utility for a year under the Plan is greater than the average ROE, also recognizing an adjustment for differences in capital structure, plus 1.28 standard deviations above the average for a group of capital intensive industries, then significantly excessive earnings may exist for the particular utility, subject to the consideration of the capital requirements of future committed investments in Ohio. The group of capital intensive industries is comprised of electric utilities, natural gas utilities, oil and gas distribution companies, water utilities, environmental companies, railroads and telecommunication services companies that have an investment-grade credit rating.

ii) Earnings in this test shall be adjusted for paragraph A.3.f. under this Plan, to exclude subsidiary equity earnings and to exclude any RTC or impairment write-offs that may occur subsequent to December 31, 2007. The equity base for purposes of this test shall be increased by any RTC write-off (to the extent that it would not have otherwise been amortized pursuant to the RCP) or impairment write-offs that have accumulated subsequent to December 31, 2007.

[Company Exhibit 1]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

DAVID M. BLANK

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

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

A. My name is David M. Blank. My business address is FirstEnergy Corp. ("FirstEnergy"), 76 South Main Street, Akron, Ohio 44308. My position at FirstEnergy is Vice President — Rates & Regulatory Affairs.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Science Degree in mathematics from Mount Union College as well as a Master of Arts Degree (Economics) from Cleveland State University. I also hold a Juris Doctor Degree from the Marshall School of Law at Cleveland State, and am a member of the Ohio Bar.

My electric utility career started in 1969 with The Cleveland Electric Illuminating Company. I have served in financial and management positions for CEI, Centerior Energy (parent corporation of CEI from 1987 to 1997) and FirstEnergy since that time. In my career, I managed the Rates and Corporate Planning functions for Centerior Energy Corporation for many years, and served as Treasurer of that company from 1994 until the merger of Centerior with Ohio Edison forming FirstEnergy in 1997. At FirstEnergy, I have managed the Rates & Regulatory Affairs function since 1997, and I was elected to my present position in April 2004.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT-- RATES & REGULATORY AFFAIRS.

A. I am responsible for rate and regulatory activities for FirstEnergy's utility subsidiaries, including Ohio Edison, CEI and Toledo Edison. My group's work includes planning and implementing regulatory strategy in the areas the Companies serve, including pricing and rate design, revenue requirements and regulatory economics, participation in electric supply procurement arrangements for the Companies, as well as working with customers and their representatives. My group is also responsible for forecasting sales and managing the RTO settlement process. I have appeared before regulatory agencies, including the PUCO, many times over many years as an expert witness in utility matters.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony is filed on behalf of Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, "Companies"). The purpose of my testimony is to sponsor overall the Application and, in this regard, its provisions should be deemed incorporated by reference as part of this testimony. In particular, I address the Companies' proposed Electric Security Plan ("ESP", or "Plan") and explain the advantages to consumers under the Plan, and why, in aggregate, the terms and conditions of the Plan are more favorable to customers than the MRO.

Q. WHAT PARAGRAPHS OF THE PLAN DO YOU SPONSOR?

A. Although I generally sponsor the ESP overall, in particular I address the following provisions of the Plan (and related Schedules):

1) Paragraph A1	RTC and Extended RTC charges for CEI
2) Paragraph A.3.b	The $150 million distribution increase and the CEI $25 million deferral of distribution related costs in 2009.

3) Paragraphs A.4.c, A.4.g, A.4.h	The $5 million investment for energy efficiency and demand side management and the $5 million investment for economic development and job retention, distribution rate freeze and allowing the Company's to make revenue neutral or new service offerings during the term of the ESP.
4) Paragraphs A.2.f, A.2.g	Associated with Securitization.
5) Paragraph A.2.m.	Remediation and reclamation of existing retired generating plants or manufactured gas sites
6) Paragraph A.3.d	Distribution Case Resolution
7) Paragraph A.7.a	Time limits on ESP acceptance
8) Paragraph A.7.b	ESP is more beneficial than MRO
9) Paragraph A.7.c	Total Plan Acceptance
10) Paragraph A.7.e	Termination of the Plan effective January 1, 2011
11) Paragraph A.7.i	Determination of generation prices after the Plan.
12) Paragraph A.7.j	Plan conditioned upon FERC approval
13) Paragraph A.7.f	Items that survive the end of the ESP plan term
14) Paragraph A.7.g	Termination of Plan due to adverse decision
15) Paragraphs A.7.h	Market prices paid by customers / aggregation groups
16) Paragraph A.8a through d	Severable short term ESP SSO
17) Paragraph B	Compliance with draft commission rules
18) Paragraph C	Proposed procedure and timing

Q. ARE THERE OTHER PORTIONS OF THE APPLICATION THAT YOU SUPPORT?

A. Yes. I also support the description of the status of the Company's corporate separation plan, the status of the Company's operational support plan and the fact that the Company's ESP and SSO Application are consistent with the policy of the state as delineated in section 4928.02 of the Ohio Revised Code, and the effect of nonavoidable generation charges on large scale aggregation groups.

Q. IS THE COMPANY'S ESP CONSISTENT WITH THE POLICY OF THE STATE AS DELINEATED IN DIVISIONS (A) TO (N) OF SECTION 4928.02 OF THE OHIO REVISED CODE?

A. Yes, it is. The statute sets out a number of long term policies for Ohio and we must remember the duration of the ESP is only three years. Nonetheless, the Plan advances many of the policy goals set out in the statutes. For example, and most importantly, the ESP promotes the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory and reasonably priced retail electric service as encouraged by Section 4928.02(A). The ESP also advances the policy of the state with regard to demand-side management, time-differentiated pricing, advanced metering infrastructure, energy efficiency programs and the development of performance standards and targets for service quality.

Overall, the General Assembly has determined that an ESP supports the policies in Section 4928.02 of the Revised Code if it is more favorable in the aggregate as compared to the expected results that would otherwise apply under a Market Rate

Option ("MRO") adopted pursuant to Section 4928.142 of the Revised Code. As explained below, the ESP satisfies this test and, thus, promotes state policy.

Q. ARE YOU FAMILIAR WITH SECTION 4928.143 (C)(1) WHICH STATES, IN PART: "...the commission shall by order approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the revised code?"

A. Yes.

Q. DO YOU HAVE AN OPINION WHETHER THE ELECTRIC SECURITY PLAN PROMULGATED BY THE COMPANIES IS MORE FAVORABLE IN THE AGGREGATE COMPARED TO THE EXPECTED RESULTS THAT WOULD OTHERWISE APPLY UNDER SECTION 4928.142 ?

A. Yes. My opinion is that the Electric Security Plan is more favorable than the expected results of the Companies' section 4928.142 Market Rate Option filing. The ESP is more favorable for customers from a qualitative standpoint as well as from a quantitative view. At a minimum, based upon and in comparison to the market prices projected by Mr. Jones and Mr. Graves, the ESP provides net present value to customers exceeding $1.3 billion over the Plan period.

Q. DOES THE PLAN CONTAIN BENEFITS TO CUSTOMERS IN ADDITION TO THE QUANTITATIVE BENEFITS?

A. Yes. As I understand the statute, SB 221 requires the Commission to evaluate an ESP including all its terms and conditions. There are a number of significant benefits for customers under the ESP not available under the MRO. Such benefits include, without limitation, the following: (1) the Plan provides price stability over the Plan period; (2) the Plan, as a comprehensive arrangement, settles pricing and service arrangements for the totality of electric service, not just generation, and includes many other provisions benefitting customers; (3) the Plan provides substantial flexibility for the Commission to manage overall price trends over the Plan period, and (4) the Plan contains a severable provision that gives the Commission additional time to consider the longer term ESP, and, should the MRO be implemented, a longer period of time so as to conduct a more measured competitive bid process. As noted above, from a quantitative view alone, customers are benefitted by the Plan by more than $1.3 billion in aggregate for the FirstEnergy Ohio Companies in present value compared to what market prices are projected to be for the Plan period. That's a present value savings averaging over $600 per customer for the Plan period on a quantitative basis alone. The ESP is more favorable for each of the three Companies individually as well, with the quantitative net present value benefit to customers, before consideration of qualitative benefits, by over $409 million for Ohio Edison, $718 million for CEI, and $175 million for Toledo Edison.

Q. PLEASE GIVE AN OVERVIEW OF THE PLAN.

A. The ESP is a comprehensive arrangement that establishes price levels for electric service for the years 2009, 2010, and 2011 at predictable and manageable levels for the Companies' customers, as well as providing benefits that extend beyond that period, as well as non-price benefits. The details of the Plan are in the Application and its Attachments; the following highlights a number of primary features of the Plan.

Prices for base generation service are established at levels less than the market price levels experts expect would be charged for the Companies' load for those years. And, in addition, at least 10% of those base generation prices are deferred for future recovery so that the rate impact of electric service starting in 2009 can be managed to moderate levels. This is particularly true when one recognizes the duration of time since the Companies' base rates were last established in 1990 for Ohio Edison and in 1996 for CEI and Toledo Edison. The deferrals accrue a carrying charge at a very favorable interest rate and are recovered over a ten-year period beginning in 2011. Transmission costs are a pass-through of the costs levied on the companies by the regional transmission organization. Distribution costs are established based on an aggregate $150 million annual revenue increase, in resolution of issues in the Companies' pending rate cases. A five-year stay-out period would be established before the Companies' next increase in distribution base rates. A performance-based distribution improvement rider is established. Importantly for CEI customers, the ESP proposes to waive RTC and Extended RTC charges starting January 1, 2009. The residential credits for CEI customers will end at the same time. Under the prior approved regulatory plans, CEI's RTC and Extended RTC charges, and the residential credits, continued to be effective until the end of 2010, largely as a result of the very substantial shopping with third party suppliers in the CEI area compared to the other companies. The early termination of RTC charges by itself is a rate benefit to customers of $591 million. With very limited exceptions, all beyond the control of the Companies or its generation supplier, the rates in the Plan are not subject to change during the Plan period as a result of cost variances. Those exceptions include MISO transmission charges, costs associated with fulfilling reserve capacity requirements through purchases, additional renewable requirements beyond those called for in SB 221, new taxes, fuel cost increases in 2011 compared to 2010, transportation surcharges and new environmental requirements (the latter two in excess of specified levels).

The Plan contains a broad set of additional benefits for customers and commitments from the Companies.

- The first is that the Commission, while having the opportunity to approve the three-year Plan, can subsequently change its mind about the appropriateness of continuing with the generation pricing for the third year (2011). This option offers the Commission significant flexibility in its decision making, to the benefit of customers. If, by the end of 2009, the already approved three-year Plan still looks favorable compared to an MRO, the Commission, having already approved the Plan, needs to take no additional action to avail itself and customers of the third year arrangements. However, upon good cause shown, or on its own initiative, the Commission can hold a hearing to consider whether the third year generation pricing is no longer appropriate, and, if it so desires, can reject the third year generation pricing and move directly to market rates.

- Second, the Plan provides substantial funding—$96 million over the 3-year Plan period—for four specific programs:
    1. The Companies agree to undertake an AMI pilot to determine the viability of economically deploying the technology, and will not seek recovery from customers of the first $1 million spent on the pilot.
    2. The Companies agree to spend up to $25 million, in annual amounts of up to $5 million from 2009 through 2013 for energy efficiency and demand side management activities, funds that will not be recovered from customers.
    3. The Companies agree to spend up to $25 million, in annual amounts of up to $5 million annually from 2009 through 2013 for economic development and job retention, funds that will not be recovered from customers.
    4. As part of a new supply agreement between the Companies and FirstEnergy Solutions ("FES"), FES will support and/or undertake environmental remediation of existing retired generating plans owned by the Companies and/or manufactured gas plant sites for which the Companies have remediation obligations. FES's cost responsibility under this program will be an annual maximum of $15 million for each year of the Plan period.
- Remaining legacy issues, particularly regulatory asset recovery for costs previously incurred for the benefit of customers, stemming from the ETP, the line extension case, the RSP and RCP and transmission deferral cases

are resolved, thereby establishing improved pricing stability and saving time for all parties and the Commission and its staff, issues that would otherwise be dealt with in individual cases requiring substantial commitment of time and resources. As part of this feature, recovery of the post date certain balances from the distribution case associated with the ETP deferrals and RCP distribution deferrals is delayed until January 1, 2011 with carrying charges accruing at very favorable interest rates for customers .

- Customers are not subject to any escalation in the stated generation rates in 2009 and 2010 associated with fuel costs (excluding fuel transportation fuel surcharges in excess of stated levels), the cost of meeting renewable requirements of SB 221, and environmental costs associated with existing laws and existing interpretation of such laws as well as the first $50 million of costs associated with new such laws and interpretations, as described in the application.
- Customers continue to have the green option available to them through extending the Commission-approved program under which customers can "green up" their generation supply through purchase of renewal energy credits made available by the Companies under a REC-acquisition program.
- In response to concerns raised during the legislative process regarding the need for new generating capacity, the utilties' supplier agrees to increase capacity for advanced energy resources by 1000 MW from January 1, 2007 through December 31, 2011 as described in the Plan. This commitment will be fulfilled through (i) new or upgrading existing generation, which may

include renewable generation through contracts or otherwise; (ii) maintaining existing generation in service that would otherwise be shutdown pursuant to court order without installing environmental control equipment or repowering consistent with such order; and/or (iii) additional generation. This Plan commitment benefits customers by assuring provision of capacity to help meet the region's long-term energy needs.

- As part of a new supply agreement between the Companies and FES, FES will be responsible for providing the renewable requirements for the generation supply during the Plan period at no further cost to customers .
- The Companies commit to make capital investments in their energy delivery systems in the aggregate of $1 billion over the period 2009 through 2013.
- The Companies also commit to undertake a comprehensive study of energy delivery system enhancement, including Smart Grid technologies.
- The deferrals that result from the phase-in of generation rates accrue a carrying charge at a very favorable interest rate for customers . In addition, the Plan includes a process pursuant to which the Company can seek Commission authorization for securitization of the deferrals which may result in even more value to customers .
- As part of the performance-based distribution improvement rider, the Companies agree to establish SAIDI targets with rate credits or charges based on level of achievement to the SAIDI target. There is a dead band around the targets where neither credits nor charges are applied, but the structure of the dead band is asymmetrical in favor of the customer.

- The Plan provides a means to expand economic development, energy efficiency and demand side management efforts within Ohio without jeopardizing the financial health of the individual Companies.

Q. PLEASE PROCEED WITH MORE DETAIL AS TO HOW THE ESP IS MORE FAVORABLE THAN THE MRO. START WITH THE PRICE STABILITY POINT YOU REFERENCE ABOVE.

A. First, our customers have advised us again and again that they desire stability regarding pricing. I believe the ESP offers substantial price stability and the ability to plan for future pricing in comparison to what is available with market prices. The Plan results in aggregate price increases totaling 5.32% in 2009, 4.01% in 2010, and 5.99% in 2011. The increase in 2009 includes the impact of the increase in distribution rates. While these percentages do not include the impact of riders (such as the 2011 fuel rider, or the reserve capacity rider, for example), it is not known or knowable at this time whether those riders will be triggered, and, to the extent they are, it is expected that market prices would reflect at least that much increase. We have done our best to keep the impact of the riders to a minimum in order to improve the price stability feature of the Plan. I should further point out that the increases reflect—and are inflated by—the impact of expiring customer contracts as part of the overall increase.

Q. ONE OF THE SIGNIFICANT BENEFITS YOU LISTED ABOVE IS THAT THE PLAN IS A COMPREHENSIVE ARRANGEMENT. WHY DOES THAT FACTOR BENEFIT CUSTOMERS IN COMPARISON TO AN MRO?

A. SB 221 provides new flexibility in the crafting of ESPs, flexibility that the Companies' proposed ESP takes advantage of in their recommendation of a comprehensive plan. The ESP deals with the totality of electric service, generation, transmission, and distribution, even though under Ohio law those are separate and unbundled service categories. The importance of the comprehensive plan is that many provisions specifically providing customer benefits are made available in all aspects of the electric service that would not be available with a market rate option, as I will describe below. For example, the Companies commits to funding up to $96 million in program costs to directly support customers over a five -year period, including the energy efficiency, economic development, AMI and environmental remediation funding programs. The ESP establishes specific rate patterns for distribution rates, with one important feature establishing a five-year stay-out period for increasing base rates. Another benefit is bringing the presently pending distribution rates to a conclusion, including establishing certainty for customers about the recovery patterns for legacy deferral issues. Introduction of the performance-based rider mechanism is another factor that demonstrates the advantage of a comprehensive arrangement. Most – but not all – of these matters could of course be dealt with in separate regulatory proceedings, all of which would serve primarily to occupy valuable time and space on the Commission's docket, as well as for the parties involved.

Q. ANOTHER OF THE "SIGNIFICANT BENEFITS" YOU CITE RELATES TO FLEXIBILITY. PLEASE DESCRIBE HOW FLEXIBILITY RESULTS IN THE ESP BEING MORE FAVORABLE THAN AN MRO?

A. The flexibility offered by the Plan is shown primarily in the ability offered to the Commission to manage price levels for customers over time, while at the same time attaining improved certainty regarding pricing among the various rate schedules. Specific factors include the following, among others:

- The Plan proposes a three-year pattern for generation pricing. As raised above, the Commission, once having accepted the Plan, can subsequently reject the year 3 generation pricing, if among other reasons, the Commission believes more favorable arrangements are available in the marketplace.
- The Plan offers a phase-in program for base generation rates, with the costs deferred under the program will be recovered over an extended period of time with carrying charges at a level favorable to customers. This program gives consumers an opportunity to adjust over time to rates more representative of the market.
- Under the Plan, the Commission may elect to defer a portion of reserve capacity costs otherwise recoverable under the rider structure, thereby providing additional ability to manage the price pattern over time.
- The rate schedule pricing proposed in the Plan presents the Commission with additional flexibility in managing price patterns among the different rate schedules. In this way, the Commission is presented with a rate

structure that generally permits maintenance of existing rate patterns. An example of this relates to continuation of rate differences for residential space heating customers in order to help moderate increase levels from today's preferential levels. This moderation would lack a basis under a pure market plan.

- To improve the ability to implement the state's economic development and job retention goals, any such price reductions intended to bring improved economic conditions to the state are shared by all customers among the three Companies, rather than being limited to a single group of customers, thereby enhancing the flexibility of the Commission and the state in addressing this important issue. An example of this relates to Toledo Edison, where a disproportionate amount of the load serves, compared to the Ohio system load, industrial business provided under special arrangements. Under the Plan, the Commission would have additional flexibility in addressing the needs of industrial customers in Toledo area.

Q. PLEASE DESCRIBE THE QUANTITATIVE BENEFITS AVAILABLE TO CUSTOMERS UNDER THE ESP COMPARED TO AN MRO.

A. We project the minimum level of quantitative benefits to customers from the totality of the Plan in aggregate compared to the section 4928.142 plan to be more than $1,300,000,000 in present value dollars. In addition, many of the benefits are not easily susceptible to quantification, so no amount has been assigned to those Plan features in the amount identified above. As a result, the stated value is a minimum value.

By company, projected minimum quantitative benefits over the Plan period, without consideration of the qualitative benefits, are as follows:

Ohio Edison:	$409,100,000
CEI:	$718,500,000
Toledo Edison:	$175,800,000
Total	$1,303,400,000

Q. HOW DID YOU DETERMINE THE MINIMUM LEVEL OF QUANTITATIVE BENEFITS?

A. We begin the process by identifying prices levels in the ESP compared to prices for generation expected to be available under a market option for the Plan period. We also identify other non-rate quantitative benefits available in the ESP. We consider the year-by-year value of each of those features, and determine the present value of the sum of price and non-price elements for the ESP, and for the market prices for the same period, and then compare the difference between the two present value amounts. Attachment 1 to this testimony contains a summary of the results for the Companies in total as well as for each individually.

In particular, we identify the following quantitative elements for the ESP:

1. Revenues from the distribution rate case at $150 million per year, with modest sales growth, for 2009-2011, recognizing the CEI distribution increase does not begin until May 2009.

2. Revenues from the distribution service improvement rider for the Plan period 2009-2011.

3. Revenues from the base generation rate, reduced by the deferral amount, compared to the generation rate in effect during 2008, for the Plan period 2009-2011.

4. Revenues to recover the deferred generation cost, starting in 2011, and extending through 2022, including the impact of carrying charges on the unrecovered deferred balance.

5. Recovery of the deferred distribution expense for CEI starting in 2011 and continuing through 2035, including the impact of carrying charges on the unrecovered deferred balance for that item.

6. Recognition of the individual company benefits attributable to the Economic Development Rider; note that on an total basis this factor does not add to the Plan's overall present value level, but it does impact the individual company present value amounts.

7. Value of the energy efficiency, economic development, AMI and environmental remediation programs, totaling $96 million over the period. All programs are for the benefit of our customers the funding amounts are not included in future *customer rates.*

8. Value of the waived CEI RTC and Extended RTC charges, net of the residential credits, initially approved under the ETP case (Case No. 99-1212-EL-ETP, and further preserved in the RSP and RCP cases (Case Nos. 03-2144-EL-ATA and 05-1125-EL-ATA respectively), with a value over the period of $591 million.

Then we identify these elements for the market option:

1. Revenues from the distribution rate case at $150 million per year, with modest sales growth, for 2009-2011, recognizing the CEI distribution increase does not begin until May 2009. This is the same as included in the ESP case.
2. Annual revenues from the expected generation rates under a market option, compared to revenues from the generation rate in effect during 2008, for the Plan period 2009-2011.

Q. HOW DID YOU DETERMINE THE EXPECTED GENERATION RATES UNDER A MARKET OPTION?

A. I used the average of the market rates for each year of the Plan period as determined by Mr. Jones and by Mr. Graves. The following table identifies the values from their testimony, including the resultant average that I have used as the market generation rate for my calculation. Note that transmission costs are excluded from these market rates; the ESP generation rates do not include transmission costs as well.

Market Rates[1] from the Testimony of Mr. Jones and Mr. Graves

	$/MWH		
	Mr. Jones	Mr. Graves[2]	average
2009	81.69	83.45	82.57
2010	88.66	81.87	85.27
2011	94.99	81.39	88.19

[1] Net of transmission costs

[2] The values are the average of the 50% level for Mr. Graves' two methods

Q. HOW DID SHOPPING IMPACT YOUR ANALYSIS?

A. For both the ESP and for the market cases, we have assumed that there was no shopping. That way the results are not skewed one way or another due to any shopping differences that may occur under either the ESP or the market option.

Q. HOW DID YOU TREAT SOME OF THE OTHER FEATURES OF THE PLAN IN YOUR EVALUATION?

A. Some features that would be expected to impact both the ESP and the market plan are not included on either side of the present value equation. This would include such items as the 2011 fuel rider, and any rider impact for new environmental costs, new taxes and for purchased reserve capacity and for the fuel transportation surcharge. On the ESP side, we do not know the amounts that these riders will have, or even whether they will be triggered. On the MRO side, market rates would be expected to be increased to include the costs used as the basis for the riders. Even so, the amount includable in the ESP is likely to be less than the amount includable for the MRO for the fuel transportation surcharge and for the new environmental costs as a result of the threshold value that must be exceeded before a charge to customers is triggered. The revenue from the distribution case is included in both the ESP and the MRO cases.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EVALUATION.

A. Based on the results of this analysis, the Plan for the Companies in aggregate, and for each individual Company, is clearly favorable for customers, even before any consideration is given to the qualitative factors discussed.

Q. PLEASE DISCUSS THE AGGREGATE VALUE OF THE SHORT-TERM ESP TO THE CUSTOMERS OF THE COMPANIES IN AGGREGATE AND INDIVIDUALLY.

A. The most significant value of the Short-term ESP is the additional time provided to the Commission in contemplating its decision regarding approval of the longer-term ESP and in conducting a competitive bid if the MRO is implemented. As Mr. Warvell identifies in his testimony regarding the Market Rate Option, the timeline available to the Commission for its deliberations regarding generation service starting January 1, 2009 is very short. I understand that the Companies would not be permitted to initiate their competitive bid until 150 days after the filing of this Application. This means that December 29, 2008 would be the earliest date the bid could be conducted. The Companies have no wholesale power arrangements beyond December 31, 2008. A concern exists that such an aggressive timeline, while unavoidable, might inhibit bidder participation to the detriment of customers. In contrast, there are many advantages of the Short-term ESP timeline. It represents a more typical "timeline." This elongated timeline directly benefits bidders by allowing them to plan and participate in the bidding process in an accustomed manner and timeframe. Customers, thereby, will benefit because more bidders will be attracted to participate in the solicitation, which one would expect to result in lower priced bids.

Q. HAVE YOU PERFORMED A QUANTITATIVE EVALUATION OF THE SHORT-TERM ESP COMPARED TO AN MRO?

A. Yes. I have compared the Short-term ESP pricing to the average of the 2009 market rates projected by Mr. Graves and Mr. Jones. The Short-term ESP generation rate, including the amount deferred, is $77.50 per MWH. The average 2009 market price, as reported earlier in my testimony, is projected to be $82.57 per MWH. Both values exclude the cost of transmission service. The Short-term ESP evaluation would include an average Delivery Service Improvement Rider averaging $2.00 per MWH and the CEI distribution deferral. Even with the DSIR being considered (in aggregate or Company-by-Company), the Short-term ESP value is more favorable than the projected 2009 MRO market price. I must note, though, in my view any strictly economic analysis of the Short-term ESP is greatly overshadowed by the flexibility offered by the Short-term ESP to the Commission in timing for its longer-run decision.

Q. HOW DOES THE PLAN ADDRESS GOVERNMENT AGGREGATION?

A. Two parts of the Plan specifically reference government aggregation. The first part relates to deferral of a portion of generation costs and the recovery of those deferrals. The second deals with application of standby charges. Otherwise, the Plan applies equally to customers in a government aggregation program and all other customers.

Q. PLEASE DESCRIBE THE ISSUE REGARDING GENERATION COST DEFERRAL

A. Section 4929.20(I) identifies, in part, that customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code (the provision that authorizes rate phase-ins and recovery of resulting deferred costs) that is proportionate to the benefits received. The tariffs the Companies have proposed to implement this requirement of the Revised Code, are described in the testimony of Mr. Warvell.

Q. PLEASE DESCRIBE THE ISSUE RELATING TO STANDBY CHARGES.

A. Section 4929.20 (J) provides provisions regarding election of standby charges for customers being provided generation service as part of a government aggregation group. Generally, such customers, or the legislative authority that formed or is forming a governmental aggregation group, on behalf of the customers that are part of the government aggregation group, have the option to elect not to receive standby service. However, if such customers return to the utility for generation service at any time during the Plan, they then pay standard service offer market prices for such service rather than the anticipated more favorable pricing provided by the Plan. While the Companies' Plan provides this option for government aggregation customers, the Plan also provides this option to any customer electing generation service from an alternative supplier. In the latter case, a customer returning to utility generation service returns at the higher of SSO market prices or the SSO prices otherwise applicable in the ESP. Mr. Warvell describes the Plan in more detail in his testimony.

Q. WHAT IS THE EFFECT OF THE PLAN'S NONAVOIDABLE GENERATION CHARGES ON LARGE-SCALE AGGREGATION GROUPS?

A. The overall effect of the Plan's nonavoidable generation charges is beneficial to customers served by large-scale aggregation groups, just as it is beneficial for all customers. The nonavoidable generation provisions, such as the default service charge, help provide the risk mitigation arrangements that are essential for the Companies to have the financial capacity to propose the Plan in its present form for the benefit of all customers. Without such arrangements to provide financial resources and mitigate the risk associated with the Plan, the Companies could not make available the pricing and other beneficial provisions of the Plan, whether or not customers shop with third party suppliers and the cost and prices to all customers would be higher. A specific analysis of the effect of these charges on large-scale aggregation groups would require reviewing pricing and cost data from governmental aggregators and/or their suppliers, which information is not available to the Companies. In any event, large scale aggregation groups are affected the same as other customers with no negative disproportionate effects. Unavoidable charges arising from deferrals authorized prior to the effective date of SB 221, such as our fuel deferral rider, are explicity excluded from consideration by R.C. 4928.20(K),

Q. ARE YOU FAMILIAR WITH THE TESTIMONY SPONSORED BY COMPANY WITNESSES REGARDING THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST, AND PARTICULARLY THE PROPOSED EXCLUSION OF THE DELIVERY SERVICE IMPROVEMENT RIDER REVENUES FROM THAT TEST?

A. Yes.

Q. WHAT IS THE RATIONALE FOR THE EXCLUSION OF THE DELIVERY SERVICE IMPROVEMENT RIDER REVENUES FROM THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST?

A. To supplement what Mr. Schneider describes in his testimony, the rider is intended to assist in providing the Companies with the financial capacity to meet the very challenging circumstances that they face in needing to meet the needs presented by rebuilding an aging infrastructure; recruiting, training, and incorporating into the work force qualified staff members necessary to replace the large cadre of retiring staff members, which will require staffing levels to be temporarily increased to accommodate knowledge transfer; while at the same time meeting the dramatically increasing costs of providing customer service, including longer lead times and more restrictive payment terms in procuring increasing costly equipment, such terms largely requiring upfront payment, sometimes years before equipment is delivered, such that there is no regulatory recovery for such cost.

The DSIR is an incentive-type mechanism tied to reliability performance that will assist in ensuring that customers' and the Companies' expectations are aligned and assure, along with the commitment to make capital investments in the distribution system from January 1, 2009 through December 31, 2013 of at least $1 billion, that sufficient emphasis and resources are being dedicated to the reliability of the distribution system. It makes no sense to design an incentive mechanism, and would in fact negate the incentive, just to later have such incentive used in an earnings test and potentially lead to an adjustment and refund. Including the revenues provided by the rider in the determination of whether the Companies were receiving significantly excessive earnings, increases the prospect that such incremental amounts might be considered "significantly excessive", leading to a reduction or perhaps complete elimination of the rider revenues. Such action would defeat the purpose of approval of the rider in the first place. By excluding the rider revenues from the earnings test to begin with, the rider can perform its intended purpose.

In addition, Section 4928.143(F) states, in part, "Consideration also shall be given to the capital requirements of future committed investments in this state." The Companies' $1 billion commitment to distribution investment should certainly be taken into account in any such Commission evaluation and assuring that the

Companies' ability to fulfill that commitment is not jeopardized is, in this context, an appropriate consideration.

Q. PLEASE EXPLAIN WHY THE COMPANIES INCLUDE AN OPTION FOR SECURITIZATION?

A. SB 221 enables the Companies to include in their electric security plan an option to securitize any phase-in. The Companies believe that securitization may be beneficial to its customers.

Q. ARE THE COMPANIES ASKING THE COMMISSION IN THIS PLAN TO APPROVE SECURITIZATION OF THEIR DEFERRED GENERATION COSTS?

A. No. The Companies seek Commission approval of a proposed framework pursuant to which the Commission would review future requests for securitization from the Companies.

Q. WHY HAVE THE COMPANIES FILED A SECURITIZATION FRAMEWORK?

A. The securitization framework attached to the ESP as Option Two of Attachment A, which my testimony supports and is incorporated herein, sets forth the foundation or guiding principles that are necessary for any securitization transaction. I believe the proposed framework sets out a reasonable process for addressing securitization in the future. It is very unlikely that any securitization transaction would be a viable option without the framework. The framework also creates a process pursuant to which the Companies may apply for, and the commission will review, securitization of generation phase-in costs, as more fully described in Attachment A. Thus, the

Companies file the securitization framework as part of Attachment A to preserve the option that the legislation contemplates.

Q. WHAT IS YOUR RESPONSE TO THE CONCEPT THAT SOME PARTIES MAY PREFER THAT SOME PLAN PROVISIONS BE ACCEPTED WHILE OTHER PLAN PROVISIONS BE MODIFIED?

A. The Plan is an integrated, comprehensive package for all three Companies that must be accepted for all three Companies, not just one or two. It is designed to provide customer benefits while at the same time providing the Companies the ability to assure that they can follow through on providing those benefits. Any selective pruning or modification of the Plan, particularly seeking to preserve benefits while removing elements that provide the ability to provide the benefits is counterproductive to being able to offer the benefits of the Plan at all.

Q. ARE YOU FAMILIAR WITH THE COMPANIES' CORPORATE SEPARATION PLAN?

A. Yes.

Q. PLEASE SUMMARIZE AND DESCRIBE ASPECTS OF THE COMPANIES' CORPORATE SEPARATION PLAN THAT DEMONSTRATE COMPLIANCE.

A. FirstEnergy has separated its organization into three independent business entities: a competitive services unit, a corporate support unit and a utility services unit. The competitive services unit now owns all FirstEnergy generating assets. The corporate support services unit retains corporate related functions such as accounting, treasury, legal, human resources and industrial relations, communications, real estate and other shared functions. Finally, the utility services unit, containing the Companies, maintains physical and operational control of the distribution assets. FirstEnergy's transmission assets are owned by American Transmission Systems Inc. Additionally, the Companies have in place a Commission-approved Code of Conduct and a Cost Allocation Manual as a means to ensure regulatory compliance and eliminate the sharing of information and resources between the regulated transmission and distribution units and the competitive services unit. To ensure all employees are aware of the Code of Conduct rules the Companies have a training program in place that all employees must complete on an annual basis. The Companies are now strictly distribution companies owning no generation assets. All of the Companies' generation assets have been divested. The Corporate Separation Plan is in Compliance with R.C. section 4928.17 and O.A.C. Chapter 4901:1-37. The compliance officer for the Companies, who is the contact person for the Commission and staff on corporate separation matters, currently is R.S. Ferguson.

Q. DID THE COMPANIES SEEK ANY WAIVERS? IF SO, PLEASE EXPLAN.

A. The Companies sought waivers for and clarifications of specific rules in the Code of Conduct and Cost Allocation Manual requirements. Generally, these waiver requests sought relief for (1) the flow of information and interaction between electric utilities and between the corporate support unit and other affiliates, (2) the sharing of resources permitted by Senate Bill 3, and (3) the commission oversight of unregulated affiliates. The Companies also sought approval of their interim corporate separation plan pursuant to Rule 4901:1-20-16(G)(1)(d), which required waiver of certain financial separation arrangements under section (G)(3).

Q. WERE THESE WAIVER REQUESTS GRANTED BY THE COMMISSION?

A. Yes. The Commission found good cause to grant the waivers requested by the Companies. Furthermore, rules pertaining to the Companies' remaining waivers were modified and/or removed from the final language of Chapter 4901:1-20-16 and thus certain waivers were no longer necessary.

Q. WILL THE COMPANIES SEEK TO CONTINUE ANY WAIVER THAT WAS PREVIOUSLY GRANTED BY THE COMMISSION SHOULD PROPOSED CHAPTER 4901:1-37 BE ADOPTED IN ITS CURRENT FORM?

A. Although revisions or amendments to its current plan are not anticipated, the Companies have submitted comments to the Corporate Separation Rules in Case No. 08-777-EL-ORD to limit the restrictions set forth in Chapter 4901:1-37-04(D)(1) and (D)(3), which would prohibit information and resource sharing among the regulated utilities and between the corporate support unit and other FirstEnergy affiliates. The Companies initially petitioned for this waiver to achieve operating efficiencies, and the commission granted the Companies request. If Sections (D)(1) and (D)(3) are not modified, then the Companies will again, under the same rationale, need to seek a waiver and will at that time file any revisions or amendments to its plan deemed necessary.

Q. HAS THE COMPANIES' OPERATIONAL SUPPORT PLAN, FILED PURSUANT TO DIVISION (A)(2) OF SECTION 4928.31 OF THE REVISED CODE, BEEN IMPLEMENTED?

A. Yes. It has.

Q. ARE THERE ANY OUTSTANDING PROBLEMS WITH THE COMPANIES' OPERATIONAL SUPPORT PLAN?

A. No.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Present Value Benefits of ESP Compared to Market Rates
FirstEnergy -- Ohio Utilities

SUMMARY - TOTAL OHIO

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	82.57
2010 Market Rate average($/MWH)	85.27
2011 Market Rate average ($/MWH)	88.19

Consultant Market Rates		
Jones		Graves
	(less Transmission)	
81.69	2009	83.45
88.66	2010	81.87
94.99	2011	81.39

Year		2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)		57,202,000		57,705,000		58,211,000		58,744,000		59,284,445		1,451,558,323	
ESP		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$137.0		$150.0		$151.0						
Distribution Improvement Rider		2.00	$114.4	2.00	$115.4	2.00	$116.4						
ESP Generation Rate		67.50		71.50		75.50							
Generation Increase over 2008 Rate of 68.18		-0.68	($39.1)	3.32	$191.4	7.32	$425.9						
Economic Development Rider			$0.0		$0.0		$0.0						
AMI Study			($1.0)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			($10.0)		($10.0)		($10.0)		($10.0)		($10.0)		$0.0
Environmental Remediation & Reclamation			($15.0)		($15.0)		($15.0)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			($316.0)		($275.0)		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)		0.00	$0.0	0.00	$0.0	2.01	$117.0	2.01	$118.1	3.25	$192.7		$1,558.4
Deferral Recovery - CEI Distribution ($25M)		0.00	$0.0	0.00	$0.0	0.03	$1.7	0.03	$1.7	0.03	$1.7		$42.2
Total Revenues Per Year			($129.7)		$156.8		$787.0		$109.8		$184.4		$1,600.6
NPV of Total Revenues Per Year	$1,577.1												

Consultant Market Rates		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$137.0		$150.0		$151.0
Generation Rate		82.57		85.27		88.19	
Generation Increase over 2008 Rate of 68.18		14.39	$823.0	17.08	$985.7	20.00	$1,164.5
Total Revenues Per Year			$960.0		$1,135.7		$1,315.5
NPV of Total Revenues Per Year	$2,880.5						

NPV: Ohio Summary	Total Ohio	CEI	OE	TE
NPV: ESP	$1,577.1	$189.9	$963.4	$423.8
NPV: Market Rates	$2,880.5	$908.5	$1,372.4	$599.6
Benefits to Customers (Market - ESP)	$1,303.4	$718.5	$409.1	$175.8

SUMMARY - THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	82.57
2010 Market Rate average($/MWH)	85.27
2011 Market Rate average ($/MWH)	88.19

Consultant Market Rates		
Jones		Graves
	(less Transmission)	
81.69	2009	83.45
88.66	2010	81.87
94.99	2011	81.39

Year	2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)	19,967,000		20,133,000		20,298,000		20,471,000		20,645,004		501,344,773	
ESP	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates		$21.5		$34.5		$34.8						
Distribution Improvement Rider	2.28	$45.5	2.28	$45.8	2.28	$46.2						
ESP Generation Rate	67.50		71.50		75.50							
Generation Increase over 2008 Rate of 69.02	-1.52	($30.3)	2.48	$49.9	6.48	$131.5						
Economic Development Rider		$16.0		$16.0		$16.0						
AMI Study		($0.3)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM		($3.5)		($3.5)		($3.5)		($3.5)		($3.5)		$0.0
Environmental Remediation & Reclamation		($0.5)		($0.5)		($0.5)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits		($316.0)		($275.0)		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)	0.00	$0.0	0.00	$0.0	2.02	$41.0	2.02	$41.4	3.27	$67.5		$543.9
Deferral Recovery - CEI Distribution ($25M)	0.00	$0.0	0.00	$0.0	0.08	$1.7	0.08	$1.7	0.08	$1.7		$42.2
Total Revenues Per Year		($267.7)		($132.7)		$267.2		$39.6		$65.7		$586.0
NPV of Total Revenues Per Year $189.9												

Consultant Market Rates	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates		$21.5		$34.5		$34.8
Generation Rate	82.57		85.27		88.19	
Generation Increase over 2008 Rate of 69.02	13.55	$270.6	16.25	$327.1	19.17	$389.1
Total Revenues Per Year		$292.1		$361.6		$423.8
NPV of Total Revenues Per Year $908.5						

NPV: Cleveland Electric	
NPV: ESP	$189.9
NPV: Market Rates	$908.5
Benefits to Customers (Market - ESP)	$718.5

SUMMARY - OHIO EDISON

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	82.57
2010 Market Rate average($/MWH)	85.27
2011 Market Rate average ($/MWH)	88.19

Consultant Market Rates		
Jones	(less Transmission)	Graves
81.69	2009	83.45
88.66	2010	81.87
94.99	2011	81.39

Year		2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)		26,460,000		26,738,000		27,019,000		27,308,000		27,602,840		688,313,507	
ESP		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$75.0		$75.0		$75.5						
Distribution Improvement Rider		1.97	$52.1	1.97	$52.7	1.97	$53.2						
ESP Generation Rate		67.50		71.50		75.50							
Generation Increase over 2008 Rate of 67.92		-0.42	($11.1)	3.58	$95.7	7.58	$204.8						
Economic Development Rider			($8.6)		($8.6)		($8.6)						
AMI Study			($0.5)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			($4.6)		($4.6)		($4.6)		($4.6)		($4.7)		$0.0
Environmental Remediation & Reclamation			($14.0)		($14.0)		($14.0)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)		0.00	$0.0	0.00	$0.0	2.00	$53.9	2.00	$54.5	3.23	$89.1		$725.4
Total Revenues Per Year			$88.4		$196.2		$360.2		$49.9		$84.4		$725.4
NPV of Total Revenues Per Year	$963.4												

Consultant Market Rates		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$75.0		$75.0		$75.5
Generation Rate		82.57		85.27		88.19	
Generation Increase over 2008 Rate of 67.92		14.65	$387.7	17.35	$463.8	20.27	$547.6
Total Revenues Per Year			$462.7		$538.8		$623.1
NPV of Total Revenues Per Year	$1,372.4						

NPV: Ohio Edison	
NPV: ESP	$963.4
NPV: Market Rates	$1,372.4
Benefits to Customers (Market - ESP)	$409.1

SUMMARY - TOLEDO EDISON

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	82.57
2010 Market Rate average($/MWH)	85.27
2011 Market Rate average ($/MWH)	88.19

Consultant Market Rates		
Jones	(less Transmission)	Graves
81.69	2009	83.45
88.68	2010	81.87
94.99	2011	81.39

Year Sales (MWH)	2009 10,775,000		2010 10,834,000		2011 10,894,000		2012 10,965,000		2013 11,036,601		2014 - 2035 261,900,043	
ESP	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates		$40.5		$40.5		$40.8						
Distribution Improvement Rider	1.56	$16.8	1.56	$16.9	1.56	$17.0						
ESP Generation Rate	67.50		71.50		75.50							
Generation Increase over 2008 Rate of 67.28	0.22	$2.4	4.22	$45.7	8.22	$89.5						
Economic Development Rider		($7.4)		($7.4)		($7.4)						
AMI Study		($0.2)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM		($1.9)		($1.9)		($1.9)		($1.9)		($1.9)		$0.0
Environmental Remediation & Reclamation		($0.5)		($0.5)		($0.5)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits		$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)	0.00	$0.0	0.00	$0.0	2.03	$22.1	2.03	$22.2	3.28	$36.2		$289.1
Total Revenues Per Year		$49.7		$93.3		$159.6		$20.4		$34.3		$289.1
NPV of Total Revenues Per Year $423.8												

Consultant Market Rates	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates		$40.5		$40.5		$40.8
Generation Rate	82.57		85.27		88.19	
Generation Increase over 2008 Rate of 67.28	15.29	$164.8	17.99	$194.9	20.91	$227.8
Total Revenues Per Year		$205.3		$235.4		$268.5
NPV of Total Revenues Per Year $599.6						

NPV: Toledo Edison	
NPV: ESP	$423.8
NPV: Market Rates	$599.6
Benefits to Customers (Market - ESP)	$175.8

[Company Exhibit 2]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

HARVEY L. WAGNER

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

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

A. My name is Harvey L. Wagner. My business address is FirstEnergy Corp. ("FirstEnergy"), 76 South Main Street, Akron, Ohio 44308. I am Vice President, Controller and Chief Accounting Officer of FirstEnergy and its subsidiary companies, including Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, "Companies").

Q. WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I earned a Bachelor of Arts degree in accounting from Grove City College in 1974 and a Master of Business Administration degree, with a concentration in finance, from The University of Akron in 1980. I also completed the Duke University Advanced Management Program in 1986. I joined Ohio Edison — which merged in 1997 with Centerior Energy to form FirstEnergy — in 1974 and served in various accounting positions before being elected assistant comptroller in 1983. I was elected comptroller of Ohio Edison in 1990 and controller and chief accounting officer of FirstEnergy in 1997. I was elected to my current position in 2001.

Q. PLEASE DESCRIBE YOUR DUTIES AS VICE PRESIDENT, CONTROLLER AND CHIEF ACCOUNTING OFFICER.

A. I am responsible for: insuring that the financial, accounting, and tax records of FirstEnergy and its subsidiaries are maintained in conformity with generally accepted accounting principles ("GAAP") and regulatory requirements; disbursements to employees, tax authorities and vendors; external financial reporting; accounting research in connection with proposed accounting standards and proposed business transactions; and cost analysis and account classification of construction projects.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to fully and completely address and support all schedules that I sponsor in the Companies' Electric Security Plan ("Plan"). I will also address the accounting authority the Companies are requesting in this proceeding.

Q. MR. WAGNER, PLEASE IDENTIFY EACH ELECTRIC SECURITY PLAN PARAGRAPH AND SCHEDULE YOU ARE SPONSORING.

A. I am sponsoring all or portions of the following Plan paragraphs and schedules filed with the Application:

Plan and Schedules	Title or Description
Plan Paragraph A.3.h.	New ESP Deferrals – Storm Damage Expenses, Line Extension Costs due to Changes in Cost Recovery, Distribution Capital Investment-Related Costs, and Associated Deferred Interest
Plan Paragraph A.6.b. and Attachment G - Section 1	Deferrals – RCP Distribution, ETP Transition Taxes, Line Extensions and CEI's ESP Distribution-Related Costs

Plan and Schedules	Title or Description
Plan Paragraph A.6.c. and Attachment G - Section II	2005 Deferred Transmission Costs
Plan Paragraph A.7.d. and Attachment H	Significantly Excessive Earnings Evaluation
Schedule 6a	Workpapers Deferral Calculation – RCP Fuel
Schedule 6b	Workpapers Deferral Calculation – RCP Distribution
Schedule 6c	Workpapers Deferral Calculation – RCP DSM
Schedule 6d	Workpapers Deferral Calculation – ETP Transition Tax
Schedule 6e	Workpapers Deferral Calculation – Line Extension
Schedule 6f	Workpapers Deferral Calculation – Generation
Schedule 6g	Workpapers Deferral Calculation – Storm Damage
Schedule 6h	Workpapers Deferral Calculation – Incremental Line Extension Costs
Schedule 6i	Workpapers Deferral Calculation – Distribution Investment
Schedule 6j	Workpapers Deferral Calculation – 2005 Deferred Transmission Costs
Schedule 7a	Projected Income Statements
Schedule 7b	Projected Balance Sheets
Schedule 7c	Projected Sources and Uses of Funds Statements

Q. PLEASE EXPLAIN THE PORTIONS OF PARAGRAPH A.3.h. OF THE PLAN FOR WHICH YOU ARE RESPONSIBLE.

A. The Companies are requesting that they be authorized to defer storm damage costs to the extent that such costs exceed $13.9 million annually (companies in aggregate). The Companies are also requesting authorization to defer additional costs, including post-in-service interest costs, that result from changes in the recovery of line extension costs as a result of rules and/or policies that are implemented pursuant to R.C. Section 4928.151, compared to the Companies' proposal in Case No. 07-551-EL-AIR. In addition, the Companies request authorization to defer costs associated with distribution capital investments, placed in service subsequent to December 31, 2008, that are made to improve reliability and/or enhance the efficiency of the distribution system, as described further on Attachment HLW-1 to my testimony. Such costs would include depreciation, property tax obligations, and post-in-service interest on the capital investment balance computed monthly at a rate of 0.7083 percent. The Companies request that interest be deferred monthly during the period January 1, 2009 through December 31, 2013, at a rate of 0.7083 percent, on the cumulative deferred storm damage costs, deferred additional line extension costs, deferred costs associated with the distribution capital investments and the deferred interest costs. The unamortized balances serving as the base for deferring interest will not be reduced for accumulated deferred income taxes related to the deferred costs during the 2009-2013 periods. The Companies request recovery of these cost deferrals over a period of approximately 10 years effective January 1, 2014. Interest will be deferred monthly on the unamortized deferral balances, net of accumulated deferred income taxes, at a monthly rate equal to one-twelfth of the annual weighted book cost of long-term debt outstanding on December 31, 2013 for each Company beginning January 1, 2014, until full recovery has been achieved.

Q. PLEASE EXPLAIN PARAGRAPH A.6.b. OF THE PLAN.

A. Paragraph A.6.b. of the Plan describes a distribution rider that will be effective January 1, 2011, to recover deferred costs authorized by the Commission under the Companies' ETP and RCP plans and the line extension proceeding Case No. 01-1708-EL-COI – transition taxes, distribution costs, and line extension costs. I have projected the deferral balances as of December 31, 2008, consistent with the methodology used to project the deferral balances after the date certain in the Companies' Application in Case Nos. 07-551-EL-AIR et al. The deferred distribution costs are increased in 2009 to include $25 million of CEI deferrals as described in Paragraph A.3.b. of the Plan. For the period January 1, 2009 through December 31, 2010, the Companies propose to defer interest on the unamortized balances (without reduction for accumulated deferred income taxes) at the rate of 0.7083 percent per month. The rider that becomes effective on January 1, 2011, will be based on the unamortized deferral balances as of December 31, 2010, net of accumulated deferred income taxes, with a return component equal to the weighted average book cost of long-term debt outstanding on December 31, 2010 for each Company. The rider will stay in place until the deferred costs, including interest deferred subsequent to December 31, 2008, have been fully recovered.

Q. PLEASE EXPLAIN PARAGRAPH A.6.c. OF THE PLAN.

A. Paragraph A.6.c. of the Plan describes the need to recover remaining 2005 deferred transmission costs and related interest deferrals that were authorized by the Commission in Case No. 04-1931-EL-AAM to be recovered over a five-year period beginning January 1, 2006. The rider that becomes effective on January 1, 2009, will be based on the unamortized deferral balances as of December 31, 2008. The rider will stay in place until the deferred costs, including interest, have been fully recovered or January 1, 2011, whichever comes first.

Q. PLEASE EXPLAIN THE PORTION OF PARAGRAPH A.7.d. RELATING TO THE SIGNIFICANTLY EXCESSIVE EARNINGS EVALUATIONS FOR WHICH YOU ARE RESPONSIBLE.

A. I am responsible for identifying and quantifying transactions that are included in the accounts for each of the Companies under GAAP, but are excluded from their Ohio regulatory books of account, for purposes of the significantly excessive earnings evaluations under Section 4928.143 (F) of the Ohio Revised Code. Items that are excluded for this purpose from the Ohio regulatory books of account are cited on Attachment H, which I partially sponsor to the extent that it addresses matters within the scope of my testimony.

Q. COULD YOU GIVE EXAMPLES OF ITEMS THAT WOULD BE EXCLUDED FROM THE OHIO REGULATORY BOOKS OF ACCOUNT FOR PURPOSES OF THE SIGNIFICANTLY EXCESSIVE EARNINGS EVALUATION?

A. Yes. Examples of subsidiaries of the Companies whose operations are not related to providing electric distribution service to customers in Ohio are:

- Ohio Edison Company
  - Pennsylvania Power Company – an electric distribution company providing service to customers in the Commonwealth of Pennsylvania.
  - PNBV Capital Trust – an investment trust holding lease obligation bonds issued in connection with the sale and leaseback of the Perry and Beaver Valley Unit 2 generating facilities.
- The Cleveland Electric Illuminating Company
  - Shippingport Capital Trust – an investment trust holding lease obligation bonds issued in connection with the sale and leaseback of the Bruce Mansfield Plant.

An example of an asset impairment would be the write-off of goodwill computed in accordance with Statement of Financial Accounting Standards ("SFAS") No. 142, which is the currently applicable standard, or SFAS No. 157 that will become effective for the Companies in 2009 under the provisions of Financial Accounting Standards Board Staff position SFAS 157-2. For purposes of the significantly excessive earnings evaluation, earnings for the year would exclude the impact of the impairment loss in the numerator of the calculation and the denominator would exclude the cumulative impact of all such impairments recognized since January 1, 2008.

Q. IS THERE AN ELEMENT OF THE PLAN THAT WOULD RESULT IN THE IMPAIRMENT OF AN ASSET?

A. Yes. Paragraph A.1.a. of the Plan waives the RTC and Extended RTC charges for CEI's customers on a service rendered basis on and after January 1, 2009. Once it becomes probable that the Plan will be implemented (Commission approval), CEI will be required by GAAP to write off the estimated deferred transition costs and shopping incentives that will not be recovered. The write-off is estimated to be approximately $485 million ($306 million after taxes) -- 19% of CEI's total equity as of June 30, 2008.

Q. ARE YOU RECOMMENDING THAT THIS CEI IMPAIRMENT BE EXCLUDED FROM THE OHIO REGULATORY BOOKS OF ACCOUNT FOR PURPOSES OF THE SIGNIFICANTLY EXCESSIVE EARNINGS EVALUATION?

A. Yes, I am. Assuming that the write-off is recognized in 2008, I recommend that the denominator for CEI's return on equity calculation for calendar year 2009 be increased by the average amount of the write-off that relates to Extended RTC recovery that otherwise would have taken place in 2009 and the full amount relating to 2010. That after-tax amount is estimated to be $239 million. The adjustment for 2010 would be the average of the amount of the write-off that relates to Extended RTC recovery that otherwise would have taken place in 2010. The after-tax amount for 2010 is estimated to be $86 million. No adjustment for calendar years beyond

2010 would be necessary for this item because the Extended RTC was scheduled to terminate as of December 31, 2010.

Q. PLEASE EXPLAIN SCHEDULE 6a.

A. Schedule 6a displays, for each of the Companies individually and for all of the Companies collectively, the actual balance of fuel deferrals and related interest as of June 30, 2008 attributable to RCP fuel deferrals for the years 2006 and 2007. The schedule also shows the calculation of estimated interest to be deferred during the period July 1, 2008 through December 31, 2008. The aggregate estimated balance to be recovered as of December 31, 2008 shown on page 5 of Schedule 6a is $235,014,038 (Plan Paragraph A.6.d.), comprised of deferred fuel costs of $206,811,856 and deferred interest of $28,202,182.

Q. PLEASE EXPLAIN SCHEDULE 6b.

A. Schedule 6b displays, for each of the Companies individually and for all of the Companies collectively, projected deferral and recovery activity related to the RCP distribution deferrals for the period January 1, 2009 through December 31, 2035. The balance for each company as of December 31, 2008 was estimated, taking into account anticipated reductions to the deferral balances for OE and TE related to projected overcollections of costs being recovered through their respective RTC tariffs through December 31, 2008. The top section of Schedule 6b summarizes the annual increases to the deferral balances during 2009 and 2010 resulting from additional CEI deferrals in 2009 ($25 million) pursuant to Paragraph A.3.b. of the

Plan and interest to be deferred monthly at the rate of 0.7083 percent in 2009 and 2010. The monthly detail showing the increase to the deferral balances during those years is shown directly below the summary.

The middle section of Schedule 6b displays the recovery factors used to develop the tariff rate to recover the estimated December 31, 2010 deferral balances for each Company. Those factors are:

- The estimated December 31, 2010 deferral balance
- The 25-year recovery period
- The estimated weighted average cost of long-term debt as of December 31, 2010
- The Commercial Activity Tax rate
- The composite federal and state income tax rate

Below the recovery factors section is an analysis of the annual recovery of the RCP distribution deferrals over a twenty-five year period. Column B shows annual estimated distribution deliveries in gigawatt-hours. Column C displays annual revenue based on the sales estimate in Column B and the tariff rate that was computed using the recovery factors described above. The Commercial Activity Tax payable on the revenues is shown in Column D. Column F displays the portion of the revenue included in Column C that represents the return on the unamortized deferral balances, net of accumulated deferred income taxes, using the weighted average cost of long-term debt displayed in the recovery factors section above. Column E represents the balance of revenue, after provision for the Commercial Activity Tax under Column D and the investment return under Column F, that constitutes the recovery of the distribution deferrals. Amortization of the deferrals for the year is equal to the amount recovered under Column E and is the amount by which the unamortized balance for the prior year in Column G is reduced to produce the ending unamortized balance in Column G for the current year.

Q. PLEASE EXPLAIN SCHEDULE 6c.

A. Schedule 6c illustrates how RCP demand side management costs would be deferred and amortized for each company during the period June 1, 2008 through December 31, 2011. The schedule also illustrates how the tariff rider would be computed for six semi-annual recovery periods beginning October 1, 2008.

Q. PLEASE EXPLAIN SCHEDULE 6d.

A. Schedule 6d is similar to Schedule 6b and relates to the deferral and recovery of ETP transition taxes. The only difference in approach on Schedule 6d is that recovery of the deferrals is accomplished over a five-year period. All other factors such as the rate and method for deferring interest in 2009 and 2010, the investment return during the recovery period and the applicable tax rates are identical to the factors used on Schedule 6b.

Q. PLEASE EXPLAIN SCHEDULE 6e.

A. Schedule 6e is similar to Schedules 6b and 6d and relates to the deferral and recovery of line extension costs pursuant to Case No. 01-2708-EL-COI. Except for the deferral balances themselves, all factors on Schedule 6e, including the five-year recovery period, are identical to the factors included on Schedule 6d.

Q. PLEASE EXPLAIN SCHEDULE 6f.

A. Schedule 6f displays, for each of the Companies individually and for all of the Companies collectively, projected deferral and recovery of generation costs sponsored by Mr. Warvell. There are two Schedule 6f options included – Option One assumes no securitization of the generation deferral balances and Option Two assumes securitization. While additional information regarding these options is contained in Attachment A attached to the Plan, set forth below is an explanation of each option.

Under Option One, Schedule 6f is very similar to Schedules 6b, 6d and 6e. The monthly amounts deferred (this illustration assumes the same amount for each month of the respective year) and the deferred interest attributable to each month is summarized in the top section of the schedule. Under Option One, amounts deferred in 2009 and 2010 will begin to be recovered on January 1, 2011, over a ten-year period, based on the same recovery factors used on Schedules 6b, 6d and 6e. If the Commission does not terminate the Plan as of January 1, 2011, amounts deferred in 2011 and 2012 (interest only in 2012) will begin to be recovered on January 1, 2013, in the same manner as the 2009 and 2010 deferrals.

Under Option Two, generation costs estimated to be deferred in 2009 would be securitized in 2010 and recovered over a ten-year period beginning January 1, 2010; generation costs estimated to be deferred in 2010 would be securitized in 2011 and recovered over a ten-year period beginning January 1, 2011; and generation costs estimated to be deferred in 2011, if applicable, would be securitized in 2012 and recovered over a ten-year period beginning January 1, 2012. The recovery factors used to develop the applicable recovery tariffs under Option Two are the same as those for Option One except for the rate of return on the unamortized balances. Under Option Two the rate of return will reflect the actual cost of the securitization. A notable difference between Option One and Option Two is the inclusion of additional cost deferrals in 2010 and 2011 under Option Two, representing the annual debt service costs resulting from the securitization, assuming the Commission were to opt for increasing the phase-in credit instead of increasing the generation cost recovery rate. If the Commission would opt to increase the generation cost recovery rate, the additional cost deferrals in 2010 and 2011 would not result under Option Two.

Q. PLEASE EXPLAIN SCHEDULE 6g.

A. Schedule 6g illustrates how storm damage expenses that exceed $13.9 million annually from 2009 through 2013 would be deferred. The concepts and methods on Schedule 6g are similar to those of Schedules 6b, 6d and 6e, except that recovery would take place over a ten-year period beginning January 1, 2014 and the annual weighted book cost of long-term debt is based on debt outstanding as of December 31, 2013. All other recovery factors are the same.

Q. PLEASE EXPLAIN SCHEDULE 6h.

A. Schedule 6h is similar to Schedule 6g and illustrates the deferral and recovery of incremental line extension costs under the proposed Plan. The top section of the schedule illustrates annual amounts deferred by cost component – incremental line extension costs and post-in-service interest deferrals less any costs ineligible for recovery. Interest on the deferred balances is also illustrated in the annual summary. Below the summary illustration are the details by month from January 1, 2009 through December 31, 2013. Below the recovery factors section is an illustration of the annual recovery of the incremental line extension costs over a ten-year period. All of the recovery factors are consistent with those used on Schedule 6g.

Q. PLEASE EXPLAIN SCHEDULE 6i.

A. Schedule 6i is similar to Schedules 6g and 6h and displays the projected cost deferrals associated with distribution capital investments placed in service subsequent to December 31, 2008. The top section of the schedule identifies the annual amounts to be deferred by cost component – depreciation, property taxes and post-in-service interest deferrals. Interest on the deferred balances is also displayed in the annual summary. Below the summary are the details by month from January 1, 2009 through December 31, 2013. The balance of the schedule is identical to Schedules 6g and 6h, with recovery over a ten-year period. All of the recovery factors are consistent with those used on Schedules 6g and 6h.

Q. PLEASE EXPLAIN SCHEDULE 6j.

A. Schedule 6j summarizes, for each of the companies, the change in the 2005 deferred transmission costs during the period July 1, 2008 through December 31, 2008. The amounts shown as a reduction of principal represents amortization of the deferred costs relating to amounts to be recovered during that six-month period. The monthly interest amounts represent additional deferred interest on the declining balance of 2005 deferred transmission costs. The 2005 deferred transmission costs will be recovered over a two-year period beginning January 1, 2009, through the Deferred Transmission Costs Recovery Rider described by Mr. Warvell.

Q. PLEASE DESCRIBE SCHEDULES 7a, 7b and 7c.

A. These schedules contain projected financial statements for each of the Companies as required by the Commission's regulations regarding ESPs. These financial statements are based on the Companies' most recent business plans reviewed with FirstEnergy's Board of Directors and assume that the provisions of the Plan are implemented as proposed. Data used to prepare the projected income statements are the direct output of our SAP automated accounting and planning system for the 2009-2011 forecast period. Costs were estimated by all of our business units to populate the SAP planning system based on the business plans for each business unit. The projected balance sheets and sources and uses of funds statements reflect capital costs from the SAP planning system that were also identified through the business plans for each business unit. All other financial assumptions were developed by our Finance and Performance Management groups.

Q. WOULD YOU PLEASE SUMMARIZE THE ACCOUNTING AUTHORITY YOU ARE REQUESTING IN THIS PROCEEDING?

A. Yes. The Companies are requesting authority to establish regulatory assets associated with the following provisions of the proposed Plan:

- $25 million of CEI's distribution-related costs pro-rated ratably over the January through April 2009 period.
- Deferred interest during the period January 1, 2009 through December 31, 2010 on the accumulated RCP distribution deferrals, ETP transition taxes, line extension deferrals pursuant to Case No. 01-2708-RL-COI, 2005 deferred transmission costs and CEI's ESP distribution-related costs, including accrued interest.
- Storm damage expenses incurred during the period January 1, 2009 through December 31, 2013, to the extent they exceed $13.9 million annually in total for the Companies during each of those five years.
- Incremental line extension costs, including post-in-service interest costs, that result from changes in the recovery of line extension costs as a result of rules and/or policies that are implemented pursuant to R.C. Section 4928.151, compared to the Companies' proposal in Case No. 07-551-EL-AIR.
- Depreciation, property tax obligations and post-in-service interest on the capital investment balance associated with distribution capital investments, placed in service subsequent to December 31, 2008, that are made to improve reliability and/or enhance the efficiency of the distribution system.

- Generation costs incurred during the period January 1, 2009 through December 31, 2010 (or December 31, 2011 if the Commission elects not to terminate the Plan as of January 1, 2011), that are subject to the phase-in provisions of the Plan to the extent that such costs differ from amounts recovered from customers.
- Deferred interest during the period January 1, 2009 until full cost recovery is accomplished, on the accumulated ESP storm damage deferrals, ESP incremental line extension cost deferrals, ESP deferrals associated with distribution capital investments, and ESP generation cost deferrals, including accrued interest.
- Deferrals, including interest, associated with tracking cost recovery in connection with tariff riders that are subject to the reconciliation process, such as uncollectible generation costs, that are not otherwise addressed above.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

System Reinforcement
Costs associated with reinforcing our infrastructure. Examples include, but are not limited to, line terminal upgrades, line/wave traps, line reconductoring, line upgrades, replacement of a breaker due to load or interrupting current limitations, rebuilds to improve capacity.

Obsolete Equipment
Costs associated with replacements of equipment due to inability to get parts, or outdated equipment. Remote terminal unit replacements, full line rehabilitation, transformer replacement, breaker replacement, substation spare equipment, line rebuilds, carrier set replacements, batteries/charger replacements, oscillograph digital fault recorder replacements and other distribution equipment.

Failures, Relocations, Storms
Costs associated with replacement of equipment and devices; Costs associated with relocation of facilities for which the Companies do not receive reimbursement..

IT Services
Costs associated with Information Technology services such as hardware and software programs used to support customer service, operating and regional support, and regional dispatching personnel. The programs are used for improvements with customer service reliability or any other need for supporting the Companies' electric service.

Corrective Maintenance
Capital costs associated with the unplanned repair and maintenance of the system.

Reliability
Capital costs incurred to improve/reinforce the reliability of the infrastructure assets. Examples include, but are not limited to, system control and data acquisition and motor operated air break switch additions, recloser addition to distribution lines, relaying replacements, transrupters, circuit reliability index improvements, etc.

Other
Capital costs associated with projects required to improve relieve or correct an existing or projected voltage or thermal condition. Some specific examples include, but are not limited to, new substations, transformer additions, transformer replacement, substation capacitor installation, line capacitor installation, and feeder/exit additions; Costs associated with the installation or removal of meters; Costs associated with street lighting and lighting services. Capital associated with the purchase and upkeep of tools and work equipment. This also includes transportation tools and equipment. Costs associated with tree trimming and vegetation management program.

[Company Exhibit 3]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

DONALD R. SCHNEIDER

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

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

A. My name is Donald R. Schneider. My business address is FirstEnergy Service Company ("FirstEnergy"), 76 South Main Street, Akron, Ohio 44308. I am Senior Vice President, Energy Delivery & Customer Service of FirstEnergy and FirstEnergy Corp.'s subsidiary companies, including Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, "Companies").

Q. WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I earned a Bachelor of Science degree in electrical engineering from Youngstown State University in 1988, and I am a Registered Professional Engineer in Ohio. I also completed a number of managerial and executive programs, including the Kellogg School of Management's Advanced Executive Program at Northwestern University; the executive seminar, "Strategic Leadership: Business & Public Policy Process," presented by the Washington Campus in Washington, D.C.; and the Massachusetts Institute of Technology's Reactor Technology Program for Utility Executives. I joined OE — which merged in 1997 with Centerior Energy to form FirstEnergy Corp. — in 1982 as a technician at the W. H. Sammis Plant. I served in a variety of engineering and maintenance positions in the generation area, including plant manager of the Bruce Mansfield Plant before being named Vice President of Fossil Operations in 2001. I was appointed Vice President of Commodity Operations for FirstEnergy Solutions Corp. in 2004 and Vice President of Energy Delivery and

Customer Service for FirstEnergy in 2006. I was appointed to my current position in 2007.

Q. PLEASE DESCRIBE YOUR DUTIES AS SENIOR VICE PRESIDENT, ENERGY DELIVERY & CUSTOMER SERVICE.

A. I directly or indirectly oversee our energy delivery business, which includes approximately 8,000 employees, 89,000 miles of transmission and distribution lines and 1,525 distribution substations in Ohio, Pennsylvania and New Jersey.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the provisions in the Companies' Electric Security Plan ("Plan") which address the Companies' proposed (i) Delivery Service Improvement Rider ("DSI rider"), (ii) SAIDI target adjustment and performance range, (iii) rear lot reduction factor applicable only to CEI, (iv) $1 billion capital commitment, and (v) comprehensive Smart Grid study.

Q. WHAT PARAGRAPHS OF THE PLAN DO YOU SPONSOR?

A. I sponsor the following provisions of the Plan:

1) Paragraph A.3.e. Delivery Service Improvement Rider

2) Paragraph A.3.f. SAIDI targets and performance band

3) Paragraph A.3.g. Capital Investment Commitment

3) Paragraph A.4.f. Smart Grid Study

Q. PLEASE PROVIDE A HIGH LEVEL OVERVIEW OF THE COMPANIES' ENERGY DELIVERY AND CUSTOMER SERVICE BUSINESS.

A. Our key areas of focus in Energy Delivery and Customer Service are our employees, safety, customer satisfaction, reliability and financial performance. Although the 602 distribution substations, 533,000 distribution transformers and 1.2 million poles are crucial components of the energy delivery and customer service business here in Ohio, the backbone is the 8,000 energy delivery and customer service employees who devote their talents and skills to keeping the lights on, restoring service after an outage, and keeping customers informed about what we are doing every step along the way. It is a given that customers demand safe, reliable distribution service—and that they want it at a reasonable cost. However, the ability to consistently deliver this safe, reliable, reasonably priced power does not come without its challenges.

Q. WHAT ARE SOME OF THESE CHALLENGES?

A. Our challenges include an aging workforce and the need to hire and train new employees, with the knowledge that we will need to accommodate the transfer of knowledge necessitated by the demographic issues leading to a disproportionate number of retirements. We are also challenged with the aging of our system and making decisions that balance the fact that although customers cannot afford to pay for an entirely new system, adequate reliability necessitates capital improvements. We are challenged with the increasing costs of materials, supplies and equipment (for example, over the last five years the price of wire has increased over 70%, the price of transformers have increased over 40%, and the price of fuel for our trucks has almost doubled). We are faced with long lead times from our equipment manufacturers who are increasingly requiring us to order and pay for equipment years in advance merely to have our name on the waiting list to receive these products. This is very different and much more dynamic than when I started my career. In addition, perhaps our greatest challenge is obtaining the capital required to meet our commitments to these and other future investments. While we were able to absorb the effect of regulatory lag to some extent in the past, the increasing demands like these for cash are what drive the need for evolving the regulatory expedients that assure we have the financial capability to meet the needs of our customers.

Q. CAN THE COMPANIES MEET THEIR COMMITMENT TO THE KEY AREAS OF FOCUS ABSENT ACCEPTANCE OF THE COMPANIES' PLAN?

A. It would be quite difficult. Significant funding is required to maintain or improve performance in each of these key areas of focus. The Companies' Plan includes a DSI rider during the period January 1, 2009 through December 31, 2011 which would provide the Companies the financial wherewithal to remain healthy and capable of continuing their ongoing commitments to the energy delivery and customer service business.

Q. WHAT IS THE DSI RIDER?

A. As stated in the Companies' Plan, the DSI rider was designed to recognize the changing environment, both from an equipment procurement and employee demographic standpoint, of providing electric distribution service, including each of our key areas of focus. This rider would enable the Companies to place emphasis on and dedicate adequate resources to all aspects of the delivery of reliable distribution service. This rider as proposed is a non-bypassable distribution charge equal on average to \$0.0020 per kWh to be effective January 1, 2009 on a service rendered basis. Companies' witness Hussing describes in more detail how this rider would be implemented. The DSI rider would not offset or comprise a contribution in aid in any construction project, but rather, as I stated before, is proposed to ensure the overall health and financial sustainability of the Companies and to ensure that they are in a position to devote appropriate resources to reliability matters. The DSI rider would be subject to an upward or downward adjustment each calendar year based on a pre-defined range of SAIDI performance set forth in the Companies' Plan. The pre-defined range is detailed on Attachment E to the Plan.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANIES' SAIDI RELIABILITY PERFORMANCE.

A. Over the last several years, customers have enjoyed steadily improving SAIDI reliability performance. In fact, TE customers have experienced top quartile levels of performance in each of the last three years.

Q. WHAT ARE THE COMPANIES' CURRENT SAIDI PERFORMANCE TARGETS?

A. OE and TE currently have a SAIDI target of 120 minutes and CEI has a SAIDI target of 95 minutes.

Q. WHAT ADJUSTMENTS ARE THE COMPANIES' PROPOSING TO THEIR SAIDI TARGETS?

A. OE and TE are not proposing any adjustment to their existing 120 minute SAIDI targets. CEI proposes to modify its SAIDI target from 95 minutes to 120 minutes.

Q. WHY SHOULD CEI'S SAIDI TARGET BE ADJUSTED TO 120 MINUTES?

A. A critical part of our focus on reliability is to recognize and make sound business decisions based on the performance and health of our energy delivery assets and their associated impacts on reliability. It is important to implement cost effective solutions and ensure that such solutions are managed efficiently. Currently, CEI has the most aged distribution system of the three Companies. In addition, CEI's system design and service area geography make it more difficult than the other two companies to obtain and maintain a low SAIDI. I believe that 120 minutes represents the optimal reliability performance for CEI, and it provides an excellent value to customers when balancing reliability performance with the costs of achieving such reliability.

Q. ARE THE COMPANIES' PROPOSING ANY OTHER CHANGES?

A. Yes. CEI is proposing a rear lot reduction factor. OE and TE are not proposing any adjustments as part of this Plan.

Q. WHAT IS A REAR LOT REDUCTION FACTOR?

A. CEI's service area geography makes it extremely difficult to maintain low customer outage minutes. The most prominent example is the large number of rear lot facilities. CEI experiences significant issues associated with crews being able to restore service timely to customers served on rear lot circuits based on the number of such customers and the need to manually haul poles and other equipment to such sites as opposed to using trucks. As a result of the number of obstructions at such sites including trees, fences, garages, etc., restoration times are significantly longer. In an effort to establish a representative outage duration time which takes into account the challenges of rear lot construction, customer outage minutes would be multiplied by a factor of .5 ("Rear Lot Reduction Factor") on such circuits where fifty percent or more of the premises are served by rear lot facilities.

Q. WHY IS IT NECESSARY FOR CEI TO HAVE A REAR LOT REDUCTION FACTOR AND NOT THE OTHER COMPANIES?

A. CEI has a disproportionate number of rear lot facilities which inflate CEI's customer outage minutes. In fact, CEI has approximately 400 circuits where over 50% of the customers on those circuits are served from rear lot facilities. Although OE and TE have some rear lot facilities, they do not have them to the degree CEI does. Thus, in order to account for this anomaly and ensure that reliability is measured based on an apples to apples comparison among the Companies, it is necessary to apply the Rear

Lot Reduction Factor to the CEI circuits where 50% or more of the customers are served from rear lot facilities.

Q. PLEASE EXPLAIN THE PERFORMANCE RANGE THAT WOULD BE APPLIED TO THE COMPANIES' SAIDI TARGETS?

A. A performance range is typically a symmetrical band that recognizes that with changing weather conditions and other factors outside the Companies' control using an absolute number as a performance criterion is not practical. Thus, a performance band establishes a pre-defined range. The Companies' Plan proposes a performance band such that at both, the high end and the low end of the band, the Companies remain in the first or second quartile of industry performance. This proposed performance band would require the Companies to continue to pay exceptional attention to detail, drive for continuous improvement and maintain focus on strategic capital planning. In addition, the Companies proposed performance band is asymmetrically skewed to benefit customers.

Q. HOW IS THE COMPANIES' PROPOSED PERFORMANCE BAND ASYMMETRICAL?

A. The proposed performance band is asymmetrical in that with a SAIDI of 120 minutes deviating upward from the target by 16 minutes would trigger a reduction of the DSI rider, but a downward deviation from the target must be at least 31 minutes before triggering an addition to the DSI rider. The performance band, which is set forth in Attachment E to the Plan, would incent the Companies to achieve a level of performance which IEEE (as defined below) characterizes as top decile (not merely quartile) SAIDI performance of 89 minutes or less and not recognize the Companies for maintaining first or second quartile SAIDI performance.

Q. HOW DO YOU QUANTIFY TOP QUARTILE AND SECOND QUARTILE PERFORMANCE?

A. When I reference top quartile and second quartile performance, I am using terminology and performance quantifications developed by the Institute of Electrical and Electronics Engineers ("IEEE") which is a leading authority in the area of electric power. IEEE examines the reliability performance of approximately 100 electric distribution companies in the United States based on the 2.5 beta method (which calculates a statistical five year threshold of performance and provides a common base to perform an apples to apples comparison) and ranks the utilities to enable the utility to determine how its performance compares against other utilities in the nation. The utilities are then divided into four quartiles. The first two quartiles represent top performance. IEEE's 2006 study placed TE's reliability performance in its first quartile and OE and CEI's reliability performance in its second quartile. Furthermore, this IEEE study places a SAIDI performance of 89 in its top decile and a SAIDI performance of 135 in the middle of its second quartile.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE COMPANIES INTEND TO IMPROVE THEIR RELIABILITY PERFORMANCE UNDER THE PLAN?

A. As part of the Companies' Plan, the Companies commit to make capital investments in their energy delivery system in an aggregate of at least $1 billion dollars from 2009 through 2013. This capital investment would help ensure that sufficient capital is being spent to address distribution system improvements.

Q. HOW DO THE COMPANIES PRIORITIZE THEIR CAPITAL SPEND?

A. The Companies perform a value-of-service analysis to ensure that capital dollars are targeted such that customers receive the greatest benefit from capital projects performed on the distribution system. A value-of-service analysis guides the Companies to improve reliability by reducing customer outage minutes. Projects which provide the highest customer minute benefit at the lowest cost will have the highest benefit-to-cost ratio. In addition, the Companies also hire industry recognized independent third-party consultants, to conduct detailed reviews of all the Companies' proposed capital spending including specific projects, programs, and blankets. These review sessions ensure that the necessary engineering rigor around the justification has occurred, that the thoroughness of the project scope and cost estimates has been developed, and that the anticipated benefits are accurately represented.

Q. ARE THE COMPANIES PURSUING ANY OTHER INITIATIVES?

A. Yes. As part of their Plan, the Companies would commit to undertake and complete a comprehensive Smart Grid study on or before December 31, 2009.

Q. PLEASE EXPLAIN THE SCOPE OF THIS STUDY.

A. This study, as more fully described on Attachment E, would address the readiness of the Companies' respective system to implement Smart Grid technology and would identify any changes/upgrades that may be needed to deploy Smart Grid. Upon completion of the study, the costs of which would be borne by the Companies, the Companies would share the results with the Commission Staff and the OCC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[Company Exhibit 4]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

GREGORY F. HUSSING

ON BEHALF OF

OHIO EDISON COMPANY
THE TOLEDO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Gregory F. Hussing. I am employed by FirstEnergy Service Company as Director, Regulatory Analytics. My business address is 76 S. Main Street, Akron, Ohio 44308.

Q. HOW LONG HAVE YOU BEEN EMPLOYED BY FIRSTENERGY?

A. I have been employed by FirstEnergy or a predecessor company since August 1987.

Q. WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I received a Bachelor of Science degree in Engineering Technology from the University of Akron in 1987 and a Masters in Business Administration also from the University of Akron, in 1994. I joined Ohio Edison in 1987 as Distribution Technician, holding a variety of staff and supervisory positions in the Energy Delivery Group. Since the formation of FirstEnergy Corp. in 1997 and prior to my current position, I have held the positions of Manager of Corporate Metering, Manager of Retail Supplier Settlements, Manager of Transmission Operations Support, and Director of Rates and Regulatory Affairs. In addition, I am a member of the Edison Electric Institute Rate Research Committee.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, the "Companies" or "Company"). The purpose of my testimony is to address and support the design of proposed rates and associated tariff sheets of the Companies' Electric Security Plan ("ESP"). In addition, I will also be discussing an Advanced Metering Infrastructure ("AMI") pilot program and implementation of several Tariff Riders as part of the Companies' ESP.

Q. WHAT SCHEDULES ARE YOU RESPONSIBLE FOR?

A. I am responsible for all or part of the following schedules:

Schedules	Title/Description
Schedule 1a	Rate Impacts 2008 to 2009 by Proposed Rate Schedule
Schedule 1b	Rate Impacts 2009 to 2010 by Proposed Rate Schedule
Schedule 1c	Rate Impacts 2010 to 2011 by Proposed Rate Schedule
Schedule 2	Revenue Targets for Base Distribution Rates
Schedule 3a	Proposed Tariff Schedules 2009
Schedule 3b	Proposed Tariff Schedules 2010
Schedule 3c	Proposed Tariff Schedules 2011
Schedule 4a	Former Tariff Schedules to 2009 proposed
Schedule 4b	Former Tariff Schedules to 2010 proposed
Schedule 4c	Former Tariff Schedules to 2011 proposed
Schedule 5f	Work paper for the Non Distribution Uncollectible Rider
Schedule 5g	Work paper for the PIPP Uncollectible Recovery Rider
Schedule 5h	Work paper for the Base Distribution Rates
Schedule 5i	Work paper for the Delivery Service Improvement Rider
Schedule 5m	Work paper for the Economic Development Rider
Schedule 5n	Work paper for the Delta Revenue Recovery Rider
Schedule 5o	Work paper for the Demand Side Management and Energy Efficiency Rider
Schedule 5p	Work paper for the Reasonable Arrangements Rider
Schedule 5q	Work paper for the Deferred Distribution Cost Recovery Rider

Q. WHAT OTHER WITNESSES SUPPORT PORTIONS OF THE SCHEDULES 3A THROUGH 4C?

A. Company Witness Kevin Warvell is responsible for the Generation and Transmission related Tariffs included in Schedules 3a through 4c and related Schedule 5's.

CURRENT AND PROPOSED RATE SCHEDULES

Q. PLEASE DESCRIBE THE CONTENTS OF SCHEDULES 1A THROUGH 1C?

A. Schedules 1a through 1c are annual rate impact summary schedules representing rate impacts on a proposed rate schedule basis for 2009 through 2011. The proposed rate classifications as defined in the Companies' distribution rate case are Residential Schedule (Rate RS), General Service Secondary (Rate GS), General Service Primary (Rate GP), General Service Sub-transmission (Rate GSU), General Service Transmission (Rate GT), Street Lighting (Rate STL), Traffic Lighting (Rate TRF), and Private Outdoor Lighting (Rate POL). The schedules also show the underlying billing determinants and calculation of the associated annual rate impacts by individual tariff schedule and by specific rate blocks and riders. In order to illustrate the ESP's year to year comparisons, the billing determinants for Schedules 1a through 1c have been kept constant.

Q. PLEASE DESCRIBE THE BASIS FOR THE BILLING DETERMINENTS UTILIZED IN SCHEDULES 1A THROUGH 1C?

A. The revenue summaries for each year, shown on Schedules 1a through 1c, are based upon the billing determinants from the "3 + 9" (3 months of actual data and 9 months of forecasted data) Update Filing of the Companies' distribution rate case - Case No. 07-551-EL-AIR.

Q. PLEASE DESCRIBE THE CONTENTS OF SCHEDULES 3A THROUGH 3C?

A. Schedules 3a through 3c contain the proposed tariffs effective for the corresponding time period of 2009 through 2011. Sections of the tariffs shown in Schedule 3a that do not have changes will not be included in Schedules 3b and 3c. These sections include Sheet 3 - Definition of Territory, Sheet 4 - Electric Service Regulations and Sheet 75 - Miscellaneous Charges.

Q. PLEASE DESCRIBE THE CONTENTS OF SCHEDULES 4A THROUGH 4C?

A. Schedule 4a contains the current rate schedules, marked to highlight the differences between the current schedules and the proposed 2009 schedules. Due to the extent and nature of the changes, portions of the current tariffs have been completely deleted and replaced. These complete replacements, as well as the red-line changes, are identified in the table of contents and on the specific page in the schedules. Schedule 4b contains the red-line changes to Schedule 3a (year 2009) that produce the 2010 rates. Schedule 4c contains the red-line changes to Schedule 3b (year 2010) that produce the 2011 rates. Sections of the tariff shown in Schedule 4a that do not have changes over the relevant period will not be included in Schedules 4b and 4c. These sections include Sheet 3 - Definition of Territory, Sheet 4 - Electric Service Regulations, and Sheet 75 - Miscellaneous Charges.

Q. WHAT CONSIDERATIONS AND OBJECTIVES FORM THE BASIS OF THE PROPOSED RATE DESIGN IN THE COMPANIES' ESP?

A. There are two main considerations forming the basis for the proposed rate design in the Companies' ESP. The first consideration is to utilize the rate classifications developed in the Companies' distribution rate case. These proposed rate classifications are utilized in the various tariff riders which implement the components of the ESP. The second major consideration is to incorporate the concept of gradualism in the transition from historic rate levels and structures to the proposed rate classifications and components of the ESP. The transition from historic rate levels and structures to proposed rates must be accomplished through a reasoned and gradual approach in order to accomplish the objective of mitigating significant customer impacts. Incorporating the concept of gradualism is a useful tool in managing overall customer impacts resulting from rate design objectives. Furthermore, it is desirable from the perspective of economic stability to proactively address issues of disproportionate rate impact typically felt by those customers previously served on tariffs with below average rates.

Q. HOW DID YOU COME TO YOUR OVERALL RATE DESIGN FOR THE BASE RATES INCLUDED IN SCHEDULES 3A THROUGH 3C?

A. Schedule 2 calculates the target revenues for the base distribution rates included in schedules 3a through 3c. With some exceptions as listed below, the base distribution rates utilize the Companies' "3 + 9" (3 months of actual data and 9 months of forecasted data) Update Filing of the Companies' distribution rate case. The tariff schedules included in Schedules 3a through 3c reflect the following changes to those tariffs:

- Incorporated a single rate block structure for the Residential Service rate "RS" versus the proposed two block rate structure.
- Incorporated the terms of the Stipulation and Recommendation filed with the Commission on February 11, 2008, which address revenue distribution and rate design.
- Incorporated tariff rates that produce the distribution increase per the terms of the ESP.
- Removed the Demand Side Management Rider, Original Sheet 97, and incorporated the same charge into the Demand Side Management/Energy Efficiency Rider.
- In order to be consistent with other riders proposed in the ESP, the seasonal price change in the Billing and Payment section of the Electric Service Regulations was modified.

<u>TARIFF RIDERS</u>

Q. WHAT RIDERS ARE YOU SUPPORTING AS PART OF THE ESP?

A. I will be addressing the Riders shown below. Company Witness Kevin Warvell will address the remaining riders of the ESP.

Distribution Service Rider
Regulatory Transition Charge and Residential Transition Rate Credit Rider
Green Resource Rider
Experimental – Dynamic Peak Pricing Rider
Reasonable Arrangements Rider
Demand Side Management and Energy Efficiency Rider

Non-Distribution Uncollectible Rider
Delivery Service Improvement Rider
Deferred Distribution Cost Recovery Rider
Economic Development Rider
Delta Revenue Recovery Rider
PIPP Uncollectible Recovery Rider
Grandfathered Contract Rider

<u>Distribution Service Rider</u>

The Distribution Service Rider is only applicable to CEI customers from January 1, 2009 through April 30, 2009. Implementation of this Rider is necessary because the proposed non-distribution tariffs will be effective January 1, 2009 by the new rate schedule classifications but the proposed distribution tariff changes are not effective until May 1, 2009. The Rider provides a means of integrating new rate classifications with the current rate schedule distribution related charges from January 1, 2009 through April 30, 2009. The new rate classifications will be utilized for all non-distribution related rate calculations, while the Distribution Service Rider will incorporate the current distribution tariff related sections. Thus, the Rider will integrate the current distribution related charges into the new set of proposed tariff schedules. The Rider will not be effective after April 30, 2009 when distribution charges will be calculated based upon the new proposed rate classifications.

<u>Regulatory Transition Charge and Residential Transition Rate Credit Rider</u>

The Regulatory Transition Charge and Residential Transition Rate Credit Rider is only applicable to CEI customers. This Rider is similar in application as the Distribution Service Rider for CEI, in which the current RTC and Residential Transition rates credits were moved into a Rider to accommodate the transition expected in May 2009 to the new proposed rate classifications. Per the terms of the ESP, the charges and credits associated with this Rider will be waived.

Green Resource Rider

The Companies will offer a Green Resource Rider similar to that approved in Case No. 06-1112-EL-UNC. The Companies current Green Resource program will expire on December 31, 2008 due to the expiration of the Companies' REC contracts. The existing voluntary green product tariff offering provides customers an opportunity to purchase a specific number of Renewable Energy Certificates (RECs) on a monthly basis. The cost per REC set forth in the tariff is determined by a competitive bidding process for the RECs, plus the administrative cost of the green product program. The Companies propose to continue offering customers the opportunity to support alternative energy resources through the purchase of RECs. The new competitive bid will follow the same process as described in Case No. 06-1112-EL-UNC.

Economic Development Rider

The purpose of the Economic Development Rider is to promote gradualism and mitigate overall bill impacts to customers through a series of credits and charges. This rider is made up of several components, including: (1) Residential Non-Standard Credit Provision, (2) Interruptible Credit Provision, (3) Street Lighting (STL) and Traffic Lighting (TRF) Credit Provision, (4) General Service - Transmission (Rate GT) Provision, and (5) Standard Charge Provision. Implementation of the rider permits mitigation and balancing of customer impacts across the proposed rate schedules as a result of transitioning from current legacy rates and rate design to the proposed ESP tariffs. As stated earlier in my testimony, it is better to proactively address disproportionate rate impacts typically felt by those customers previously served on tariffs below average rates in order to promote economic stability. Therefore, charges associated with this effort are a social cost benefiting all customers, and as such, all customers should bear the cost of these efforts. If any of these charges were avoidable, it would be very difficult, if not impossible, for the Companies to promote and sustain this effort. Those customers that wanted to avoid this social charge could shop, which would provide for fewer sales over which to spread these social costs. As the cost became more expensive on a per sales basis, it would provide greater incentive for customers to shop that would ultimately result in the Companies being unable to sustain this effort. As permitted by R.C. 4928.143(B)(2)(i), the credits and charges associated with this rider have been allocated across and among the Companies. The sum of all the credits and charges, per the terms of the Rider, will be revenue neutral across the Companies. The credits associated with this Rider will be forfeited if a customer receiving the credit switches generation service to a Certified Retail Electric Supplier (CRES). The charges under this Rider cannot be avoided by a customer who switches to a CRES.

<u>Reasonable Arrangement Rider</u>

The economic challenges facing the State of Ohio were clearly a major concern in the deliberations over Am. Sub. S.B. 221. Therefore, in recognition of the importance of regional economic growth and development in the Companies' service territory and to help facilitate the state's effectiveness in the global economy, the Companies will establish a rider which provides the mechanism to administer tariff discounts pursuant to R.C. 4905.31, R.C. 4905.34, and under the Commission's proposed rules pursuant to 4901:1-38 – Reasonable Arrangements. The Reasonable Arrangement Rider further provides a means of encouraging energy efficiency and economic development, including job creation and retention, capital investment and incremental and retained load. Mechanisms such as this help promote the economic vitality of the area served and thereby foster job retention and promote economic development. The discounts associated with this Rider will be forfeited if a customer receiving the discount switches generation service to a Certified Retail Electric Supplier (CRES). Customers that switch to another supplier do so because it is in their best economic interests and because such supplier is offering a discount greater than that offered from the Companies through this Rider. Therefore, such customer should not also be receiving an additional discount from the Companies which is then subsidized by all other customers.

<u>Demand Side Management and Energy Efficiency Rider</u>

The Demand Side Management and Energy Efficiency Rider will recover costs incurred by the Companies associated with energy efficiency and demand side management programs, including recovery of lost distribution revenues. As permitted by R.C. 4928.143(B)(2)(i), the charges associated with this rider will be allocated across the Companies.[1] In an effort to encourage customers to implement energy efficiency initiatives, the rider is structured in such a way that customers may avoid a charge by implementing customer-sited programs that help the Companies secure compliance with R.C. 4928.64 and 4928.66.

Delta Revenue Recovery Rider

Pursuant to R.C. 4905.31, as amended by S.B 221, utility recovery of revenue foregone as a result of discounts in special arrangements is permitted. The approval of a special arrangement must also include approval of complete revenue recovery resulting from such an arrangement. To do otherwise jeopardizes the financial viability of the Companies because of the limited ability to absorb such lost revenue. Because the Companies are stand alone distribution utilities with limited resources, they cannot absorb the costs of discounts from Commission-approved tariffs that reflect discounts associated with generation service. Moreover, the Companies must purchase all the necessary generation that is provided to SSO customers. The price at which that generation is sold to SSO customers is limited to cost recovery with no profit margin. If the Companies are required to absorb the delta revenue in whole or in part, the net result is a financial loss on the transaction. Absent recovery of the delta revenue from other customers, who are the beneficiaries of the resultant economic development, there are no other transactions from which the Companies can make up the delta revenue. Less than complete recovery of foregone revenue would also hinder the Companies' abilities to undertake the significant investment the

[1] The exception to this is the recovery of the Companies' current Residential Demand Side Management program in which the charge will be calculated the same as that filed in the Update Filing of the

Companies have committed to improve the energy delivery system from which all customers on the system will benefit. The Delta Revenue Recovery Rider is the tariff mechanism to recover the delta revenue associated with existing special contracts that continue past December 31, 2008 and discounts provided to customers via the Reasonable Arrangements Rider, or unique contracts. The Rider's initial charges represent the recovery of CEI's contracts that are presently in place and continue past December 31, 2008. These charges will be recovered only from CEI's customers. The development of this charge was based on the difference between each contract customer's estimated 2009 and 2010 charges, per the provisions of each contract, and the estimated 2009 and 2010 charges based on proposed tariff rates, without application of any contract provisions. The delta revenue associated with any new contracts entered on or after January 1, 2009, will be allocated across and among all Companies as permitted by R.C, 4928.143(B)(2)(i). The charges associated with the Rider cannot be avoided by switching to a CRES.

Non-Distribution Uncollectible Rider

The Companies' collection practices are guided by the rules of the Commission, which require substantial notice periods and seasonal shutoff moratoria. These rules promote social objectives, which of course have a cost in terms of the amount of arrears that may ultimately be written off. In order to financially sustain this cost, it is appropriate that the Companies be able to recover the totality of the uncollectible accounts that are the result of state policy.

Companies' distribution rate case - Case No. 07-551-EL-AIR.

In contrast to incumbent SSO generation service, third party CRES suppliers are better able to control uncollectible costs. For example, CRES suppliers can select which customers they wish to supply. Conversely, the Companies serve as the default service provider and therefore have the ultimate responsibility for service to customers in their service territories. CRES suppliers can establish their own credit rules to minimize uncollectible accounts. In contrast, as described above, the Companies are guided by state policy regarding customer service arrangements. The result is that as a whole, CRES suppliers have a much better opportunity to manage their costs. The Companies' uncollectible costs, in contrast, are the result of implementation of state policy. In many ways, the Companies' uncollectible costs are very similar to PIPP costs, which are allocated to all customers. Treating the Companies' uncollectible costs in the same way, full recovery, and recovery from all customers as an unavoidable rider is the fairest way to deal with this implementation of state policy. Accordingly, a Non-Distribution Uncollectible Rider shall be established to recover uncollectible non-distribution related costs. Such a mechanism was discussed by PUCO Staff in the Staff Report issued in the Companies' distribution rate case, in which it was recommended that the Companies recover in distribution rates only that portion of total uncollectible expenses associated with distribution service. This Rider will be reconciled annually to reflect actual non-distribution uncollectible expense. The calculation of the Rider will be based on four components: (1) the ratio of total uncollectible expense to total retail and other revenues, (2) the estimated return earned on customer deposits, (3) the interest expense associated with the customer deposits balance, and (4) projected revenues not associated with distribution service. The charges under this Rider cannot be avoided by customers switching to a CRES supplier. As discussed in detail above, recovery from all customers as an unavoidable rider is the fairest way recover such costs.

Delivery Service Improvement Rider

As described in the testimony of Companies' witness Schneider, in recognition of the importance of the overall health and financial sustainability of the distribution business and the need to assure the continued reliability of the distribution system, the Companies during the period January 1, 2009 through December 31, 2013, shall establish a delivery service improvement rider (DSIR). The DSIR cannot be avoided by a customer who switches to a CRES.

Deferred Distribution Cost Recovery Rider

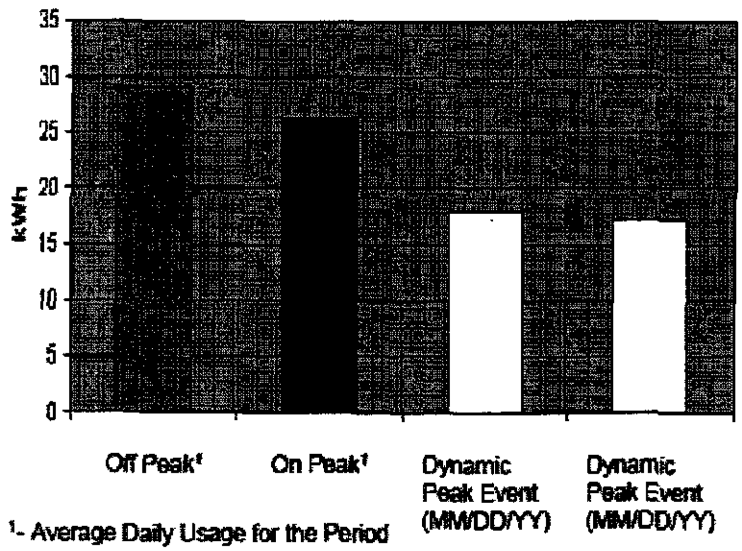
As supported in the testimony of Companies' witness Wagner, a Deferred Distribution Cost Recovery Rider will be effective January 1, 2011 to recover the following: 1) the post-May 31, 2007, unrecovered balances of distribution costs deferred under the Rate Certainty Plan (Case No. 05-1125-EL-ATA); 2) the CEI deferred distribution-related costs during the period January 1, 2009 through April 30, 2009; and 3) the post-May 31, 2007 unrecovered balances of deferred transition taxes under the Electric Transition Plan (Case No. 99-1212-EL-ETP); and 4) the post-May 31, 2007 unrecovered balances of line extension deferrals pursuant to Case No. 01-2708-EL-COI. The distribution-related costs associated with this Rider represent costs that have been incurred and paid by the Companies in the past to permit the

GFH – Attachment 1

Illustrative example of the type of information that would be provided to customers of the pilot program as part of their monthly bill. The example is illustrative of only the Dynamic Peak Pricing including the reduction of the Generation Phase-In Rider.

Usage Summary for the Billing Period	Energy		Rate		Cost
Off Peak	874 Kwh	x	$.052303	=	$ 45.71
On Peak	439 Kwh	x	$.105095	=	$ 46.14
Dynamic Peak Day Events	35 Kwh	x	$.220000	=	$ 7.70
Total Electric Usage	1,348 Kwh			=	$ 99.55

Your Daily Peak Usage



Companies to provide service to customers. However, customers have not yet paid these costs even though they have benefited from the availability of and used the electricity that resulted from the deferred costs. Because the costs to be recovered through the Rider represent incurred costs that cannot be avoided by the Companies if customers shop in the future, the Rider cannot be avoided by customers that switch to a CRES supplier.

PIPP Uncollectible Recovery Rider

The PIPP Uncollectible Recovery Rider will be established to recover PIPP uncollectible expenses should the Ohio Department of Development ("ODOD") change the current recovery mechanism of PIPP uncollectible expenses such that the Companies would bear uncollectible costs associated with PIPP customers. The rider will be reconciled annually. The Rider cannot be avoided by customers that switch to a CRES supplier because it is based on a social cost that provides support to those most in need. All customers should bear this social cost and not be limited to just those customers that take SSO generation service from the Companies. In addition, these costs are currently incorporated in the Companies' Universal Service Rider, which is a non-bypassable rider.

Grandfathered Contracts Rider

The purpose of the Grandfathered Contracts Rider is to manage legacy issues contained in existing CEI contracts that continue after December 31, 2008, in which such Rider charges are specifically referred to in a contract and are required to maintain appropriate billing per the contract terms.

Q. WHAT OTHER RIDERS ARE THE COMPANIES PROPOSING IN THE ESP?

A. The Companies are proposing the Dynamic Peak Pricing program as the tariff mechanism to implement the ESP AMI Pilot program.

Q. PLEASE DESCRIBE THE PURPOSE OF THE COMPANIES' PROPOSED AMI PILOT AND THE DYNAMIC PEAK PRICING PROGRAM.

A. The purpose of the AMI pilot is to determine whether a program that combines Summer time-of-day generation rates with real time energy usage information can effectively change customer behavior and energy consumption. The program will provide participating customers with the ability to lower energy costs by shifting electricity usage during on peak times to off peak times when demand for electricity and rates are lower.

The Companies will offer a Dynamic Peak Pricing Program. The Dynamic Peak Pricing rate design was chosen because it is a standard pricing model that provides strong incentives for customers to modify their usage behavior during periods of high demand for electricity. Once participants in the study are selected, the Companies will choose a similar group of customers as a control group for comparison. The Companies will implement the pilot program using advanced metering technology in conjunction with its existing technical resources such as communication, meter data management and billing systems. These systems can accommodate a pilot size of approximately 500 customers. The pricing program will be offered to customers that the Companies have determined to have discretionary summer usage, such as air-conditioning. The data collected via the pilot program will provide information indicative of the target group's behavior to dynamic price signals combined with the availability of real-time usage information and enhanced billing data summaries provided along with their monthly bill. An example of such a summary is provided in attachment GFH-1. The Companies also propose to share the results of the pilot with a collaborative group of major stakeholders which would provide assistance to the Companies on potential cost-effective AMI designs going forward. In addition, the Companies will not seek cost recovery of the first $1 million in costs associated with pilot program. Any costs incurred above that amount will be recovered through the Companies' proposed Demand Side Management and Energy Efficiency rider. A summary of the program is shown in Attachment F of the ESP.

Participants in the Dynamic Peak Pricing program will be subject to generation rates that vary based upon time of use periods. The time of use On-Peak hours will be Monday through Friday 11:00 am to 5:00 pm (EST), with all other hours being Off-Peak. The time of use rates will encourage customers to shift usage from On-Peak times to Off-Peak times. Further, the On-Peak price will be increased up to 12 times per year during Critical/Dynamic Peak conditions in the summer. The Companies will provide day-ahead notification via e-mail, telephone and/or text message to the participant the day before a Critical/Dynamic Peak Day event. Upon notification of the Critical/Dynamic Peak Day, participants are encouraged to shift or decrease energy usage between the hours of 11:00 am and 5:00 pm (EST) to lower their energy costs. Likewise, participants are encouraged to shift or decrease energy usage during On-Peak times on non-critical days. Participants will pay the otherwise applicable residential tariff rate during the non-summer period. To encourage participation in the Pilot, the Company will offer the participants that remain on the program a $25 dollar participation payment at the end of each summer program period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

[Company Exhibit 5]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

KEVIN T. WARVELL

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

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

A. My name is Kevin Warvell. My business address is 76 South Main Street, Akron, Ohio 44308. I am employed by FirstEnergy Service Company as the Director of Rate Strategy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a bachelor's degree in Accounting and Finance from Ohio Northern University. I joined FirstEnergy in March 2001. I have been in my current position as Director of Rate Strategy since October 2007. Prior to that, I was a Manager in the Business Service organization, a Director of Planning and Performance Tracking, and a Director of Wholesale and Transmission Analytics. In these various roles, I was responsible for overseeing wholesale market transactions of purchases and sales of power. I was also responsible for participating in the hedging of congestion in the MISO and PJM auction process. Before working at FirstEnergy, I was a General Manager and Controller for corrugated manufacturing companies.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF RATE STRATEGY.

A. As Director, Rate Strategy, I am responsible for rate tariffs and developing and clarifying policies/procedures associated with electric service to customers. My group develops, designs and/or reviews new and existing tariffs, evaluates customer issues and handles various regulatory matters to facilitate a better understanding of rate policies, tariffs and procedures. In addition to these matters, my group interacts with regulatory agencies and staff on various regulatory matters. I am also responsible for assisting in the development of rate strategies as well as analyses related to the design and administration of rates and regulations for electric service.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company ("Companies"). The purpose of my testimony is to discuss the development of the following for the Electric Security Plan ("Plan"): (1) generation charges for the Companies, (2) aspects of the Companies' generation rate phase-in, (3) charges related to planning reserve requirements and commitments to add new or upgrade existing generation capacity, (4) standby and default service charges, (5) recovery of RCP fuel cost deferrals arising in 2006 and 2007, (6) fuel transportation surcharge costs and the incremental fuel rider for 2011, (7) seasonally adjusted generation rates and generation rate phase-in riders by voltage level, (8) optional time-of-use rates by voltage level, (9) the Economic and Optional Load Response Rider, and (10) Deferred Transmission Cost Recovery. I also discuss the development of transmission rates in the Plan. Specifically, I will discuss the process for splitting transmission revenue into demand and energy revenue. I will then discuss how this revenue was allocated to the schedules to be divided by the appropriate billing units. Lastly, I will discuss the schedule for updating transmission rates in the future.

Q. WHAT ARE YOU RESPONSIBLE FOR IN THIS FILING?

A. I am responsible for all or part of the following attachments and schedules:

<u>Item</u>	<u>Title/Description</u>
Attachment A	Generation Deferral/Recovery
Attachment B	Fuel Transportation Surcharge

Attachment C	Generation Price for Returning Shoppers
Attachment D	FES Advanced Energy & Capacity Addition Commitment
Schedule 5a	Workpaper for Generation Service Rider
Schedule 5b	Workpaper for Generation Phase – In Credit Rider
Schedule 5c	Workpaper for Deferred Generation Cost Recovery Rider
Schedule 5d	Workpaper for Fuel Transportation Surcharge & Environmental Control Rider
Schedule 5e	Workpaper for Fuel Cost Adjustment Rider
Schedule 5j	Workpaper for Capacity Cost Adjustment Rider
Schedule 5k	Workpaper for Transmission and Ancillary Services Rider
Schedule 5l	Workpaper for Deferred Transmission Cost Recovery Rider
Schedule 5r	Workpaper for Deferred Fuel Cost Recovery Rider
Schedule 5s	Workpaper for Economic Load Response Program Rider
Schedule 5t	Workpaper for Optional Load Response Program Rider

Q. WHAT IS THE TERM OF THE PLAN?

A. The Plan term is tied to the period that fixed base generation charges are offered and will be three years, 2009-2011, with the third year subject to termination at the option of the Commission. Under the Plan, the Commission, through a final order issued on or before to December 31, 2009, can, after a hearing, choose to terminate the Plan effective December 31, 2010. Should the Commission so terminate the Plan after the second year, the Companies' obligation for generation pricing in 2011 and certain other obligations identified in paragraphs 7e and 7f of the Plan will terminate effective December 31, 2010. Unless the Companies otherwise agree, the generation price effective upon termination of this Plan will be determined pursuant to a competitive bid established through the competitive bidding process contained in the MRO filed by the Companies, modified as necessary.

Q. WHAT ARE THE STANDARD SERVICE OFFER BASE GENERATION RATES PROPOSED IN THE PLAN AND HOW DID YOU DEVELOP THE OVERALL RATE FOR GENERATION AND THE GENERATION PHASE-IN RIDERS?

A. As part of the generation supply and pricing proposal, the Companies have committed to fixed generation prices, subject to limited exceptions, to formulate the Standard Service Offer ("SSO") for the plan period, 2009-2011. The Companies offer a fixed generation price separately for 2009, 2010, and 2011, with each year's price being phased-in over a period of time. Phasing-in the SSO pricing mitigates the impact upon customers as pricing is transitioned to more closely reflect market pricing. The proposed Plan base generation rate of 7.5 cents/kWh in 2009, 8.0 cents/kWh in 2010, and 8.5 cents/kWh in 2011 is reasonable and favorably priced compared to the results provided in the testimony on expected outcomes of competitive bid processes as a part of market rate offer offered by Dr. Scott Jones and Dr. Frank Graves.

Q. PLEASE DISCUSS YOUR ANALYSIS OF THE TESTIMONY REGARDING RETAIL PRICES?

A. Both Drs. Jones and Graves followed what I believe is a logical approach to developing a retail price. They began by using monthly published market forwards for 2009, 2010, and 2011 for the financially traded hubs in MISO and PJM. The experts used published forwards from NYMEX and PLATTS. The forward prices are based on a 50mw/hr block of energy during on-peak and off-peak time periods. These prices can fluctuate daily based on changes in other commodity prices that drive energy costs such as oil, natural gas and coal, as well as in response to other factors such as, for example, developments with respect to environmental legislation. Both Drs. Jones and Graves used historical data for the Companies to determine the value for shaping the Companies' load. Load shaping is necessary because customers do not use fixed blocks of power at an average consumption level, and adjustment is required to reflect their swings of usage from on-peak and off-peak demand. Both made adjustments to account for the fact that the price of electricity is different, depending on the specific location (called a "congestion adjustment" in their testimony). They both also properly took into account MISO transmission costs which include, among other things, ancillary service charges, congestion, MISO administration charges and network services. With respect to these transmission costs, both of these experts conservatively assumed a rate of \$7.5/mwh to \$7.64/mmwh which is slightly less than the Companies' current average transmission rate of \$7.92/mwh. Moreover, this charge is expected to become more volatile and thus present a greater risk factor in the future when ancillary services become market-based instead of tariff-based as they are today. Other factors that could influence the transmission costs are increased RTO infrastructure costs as well as uncertainty surrounding capacity (generation resource adequacy) and how it will be dealt with in the MISO rules. Lastly, both experts properly considered the value of distribution losses that occur as power flows through the distribution system.

Both experts supplied reasonable estimations for the value of the risk premium and, as well, considered the prices and margins experienced in other competitive bid processes for electricity. The risk premiums include price risk, volatility risk with volume especially regarding governmental aggregation and other risks related to measuring a retail product. Based on their analyses, the base generation prices of 7.5 cents/kWh in 2009, 8.0 cents/kWh in 2010 and 8.5 cents/kWh in 2011 proposed in the Companies' Plan are lower than current projections for retail market prices in those periods that would be expected from an MRO.

Q. DO YOU BELIEVE THAT THE MARKET PRICES PROVIDED BY DRS. JONES AND GRAVES ARE CONSERVATIVE?

A. Yes. I believe that the retail prices in these analyses are conservative for several reasons. First, recent changes in views on environmental regulation appeared to have a downward effect on market prices. I believe this reaction is temporary in nature and that future legislation, and the uncertainty regarding future legislation will cause prices to rise again. Second, there presently exists a large basis spread between PJM West Hub and Cinergy Hub, placing downward pressure on MISO reported prices. This phenomenon appears to be caused by off-peak prices being lower than the current market price of coal to produce the off-peak power. As generating units in the MISO footprint continue to run high priced coal units below the incremental cost of coal, off peak prices remain lower in MISO. If this current practice stops, as one would expect, off-peak MISO prices would rise in response. Finally, I believe that 2010 and 2011 market forwards do not yet fully reflect the recent dramatic rise in fuel costs. While this factor appears to be captured in 2009 prices – I do not believe that it is fully reflected in 2010 and 2011, thus making 2010 and 2011 prices somewhat conservative. Therefore, I believe the analyses and methodology used by both of these experts are not only fundamentally sound, but also generally conservative.

Q. DO THE ABOVE- DESCRIBED BASE GENERATION CHARGES INCLUDE THE COST OF RENEWABLE ENERGY RESOURCES REQUIRED BY SB 221?

A. Yes. The base generation charges described above include all required renewable energy resources during the Plan period, and/or the equivalent in renewable energy credits, in a sufficient amount to comply with the requirements of R.C. 4928.64, without additional charge to customers during the Plan period. As the analyses of Drs. Jones and Graves do not factor in the cost of such compliance, their results are again conservative.

Q. WHAT ARE THE BASE GENERATION RATES IN THE PLAN AND THE GENERATION CHARGES REFLECTING THE PHASE-IN, AND PLEASE EXPLAIN HOW YOU DEVELOPED THE GENERATION PHASE-IN RIDERS?

A. To mitigate the impact of changes in retail rates, the Plan offers a phase-in of a portion of fixed base generation rates. In 2009, the overall average base generation price across all customers in the three Companies is 7.5 cents/kWh, but the charge to be paid by customers in 2009 will be the phased-in price of 6.75 cents/kWh. In 2010, the overall average base generation charge will be fixed at 8.0 cents/kWh, with the phased-in price for that year being 7.15 cents/kWh. Finally, in 2011, the overall average base generation charge will be 8.5 cents/kWh, with the phased-in price for 2011 being 7.55 cents/kWh, assuming, as explained herein, the Commission has elected not to terminate the Plan at the end of the second year. These generation charges and phase-in credits (representing the reduction to the amount customers pay during the Plan period due to the phase-in) will be the same for each of the Companies and will be seasonally and voltage adjusted for all three years in retail tariffs. As described more fully in the following testimony, the minimum default service charge of 1.0 cent per kWh is part of the base generation charges in Rider GEN for non-shopping customers, and separately charged to shopping customers through Rider MDS, over the Plan period, but is not subject to the phase-in. The phase-in credit will be reflected in charges paid by customers through Rider GPI, which is the mechanism that applies the phase-in credit to the base generation rates. The deferred amount arising from the phase-in credit, discussed below, will be recovered from customers through a rider, Rider DGC, that will recover both deferred costs and associated carrying charges.

Q. HOW WERE THE ESTIMATED AMOUNTS OF $430 MILLION IN 2009, $490 MILLION IN 2010, AND $550 MILLION IN 2011 DEVELOPED FOR DEFERRALS RELATING TO THE PROPOSED GENERATION PHASE-IN RIDER?

A. The proposed phase-in rates described above were applied to projected kWh sales over the Plan period, and that amount was compared to the amount resulting from applying the base generation charges without the phase-in to the same projected kWh sales. The difference between these two amounts was used to develop these estimates. As discussed in greater detail in Attachment A, the current estimate for the deferred amount for 2009 is $430 million, for 2010 is $490 million, and for 2011 is $550 million. The size of the phase-in credit itself reflects the Companies' attempt to balance the rate impact on customers through the use of a deferral mechanism. The actual amount of the deferral will depend upon actual kWh sales experienced over the Plan period.

Q. REGARDING THE PHASE-IN DEFERRALS MENTIONED ABOVE, WHEN WILL RECOVERY BEGIN AND OVER WHAT PERIOD WILL THE DEFERRAL BE AMORTIZED?

A. For the amount of deferral created in years 2009 and 2010, recovery would begin January 1, 2011 and be amortized over a period not to exceed ten years. For any deferrals created in 2011, recovery would begin January 1, 2013 and be amortized over a period not to exceed ten years. In either case, recovery will be through a non-bypassable deferred generation cost rider. Members of a governmental aggregation group shall be responsible only for the portion of the Rider DGC charge that is proportionate to the benefit that the electric load centers within the jurisdiction of the governmental aggregation as a group receive.

Q. WILL THE DEFERRAL ASSOCIATED WITH THE PHASE-IN INCLUDE CARRYING CHARGES?

A. Yes, and this subject area is specifically discussed by Mr. Wagner. Additional details of this deferral also are included on Attachment A to the Plan.

Q. HOW DID YOU DEVELOP THE SEASONAL RATES BY VOLTAGE LEVEL INCLUDED IN THE GENERATION AND GENERATION RATE PHASE-IN RIDERS?

A. The total generation rate for the combined Companies was adjusted by voltage level to account for distribution losses. Each voltage level rate was then adjusted to reflect seasonality. The arithmetic averages of the MISO load zone day-ahead Locational

Marginal Price ("LMP") for the Companies were utilized for this seasonal adjustment. These averages were developed for: (1) the summer months of June, July and August, (2) the non-summer months, and (3) the entire period. The 24 month period ending December 2007 was used for this analysis. A ratio of the summer average to the entire period average was utilized to calculate the summer generation rates. A ratio of the non-summer average to the total average was utilized to calculate the non-summer generation rates. The generation phase-in riders were calculated using the same methodology.

Q. WHAT IS THE SIGNIFICANCE OF THE MISO LOAD ZONE DAY-AHEAD LMP FOR THE COMPANIES?

A. The MISO Day-Ahead LMP for the Companies' load zone is the hourly price of energy MISO charges suppliers for energy delivered to the load zone. This price would not include the cost of serving distribution losses. These historical hourly prices enable the calculation of a seasonal price relationship for the Companies' load zone.

Q. WHAT IS THE PURPOSE OF THE MINIMUM DEFAULT SERVICE RIDER, HOW WAS THE CHARGE DEVELOPED, AND HOW WILL IT BE APPLIED?

A. This non-bypassable charge is necessary to recover, among other things, generation related administrative costs and hedging costs associated with the Companies' obligation to serve the entire load of their retail customers. The Companies are required to be the default provider of retail generation service to all customers within their service territories. The Companies must plan and incur costs so that if no customers switch to alternative suppliers, the Companies are prepared to have adequate generation supply to serve such their entire retail load. To accomplish this, the Companies must procure generation and incur costs associated with that procurement based on a forecast and assumptions regarding the number of customers and amount of load to serve, while always being in a position to serve all customers. If more customers shop than anticipated, for any variety of reasons, then the Companies have procured generation that they do not need to serve their retail load. For example, if market prices decline relative to the price offered by the Companies and more customers shop with an alternative supplier than anticipated, the Companies are left with higher priced generation for a load they no longer serve and then must sell that generation at a loss in an environment where market prices are falling. If fewer customers shop than anticipated, the Companies may find themselves short generation and be forced to go into the market to acquire power to serve the unanticipated load. Therefore, this charge addresses the cost of hedging generation to serve the Companies' retail load and the associated risk of customers leaving and shopping with an alternative supplier. As part of the base generation price in Rider GEN, a fixed non-bypassable charge of 1.0 cent/kWh provides for these costs and risks associated with the requirement of being the default provider for the customers in the Companies' service territories. For shopping customers, this charge is applied through Rider MDS, which by its terms applies only to shopping customers. Therefore, all retail customers are obligated to pay the minimum default service charge regardless of whether they are shopping or taking retail generation service from the Companies. The effect of this charge is to reduce risk otherwise borne by the Companies thereby permitting the base generation price to be offered at a lower level than otherwise would have been achievable. Without this non-bypassable charge, the base generation charges contained in the Plan would need to be adjusted higher.

Q. PLEASE DISCUSS HOW THE COMPANIES WILL MEET CAPACITY REQUIREMENTS FOR POWER PROVIDED UNDER THE PLAN.

A. Capacity requirements for load will be provided by FES under a wholesale power supply agreement, and the Companies will recover the cost through the general pricing provisions for base generation as discussed throughout this testimony.

Q. WILL CAPACITY REQUIREMENTS ASSOCIATED WITH PLANNING RESERVE REQUIREMENTS RECEIVE SEPARATE TREATMENT?

A. Yes. Capacity purchases required to meet FERC, NERC, MISO or other applicable standards for planning reserve margin requirements for the Companies' retail Ohio load will be provided by FES through FES-owned capacity as described below. In the event this capacity is insufficient, FES will supply the needed capacity to meet the planning reserve requirement, but the associated costs of doing so will be included in the wholesale power supply agreement, and recovered by the Companies pursuant to a separate charge recovered from customers through Rider CCA. More specifically, generation capacity currently owned or controlled by FES located in MISO, including the capacity associated with Ohio Valley Electric Corp. ("OVEC") arrangements, but excluding the PJM assets of Beaver Valley and Seneca, will be made available to meet such planning reserve requirements. In addition, FES capacity at the Fremont Station will also be made available to meet such planning reserve requirements when completed. The Fremont Station is a 700 MW plant currently under construction with an anticipated completion date in 2010. To the extent the above capacity is insufficient to meet the Companies' entire retail load planning reserve requirements, thereby causing FES to purchase capacity for the period of May 1 through September 30 of 2009, 2010 or 2011, the costs of such purchases will be included in and recovered pursuant to Rider CCA. Costs experienced by FES for the remainder of the year shall not be recoverable. The current nomenclature that MISO uses for generation capacity is Designated Network Resources (DNR). Owning DNR is a requirement of being able to purchase Network Integrated Transmission Service from MISO, which is necessary to serve retail customers. This rider does not apply to customers during the period they take electric generation service from an alternative supplier. The Commission may elect to increase the generation phase-in credit (and consequentially the associated deferred phase-in dollar amount) to the extent any charges for the planning reserves exceed 1.5% of the existing total rate to the customer thereby giving the Commission additional flexibility.

Q. WHAT COSTS ARE TO BE RECOVERED IN THE PROPOSED FUEL TRANSPORTATION SURCHARGE AND ENVIRONMENTAL CONTROL RIDER ("RIDER FTE")?

A. This rider is designed to recover two categories of costs. The first category is fuel transportation surcharge costs in excess of $30 million, $20 million, and $10 million annually for 2009, 2010, and 2011, respectively. The second category consists of any additional costs, in excess of $50 million during the Plan period, of complying with new requirements for renewable resources (other than required by

S.B. 221), new taxes, and new environmental laws or new interpretations of existing environmental laws that take effect after January 1, 2008. The Companies have attempted to keep such "opener" type provisions to a minimum, however a few limited ones are necessary and serve to help keep the standard SSO generation charges lower than they would otherwise need to be.

Q. PLEASE BRIEFLY DESCRIBE THE MECHANICS OF THE PROPOSED RIDER FTE.

A. Proposed Rider FTE will recover incremental costs above a baseline for fuel transportation surcharges and certain other costs described in the previous answer. The charge in Rider FTE will be enumerated in cents per kWh and applicable to non-shopping retail customers of the Companies. The rider will be revised quarterly and will include a reconciliation component for the over/under collection balance of actual recoverable costs, including applicable interest. An illustrative example of the implementation of the Rider FTE is found in Schedule 5d. Rider FTE is not applied to customers during the period they take retail generation service from a certified supplier.

Q. WILL THE SAME RIDER FTE AND CHARGE BE APPLICABLE TO EACH OF THE THREE COMPANIES?

A. Yes. These generation-related costs are averaged across the three Companies' sales in aggregate.

Q. HOW LONG WILL RIDER FTE BE IN EFFECT?

A. The Rider FTE will be in effect from January 1, 2009 through December 31, 2011, and during 2012 for the reconciliation amount from the fourth quarter of 2011, if any, to be refunded or recovered.

Q. WHAT IS THE BASIS FOR THE PROPOSED FUEL COST ADJUSTMENT RIDER ("RIDER FCA")?

A. The Companies have not proposed a separate recovery mechanism to recover increased fuel costs for the 2009-2010 period, thereby absorbing the risk of fuel price increases for 2009 and 2010. However, given the uncertainty of fuel prices more than two years out into the future, the Companies are proposing to implement a Fuel Cost Adjustment Rider for 2011.

Q. WHAT COSTS ARE RECOVERED IN THIS RIDER FCA?

A. This charge is designed to recover the 2011 cost of fuel in excess of the level of those costs incurred during 2010, excluding fuel transportation surcharge, emission allowances, fuel handling, disposal, lime, urea, and ammonia costs at the FES plants in MISO, including OVEC and Fremont - when placed in service, but excluding the PJM assets of Beaver Valley and Seneca. For purposes of the Rider FCA, it will be assumed that 100% of the generation from these plants is used to provide service under the ESP, which is an appropriate assumption given that the companies projected load exceeds the peak output of the FES MISO plants..

Q. PLEASE BRIEFLY DESCRIBE THE MECHANICS OF THE PROPOSED RIDER FCA.

A. The Companies are proposing Rider FCA, in cents per kWh, applicable to non-shopping retail customers of the Companies to collect the aforementioned incremental 2011 fuel costs on a forecasted basis. Since the charge will be based upon forecasted costs, the rider will be revised quarterly and will include a reconciliation component for the over/under collection balance of actual recoverable costs, including applicable interest. An illustrative example of the implementation of the rider is found in Schedule 5e. This Rider FCA is avoidable by customers during the period they take retail generation service from a certified supplier.

Q. WILL THE SAME FCA RIDER AND CHARGE APPLY TO EACH OF THE THREE COMPANIES?

A. Yes, the same FCA Rider and charge will apply to each of the Companies since average fuel costs per MWh do not differ by Company in this calculation.

Q. HOW LONG WILL RIDER FCA REMAIN IN EFFECT?

A. The Rider FCA will be in effect during 2011, and in 2012 just long enough for the reconciliation amount, if any, from the fourth quarter of 2011 to be refunded or recovered.

Q. WHAT IS THE BASIS FOR THE PROPOSED DEFERRED FUEL COST RIDER ("RIDER DFC")?

A. The Commission, as part of its approval of the Companies' Rate Stabilization Plan, (the "RSP"), approved a mechanism to allow the Companies to recover certain fuel costs in relation to comparable fuel costs incurred during the base line year of 2002. In that case, the Commission also approved 2006-2008 as the recovery period, subject to reconciliation. As a first step toward implementing this provision of the RSP, the Companies instituted a separate proceeding with the Commission under

Case No. 05-704-EL-ATA to recover such fuel costs through a rider mechanism (the "05-704 Fuel Cost Recovery Proceeding"). Subsequently, the Companies filed their Rate Certainty Plan (the "RCP") and included an alternative to the 05-704 Fuel Cost Recovery Proceeding, which was later consolidated with the RCP proceeding. Among other terms, the RCP established cash recovery of a portion of the eligible fuel costs incurred during the 2006-2008 period (the "Fuel Recovery Mechanism" or "FRM") and authorized the deferral for future recovery, in the Companies' next distribution rate case, of the remaining eligible fuel costs, in excess of the 2002 base line cost level not recovered through the FRM. The balance of the fuel deferrals with carrying charges was to be amortized over a 25 year period.

In response to a decision from the Ohio Supreme Court, the Companies filed an application in Case No. 07-1003-EL-ATA that proposed two new fuel riders. One rider was designed to recover fuel costs that were authorized for recovery in previous cases, but had not yet been deferred as permitted under the RCP case. Subsequently, the Commission approved this recovery mechanism to recover eligible fuel costs arising during 2008. In the same Finding and Order, the Commission rejected the proposed recovery mechanism to recover deferred fuel costs arising during 2006-2007 and directed the Companies to file a separate application proposing an alternative recovery mechanism. The Companies filed an alternative recovery mechanism for the fuel costs deferred during 2006-2007 in Case No. 08-124-EL-ATA. While this proceeding is pending before the Commission, the Companies have requested in this Application that this issue be resolved in this case. If so resolved, then the current pending Case No. 08-124-EL-ATA would be rendered moot.

Q. WOULD THE PROPOSED RIDER DFC CONSTITUTE THIS ALTERNATIVE RECOVERY MECHANISM?

A. Yes it does, and if approved would supplant the recovery mechanism proposed in Case No. 08-124-EL-ATA.

Q. PLEASE BREIFLY DESCRIBE THE MECHANICS OF THE PROPOSED DEFERRED FUEL COST RECOVERY ("RIDER DFC").

A. Rider DFC is designed to recover, in cents per kWh, charges to applicable retail customers of the Companies to collect the 2008 year-end balance related to the 2006 and 2007 fuel deferrals, shown on Schedule 6a, plus applicable interest and adjusted for the Commercial Activities Tax. Rider DFC is applicable retail customers include all tariff customers and those customers served on special contracts that permit recovery of such costs.

Q. WHEN WOULD THE PROPOSED RIDER DFC BE IN EFFECT?

A. The Companies request that the new Rider DFC be implemented on a service-rendered basis commencing January 1, 2009 and continuing until full recovery of the deferred fuel costs, associated carrying costs, and Commercial Activities Tax.

Q. CAN YOU DESCRIBE IN MORE DETAIL THE CALCULATION OF THE DEFERRED FUEL COSTS THAT WOULD BE RECOVERED IN THE PROPOSED RIDER?

A. Certainly. Under the RCP, the Companies have deferred, for future recovery, specific fuel costs in excess of the 2002 baseline amount which are not recovered through the Fuel Recovery Mechanism (FRM). The estimated balances to be recovered through the Rider DFC for each of the three Companies are set forth on page 1 of Schedule 5r[1] totaling $235 million.

Q. EACH OPERATING COMPANY WILL HAVE SEPARATE CHARGES FOR RIDER DFC, CORRECT?

A. Yes. A separate rider value was established for each of the Companies. The annual revenue requirement associated with the level of each Company's deferred fuel cost, including carrying charges (return) and an annual amortization expense based upon 25 years, is divided by the projected energy sales for the test year in the Distribution Rate Case No. 07-551-EL-AIR (twelve months ended February 2008). See page 2 of Schedule 5r for details of these calculations. The result is adjusted for the applicable Commercial Activities Tax. The carrying charge (return) is calculated based upon each Company's weighted book cost of debt as of June 30, 2008.

Q. HOW LONG WILL RIDER DFC REMAIN IN EFFECT?

A. Rider DFC will remain in effect for the period of time it takes to allow full recovery of the deferred fuel costs and associated carrying costs, not to exceed 25 years. Revenues are proposed to be collected based upon the DFC amount multiplied by the kWh sales of customers to which the DFC Rider applies. The charges will continue to be applicable until and unless modified by the Commission, but only until the actual December 31, 2008 balance and associated carrying charges are fully recovered. The cents per kWh charge for each of the Companies are: 0.0375¢ for OE; 0.0339¢ for CEI; and 0.0260¢ for TE.

[1] The only portion of the balance that is estimated is the interest for July through December 2008.

Q. HOW WILL THE COMPANIES KNOW WHEN FULL RECOVERY HAS OCCURRED AND THUS TERMINATE RIDER DFC?

A. Each of the Companies will track recovery of the balance on a monthly basis and discontinue the charge once the balance has been fully recovered. Tracking of the recovery of the balance will be based upon actual monthly revenues billed pursuant to the Rider. The Commercial Activity Taxes and carrying charges on the previous month's un-recovered balance (net of associated accumulated deferred income tax balances) will be subtracted from these monthly revenues. The remaining monthly revenues will be applied toward recovery of the deferred fuel balance. Commercial Activity Taxes are equal to the Rider DFC revenues times the Commercial Activity Tax percent effective for a given month. The carrying charges are based upon the previous month's unrecovered deferred balance, the current month's Rider DFC revenues and related Commercial Activity Taxes, the deferred income tax rate, and the weighted book cost of debt as of June 30, 2008.

Q. PLEASE DESCRIBE THE STANDBY CHARGE PROPOSED AS PART OF THE POWER SUPPLY RESERVATION RIDER ("RIDER PSR") IN THE COMPANIES' PLAN?

A. Customers that switch to an alternative supplier will be entitled to avoid the bypassable generation charge and bypassable portion of the transmission rider. A standby charge of 1.5 cents per kWh in 2009, 2.0 cents per kWh in 2010 and 2.5 cents per kWh in 2011 will be applied to customer's bills through Rider PSR unless the customer or a legislative authority that formed, or is forming governmental aggregation group on behalf of all customers within such group elect to waive such price protection. Customers that switch to an alternative supplier and elect not to pay the standby charge, but who thereafter return to the utility for generation service at any time during the period of the Plan will pay a market price for retail generation service, as set forth in Attachment C. If a customer pays the standby charge each month while the customer is taking electric generation service from an alternative supplier, then that customer will have the right to return to the standard service offer base generation price, provided that the customer shall in that circumstance be required to remain a retail generation service customer of the utility for a period of not less than 12 months or for the remaining term of the Plan, whichever is shorter.

Q. PLEASE EXPLAIN THE PURPOSE OF THE STANDBY CHARGE INCLUDED AS PART OF RIDER PSR.

A. 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, whenever it may occur. In the wholesale markets this is done through an option premium (call option). Call options are costly. As such, if the Companies hedge the risk of customers returning, there is the potential to lose significant investment in energy forwards, thereby potentially placing the Companies' credit at risk. 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.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE ECONOMIC LOAD RESPONSE PROGRAM RIDER ("RIDER ELR").

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. The general terms and conditions of Rider ELR are modeled after the current Ohio Edison interruptible tariffs. The Rider obligates such customers to designate a contract firm load, and then be subject to interruption or required to buy power at market prices during a buy-through period. In exchange for being subject to these terms and conditions, an interruptible program credit is applied to the customers' curtailable load. The value of the interruptible program credit is based upon the market value of MISO designated network resource ("DNR") (MISO's term for generation capacity). This capacity is sold bilaterally for prices approaching $64/MW/day on an annual basis, which is the price utilized to calculate a $1.95/kW/month curtailable credit. The interruptible program credit is applied to the customer's realizable curtailable load. This realizable curtailable load is calculated by subtracting the customer's contract firm load from its average hourly demand during summer weekdays between the hours of noon and 6:00 p.m., and represents the amount of load for which the Companies can avoid procuring generation capacity, as DNR requirements are based upon the peak load forecast for the year - which for the Companies occurs in the summer.

Q. PLEASE DESCRIBE THE OPTIONAL LOAD RESPONSE PROGRAM RIDER ("RIDER OLR") AND COMPARE IT TO RIDER ELR?

A. Rider OLR is designed with the same general terms and conditions as the Rider ELR, but applies only to emergency interruptions and is available to new participants as well as existing customers. The Rider ELR is designed to be utilized with the interruptible credit provision of the Societal Benefits and Economic Development Rider ("Rider SBE"). Rider SBE is designed for interruptible customers who are taking service as of July 31, 2008. These customers are currently subject to Economic Buy Through Option Events and this concept is incorporated into the Rider ELR. Rider OLR is designed for use with new interruptible customers/load as an interruptible credit that recognizes that the 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 SBE.

Q. PLEASE EXPLAIN HOW THE COMPANIES PROPOSE TO RECOVER TRANSMISSION-RELATED COSTS IN THE PLAN.

A. The Companies propose to implement a similar recovery mechanism for transmission costs as exists in the Companies' tariffs today, i.e., recovery, through a reconcilable rider, of all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the Companies by FERC or a regional transmission organization ("RTO"), independent transmission operator, or similar organization approved by FERC. More specifically, the Companies propose to implement a tariff rider for the recovery of transmission, ancillary service-related costs and congestion costs incurred by the Companies under the Midwest

Independent Transmission System Operator (MISO) Open Access Transmission Tariff and Transmission Energy Markets Tariff ("together, "MISO Tariff") or other similar MISO tariffs or agreements. Such transmission, net congestion, and ancillary service charges reflect applicable FERC-approved charges or rates. This rider would be avoidable by customers for the period that they take electric generation service from an alternative supplier. This proposal is set forth in greater detail in the Transmission and Ancillary Services ("Rider TAS").

Q. PLEASE EXPLAIN WHY SUCH A RIDER MECHANISM IS APPROPRIATE FOR RECOVERY OF THESE COSTS.

A. This rider mechanism is appropriate for the recovery of transmission and ancillary service-related costs and congestion costs because these costs, which are and will be subject to frequent adjustment by MISO and over which the Companies have little to no control, represent federally-approved rates for services the Companies obtain under the MISO Tariff. The Companies propose to recover only their costs of such services under the MISO Tariff, and the proposed rider mechanism is the best way to ensure that they recover neither more nor less than those costs.

Q. HOW WILL RECONCILIATION OF THE TRANSMISSION RIDER WORK?

A. Reconciliation adjustments will be calculated each year. Rider rates each year will be based on the projected sales to customers taking transmission service from the Companies for that year and on the projected costs to provide transmission, ancillary service and congestion under the MISO Tariff in that year, adjusted to account for the over-or under- collections in the appropriate reconciliation period.

Q. PLEASE GIVE AN OVERVIEW OF THE TRANSMISSION RATE DESIGN.

A. Transmission rates are now consistent with the voltage-based rate schedules from the Companies' distribution rate case filing (Case No. 07-551-EL-AIR), and use the same billing units as the distribution schedules. The transmission charges for the three lighting schedules (Traffic Lighting, Street Lighting, and Private Outdoor Lighting) have been combined into a single kWh-based schedule. The transmission rider will account for the same expenses as the previous two years (*see* May 1, 2008 and May 1, 2007 filings in Case No. 07-128-EL-ATA), with the exception that it will no longer include the amortization of the 2005 Transmission Expense Deferral. The deferral will now be collected through a new, non-bypassable Deferred Transmission Cost Recovery Rider ("Rider DTC").

Q. WILL THE TRANSMISSION RATES INCLUDED IN THE PLAN BE UPDATED BEFORE JANUARY 1, 2009?

A. Yes. The rates included in the Plan are intended to be placeholders that are revenue neutral to the rates that are currently in effect. The Companies will file transmission rates on or before October 17, 2008 to be effective on January 1, 2009. Thereafter, the Companies will continue to file in mid-October for rates to be effective for January 1 through December 31 of the following calendar year.

Q. HOW WAS THE REVENUE REQUIREMENT FOR THE TRANSMISSION RATES DETERMINED?

A. The revenue requirement was calculated by applying current transmission rates (effective July 1, 2008) to the billing units found in the distribution rate case update filing. The 2009 portion of the amortization of the 2005 Transmission Expense Deferral was then subtracted from the revenue requirement.

Q. WERE ANY MODIFICATIONS MADE TO THE UPDATE FILING BILLING UNITS?

A. Yes. Modifications were made to some of the special contract billing units. Specifically, special contract demands were broken down by rate blocks, a distinction not made in the distribution case, and Toledo Edison Street Lighting and Traffic Lighting kWhs were adjusted to reflect the inclusion of lighting contracts that had previously been assigned to General Service Secondary.

Q. HOW WERE THE DEMAND ALLOCATION FACTORS DEVELOPED?

A. Demand is allocated based on a four coincident peak methodology. The demand for each rate schedule at the time of the monthly peak was determined for the summer months of 2007 (June-September). The four months were added together for each schedule and divided by the total to determine the allocation factors to be applied to the demand revenue requirement.

Q. HOW WERE THE ENERGY ALLOCATION FACTORS DEVELOPED?

A. The billed sales used in the distribution rate case update filing were adjusted for transmission and distribution losses. The adjusted sales for each schedule were divided by the total company adjusted sales to determine the energy allocation factors.

Q. WHY ARE EXPENSES THE SAME EVERY MONTH FOR THE SCHEDULE COVERING THE TRANSMISSION RIDER?

A. The expenses included throughout the various schedules are meant to be illustrative. The Companies' 2009 budget assumed that beginning January 1, 2009, all Transmission and Ancillary-related expenses from MISO would be charged by the generation supplier and not the Load Serving Entity. Thus, the Companies do not currently have a forecast for such expenses. Placeholders were developed to demonstrate the mechanics of the Rider.

Q. HOW WERE THE EXPENSE PLACEHOLDERS DEVELOPED?

A. Expenses were set equal to the total revenue requirement (excluding amortization of the 2005 transmission expense deferral) upon which the revenue neutral rates were calculated. The demand and energy split was based on projected expenses in the May 1, 2008 filing for the July 1 – December 31, 2008 period. For each component, the demand and energy-related expenses were split in the same proportion as they were in the May 1 filing and each value was divided by 12 to produce an identical monthly number. In this way, the placeholders approximate the breakdown of MISO expenses and the transmission reconciliation as forecasted in the most recent 6 month period for which expenses are available.

Q. WHY ARE CURRENT AND PROPOSED TRANSMISSION RATES THE SAME?

A. The 2009 placeholder rates were developed to be revenue neutral to the current transmission revenues. In addition, there is a "mapping" issue between the current transmission rates and the new voltage-based schedules. The 2009 rate schedules are based on the Companies' proposal in the distribution rate case, while the 2008 schedules are legacy rates prior to the distribution rate case. Because mapping was done on a customer by customer basis, any comparison between previous rate schedules and new voltage schedules would be inappropriate. This filing assumes current and proposed rates are the same.

Q. PLEASE DESCRIBE THE RIDER TO RECOVER DEFERRED TRANSMISSION COSTS ("RIDER DTC")..

A. Rider DTC is designed to recover that portion of costs included in the current transmission rider that has been excluded from the new transmission rider. Rider DTC will be nonbypassable because it includes only 2005 costs that have already been approved for recovery by the Commission pursuant to the Finding and Order in Case No. 04-1931-EL-AAM, wherein the Commission permitted the Companies to defer certain incremental transmission- and ancillary service-related charges, with recovery of such deferrals authorized in Case No. 04-1932-EL-ATA. Under the Plan, recovery of such deferrals will continue, commencing January 1, 2009, and ending December 31, 2010, pursuant to Rider DTC.

Q. WHAT RIDERS ARE BYPASSABLE FOR A CUSTOMER DURING THE PERIOD THE CUSTOMER TAKES ELECTRIC GENERATION SERVICE FROM AN ALTERNATIVE SUPPLIER?

A. The following riders are bypassable during the period a customer takes electric generation service from an alternate supplier:

1. Generation Service Rider (GEN)
2. Generation Phase – In Credit Rider (GPI)
3. Fuel Transportation Surcharge & Environmental Control Rider (FTE)
4. Transmission and Ancillary Services Rider (TAS)

5. Fuel Cost Adjustment Rider (FCA)

6. Capacity Cost Adjustment Rider (CCA)

7. Power Supply Reservation Rider (PSR) (If so elected by the customer or the governmental aggregation program of which the customer is a member.)

Deferred Generation Cost Recovery Rider ("Rider DGC") may be avoidable by customers that are members of a governmental aggregation group. The members of the governmental aggregation group shall be responsible only for the portion of the Rider DGC charge that was proportionate to the benefit that the electric load centers within the jurisdiction of the governmental aggregation as a group receive.

Q. Are you proposing any changes to the Companies' Electric Service Regulations *(ESR) in this proceeding?*

A. Yes. In Case No. 07-551-EL-AIR, the section in the ESR addressing Return to Standard Offer Supply, the Companies' noted in that section of the ESR that no changes were recommended at that time since a framework for, and rules relating to, generation service were uncertain. Now that more clarity has been provided, and consistent with the Companies' proposals in this instant case, modifications to this section are recommended and reflected in Schedule 3.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[Company Exhibit 6]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan	)	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

SCOTT T. JONES

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

Public Utilities Commission of Ohio

DIRECT TESTIMONY
OF
SCOTT T. JONES

I INTRODUCTION

I.A Witness Qualifications

Q: **Please state your name and professional position.**

A: My name is Scott T. Jones. I am the head of the Global Energy practice of FTI Consulting. My firm specializes in strategic, economic, financial, and public policy consulting services to private and public organizations.

Q: **What is your professional and educational background?**

A: I have been involved in issues related to the regulation of utilities and regulatory policy for more than 20 years. My experience in the energy industry, including forecasting and market price determination, spans 31 years. Over this period, I have been an executive in the oil and gas industry on two occasions and a consultant to numerous regulated utilities. My experience includes the provision of expert testimony on a variety of topics such as price formation, market power, and regulatory policy. I provided testimony on behalf of FirstEnergy in Case No. 99-1212-EL-ETP, which was FirstEnergy's electric transition plan. I hold a Ph.D. in economics from

Virginia Tech. My resume, attached to this testimony as Exhibit 1, provides further detail about my background and experience.

I.B Purpose

Q: **Please state the purpose of your testimony.**

A: I have been asked by FirstEnergy to calculate the expected prices that retail customers would pay if Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company ("the Ohio Companies") were to procure full requirements electric service to meet their standard service offer obligation during each of the years 2009, 2010, and 2011 through a competitive bidding process such as is contemplated in R.C.Section 4928.142.

I.C Summary of Conclusions

Q: **Please summarize your conclusions.**

A: I conclude that customers of the Ohio Companies would pay the following market-rate offer prices for full requirements service:

- 2009: $90.47/MWh
- 2010: $98.34/MWh
- 2011: $105.49/MWh[1]

[1] These prices are calculated using market data as of July 15, 2008.

II POLICY BACKGROUND

Q: Please explain the policy background for the calculation of market-rate offers to service the Ohio Companies' standard service offer load.

A: R.C. 4928.141 states that "Beginning January 1, 2009, an electric distribution utility shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service." Section 4928.141 further states that the utility's first application to the Public Utilities Commission of Ohio ("PUCO") to establish its standard service offer must include a filing under Section 4928.143 ("electric security plan") and that the utility may at its discretion make a simultaneous filing under Section 4928.142 ("market-rate offer").

Q: *Please describe the procurement process that is prescribed by the law.*

A: R.C. 4928.142 requires that a utility's market-rate offer must be established through an "open, fair, and transparent competitive solicitation" that provides for the following: clear product definitions; standardized bid evaluation criteria; design, administration, oversight by an independent third party, and evaluation of the bids.

Q: Does R.C. 4928.142 include criteria for ensuring that the solicitation is competitive?

A: Yes. Prior to conducting a solicitation, the electric distribution utility must file an application with the PUCO demonstrating that the utility (or its transmission affiliate) belongs to a FERC-approved regional transmission organization ("RTO") or that there is "comparable and nondiscriminatory access to the electric transmission grid"; that such RTO has a market-monitor function and the ability to identify and mitigate market power or the utility's market conduct; and that pricing information is published for traded electricity peak and off-peak energy products that begin delivery at least two years from the date of the publication. Further, upon completion of the solicitation, the PUCO shall select the least-cost bid winner(s) and determine whether any of the three criteria delineated in R.C. 4928.142(C) were not met: that each portion of the solicitation was oversubscribed; that there were four or more bidders; and that at least 25 percent of the load was bid upon by parties other than the distribution utility.

III CALCULATION OF MARKET-RATE OFFER PRICES

Q: Please describe the nature of the product that the Ohio Companies would seek to procure if they were to establish standard service offer prices under R.C. 4928.142.

A: The Ohio Companies would procure full requirements electric service sufficient to meet their standard service offer load for all retail customers using staggered supply periods covering each of the years 2009, 2010, and

2011. Full requirements service includes generation adequate to meet the needs of all customers that take service under the standard service offer. For purposes of my testimony, I included all required energy (including losses) as well as all transmission, capacity, and ancillary services required by the Midwest ISO to serve the Ohio Companies' standard service offer load.

Q: **Please describe the methodology you use to calculate the expected market-rate offer price.**

A: As explained in more detail below, I begin by calculating what I refer to as "direct cost components" of full requirements service. I was provided with load forecast data for the residential, commercial, industrial, and street lighting rate classes, and I calculate direct costs separately for each rate class. These direct costs include such costs as procurement of real-time energy from the wholesale market, and of transmission services from the Midwest ISO. In calculating direct costs, I assume that the quantities and prices of all of these direct cost component services and products are perfectly knowable by the supplier *ex ante*, and that the supplier can perfectly hedge these costs.

Of course, the direct cost components are in fact highly uncertain, and they cannot be hedged perfectly. Thus, as explained in more detail below, I include a "margin" to reflect the amount of expected return that a bidder would require for accepting the substantial risks of providing full requirements service at fixed prices for the Ohio Companies' standard service offer. I calculate separate margins for each year for customers that represent relatively low shopping risk and for customers that represent relatively high shopping risk.

Finally, I create a single market-rate offer price for each year based on a weighted average of all customer classes.

III.A Calculation of Direct Cost Components

Q: **What are the direct cost components that must be included in the pricing of the standard service offer?**

A: The direct cost components include the price for round-the-clock energy; locational cost adjustments; load-shaping costs; capacity costs; transmission and ancillary services costs; and any distribution losses.

III.A.1 Round-the-Clock Energy Prices

Q: **Please describe the methodology you use to calculate the round-the-clock energy price for the Ohio Companies' standard offer load.**

A: The round-the-clock price is equal to the average price that a buyer would pay if he or she were to purchase an equal amount of energy in every hour of the day over some time period. The round-the-clock price is calculated using forward peak and off-peak contract prices, weighted by the number of peak and off-peak hours.

For my analysis, I use prices for calendar peak and off-peak contracts as of July 15, 2008 for 2009, 2010, and 2011 for delivery at Cinergy Hub.

Cinergy Hub is a liquid pricing point in the Midwest ISO for which market prices are publicly available. Calendar contracts for peak (or off-peak) power are contracts that provide for delivery of a fixed amount of electricity for each peak (or off-peak) hour of the year.

I multiply each year's peak price by the number of peak hours in that year and each year's off-peak price by the number of off-peak hours in that year. I sum the results of these calculations and then divide by the number of hours in the year to arrive at the average round-the-clock price for the year. I use the same steps to calculate the round-the-clock price for 2009, 2010, and 2011. The round-the-clock energy prices for Cinergy Hub for each year are shown in *Exhibit 2*.

III.A.2 Locational Cost Adjustments

Q: **Please explain why it is necessary to include a locational cost adjustment factor.**

A: As noted, in calculating round-the-clock energy prices I have used forward market price data for contracts that deliver into Cinergy Hub. This is because the Cinergy Hub is a liquid trading location in the Midwest ISO area, and because prices for transactions are commonly reported in the trade press. However, there is a relatively small amount of transmission congestion between the Cinergy Hub and the Ohio Companies' load zones, which results *in differences in the cost of service and prevailing prices in the two areas.*

Q: **Please describe the methodology you use to calculate the cost of the locational adjustment for procuring energy to meet the Ohio Companies' standard service offer obligation.**

A: To calculate the locational adjustment factor, I have analyzed historic locational marginal price ("LMP") data for the two locations for the time period September 2005 to August 2007. I have used two complete years of LMP data in order to account for both seasonality and any anomalies that might occur in the data for partial years or for a shorter time period. Based on this comparison, I find that on average the LMP in the Ohio Companies' load zone is about 70 cents per MWh higher than the LMP at Cinergy Hub. I thus conclude that a supplier bidding to meet the Ohio Companies' standard service offer load would reasonably expect that real-time energy prices would be about 70 cents per MWh higher than Cinergy Hub prices.

III.A.3 Load-Shaping Adjustment

Q: **Please explain why it is necessary to include a load-shaping adjustment factor.**

A: As noted, the round-the-clock energy price is calculated based on the cost of providing an equal amount of energy in each hour of the year. While the round-the-clock price is a useful indicator of the cost of energy, it is only a beginning step to calculating the cost of serving actual load. This is because consumers do not use electricity at constant rates throughout the year.

Instead, their consumption varies minute by minute in response to numerous factors.

Market prices for power also vary throughout the day. In particular, prices tend to be lower in off-peak hours when relatively less costly base load generation resources (e.g., nuclear and some coal generation plants) are sufficient to meet all demand; and prices tend to be higher during peak hours, when demand is higher and it is necessary to rely upon relatively higher cost generation resources (e.g., natural gas combustion turbines). Because higher load levels necessitate the reliance on higher-cost generating resources, market prices are higher when consumption is higher. As a result, the actual cost to provide energy to consumers is typically higher than the round-the-clock price would indicate.

Q: **Please describe the methodology you use to calculate the cost of shaping energy to meet the Ohio Companies' standard service offer load.**

A: To calculate the cost of this load-shaping for each customer class, I use hourly load and LMP data from September 2005 to August 2007. I calculate the total cost of serving each customer class as the product of each hour's load and that hour's LMP. I sum these products to arrive at an annual total cost of service for each customer class. I then divide this total cost by the total annual load to arrive at a load-weighted cost per MWh. I then divide this annual load-weighted cost by the simple average of LMPs for the same time period. The result of this calculation is a "load-shaping ratio" that I then multiply by each year's round-the-clock price to arrive at the load-shaped price for each customer class. The difference between these load-shaped prices and the round-the-clock prices is the load-shaping costs that are shown by customer class in Exhibit 3.

III.A.4 Capacity Cost

Q: **What is the basis for including the cost of capacity in the calculation of the market-rate offer price?**

A: The Midwest ISO requires load serving entities to demonstrate that they have sufficient generation resources both for the load they are serving and to meet reserve margin requirements. The FERC approved the Midwest ISO's long-term resource adequacy proposal on March 26, 2008.[2] However, the Midwest ISO's resource adequacy program is a work in progress, and there are several important sources of uncertainty regarding how it will operate. These uncertainties present risks to suppliers of full requirements electric service to meet the Ohio Companies' standard service offer obligation at fixed prices.

For example, while the FERC has approved the Midwest ISO's intent to use a loss-of-load study approach to calculate the reserve margin that each

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[2] Federal Energy Regulatory Commission, Docket No. ER08-394-000, Midwest Independent Transmission System Operator, Inc., Order on Resource Adequacy Proposal, March 26, 2008 ("FERC Order on Resource Adequacy Proposal").

load-serving entity will be required to meet, the FERC has noted that "more detail is needed to understand" how the Midwest ISO's approach will actually operate.[3] Additionally, the financial settlement and penalty provisions of the Midwest ISO's resource adequacy proposal are still under development.[4]

Q: **Please explain how you calculate the amount of capacity a supplier would be required to procure.**

A: It is reasonable to assume that in determining its offer price to supply the Ohio Companies' standard service offer load, a supplier would assume that it would be required to procure adequate capacity to comply with the Midwest ISO's resource adequacy requirement. As noted, the amount of capacity required to meet the Midwest ISO's resource adequacy obligations associated with the Ohio Companies' standard offer service will depend on the outcome of studies that will be conducted after the Midwest ISO's methods are developed and approved by the FERC.

For the purpose of calculating capacity costs associated with the market-offer price of serving the Ohio Companies' standard service offer load, I assume that a supplier will be required to demonstrate resources adequate to meet 113.5 percent[5] of projected annual peak load measured at the load zone (i.e., gross of distribution losses). I thus calculate capacity costs using a capacity requirement that is based on the projected peak load for the Ohio

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[3] FERC Order on Resource Adequacy Proposal at ¶¶108-109.
[4] FERC Order on Resource Adequacy Proposal at ¶22.

Companies. The potential that the Midwest ISO's methodology will lead to higher capacity requirements for load serving entities is a source of risk to a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligation at fixed prices.

Q: **Please explain how you have calculated the price of capacity.**

A: The price for procuring capacity will depend on the penalty provisions and other rules instituted by the Midwest ISO, as well as the supply and demand conditions prevailing in the capacity market. Because these rules are very much a work in progress, their exact future configuration is highly uncertain and the expected cost of complying with the future rules is also highly uncertain. For example, while the details of the penalty provisions are yet to be worked out, economic reasoning suggests that the effect of penalties could be to cause capacity prices to rise. This uncertainty is a source of risk to a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligation at fixed prices.

In my opinion, in estimating expected prices for capacity in 2009, 2010, and 2011, it is reasonable, and may likely result in a conservative result, to rely upon prices at which designated network resources ("DNR") have been bought and sold in bilateral transactions. However, as noted, there is substantial uncertainty regarding expected future prices of capacity. The North American Electric Reliability Corporation ("NERC") reports that in order

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[5] Communications with FirstEnergy.

to satisfy a targeted reserve margin of 15 percent through 2012, the Reliability*First* Region (the NERC region where the Ohio Companies are located) will rely upon both existing resources and proposed capacity additions, and that additional capacity resources will be needed to maintain the targeted reserve margin after 2013.[6] These findings are consistent with a view that capacity prices may trend upward over the next several years.

For the purpose of calculating the capacity cost component of market-rate offer prices for serving the Ohio Companies' standard offer load, I use a capacity cost of $2.20 per KW-Month (i.e., $26,400 per MW-year) based on market prices for capacity to be provided during the period June 2009 through May 2010. I calculate the capacity requirement for each customer class for each year by multiplying peak load by 113.5 percent. I then calculate the annual capacity cost for each customer class for each year by multiplying the capacity requirement by the capacity cost. Finally, I convert this annual capacity cost to a dollars-per-MWh basis by dividing the total annual cost by the total annual MWhs gross of distribution losses. The results of these calculations for 2009, 2010, and 2011 are shown in Exhibit 4.

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[6] NERC 2007 Long-Term Reliability Assessment at 32.

III.A.5 Midwest ISO Transmission and Ancillary Services Costs

Q: Please explain the methodology used to calculate the cost of Midwest ISO transmission and ancillary services incurred to serve the Ohio Companies' standard service offer load.

A: As part of the full requirements service needed to meet the Ohio Companies' standard service offer load, the supplier would be required to procure various transmission and ancillary services from the Midwest ISO ("MISO"). Market participants in MISO pay transmission rates that are determined by MISO's FERC-approved tariff. These tariffs include a number of separate components. A supplier who commits to provide the product could reasonably expect to incur transmission and ancillary service costs of approximately $7.50/MWh based on the Ohio Companies' current transmission rates.

The FERC approved the Midwest ISO's plan to implement market-based procurement of the operating reserves components of ancillary services beginning on June 1, 2008.[7] Replacing its cost-based ancillary service regime with market-based procurement will increase the uncertainty of ancillary service costs to a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligation.

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[7] Federal Energy Regulatory Commission, Docket Nos. ER07-1372-000 and ER07-1372-001, Midwest Independent Transmission System Operator, Inc., Order on Ancillary Services Filing, February 25, 2008, at ¶1 and ¶3.