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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	
Edison Company For Authority to	)	Case No. 10-388-EL-SSO
Establish a Standard Service Offer	)	
Pursuant to R.C. § 4928.143 in the Form	)	
Of an Electric Security Plan.	)	

DIRECT TESTIMONY
OF
WILSON GONZALEZ

On Behalf of
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April 15, 2010

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A1. My name is Wilson Gonzalez. My business address is 10 West Broad Street, Suite 1800, Columbus, Ohio, 43215-3485. I am employed by the Office of the Ohio Consumers' Counsel ("OCC" or "Consumers' Counsel") as a Principal Regulatory Analyst.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I have a Bachelor of Arts degree in Economics from Yale University and a Master of Arts degree in Economics from the University of Massachusetts at Amherst. I have also completed coursework and passed my comprehensive exams towards a Ph.D. in Economics at the University of Massachusetts at Amherst. I have been employed in the energy industry since 1986, first with the Connecticut Energy Office (Senior Economist, 1986-1992), then Columbia Gas Distribution Companies ("Columbia Gas") (Integrated Resource Planning Coordinator, 1992-1996) and American Electric Power ("AEP") (Marketing Profitability Coordinator and Market Research Consultant, 1996-2002). I have been spearheading the Resource Planning activities within OCC since 2004, and have been involved in numerous electric industry cases before the Public Utilities Commission of Ohio ("PUCO" or "Commission").

Q3. WHAT HAS BEEN YOUR EXPERIENCE DIRECTLY RELATED TO ESP PROCEEDINGS IN OHIO AND OTHER REGULATORY EXPERIENCE?

A3. I have filed testimony on various issues in previous "SSO" filings that involved the FirstEnergy applicants, Case Nos. 08-935-EL-SSO, 08-936-EL-SSO and 09-906-EL-SSO. I have also filed testimony in previous American Electric Power, Duke Energy of Ohio, and Dayton Power and Light "SSO" filings whose case numbers are listed in the answer to the next question.

I have been involved with many aspects of electric utility regulation since 1986 including but not limited to Rate Design and integrated resource planning, including transmission and non-transmission alternative planning. While at the Connecticut Energy Office I represented the office in one of the first DSM collaborative processes in the country (Connecticut Department of the Public Utilities Commission Docket No. 87-07-01). There I analyzed the performance and cost-effectiveness of many efficiency programs for Connecticut's electric and gas utilities that led to demonstration projects, policy recommendations, DSM programs (including rate design recommendations) and energy efficiency standards. I also performed all the analytical modeling for United Illuminating's first integrated resource plan filed before the DPUC in 1990. At Columbia Gas, I was responsible for coordinating that company's Integrated Resource Plan within the corporate planning department and DSM program development activities in the marketing department. I designed and managed residential DSM programs in Maryland and Virginia. At AEP, I conducted numerous cost-benefit analyses of programs being sponsored by AEP's corporate marketing department, including their residential load control water heater program.

For the past 4 years at OCC, I have (among other matters):

- Been involved in DSM negotiations resulting in over $300 million in energy efficiency programs with Ohio's investor owned utilities;
- Prepared DSM testimony in ten Commission cases;
- Testified before the Ohio House Alternative Energy Committee in support of energy efficiency and demand response;
- Assisted in the preparation of energy efficiency and renewable energy testimony and amendments for S.B. 221, H.B. 357, and H.B. 487; and
- Testified before the PUCO on rate design issues;
- Worked extensively on a range of topics regarding FirstEnergy SSO proposals.

Q4. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A4. Yes. I submitted testimony in the following cases before the Commission: Vectren Energy Delivery of Ohio, Case No. 04-571-GA-AIR; Dominion East Ohio, Case No. 05-474-GA-ATA; Dominion East Ohio, Case No. 07-829-GA-AIR; Vectren Energy Delivery of Ohio, Case No. 05-1444-GA-UNC; Columbus Southern Company/Ohio Power Company, Case No. 06-222-EL-SLF; Duke

Energy of Ohio, Case No. 07-589-GA-AIR, FirstEnergy Companies, Case Nos. 07-551-EL-AIR, et al.; Vectren Energy Delivery of Ohio, Case No. 07-1080-GA-AIR; FirstEnergy Companies, Case No. 08-935-EL-SSO; FirstEnergy Companies, Case No. 08-936-EL-SSO, Duke Energy of Ohio, Case No. 08-920-EL-SSO; AEP Case No. 08-917-EL-SSO, DPL Case No. 08-1094-EL-SSO; FirstEnergy Companies, Case No. 09-906-EL-SSO and Duke Energy of Ohio, Case No. 10-1999-EL-POR.

Q5. WHAT DOCUMENTS HAVE YOU REVIEWED IN THE PREPARATION OF YOUR TESTIMONY?

A5. I have reviewed the Application filed on March 23, 2010 by the Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company ("FirstEnergy" or "Company"), including the attached Stipulation and Recommendation ("Stipulation"), the Errata filing on March 30, 2010, and the Direct Testimony of Company witness William Ridmann. I have reviewed the relevant responses to OCC discovery. I have also reviewed the record in Case No. 09-906-EL-SSO.

II. PURPOSE OF TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. I recommend that the Commission reject the ESP and render a decision in the Company fully litigated Market Rate Offer ("MRO") proceeding, Case No. 09-

906-EL-SSO. The Stipulation that lays out the details of the ESP proposal fails the Commission's usual test for settlements. The truncated and exclusive process that led to the filing of the Stipulation did not constitute serious bargaining among capable, knowledgeable parties. A number of provisions in the Stipulation violate important regulatory principles and practices, challenging the integrity of Commission rules and its decided cases. The Stipulation as a package saddles consumers with significant costs, and therefore as a whole does not benefit ratepayers and the public. The package that has been presented for consideration by the Commission is not, as described in my analysis, more favorable in the aggregate than proceeding with the expected results from an MRO to establish rates for retail customers.

I find fault with the following major provisions in FirstEnergy's ESP proposal:

1. The proposed DCR Rider that would increase distribution rates, its recovery, and its rate impact on residential customers;
2. The PIPP generation sole source contract with FirstEnergy Solutions;
3. The faux savings from regional transmission organization ("RTO") transmission costs;
4. The treatment of energy efficiency lost distribution revenues;
5. The lack of a recognition of operation savings concerning Smart Grid cost recovery;
6. Economic development deals proposed without supporting information and separate review;

7. The large customer interruptible rate cost recovery from residential customers;
8. The competitive bidding auction design;
9. The lack of direct demand signals in retail rates for non-residential customers;
10. The lack of a long-term renewable energy credit ("REC") contract.

III. EVALUATION OF THE STIPULATION AND RECOMMENDATION

A. Introduction

Q7. WHAT GENERAL PROVISIONS ARE CONTAINED IN THE STIPULATION AND RECOMMENDATION FILED IN THIS PROCEEDING?

A7. The Stipulation contains the following major elements:

1. A competitive bid auction for generation services which, except for the inclusion of the sole source supply carve out for a Company affiliate (FirstEnergy Solutions) to meet PIPP load, is similar to (but not identical to) the competitive bid auction process proposed in the MRO Case (i.e. Case No. 09-906-EL-SSO);
2. Certain rate options set to expire will continue to be offered during the period of this ESP, such as the Economic Load Response ("ELR") peak demand reduction rider and the time-differentiated pricing riders for industrial customers approved in Case No. 09-541-EL-ATA. The

Stipulation would also continue, or modify and continue, most of the riders approved in the current ESP;

3. A mechanism for procuring RECs for renewable energy compliance;
4. A flat residential summer generation rate design;
5. A new Delivery Capital Recovery Rider ("Rider DCR") and provisions for only limited review of quarterly increases in rates that can reach as high as $390 million over approximately two and one half year period;
6. A provision related to the Significantly Excessive Earnings Test ("SEET");
7. Company contribution of $3 million to support economic development and job retention activities and an additional $1.5 million to support the fuel fund for low income residential customers;
8. Customers will continue to fund the Community Connections weatherization program at a level of $5 million dollars per year and provide an additional $300,000 to the City of Cleveland for energy efficiency;
9. Smart grid cost recovery provisions;
10. Settlement of issues or cases related to corporate separation, American Transmission Systems, Inc.'s ("ATSI") transition to PJM, and FirstEnergy Corporation's proposed merger with Allegheny Energy, Inc.;
11. Funding arrangements for several energy efficiency administrators who signed the Stipulation;
12. Recovery of utility energy efficiency program lost distribution revenues.

Q8. WHAT CRITERIA DOES THE COMMISSION USUALLY RELY UPON FOR CONSIERING WHETHER TO ADOPT STIPULATIONS?

A8. Typically, the Commission will adopt a Stipulation only if it meets all of the three criteria:

1. The settlement is a product of serious bargaining among capable, knowledgeable parties.
2. The settlement package does not violate any important regulatory principles or practices.
3. The settlement as a package benefits ratepayers and the public interest.

Q9. DOES THE PROPOSED STIPULATION AND RECOMMENDATION, AS FILED IN THIS PROCEEDING ON MARCH 23, 2010 AS PART OF THE APPLICATION, MEET THE CRITERIA THAT THE COMMISSION TYPICALLY RELIES UPON TO ADOPT STIPULATIONS?

A9. No. As a factual matter, many of the provisions of the Stipulation and Recommendation do not meet those criteria.

Q10. WHICH OF THOSE CRITERIA DOES THE STIPULATION AND RECOMMENDATION FILED IN THIS CASE NOT MEET?

A10. The Stipulation is problematic with respect to all three criteria considered by the Commission when evaluating a stipulation. I will treat each of the tests individually.

B. Evaluation of First Criterion.

Q11. WHY IS THE STIPULATION AND RECOMMENDATION FILED IN THIS CASE NOT A PRODUCT OF SERIOUS BARGAINING AMONG CAPABLE KNOWLEDGEABLE PARTIES?

A11. The circumstances presented in the Application itself, to which FirstEnergy attached as one of its parts the Stipulation, immediately raises questions regarding satisfaction of the first criteria for judging stipulations. The criterion is whether "[c]apable, knowledgeable parties" engaged in "serious bargaining." The two concepts are linked: serious bargaining does not exist when one side of the negotiations -- usually the utility in cases before the Commission where the utility is the applicant -- has at its disposal a vast amount of information compared to the other parties in the negotiation.

The evaluation of the first criteria is muddled in FirstEnergy Witness Ridmann's testimony. He claims the Stipulation is supported on the first criteria because the signatories to the Stipulation "ha[ve] a history of participation and experience in matters before the Commission and [are] represented by experienced and competent counsel."[1] In this characterization Mr. Ridmann addresses the parties' generalized knowledge of the regulatory process, but not the capability or knowledge of the *parties* to this particular case regarding the *facts presented in this case*. Even the proposed auction process -- about which some parties to the

[1] Ridmann Testimony, page 11 (March 31, 2010).

MRO Case (i.e. Case No. 09-906-EL-SSO) have knowledge -- has been altered from that proposed in the MRO Case. And this case involves a wide range of matters outside the auction process that were not explored by any party to the MRO Case. The negotiating process itself is a poor means by which parties can become informed about the facts underlying a proposal. The OCC has made inquiries into the contents of the Application by means of discovery -- limited by the very short time permitted by the schedule to conduct discovery -- in an effort to develop a perspective on this case that is independent of FirstEnergy's perspective. The information obtained, and the information that could be gained by parties as part of inquiries into a FirstEnergy proposal, was not available to the signatories at the time they negotiated portions of the Stipulation.

Q12. WHAT IS YOUR VIEW CONCERNING THE NUMBER OF PARTIES THAT HAVE EXECUTED THE STIPULATION AND RECOMMENDATION?

A12. The weight of any party's execution of the Stipulation must also be considered in the context of the proceeding in which it is offered. The lack of any ability to compel FirstEnergy to provide information during a negotiation process is compounded by the asymmetric position of an electric utility relative to those with whom it negotiates because the ESP process removes the Commission from issuing a binding result. As is well known by the parties and the Commission, the sequence of events related to FirstEnergy's initial ESP case, Case No. 08-935-EL-SSO, shows that FirstEnergy is in a unique position to withdraw its proposed rate plan in the event that it disagrees with the Commission's determinations.[2] In the present circumstances, FirstEnergy also negotiated from the unique position that it could continue to pursue its pending MRO application and not propose an ESP at all unless it was satisfied that the ESP settlement was more favorable for the Company than an MRO. This asymmetry in negotiating positions lessens the weight of every non-FirstEnergy party's execution of the resulting Stipulation as an expression of the parties' fundamental support for the package. The Stipulation is favorable for FirstEnergy, but not for the public.

Mr. Ridmann emphasizes the "broad range of interests" represented by the signatories to the stipulation.[3] Without a signatory party that represents residential customers, by far the largest number of the Company's customers, the Stipulation fails to represent the interests of most of FirstEnergy's customers who will be largely responsible for paying for the increased rates that will result from the ESP Stipulation and that would not have resulted from the MRO process. The attention to the diverse number of interests belies the fact that signatory parties were not focused on the overall impact of the proposed ESP on residential customers and on public policy in general. Also, the parties invited to negotiations that led to the filing of the ESP were the parties to the MRO Case. The matters addressed in the Stipulation, however, are broader in scope than the

[2] *In re FirstEnergy 2008 ESP Proceeding*, Case No. 08-935-EL-SSO, FirstEnergy's Letter Notice of Withdrawal (December 22, 2008).

[3] Ridmann Testimony, page 11 (March 31, 2010).

matters raised in the MRO Case. For example, many of the parties who intervened in this case who were not involved in the MRO Case are concerned with environmental issues or other issues that were first raised in the Stipulation.[4] Therefore, a segment of interested parties to the matters raised in this case were excluded from the negotiations, and their perspectives could not be reflected in the Stipulation's results.

Q13. DO YOU HAVE ANY OBSERVATIONS REGARDING THE LENGTH OF THE NEGOTIATIONS THAT IS MENTIONED BY MR. RIDMANN?

A13. Yes. Mr. Ridmann refers to a lengthy negotiation process that "began several months ago."[5] This statement inaccurately reflects the negotiation process, and therefore inaccurately reflects upon the seriousness of that process. The PUCO Staff made some initial efforts to convene parties to the MRO Case to gain perspectives on the Staff Comments that FirstEnergy should consider an ESP filing.[6] Those nascent efforts resulted in a meeting on December 1, 2009, but were abandoned as the hearing in the MRO on December 15, 2009 approached. No further meetings were held with all the parties to the MRO Case regarding an alternative approach until February 25, 2010.[7] The Stipulation was filed, as part

[4] Parties who were not involved in the MRO Case, but who have intervened in this case, include the Environmental Law & Policy Center, EnerNOC, CPower, Viridity Energy, Energy Connect, Comverge, Enerwise Global Technologies, Energy Curtailment Specialists, and the Council of Smaller Enterprises.

[5] Ridmann Testimony, page 11 (March 31, 2010).

[6] Staff Comments, Staff MRO Ex. 2, page 22 (November 24, 2009).

[7] Attachment 1. The e-mail string, dated February 23, 2010, includes a statement from FirstEnergy that proposes discussions on February 25, 2010.

of the Application, on March 23, 2010. This sequence of events takes three months out of the negotiation process suggested in Mr. Ridmann's testimony, and reveals that discussions that resulted in some parties signing the Stipulation were recent and rushed with insufficient time to conduct the kind of review necessary before signing a settlement of this magnitude.

Q14. WHAT IS YOUR CONCLUSION REGARDING WHETHER THE FIRST CRITERIA FOR THE EVALUATON OF STIPUATIONS IS SATIFIFED IN THIS CASE?

A14. From the above-mentioned facts and circumstances related to this case, the Stipulation is not a result of serious bargaining among capable, knowledgeable parties. Furthermore, consideration of whether compliance with the first prong is satisfied should include not only a review of who signed the Stipulation but who did not sign and the reasons that they did not sign. The OCC did not sign for a number of reasons that are discussed in my testimony.

C. Evaluation of Second Criterion.

Q15. DOES THE STIPULATION VIOLATE ANY IMPORTANT REGULATORY PRINCIPLE OR PRACTICE?

A15. Yes. The Stipulation seeks Commission approval on a number of matters that are against the PUCO's principles and practices, many of which stem from the basic framework under which the Commission operates, including rules promulgated by the Commission. Important regulatory principles and practices would be violated if the Stipulation is approved.

Q16. CAN YOUR PROVIDE AN EXAMPLE OF SUCH A VIOLATION?

A16. Yes. The Stipulation includes Rider DCR that permits distribution rates to increase at an average annual level, over the period January 1, 2012 through May 31, 2014, by as much as $161 million.[8] FirstEnergy proposes that the increases be implemented in quarterly adjustments.[9] Page 15 of the Stipulation provides that the "quarterly Rider DCR update filing will not be an application to increase rates within the meaning of R.C. § 4909.18." The increases charged to customers through Rider DCR would be for costs for the delivery of standard distribution service (e.g. not for new technology, such as for smart grid[10]). The Stipulation provision that proposes that quarterly increases in ordinary distribution rates do not fit the description of an increase in rates is absurd. The provision essentially asks the Commission to not regulate a process that is regulated.

The Stipulation contains FirstEnergy's proposal for the support required of the Company as part of the proposed quarterly Rider DCR adjustments. The Stipulation permits annual audits of FirstEnergy's filings, subject only to

[8] Stipulation, page 14. ($390 million / 29 months x 12 months = $161 million annual average).

[9] Id.

[10] Increased distribution rates in connection with CEI's smart grid proposal is the subject of another section of the Stipulation. Stipulation, page 22-23.

FirstEnergy's "burden of proof to demonstrate the accuracy of the quarterly filings."[11] Participation in the process of verifying the contents of FirstEnergy's filings is limited, according to the Stipulation, to *only* the PUCO Staff and to signatories to the Stipulation (i.e. it would exclude the OCC, which has not executed the Stipulation).[12] The process for review of distribution rates is far less than would take place under a rate case where all distribution-related costs are reviewed for accuracy and reasonableness.

Also, the regulatory process is inherently a public process, in which the OCC is an active participant on behalf of residential customers on a wide range of matters regulated by the PUCO. The restrictive process described in the Stipulation that only reviews Rider DCR adjustments -- which looks only at verification of one distribution cost factor and that excludes parties such as the OCC from participation -- lessens traditional regulatory oversight of rates and violates a basic regulatory principle and practice that requires participation in Commission proceedings by all parties affected by proceedings.

Q17. CAN YOU PROVIDE ANY OTHER EXAMPLES OF THE VIOLATION OF AN IMPORTANT REGULATORY PRINCIPLE OR PRACTICE?

[11] Stipulation, page 16.

[12] Id.

A17. Yes. The Stipulation contains a provision that an "AICUO college or university member may elect to be treated as a mercantile customer . . . for the limited purposes of R.C. § 4928.66 so long as the aggregate load of facilities situated on a campus . . . qualifies such an entity as a mercantile customer. . . ."[13] This language is very troublesome from a regulatory standpoint, providing an unprincipled manner in which the Stipulation would have the Commission treat a statute. Multiple loads may be aggregated to constitute a mercantile customer only under situations where those accounts are part of a "national account."[14] This description does not fit an academic campus. Furthermore, the favorable treatment in the Stipulation, providing for "benefit[s] made available to a mercantile customer pursuant to R.C. § 4928.66,"[15] is only available to members of the AICUO which is also not part of the definition of a mercantile customer. If academic campuses qualified as a mercantile customer, which they do not, the provision in the Stipulation is unreasonably discriminatory. The effect of the provision regarding AICUO members is similar to the provisions previously described regarding favored treatment of stipulating parties. Such favoritism conflicts with the public nature of regulation and the fair treatment of everyone affected by a rate plan.

[13] Stipulation, page 25, paragraph 5.

[14] R.C. 4928.01(A)(19).

[15] Stipulation, page 25, paragraph 5.

Q18. DO YOU HAVE ANY CONCERNS REGARDING PROTECTING THE INTEGRITY OF THE COMMISSION'S RULES?

A18. Yes. The Stipulation contains a broad waiver request, stating: "the Companies request waivers of those rules to the extent that the Commission deems necessary to approve and implement this ESP."[16] The Commission has stated its disapproval of such broad waivers that are based upon a general, rather than a specific, statement for the cause served by the waiver.[17] Stipulations should not result in later surprises to its signatory parties, other interested persons, the public, or the Commission itself. Moreover, without listing each waiver request and the reason for each request, it is impossible for the Commission to determine whether the matters sought to be waived are reasonable and in the public interest. The Commission has the responsibility to carefully review an application and explain its decisions. Without a clear understanding of each waiver and its purpose, the Commission would not be meeting this responsibility.

[16] Stipulation, page 32, paragraph 8.

[17] This Commission policy is stated, for example, in *In re FirstEnergy RSP Proposal*, Case No. 03-2144-EL-ATA, Opinion and Order, page 40 (June 9, 2004):

> The breadth of this [FirstEnergy] waiver request and the lack of any specificity as to the areas of non-compliance make it impossible for the Commission to find good cause for granting the extension of the general waiver. The Commission cannot grant a waiver where the application has been unable to state the actual company process, program or function that requires the waiver.

Q19. DO YOU HAVE ANY CONCERNS RELATED TO THE EFFECT THE STIPULATION AND RECOMMENDATION WOULD HAVE ON DECISIONS REACHED IN OTHER CASES?

A19. Yes. Tariff Sheets ELR and OLR. attached as part of the Application, include a modification to the existing tariffs providing that all interruptible capabilities for peak demand reductions after 2008 shall be deemed "incremental" for purposes of meeting the 2011 through 2013 benchmarks. [18] The treatment of such interruptible load reductions -- including whether loads subject to FirstEnergy's ELR and OLR tariffs can be considered "incremental" -- has been contentious in cases before the Commission. In June of 2009, the Company filed an application for certain waivers connected with the Company's plans to meet its energy efficiency and peak demand requirements.[19] The Commission's March 10, 2010 Finding and Order stated: "Having provided clarification regarding Rule 4901:1-39-05(E), O.A.C. [regarding the treatment of interruptible loads], as requested by FirstEnergy, the Commission lacks sufficient information in the record regarding the incremental peak demand reductions that the companies' qualifying 2009 programs were designed to achieve, *compared to the reductions that the programs in place in the preceding year had been designed to achieve.*"[20] Thus, the Commission has already determined that ELR and OLR loads are considered

[18] ELR and OLR tariffs contained in Attachment B of the Company's Application.

[19] *In re FirstEnergy 2009 Energy Efficiency and Peak Demand Reductions*, Case Nos. 09-535-EL-EEC, 09-536-EL-EEC, and 09-537-EL-EEC.

[20] Id., Finding and Order, page 6 (March 10, 2010) (emphasis added).

"incremental" only in a comparison with interruptible loads previously in place. Prior to 2009, the Company had approximately 400 megawatts of interruptible load.[21] Therefore, only truly incremental peak demand reductions over the existing 400 megawatts in 2008 should be counted as incremental savings and counted towards the peak demand reduction requirements. The Stipulation provision conflicts with the Commission's Finding and Order, which is surely against the regulatory principles and practices that guided the Commission's existing determination. The Stipulation would require the Commission to reverse its previous position that was based upon the consideration of the Commission's policies after consideration of the record in an earlier case.

Also on the topic of a conflict with earlier decisions, the Commission stated in its order in FirstEnergy's last distribution rate case that it "will not grant FirstEnergy authority to defer expenses related to storm damage indefinitely."[22] The Commission ordered an end to this special treatment of a single category of expense, "the earlier of December 31, 2011, or upon the effective date of the Commission's order in FirstEnergy's next distribution rate case."[23] The Stipulation conflicts with this Commission Order by providing for the

[21] Attachment 3, Company response to OCC-INT-4 in Case No. 07-796-EL-ATA. This number of interruptible megawatts was also confirmed by FirstEnergy personnel at the April 5th technical conference in this proceeding.

[22] *In re FirstEnergy's 2007 Distribution Rate Proceeding*, Case No. 07-551-EL-AIR, page 43 (January 21, 2009).

[23] Id.

continuation of "all deferrals previously approved in . . . 07-551-EL-AIR et al. [FirstEnergy's distribution rate case]."[24] The Commission order in the distribution rate case was clear that simply postponing FirstEnergy's next distribution rate case is not sufficient to continue the deferral treatment of storm damage expenses. Approval of the Stipulation without modification would permit this special treatment to continue without the desirable review of these expenses by interested parties and ultimately the Commission in a separate case.

Q20. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE PROVISIONS IN THE STIPULATION RELATED TO STORM DAMAGE EXPENSES?

A20. Yes. The Stipulation is vague regarding the treatment of the extended deferrals related to storm damage expense. The Stipulation states that the "storm damage deferrals shall be dependent upon deferral criteria being agreed upon by the Staff and the Companies, with such agreement being sought within thirty days of the filing of this Stipulation."[25] Some aspect of the requested deferrals is apparently subject to continuing negotiations between two parties to the Stipulation (i.e. FirstEnergy and the PUCO Staff). The stipulating parties have agreed that the continuing negotiations will not be subject to the public (i.e. litigated) review process in this case that involves parties who would have to pay the resulting charges. The Stipulation leaves the decision-making process to these two parties, eliminating even Commission review and approval of "deferral criteria." Such

[24] Stipulation, page 22.

[25] Id.

criteria should be subject to review by both interested parties and the PUCO Commissioners, and a change from the Commission's policy pronouncement regarding the end to deferrals for storm damage expenses should not depend upon a vaguely described process that lies outside this case.

Q21. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE VIOLATION OF IMPORTANT REGULATORY PRINCIPLES AND PRACTICES?

A21. Yes. The Stipulation contains provisions related to infrastructure for the Cleveland Clinic and rate discounts for Domestic Automakers. [26] Normally, these types of arrangements are filed in an application before the Commission subject to rules that require extensive background information, and such cases undergo a full review by interested parties (including by those customer who are asked to pay millions of dollars for others to receive special treatment) in cases before the Commission. As further discussed in the testimony of OCC witness Amr Ibrahim, this background information is not known by FirstEnergy and is missing from this case.

Special provisions are proposed for the benefit of the Cleveland Clinic, and the Stipulation itself states that the Cleveland Clinic "intended to file an application

[26] Stipulation, pages 26-29.

for a reasonable arrangement"[27] Ignoring the extensive Commission rules related to a subject matter, and essentially determining a case that has not even been filed without the information that must be provided in such a case, violates regulatory principles and practices related to ignoring Commission rules and making determinations without full discussion in a transparent fashion.

The Domestic Automaker rate discount funded by other customers is also discussed in the testimony of Dr. Ibrahim. The Stipulation devotes only a few lines to a discount, and the implication of the word "domestic" is unknown because the term is not defined in the Stipulation or the proposed Rider EDR, paragraph "h."[28] The Application and its included Stipulation does not contain the information regarding the impact the special support for domestic automakers will have that would normally exist as part of a separate proceeding before the Commission. The Domestic Automaker rate discount suffers the same problems as the provisions for the Cleveland Clinic regarding the violation of regulatory principles and practices.

[27] Stipulation, page 27.

[28] To the extent that "domestic" is intended to discriminate between customers based upon some aspect of their ownership, this also violates a regulatory principle and practice.

D. Evaluation of Third Criterion.

Q22. WHY DOES THE SETTLEMENT, AS A PACKAGE, NOT BENEFIT RATEPAYERS AND THE PUBLIC?

A22. Company witness Ridmann provides in his testimony a table purporting to show a net benefit on a present value basis, of the ESP compared to the MRO to customers of $280 million.[29] On the quantification of factors considered by Mr. Ridmann and those that he failed to consider, the net "benefit" of the ESP compared to the MRO is *negative*. In addition, there are other negative features of the Stipulation that are more difficult to quantify, but should be considered in making the comparison.

Q23. DO YOU AGREE WITH THE QUANTITATIVE ASSESSMENT OF NET BENEFITS PROVIDED BY COMPANY WITNESS RIDMANN?

A23. No. Witness Ridmann has produced a highly selective benefit-cost analysis which overstates the benefits and grossly underestimates the cost of the Stipulation to consumers. My more extensive, yet conservative, analysis of the Stipulation reveals that customers stand to lose from $193 to $332 million under the proposed ESP over the term of the Stipulation.[30] Thus, the ESP does not in the aggregate quantitatively benefit consumers as compared to an MRO.

[29] Ridmann Testimony, WRR Attachment 1 (March 31, 2010).

[30] Schedules WG-1, 1A, 1B.

Q24. PLEASE EXPLAIN HOW YOU REACHED THE CONCLUSION THAT THE STIPULATION AND RECOMMENDATION DOES NOT IN THE AGGREGATE QUANTITATIVELY BENEFIT CONSUMERS.

A24. I made two kinds of adjustments to the Company's net benefits table. First, I incorporated more realistic assumptions to, and adjusted the values listed in the table, concerning the net benefits related to distribution, Percentage of Income Payment Plan ("PIPP") generation, and the Regional Transmission Organization ("RTO") elements. Secondly, I added a number of elements that were missing in the Company's table concerning energy efficiency lost revenue recovery and the handling of Smart Grid costs.

Q25. WHAT IS YOUR EVALUATION OF THE STIPULATION AND RECOMMENDATION FROM A DISTRIBUTION PERSPECTIVE?

A25. According to the Company's own testimony, the Delivery Capital Recovery ("DCR") Rider contained in the Stipulation is less beneficial to customers (i.e. more costly to customers) than if the Company sought to increase rates through a fully litigated distribution rate case. Company witness Ridmann's WRR Attachment 1 lists recovery of $302.8 million over two years and 5 months through the DCR Rider even though the Stipulation allows for the recovery of $390 million; the same attachment lists the recovery of $278 million if FirstEnergy filed a separate distribution rate case. According to Witness Ridmann, this $24.8 million net cost attributed to this element of the ESP in comparison to the MRO is due to the lag in distribution cost recovery because of an assumed distribution rate case date certain of March 2011. This estimate of $302.8 million is conservative since, under the Stipulation, the Company is allowed to recover up to $390 million before a cost cap is imposed.[31]

Moreover, a distribution rate case would afford all parties and the PUCO an extensive period to review any rate increase request; including inquiries in discovery, the consideration of expert testimony, and the presentation of argument by all affected persons. For example, this deliberative process in the last FirstEnergy distribution rate case considered an application filed in June, 2007 and resulted in a Commission order in January 2009. In the past, such a deliberative process has most often lead to an eventual trimming of the Company's original rate increase request. The distribution rate case filed in 2007 -- the first in a decade for each company -- requested $340 million in annual rate increases, the Commission awarded $137 million in annual rate increases,[32] and

[31] Stipulation, page 14.

[32] *In re FirstEnergy 2007 Distribution Rate Case*, Case No. 07-551-EL-AIR, Order, page 48, paragraph (23) (January 21, 2009).

even that increase included amounts not normally awarded in rate cases according to standard regulatory principles and practices.[33]

Given that (1) the Stipulation allows the Company to exceed the listed DCR recovery by up to $87.2 million, and (2) acknowledging that if the Company filed for an increase under a rate case it is likely that PUCO-allowed increase would be less than the increase requested, I have made adjustments to the net benefit table. I have prepared three scenarios for Commission consideration. In OCC's base case shown in Schedule WG-1, I have assumed that in a Company filed distribution rate case, the additional revenue increase would be 60 percent of the amount shown by Mr. Ridmann on WRR Attachment 1, resulting in a $136 million net cost of distribution in the ESP over the MRO. In the second scenario, depicted in Schedule WG-1A, I have modified the first scenario to increase revenue from Rider DCR to the Stipulation cap amount of $390 million, resulting in a $223 million net cost of distribution in the ESP over the MRO. Schedule WG-1B shows the third scenario in which Rider DCR revenue under the ESP is

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[33] The Order in *In re FirstEnergy RCP Case*, Case No. 05-1125-EL-ATA, page 9 (January 4, 2006) stated:

> [W]e find that *exigent circumstances exist* to deviate in a controlled way from the above stated public utility regulatory principles. * * * We are mindful that such deferrals must be scrutinized to assure that the costs to be deferred are reasonable, appropriately incurred, clearly and directly related to specifically necessary infrastructure improvements and reliability needs of the Companies, and in excess of expense amounts already included in the rate structures of each of the Companies. We will approve the deferral concept in this case premised upon the understanding that the expenses related to infrastructure improvement and the increased expenses for maintenance of infrastructure and reliability will yield necessary improvements that otherwise would have been realized, for company financial reasons, over a much longer period of time.

Emphasis added. This 2006 Order resulted in the increased distribution rates above those that would have otherwise been approved in the 2007 distribution rate case. *In re FirstEnergy 2007 Distribution Rate Case*, Case No. 07-551-EL-AIR, Order, page 11 (January 21, 2009). No claim of "exigent circumstances" has been made that would provide similar increases in a newly filed rate case.

$302.8 million and that no additional revenue is approved as a result of a distribution rate case, resulting in a $302.8 million net cost of the ESP over the MRO.

Q26. WHAT IS YOUR EVALUATION OF THE STIPULATION AND RECOMMENDATION REGARDING THE PROPOSED PIPP GENERATION PROCUREMENT?

A26. The Stipulation provides for separate treatment of PIPP customers by carving out their load and sole-sourcing their generation supply through a contract with FirstEnergy Solutions at a 6 percent discount from the price to compare for these customers. Upon close study, this arrangement is not prohibited within the confines of an MRO. Moreover, such a proposal could specify no less than a 6 percent discount in its PIPP generation supply bid instrument and put it out for competitive bid. Due to its competitive, rather than negotiated nature, such a bid would most likely come in with a higher than 6 percent discount and benefit PIPP customers more.

I conservatively estimate a half of a percent more discount to the PIPP generation supply under a separate competitively bid supply. This would result in $1 million in additional savings, or an additional $1 million in cost to customers of the ESP over the MRO for this element.

Q27. WHAT IS YOUR EVALUATION OF THE STIPULATION AND RECOMMENDATION REGARDING MATTERS RELATED TO TRANSMISSION --- MISO EXIT FEES, PJM INTEGRATION FEES, AND PJM'S REGIONAL TRANSMISSION EXPANSION PLAN ("RTEP") CHARGES?

A27. The savings attributed to MISO exit fees, the PJM Integration fees, and RTEP charges misstate their consequences for FirstEnergy's retail customers, and therefore grossly inflate the benefits claimed for the ESP.

Q28. WHAT IS YOUR EVALUATION OF THE CLAIMED BENEFITS FROM NOT CHARGING RETAIL CUSTOMERS RELATED TO CERTAIN RTEP CHARGES?

A28. The claimed difference in RTEP charges between the MRO and the ESP does not exist, and should not be counted as a benefit that favors the ESP over the MRO.

Q29. WHERE DOES THE STIPULATION ADDRESS CHARGES FOR RTEP?

A29. The Stipulation provides that "[t]he Companies agree to not seek recovery through retail rates for the costs billed by PJM during the period June1, 2011 through May 31, 2016 for RTEP projects which are approved by the PJM Board prior to June 1, 2011."[34] Mr. Ridmann claimed total benefits to consumers from

[34] Stipulation, page 18.

this provision at $321.3 million dollars over five years,[35] which contributes approximately $246.1 million in discounted present value benefits in Mr. Ridmann's overall comparison of a MRO with the proposed ESP.

Q30. DO YOU DISAGREE WITH MR. RIDMANN'S EVALUATION OF THE RTEP PROVISIONS IN THE STIPULATION AND RECOMMENDATION?

A30. Yes. Several significant problems arise with respect to this claimed benefit. First, the Federal Energy Regulatory Commission ("FERC") considered FirstEnergy's argument for the waiver of such RTEP charges and did not determine that state-regulated retail customers would pay for these charges. Second, even according to FirstEnergy public statements on the matter, the benefit claimed for the RTEP provision in the Stipulation is exaggerated because the related costs are not likely to materialize. Third, there are several process-related problems with the Stipulation that could cause problems with implementation of the RTEP provisions.

Q31. HOW DID FERC ADDRESS THE ISSUE OF RTEP CHARGES FOR PROJECTS APPROVED BY PMJ PRIOR TO JUNE 1, 2011?

A31. FERC addressed the issue in its decision on December 17, 2009. FirstEnergy stated in its application to FERC regarding its proposed switch in RTO operations that would serve the Company that "ATSI LSEs [including FirstEnergy's electric

[35] Ridmann Testimony, WRR Attachment 1 (March 31, 2010).

distribution utilities] [should] continue to pay for qualifying Midwest ISO regional facilities planned and approved before June 1,2011, as required by the Midwest ISO ASM Tariff, but not pay for PJM legacy RTEP projects that were approved by the PJM Board prior to ATSIs entrance into PJM. The ATSI LSEs will, of course, pay for qualifying RTEP projects planned and approved by the PJM Board after their June 1, 2011 date when their load is integrated into PJM."[36] That matter was determined by FERC, after comment from interested parties, as follows: "Transmission owners that seek to change RTOs should be prepared to *assume the costs attributable to their decisions.* ATSI is permitted to balance the benefits it associates with its decision to join PJM under its existing tariff against the costs it anticipates it will incur in exiting the Midwest ISO and joining PJM to determine whether such a move is cost-justified. * * * We see no basis to modify the existing RTO rules simply because a particular cost allocation makes a *transmission owner's business decision* more expensive."[37]

ATSI, FirstEnergy's affiliated owner of transmission facilities, is the entity whose business decision to exit MISO and enter PJM caused the extra transmission expansion plan costs (i.e. for projects approved before entry into PJM). FERC has assigned these costs to ATSI as the decision-maker, not to ATSI's customers. Therefore, the Stipulation claims the "forgiveness" of charges through May 31,

[36] *FirstEnergy Service Company, Inc.*, FERC Docket No. ER09-1589, Application, page 35 (August 7, 2009).

[37] Id., Order Addressing RTO Realignment Request and Complaint, paragraph 113 (December 17, 2009).

2016 that are not the responsibility of FirstEnergy's retail customers. Therefore, the net benefit to this provision is zero.

Q32. WHY DO YOU STATE THAT THE RTEP-RELATED COSTS CLAIMED BY FIRSTENERGY ARE EXAGGERATED?

A32. Transmission expansion projects that have been approved by the PJM Board for recovery through RTEP are subject to change, and those changes are not reflected in FirstEnergy's numbers. On an annual basis, PJM revisits the system need for previously approved RTEP projects through its Retool Studies performed during the annual RTEP report process. FirstEnergy has assumed that the various transmission projects will proceed as planned. Approved high voltage RTEP projects often face project postponements and potential cancellations through the PJM process, opposition to such projects at the state level, and delays in construction and siting permits. At least three of the six transmission expansion projects identified by FirstEnergy in its discovery responses have been cancelled or postponed.[38] Only the Carson-Suffolk and TrAIL lines are under construction and expected to be in service in 2011.

The Amos-Kemptown transmission project (PATH) that was approved by the PJM board for inclusion in RTEP in 2007 had an in-service date of 2012.[39] On

[38] Attachment 4, Company Response to OCC Set 2-26.

[39] PJM Regional Transmission Expansion Plan 2008, page 67 (2009).

27, 2010 Commonwealth of Virginia State Corporation Commission approved a motion for the withdrawal of approval for the PATH project, effectively canceling the PATH project.[40] Another PJM region-wide project that has experienced delays and may face cancellation is the MAPP project, originally approved by the PJM Board of Managers in 2007 and based upon the existence of the PATH project.[41] Now that the PATH project has been cancelled, it is possible that the MAPP project will no longer be needed in the updated RTEP analysis.[42] The estimated total annual revenue requirement associated with PATH and MAPP that FirstEnergy claims is $134 million (i.e. June 2011- May 2016), much or all of which will not materialize.[43] Susquehanna-Roseland is a $1.1 billion project, with an estimated in-service date of 2012, and will be subject to review in the 2010 PJM RTEP analysis.[44] The New Jersey Board of Public Utilities postponed a decision regarding the Susquehanna-Roseland project, partly in connection with

[40] *Application of PATH Allegheny Virginia Transmission Corporation for Certificates of Public Convenience and Necessity to Construct Facilities*, Commonwealth of Virginia, State Corporation Commission at Richmond, VA, Case Number PUE-2009-00043, Order Granting Withdrawal (January 27, 2010).

[41] PJM Regional Transmission Expansion Plan 2007, page 10 (2008).

[42] "However, all RTEP analysis forming the basis for the MAPP project assumed the PATH project to be in-service. As with the PATH project, only the results of a comprehensive analysis – PJM's 2010 annual RTEP process – can be used to determine and support a definitive reassessment as to the future need and in-service date for MAPP." PJM 2009 Regional Transmission Expansion Plan, page 8 (2010).

[43] Response to OCC Interrogatory 2-26. The 2011 value provided by FirstEnergy was adjusted to represent the time period June 1, 2011 through December 31, 2011. Using the Company's method, FirstEnergy's 2016 values were truncated to represent costs through May 31, 2016.

[44] PJM will release the 2010 RTEP report in June of 2010. The annual RTEP report reassesses the need for all approved projects, and any project that is not completed is subject to a review for its reliability justification.

the factors cited for cancellation of the PATH project.[45] It is very likely that the projects included in the FirstEnergy's estimates will be delayed. The purported benefits FirstEnergy claims for the ESP Stipulation are exaggerated.[46]

Q33. WHAT PROBLEMS DO YOU OBSERVE REGARDING IMPLEMENTATION OF THE STIPULATION'S PROVISIONS RELATED TO RTEP CHARGES?

A33. The means by which the terms of the Stipulation would be carried out is problematic. PJM's cost allocation methodology annually re-allocates RTEP obligations, system-wide, and is not provided on a project-by-project basis by project approved date.[47] If this obstacle to the calculation of the Stipulation's RTEP charges that retail customers can be overcome, there remains the problem of verification of the calculations for purposes of FirstEnergy's charges. The Stipulation is silent regarding the how the calculations of permissible RTEP charges would be accomplished and how (or whether) such calculations would be verified in applications brought before the Commission. These are important "process" problems that are not addressed in the Stipulation.

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[45]Attachment 5, Lawrence Ragonese, "State postpones decision on N.J. Susquehanna-Roseland power line project," The Star Ledger (January 15, 2010), available at: http://www.nj.com/news/index.ssf/2010/01/state_postpones_decision_on_nj.html.

[46] The cost allocation method used by PJM has been questioned, among others by the PUCO, in the Seventh Circuit Court of Appeals. *Illinois Commerce Regulatory Commission v. FERC*, Case No. 08-1306, et al. (7th Cir. August 6, 2009). The matter is currently before FERC in Docket No. EL05-121-006.

[47] PJM OATT, Schedule 12§ (b)(i)(A).

Q34. WHAT IS YOUR EVALUATION OF THE CLAIMED BENEFIT FROM NOT CHARGING CUSTOMERS FOR MISO EXIT AND PJM INTEGRATION FEES UNDER THE PROPOSED ESP AS COMPARED TO THE MRO?

Q34. As stated earlier, FERC addressed the issue of cost responsibility in the context of ATSI's switch to PJM. The principle stated was that a transmission owner such as ATSI can switch RTOs as long as it is prepared to accept the financial consequences of that decision. FERC was specifically addressing the FirstEnergy's RTEP waiver request, but the same principle applies to the MISO exit fees and PJM integration fees.[48] These fees result from ATSI's decision to exit MISO and enter PJM, and ATSI (not retail customers served by ATSI's load serving entities) is responsible for the fees.

FirstEnergy has claimed an estimated benefit related to not passing along a portion of the MISO exit fees to retail customers in Ohio is $37.5 million. FirstEnergy claims estimated benefits to consumers under the ESP of $5 million related to the PJM integration fees. Because these amounts will not be charged to retail customers in Ohio under either a MRO or the proposed ESP, the net benefit between the two plans is zero.

[48] FERC stated that "with respect to the Ohio Commission's argument that ATSI should not be permitted to pass through an exit fee in its transmission rates, we note that ATSI does not propose to recover any costs associated with an exit fee." *American Transmission Systems, Inc.*, FERC Docket ER09-1589, Order, page 18 (December 17, 2009). FERC did not directly address the RTO fees because they were not the subject of FirstEnergy's Application in the FERC proceeding.

Q35. WHAT IS YOUR VIEW OF THE ENERGY EFFICIENCY PROVISIONS IN THE ESP, INCLUDING ITS PROVISIONS FOR LOST DISTRIBUTION REVENUES?

A35. Section E. 3 of the Stipulation addresses Energy Efficiency and Peak Demand Reduction ("EE/PDR") induced lost distribution revenues. Generally, lost distribution revenues are those revenues the Company does collect because of the implementation of energy efficiency programs. It states, that "[D]uring the term of the ESP, the Companies shall be entitled to receive lost distribution revenue for all energy efficiency and peak demand reduction programs approved by the Commission. Such lost distribution revenues do not include approved historical mercantile self-directed project[s]. The Signatory Parties agree that the collection of such lost distribution revenues by the Companies after May 31, 2014 is not addressed nor resolved by the terms of this Stipulation."[49]

Q36. WHAT CONCERNS DO YOU HAVE REGARDING THE COMPANY'S PROPOSAL TO RECOVER LOST DISTRIBUTION REVENUES?

A36. My concerns generally stem from the vagueness of the Stipulation language concerning energy efficiency savings and the open-ended nature of the cost recovery period that portend significant rate impacts for residential customers. First of all, the Stipulation language appears to allow the Company to count "*all*"

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[49] Stipulation, page 24.

EE/PDR lost distribution revenue.[50] It does not bind the term "all" to any limits or constraints under existing PUCO rules in OAC Chapter 4901:1-39, or to the results of the Technical Reference Manual that is being finalized in Case No. 09-512-GE-UNC. Will the lost revenue recovery be for "all" gross distribution lost revenues or net distribution lost revenues, the latter reducing the amount of revenue recovery for free riders already captured in the Company's forecast report?[51] Does the "all" include the savings as "deemed" or based on actual third party program impact evaluations? Also, allowing peak demand reduction program savings to count towards lost revenue recovery is problematic. Suppose the Company implements a cold storage air conditioning program for their commercial customers. Such a load shifting program could save peak kilowatts and kilowatt-hours ("kWhs") during the day, but because of storage losses, it could use more kWh during the evening when making ice. Would the Company claim "all" the kWh saved during the day without netting out the nighttime kWh of the ice-storage equipment? The Stipulation language does not shed light on these and other issues, a bad feature for a settlement document.

Second, the open-ended lost revenue recovery period proposed in the application is excessive and outside the Ohio experience regarding lost distribution revenues.

[50] Stipulation, page 24 (emphasis added). After all the controversy over the Commission's promulgation of the "Green Rules" (08-888-EL-ORD and at JCARR) concerning the "count all savings" language of ORC 4928.66, it is disappointing that the term "all" related to distribution lost revenue is not clearly defined in the Stipulation.

[51] "Free riders" are customers who would have undertaken the desired energy efficiency action anyway without the utility energy efficiency program. It is used to arrive at a net energy efficiency savings amount for a measure.

My expectations regarding the treatment of lost revenues in Ohio are based upon my review of results from ESP cases that involved Duke Energy, Ohio and Dayton Power and Light. In DP&L Case No. 08-1094-EL-SSO, lost revenues were capped over either a seven year period or when new distribution rates took effect.[52] Duke's recovery of lost revenues was limited to three years following program implementation in each vintage year of the program.[53]

The problem that arises from FirstEnergy's proposal is that if the lost revenue calculation is not capped by either a dollar amount or a time period, the balances can grow quite large. For example, a 2006 ACEEE study reveals that:

> Minnesota had a "lost-margin recovery mechanism" in place in the 1990s, but because this was cumulative, utilities were recovering financial incentive amounts greater than their actual conservation expenditures (the lost-margin incentives totaled about $40 million in 1998). This had the effect of doubling the cost of energy conservation to ratepayers.[54]

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[52] *In re DP&L's 2008 ESP Proceeding*, Case No. 08-1094-EL-SSO, Order, page 5 (February 24, 2009) (adopting stipulation, paragraph 5, page 6).

[53] *In re Duke's 2088 ESP Proceeding*, Case No. 08-920-EL-SSO, page 43 (December 17, 2008) (adopting Schultz Testimony, page 3, support for stipulation). For the American Electric Power utilities in Ohio, the result reached by the parties in Case No. 09-1089-EL-POR provides for three years of net lost distribution revenue recovery or until new distribution rates take effect. *In re AEP's Portfolio Proceeding*, Case No. 09-1089-EL-POR, Stipulation, page 9 (Section IX), paragraph 2 (November 12, 2009).

[54] Kushler, York, and Witte, "Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives," October 2006, ACEEE, page 28.

This is in fact what the FirstEnergy ESP Stipulation proposes. I estimate the Company could recover a cumulative $113.4 million in lost revenues over six years if the final lost revenue provision resulting from this ESP mimics the lost revenue provision in the last ESP, as demonstrated in Schedule WG-2.[55] The estimated total annual lost revenue recovery for residential customers in years 2012 through 2014 would be just under the residential program energy efficiency budgeted of $28 million in 2012. The figures are $31.5 million in 2013 and $35 million in 2014.[56]

The ACEEE study also notes that the electric utilities in Connecticut are "only allowed recovery of lost revenues if their earnings are below their allowed rate of return for six months."[57] Given the above reasons, and the fact that "The impacts of a loss of revenue due to an energy efficiency program could be offset by revenue growth from customer growth or by a reduction in costs," [58] I recommend that the lost distribution provision of the settlement be stricken and that the issue be addressed in a more appropriate venue. As provided for in O.R.C. Section 4901:1-39-07, the Company can file to recover energy efficiency program induced lost distribution revenues in the 2013-2015 Program Portfolio Plan

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[55] Including the lost revenue from 2009-2011 Energy Efficiency program, the total cumulative recovery is $163.1 million over six years.

[56] Exhibit FE-GLF-3, Direct Testimony of George Fitzpatrick, Case No. 09-1947-EL-POR.

[57] Id. at 26.

[58] Val Jensen, "Aligning Utility Incentives with Investment in Energy Efficiency, National Action Plan for Energy Efficiency, pages 2-6 (November 2007).

related cases. This will permit the Company, Commission, and all parties to consider long-term approaches to the recovery of distribution lost revenues such as through a revenue decoupling mechanism. A revenue decoupling mechanism adjusts rates periodically to ensure that a utility accounts as revenue for distribution fixed cost recovery no more and no less than the amount authorized in their last rate case. A revenue decoupling mechanism therefore would be more protective of consumers than the lost revenue recovery in the Stipulation that does not relate the lost revenues the Company is seeking recovery for with their authorized cost recovery.

I conservatively modeled a six-year lost revenue recovery versus a distribution rate case and a revenue decoupling mechanism with annual deviations at a positive 5 percent.[59] This results in a $109 million ESP energy efficiency lost distribution revenue dollar figure in excess of those that would be provided to FirstEnergy in an MRO setting.[60]

Q37. DO YOU AGREE WITH STIPULATION SECTIONS E-1-ii, AND E-1-vi, CONCERNING THE RECOVERY OF SMART GRID COSTS AS CURRENTLY WRITTEN?

[59] The 5 percent revenue requirement assumption is generous as the "decoupling adjustments under existing mechanisms have been very small – most often under 2 percent, positive or negative – with the majority under 1 percent." Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review." The Electricity Journal, October 2009, page 66.

[60] Schedule WG-1.

A37. No. Section E-1-ii of the Stipulation states "All costs approved in Case No. 09-1820-EL-ATA associated with the project will be considered incremental for recovery under Rider AMI." [61] Section E-1-vi then states "All reasonably incurred incremental operating expenses associated with the project will also be recovered." [62] Nowhere in those two important cost recovery sections does the concept of operational costs "net of benefits" appear.

One of the major benefits of smart grid to the utility and customers of the smart grid should be the utility operational cost saving benefits that accrue from its implementation. These range from reducing meter reader expenses, reduced call center expenses, reduced costs of responding to power outages, enhanced revenues from more accurate meter reads and additional benefits [63] that can make

[61] Stipulation, page 23.

[62] Id. at 23.

[63] The following detailed list of operational savings was contained in the Staff Reports in Case No. 07-551-EL-AIR, page 90 of each (December 4, 2007):

- -reduced meter reading costs
- -fewer meter-reading errors
- -fewer estimated meter readings
- -fewer billing adjustments
- -reduced need to enter customers' homes to read inside meters
- -credit and collection savings
- -reduced uncollectible expense
- -call center savings
- -complaint reduction
- -revenue enhancement due to:
  - improved theft detection
  - increased meter accuracy
- -remote system monitoring savings
- -meter inventory operational savings
- -distribution asset management savings.

up over 50 percent of the original investment.[64] By not including the "net of benefits" language in the Stipulation, distribution customers of FirstEnergy would overpay for the Company's implementation of smart grid.[65]

If the Commission were to approve the Stipulation, against my recommendation, I conservatively expect that smart grid costs under the ESP will be $4 million more than if separately determined and coupled with an MRO.

Q38. ARE THERE PROVISIONS IN THE STIPULATION WHOSE EFFECTS ARE DIFFICULT TO QUANTIFY FOR THEIR EFFECT ON CUSTOMER RATES, BUT THAT SHOULD ALSO BE CONSIDERED IN THE COMPARISON BETWEEN A MRO AND AN ESP?

A38. Yes, there are several provisions that should be considered by the Commission against approval of the ESP.

Q39. WHAT IS YOUR EVALUATION OF THE ECONOMIC DEVELOPMENT PORTIONS OF FIRSTENERGY'S PROPOSAL?

[64] For example, in the Southern California Edison SmartConnect filing, operating benefits make up 63 percent of the total project cost. See Edison SmartConnect Deployment Funding and Cost Recovery, Exhibit 3: Financial Assessment and Cost Benefit Analysis, 2007, Case U 338-E, page 51.

[65] The Staff Reports in Case No. 07-551-EL-AIR (December 4, 2007), supports a net of benefits rider for Smart Grid. Page 91 (all three reports) of the Staff Reports states: "Staff believes that the potential benefits of AMI to First Energy's retail customers justify adopting Rider AMI/Modern Grid as a place-holder. Staff therefore recommends the Commission approve this rider for the Company's operating companies and order the Company to maintain this Rider at a zero-dollar balance until the Staff and the Commission have an opportunity to assess the costs and benefits associated with a FirstEnergy AMI/Modern Grid rollout project as a whole. The Staff recommends that the recovery of such costs through this Rider be net of those utility benefits associated with an AMI/Modern Grid deployment."

A39. In Schedule 1 the Company estimates $2.7 million annually in delta revenue from the economic development provision of the stipulation for rate discounts for domestic automakers, for a total of $8.1 million over three years. In addition, the Company estimates in Schedule 1 that the economic development provision for expansion of the Cleveland Clinic will generate $14 million annually for a total of $70 million over 5 years. Traditionally, these types of reasonable arrangements are filed and undergo a full review by parties in the case before a Commission judgment is rendered. Similar to a distribution rate case, most reasonable arrangement applications are modified through a litigated process and mercantile applicants usually get only a portion of the benefit originally applied for. The terms of the Stipulation also unreasonably exclude large industrial customers (i.e. GT customers) from cost responsibility, which increases the cost responsibility of residential and other classes of smaller customers. OCC witness Dr. Ibrahim elaborates further on these concerns in his direct testimony.

E. Summary

Q40. IS THE ESP THAT IS PROPOSED IN THE STIPUATION MORE OR LESS FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS UNDER AN MRO?

A40. The ESP is less favorable. Contrary to the Company's analysis of the Stipulation, my analysis shows that, as stated earlier in my testimony, customers stand to lose from $193 to $332 million from an ESP rather than under an MRO, depending on the scenarios used for comparison. This is summarized in Schedules WG-1, 1A, and1B.

IV. OTHER RECOMMENDED CHANGES TO THE ESP

Q41. DO YOU OBSERVE OTHER PROBLEMS IN THE ESP PROPOSAL THAT ARE NOT EASILY PLACED IN THE CONTEXT OF THE COMPARISON BETWEEN A MRO AND AN ESP?

A41. Yes. Problems exist in the proposed ESP, and these are negative for the ESP in the sense that the Stipulation asks for the total package to be approved. Some of the same problems existed in the MRO proposed by FirstEnergy in Case No. 09-906-EL-SSO, but a settlement was not presented in that case. To the extent that the Commission is more limited by the Stipulation package regarding modifications, the ESP is less favorable than the expected results from an MRO.

Q42. DO YOU HAVE OBSERVATIONS REGARDING THE PROPOSAL FOR THE TREATMENT OF INTERRUPTIBLE LOADS AND COSTS ASSOCIATED WITH SUCH LOADS?

A42. Yes. FirstEnergy's proposed Peak Demand Reduction riders, ELR and OLR, which are used to recover the costs incurred with the non-residential customer Interruptible program offering, would be used by the Company to help meet its peak demand reduction requirements under R.C. Section 4928.66. As such, the appropriate venue for consideration of this program is the Company's energy efficiency ("EE") and peak demand reduction ("PDR") portfolio filing, as provided in OAC 4901:1-39-05. Large customers are not required to pay for residential PDR programs, such as the existing Direct Load Control Thermostat program, so residential customers should not be required to pay for large customer interruptible PDR programs that are used to meet the Company's PDR requirements. I previously presented testimony in the MRO Case, Case No. 09-906-EL-SSO, on this same matter regarding FirstEnergy's proposed Rider PDR.

An interruptible credit would stem from proposed Rider EDR, paragraph "b" that is entitled "Interruptible Credit Provision."[66] The charge for the costs for the program are listed in Rider EDR, paragraph "e," which states that it covers the cost of "credits in sections (a), (b), (c), and (f) of this Rider."[67] This cost recovery would take place from large customers, consistent with my testimony.[68] However, the Application also contains Rider DSE1, which states that it *also* recovers costs "associated with customers taking service under the Economic Load Response Rider (ELR) and Optional Load Response Rider (OLR)." This second recovery device for costs associated with the ELR and OLR -- which would incorrectly collect the costs from a broad number of tariff classes (including residential customers) -- should be eliminated in favor of full recovery for the ELR and OLR programs from large customers.

[66] Application, Attachment B, Sheet 116.

[67] Id.

[68] Rider EDR, paragraph "e" includes GS and GP customers, but inexplicably excludes GT customers who are the largest industrial customers.

Q43. WHY IS THE INTERRUPTIBLE RATE PROPOSAL CONTAINED IN THE COMPANY'S MRO CASE SUPERIOR TO THAT PROPOSED IN THE ESP?

A43. In the MRO filed by the Company, FirstEnergy proposed eliminating their ELR and OLR interruptible rates and instead, procuring its interruptible peak demand reduction through a competitive RFP. The Company estimates that the annual revenue shortfall from rates ELR and OLR will be $31 million annually that will be collected from all their customers.[69] If the Company procured its interruptible peak demand reductions through a competitive bid, they would be able to attain peak reductions at a lower cost per MW than through Rider ELR and OLR.

Q44. WHAT IS YOUR EVALUATION OF THE AUCTION DESIGN PROPOSED IN THIS ESP?

A44. None of the CBP design elements that the OCC recommended to the Commission in the FirstEnergy MRO proceeding were incorporated into the proposed ESP's Competitive Bidding Process ("CBP") design. Neither were the non-residential retail rate design elements. These are important concerns because a small increase in the auction price due to a faulty design element could translate into millions of dollars of extra customer costs. I therefore recommend that the immediate-term and the long-term CBP design embedded in Section A of the Stipulation be modified to incorporate the OCC's recommendations.

[69] Deposition of William Ridmann (April 13, 2010).

The immediate-term CBP should recognize contingencies related to the switch of ATSI operations to the PJM footprint. The ESP Application does not deal with the major contingency that should concern the PUCO regarding power supply that begins on June 1, 2011 -- the Company is located in MISO's footprint and the FirstEnergy-affiliated companies propose to switch their ATSI operations to the PJM footprint. Expert testimony in the MRO Case stated that bidders will respond to uncertainty by including a premium in their supply bids, and that modifications to the auction design should result.[70]

In the MRO Case, OCC witness James Wilson addressed the excessive period between the auctions and the period of delivery that remains in FirstEnergy's ESP proposal:

> The risk that the [proposed] auctions will lead to excessive prices can be reduced by rescheduling the auctions in early 2011, closer to the start of the first delivery year on June 1, 2011, reducing the unnecessary lead time and resulting in auction circumstances under which ATSIs RTO membership should be resolved or less uncertain.[71]

Balance should be achieved between the desire by bidders for a reasonable amount of time between the auction and the delivery period while not

[70] *In re FirstEnergy's 2009 MRO Proceeding*, Case No. 09-906-EL-SSO, OCC MRO Ex. 2, pages 14-15.

[71] OCC MRO Ex. 4, page 27 (Wilson).

increasing uncertainty related to long lead times before delivery. The July 2010 auction proposed in the ESP provides excessive lead time before the delivery period of June 1, 2011.

Adopting the OCC's recommendations from the MRO Case for any auction conducted to procure generation service should reduce the bid price, leading to significant dollar savings over the currently proposed ESP.

Q45. HOW HAS THE COMPANY PROPOSED TO CHARGE FOR GENERATION UNDER THE PROPOSED ESP?

A45. The Company proposes to utilize a wholesale to retail rate conversion process to convert the resulting descending-clock auction blended competitive bid price to retail rate Rider GEN.[72] Rider GEN includes both an energy and capacity component. It will include allocated capacity costs resulting from the PJM capacity auctions, converted to an energy basis, and subtracted from the auction results, to develop the energy charge. [73]

Q46. DURING THE CONVERSION PROCESS FROM A WHOLESALE RATE TO A RETAIL RATE, DOES THE COMPANY PROPOSE TO CHARGE NON-RESIDENTIAL CUSTOMERS RATES THAT DO NOT INCLUDE DEMAND CHARGES?

[72] Stipulation, page 7.

[73] Id., page 11.

A46. Yes. Rider GEN is a kWh charge.

Q47. WHAT IS THE HISTORY OF SUCH DEMAND CHARGES FOR LARGE, NON-RESIDENTIAL CUSTOMERS SERVED BY THE COMPANY?

A47. Demand components existed in the rates of large customers until recently. FirstEnergy proposed the elimination of the demand charges in its initial SSO filings in 2008 following S.B. 221. However, current SSO tariffs that do not contain these demand components resulted from an overall settlement that was reached in Case No. 08-935-EL-SSO. I filed testimony in opposition to that proposed change in rate structure for these customers in SSO cases that were filed in 2008 and again in the MRO Case filed in 2009, and major components of that testimony are summarized again in this testimony.

Q48. DO YOU AGREE THAT NON-RESIDENTIAL RETAIL GENERATION RATES SHOULD NOT CONTAIN DEMAND COMPONENTS?

A48. No. Demand components are charges that take into consideration the large load for generation or the heavy burden large customers place upon a generation system at a single point or points in time. The Company's proposal eliminates the principal source of responsiveness to differences in demands that has historically been in place for large customers, and that is needed going forward to reduce the bid price. FirstEnergy again proposes a generation kWh *retail rate design* that fails to appropriately focus on the *impact that the retail rates will have on customers, and therefore on bidding in the auction process.*

The elimination of the demand charges that have historically been used for non-residential generation tariffs will tend to encourage an inefficient demand for, and use of, generation resources. The change to rely solely on kilowatt-hour charges is again proposed by FirstEnergy in this case at a time when greater attention has been focused, both on the national level[74] and by the Commission,[75] on providing customers with appropriate price signals so that electricity is used in an economically efficient manner. This weakness in the design of the retail

[74] A landmark in the path towards emphasizing appropriate pricing of electricity at the federal level was the Energy Policy Act of 2005 ("EPAct 2005"). Section 1252 of EPAct 2005 required electric utilities to offer time-based electric schedules. Additional initiatives by FERC have led to increasing emphasis by regional transmission organizations on demand-responsiveness on the part of retail customers in order to meet regional energy needs with lessened reliance upon building expensive generating units. See FERC Order No. 719, concerning Wholesale Competition in Regions with Organized Electric Markets, 73 FR 61,400 (Oct. 28, 2008) where the Commission required each RTO and ISO to:

- treat demand response resources in RTOs' and ISOs' markets on a comparable basis to existing generation;
- eliminate barriers to participation of demand response resources;
- allow aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the organized energy market;
- assess and report on any remaining barriers to comparable treatment of demand response resources;
- each RTO's or ISO's Independent Market Monitor submit a report describing its views on its RTO's or ISO's assessment to the Commission

[75] For example, the Commission initiated Case 05-1500-EL-COI on December 14, 2005, at least in part to respond to the initiative set in EPAct 2005 on smart metering and demand response. Entry, page 4 (December 14, 2005). On May 30, 2007, the Commission initiated a proceeding to investigate advanced metering infrastructure ("AMI"). Case 07-646-EL-UNC, Entry (May 30, 2007). With respect to FirstEnergy particularly, the Order in Case No. 07-551-EL-AIR (a FirstEnergy distribution rate case) directed the Companies to work with Staff on "AMI/Modern Grid technology." Order, page 45 (January 21, 2009). FirstEnergy filed a Report on AMI/Smart Grid on June 1, 2009. Case No. 07-646-EL-UNC (June 1, 2009). On November 18, 2009, FirstEnergy filed an application for approval of a limited roll-out of AMI/Smart Grid technology and cost recovery, which included a proposal for pricing time of use pricing to more closely match pricing to the cost of providing electrical service. Case Nos. 09-1820-EL-ATA, et al. (November 18, 2009).

generation tariffs will be recognized by bidders, and will result in higher bids for a customer load that is inefficiently structured and more costly to serve.[76]

Q49. DOES THE COMPANY'S PROPOSAL IN THE INTERRUPTIBLE LOAD, TIME DIFFERENTIATED RATE DESIGN, AND SEASONALITY FACTOR AREAS PROVIDE ENOUGH CONTROL OVER THE GROWTH IN DEMAND?

A49. No. While the Company's interruptible rates ELR and OLR [77] for large general service customers and the included seasonality element are important to help control the growth in demand, they do not suffice to overcome that lack of a more granular demand signal. This is especially true given the voluntary nature of both of the interruptible programs and the time differentiated rate designs.

Q50. WHAT RECOMMENDATIONS DO YOU PROPOSE THE COMMISSION ADOPT WITH REGARD TO DEMAND CHARGES?

A50. The Commission should not accept FirstEnergy's proposed rate design for large customers, regardless of the proceeding in which it is proposed. When addressing this issue in their Opinion and Order in Case No. 08-935-EL-SSO, the Commission agreed "that the issues raised by various intervenors regarding the

[76] For example, some customers may operate with multiple shifts, and the elimination of demand charges could encourage reductions in shift work that is currently designed to reduce demand charges. The result could be to increase overall demand by the Company's customers and result in a more costly supply environment.

[77] Stipulation, pages 20-21.

inclusion of demand components in the generation rate design must be addressed."[78] Therefore, demand components should be re-introduced into the proposed retail generation rate design (i.e. similar to generation tariffs before the changes brought by Case No. 08-935-EL-SSO) before any bidding takes place in order to more fully reflect the cost of generation in rates. I also testified on this matter in the pending MRO Case, Case No. 09-906-EL-SSO. The result of this change in FirstEnergy's proposals, everything else being equal, would be to reduce the bid price in the proposed auctions.

Q51. HOW IS FIRSTENERGY PROPOSING TO COMPLY WITH THEIR RENEWABLE ENERGY REQUIREMENTS?

A51. The Company proposes to meet its solar and non-solar renewable requirements for the period June 1, 2011 through May 31, 2014 by issuing a separate Request For Proposal ("RFP") for Renewable Energy Credits (RECs), which process will be conducted by an independent bid manager.[79] If the RFP process does not yield

[78] *In re FirstEnergy's 2008 ESP Proceeding*, Case No. 08-935-EL-SSO, Opinion and Order, page 23 (December 19, 2008). The Commission further found that "...FirstEnergy should work with Staff, and other stakeholders, to develop a means of transitioning FirstEnergy's generation rate schedules to a more appropriate rate structure which takes into consideration of time varying generation costs of serving different customers and classifications of customers with homogenous loads and/or generation cost profiles, considers customer load factor, incorporates seasonal generation cost differentials, and, where adequate metering is available, provides customers with time-differentiated and dynamic pricing options."

[79] Stipulation, page 9.

the required number and type of RECs, the Company proposes to enter into bilateral contracts to obtain the required RECs. [80]

Q52. DO YOU BELIEVE THE PROPOSED RFP PROCESS FOR RECS WILL BE SUCCESSFUL?

A52. No. The short term nature of the RFP, three years, will probably not garner a sufficient response from the renewable developer community. The Company issued a similar short term RECs RFP last year with little success.[81] Renewable energy developers need an upfront guaranteed stream of revenue to obtain bank financing for new projects. This usually comes from the long-term sale of either the bundled energy and RECs, or they can be sold separately. Currently, lower priced voluntary REC markets provide little security for project financing, and compliance markets many times do not contain enough certainty to fully dampen concerns about risk on the part of lenders or equity investors. A government report suggests that "[S]ome possible solutions include long-term purchase commitments by large institutions or corporate buyers; state renewable energy funds offering price floors (option contracts) for future RECs; or states requiring long-term contracts as part of RPS regulations." [82] The receptivity by developers

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[80] Id.

[81] No Ohio solar RECs were bid and only 49 solar RECs were bid from contiguous states in 2009. These RFP results left the Companies with a 1,835 deficit in meeting the 2009 Ohio solar benchmark. See FirstEnergy force majeure solar Case 09-1922-EL-EEC, page 4.

[82] See Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges Ed Holt *Ed Holt and Associates Inc.*; Lori Bird *National Renewable Energy Laboratory*, pages 3-4 (January 2005).

to a longer term contract is recognized by the Company in its solar REC waiver application request. In that request it states, "...certain parties contacted by [The Company's solar RFP consultant Navigant Consulting Inc.] stated that the Commission should be interested in a long-term contract with the companies..."[83] The Company has argued that not enough solar RECs exist in Ohio and contiguous states regardless of contract length. However, this is the classic "which came first, the chicken or the egg" causality dilemma. Not until long term REC offerings become the norm for electric utilities, will the supply of RECs increase, and the corresponding price of procuring RECs will decline.

Instead of repeating a failed experiment (i.e. a short term RFP for RECs), and consequently having to respond to another FirstEnergy force majeure filing in 2010, I recommend that if the Commission approves an ESP with a RECs provision, that they modify the settlement by extending the length of the REC contract to ten to fifteen years. This will more closely mimic a highly successful solar REC auction recently completed by PECO in Pennsylvania. As a result of the RFP process, PECO has signed 10-year agreements to purchase 6 megawatts, or 80,000 solar RECs in support of Pennsylvania's Alternative Energy Portfolio Standard. [84]

[83] Id., pages 5-6.

[84] Attachment 6, March 3, 2010 – "PECO harnesses solar power – Company purchases 6 megawatts of solar credits," http://www.peco.com/newsroom/newsreleases/PECO+harnesses+solar+power.htm.

V. RESIDENTIAL CUSTOMER RATE IMPACTS FROM THE PROPOSED ESP

Q53. HAVE YOU PREPARED FIGURES THAT SHOW THE IMPACT OF THE SSO ALTERNATIVES ON RESIDENTIAL RATES?

A53. Yes. Based on the Company's Schedule 1 estimated rates,[85] my Schedule WG-3 shows the rate impact of the proposed ESP by comparison of rates with and without the effects of the ESP provisions. Three comparisons are made to May 2011 rates:

(1) May 2012 under the Company's assumptions for the ESP;[86]

(2) May 2012 with no ESP rate changes and $0 distribution rate increase;[87]

(3) May 2012 with no ESP rate changes and a distribution rate increase granted at 60 percent of that requested.[88]

Schedule WG-3 - Summary ("Summary") shows these comparisons on a rate per kWh basis; an annualized revenue basis; a monthly winter bill basis (for a residential customer using 750 kilowatt-hours of electricity); and a monthly

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[85] Company Schedule 1 "shows the estimated impact, by Company and rate schedule, of the proposed annualized rates to be in effect at May 31, 2012 ("Proposed Rates") as compared to annualized rates in effect at may 31, 2011 ("Current Rates"). Ridmann Testimony, page 14 (March 31, 2010).

[86] "ESP" per Company Schedule 1.

[87] "No ESP."

[88] "No ESP with D increase."

summer bill basis. The details of the comparison for each FirstEnergy utility are provided in WG-3, pages 2 through 10.

In the second comparison, there are four ESP provision changes that have been eliminated -- the increase in Rider DSE1; the new Rider DCR; the new Rider EDR automaker charge; and the new Rider EDR Infrastructure Improvement Provision. In the third comparison, the same four ESP provisions are eliminated but it is assumed that 60 percent of FirstEnergy's requested distribution rate case revenue increase is granted.

Q54. WHAT ARE THE RATE CONSEQUENCES OF THE ADJUSTMENTS THAT FIRSTENERGY PROPOSES UNDER THE ESP?

***A54.*.** Under the Company's proposal (i.e. the first comparison), with the ESP provisions intact, the comparable winter bill impact is a decrease of 5.7 percent, 2.3 percent, and an increase of 1.3 percent for customers served by CEI, OE, and TE, respectively. The proposed ESP impact on comparable summer bills are increases of 3.8 percent, 2.8 percent, and 3.0 percent, respectively.

The Summary shows that absent the proposed ESP (i.e. zero distribution rate increase comparison), annualized revenue based on May 2012 residential rates are estimated to decrease from May 2011 levels by 7.8 percent for CEI, 5.4 percent for OE and 2.0 percent for TE. Applying the May 2012 rates that do not have the effect of the four ESP rate changes I describe above, to residential RS usage of

750 kWh per month, results in bill decreases of 9.8 percent, 5.1 percent, and 2.0 percent for winter customers served by CEI, OE, and TE, respectively. Summer bills for 750 kWh would decrease by 0.4 percent for CEI, increase 0.1 percent for OE, and decrease 0.1 percent for TE.

In the third comparison -- no ESP rate changes but an assumed distribution rate increase -- annualized revenue based on May 2012 rates are estimated to decrease from May 2011 levels by 5.9 percent for CEI, 4.2 percent for OE, and 0.6 percent for TE. Applying the May 2012 rates to residential RS usage of 750 kWh per month results in bill decreases of 8.0 percent, 4.0 percent, and 0.6 percent for winter customers served by CEI, OE, and TE, respectively. Summer bills for 750 kWh would increase by 1.4 percent, for CEI, 1.1 percent for OE and 1.2 percent for TE.

The disadvantages of the ESP are reflected in the comparison of the rates for the three scenarios

VI. CONCLUSION

Q55. DOES THIS CONCLUDE YOUR TESTIMONY?

A55. Yes. However, I reserve the right to incorporate new information and/or discovery responses that may subsequently become available. I also reserve the right to supplement my testimony in response to positions taken by the PUCO Staff or other parties.

Schedule 1

Present Value Costs of ESP Compared to MRO and Separate Cases							
Case One: DCR, Modified Distribution Rate Case and Revenue Decoupling Scenario						Schedule WG-1	
TOTAL OHIO							
FE Assumptions							
(1) CBP Price ($/MWH) 61.50							
(2) RS Retail Generation Rate (Non-Seasonal) ($/MWH) 63.23							
(3) PIPP RS Generation Discount 6%							
(4) PIPP RS Retail Generation Rate (Non-Seasonal) ($/MWH 59.44)							
(5) Net Present Value Discount Rate 8.48%							
Sales Forecast	June 11 - May 12 (MWH)	June 12 - May (MWH)	June 13 - May (MWH)	June 14 - May (MWH)	June 15 - May 16 (MWH)	June 16 - May 17	
(6) RS PIPP	1,193,396	1,202,877	1,200,378	1,194,670	1,188,591		
(7) Total	52,521,450	53,274,861	54,175,960	54,818,825	54,685,040		
ESP Provisions	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue	
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	
(8) Delivery Capital Recovery (DCR) Rider $2.34/MWH	51.3	124.5	127.0				
(9) PIPP RS Generation Revenue $ 59.44/MWH	70.9	71.5	71.3				
(10) Economic Development Funds	-1.0	-1.0	-1.0				
(11) *Fuel Fund ($0.5) ($0.5) ($0.5)*	-0.5	-0.5	-0.5				
(12) MISO Exit Cost Estimate	0.0	0.0	0.0	0.0	0.0		
(13) PJM Integration Cost Estimate ($5.0)	0.0	0.0	0.0	0.0	0.0		
(14) RTEP Estimate	0.0	0.0	0.0	0.0	0.0		
Lost Revenue Collected Under ESP (Assumes 6 year provision of last stip.)	6.8	14.6	23.3	23.3	23.3	23.3	
Smart Grid Cost (1)	8.5	14.7	12.9				
(15) Total Revenues Per Year	**136.0**	**223.9**	**232.9**	**23.3**	**23.3**	**23.3**	**$662.6**
MRO Provisions	Revenue	Revenue	Revenue	Revenue	Revenue		MRO Savings
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
(16) Distribution Rate Case (Based on Rider DCR Discounted by 35%)	28.3	68.6	70.0				136.0
(17) PIPP RS Generation Revenue Discounted .5 Percent	70.6	71.2	71.0				1.0
Estimated Lost Revenue Collected Under MRO (2)	0.3	0.7	1.2	1.2	1.2	1.2	108.8
Smart Grid Cost Discounted 10% by Operational Savings	7.6	13.3	11.6				3.6
(18) Total Revenues Per Year	**$106.8**	**$153.7**	**$153.7**	**$1.2**	**$1.2**	**$1.2**	**$417.7**
MRO Savings per Year	**29.2**	**70.1**	**79.3**	**22.1**	**22.1**	**22.1**	**$244.9**
Present Value Summary							
(19) NPV: ESP	**$545**						
(20) NPV: MRO	**$352**						
(21) Benefits to Customers (MRO - ESP)	**($193)**						
(1) $72.2 Million Smart Grid Cost from Case No. 09-1820-EL-ATA and with federal match (Distributed according to Response to OCC Set 1 DR 25)							
(2) Assumes Lost Revenue Recovery occurs through distribution rate case and decoupling with 5 percent annual adjustment							
OCC Assumptions							
Rate Case Reduction Percentage	0.6						
PIPP Percentage Reduction from Competitive Bid	0.935						
Lost Revenue Adjustment Factor	0.05						
Smart Grid Operational Savings Factor	0.9						

Schedule WG-1A

Present Value Costs of ESP Compared to MRO and Separate Cases

Case Two: DCR at Cap, Modified Distribution Rate Case and Revenue Decoupling Scenario

TOTAL OHIO							
FE Assumptions							
(1) CBP Price ($/MWH) 61.50							
(2) RS Retail Generation Rate (Non-Seasonal) ($/MWH) 63.23							
(3) PIPP RS Generation Discount 6%							
(4) PIPP RS Retail Generation Rate (Non-Seasonal) ($/MWH 59.44)							
(5) Net Present Value Discount Rate 8.48%							
Sales Forecast	June 11 - May 12	June 12 - May	June 13 - May	June 14 - May	June 15 - May 16	June 16 - May 17	
	(MWH)	(MWH)	(MWH)	(MWH)	(MWH)		
(6) RS PIPP	1,193,396	1,202,877	1,200,378	1,194,670	1,188,591		
(7) Total	52,521,450	53,274,861	54,175,960	54,818,825	54,685,040		
ESP Provisions	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue	
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	
(8) Delivery Capital Recovery (DCR) Rider at $390 Million Cap	66.1	160.4	163.6				
(9) PIPP RS Generation Revenue $ 59.44/MWH	70.9	71.5	71.3				
(10) Economic Development Funds	-1.0	-1.0	-1.0				
(11) Fuel Fund ($0.5) ($0.5) ($0.5)	-0.5	-0.5	-0.5				
(12) MISO Exit Cost Estimate	0.0	0.0	0.0	0.0	0.0		
(13) PJM Integration Cost Estimate ($5.0)	0.0	0.0	0.0	0.0	0.0		
(14) RTEP Estimate	0.0	0.0	0.0	0.0	0.0		
Lost Revenue Collected Under ESP (Assumes 6 year provision of last stip.)	6.8	14.6	23.3	23.3	23.3	23.3	
Smart Grid Cost	8.5	14.7	12.9				
(15) Total Revenues Per Year	**150.8**	**259.7**	**269.5**	**23.3**	**23.3**	**23.3**	**$749.8**
MRO Provisions	Revenue	Revenue	Revenue	Revenue	Revenue		MRO Savings
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
(16) Distribution Rate Case (Based on Rider DCR)	28.3	68.6	70.0				223.2
(17) PIPP RS Generation Revenue	70.6	71.2	71.0				1.0
Estimated Lost Revenue Collected Under MRO (2)	0.3	0.7	1.2	1.2	1.2	1.2	108.8
Smart Grid Cost (1)	7.6	13.3	11.6				3.6
(18) Total Revenues Per Year	**$106.8**	**$153.7**	**$153.7**	**$1.2**	**$1.2**	**$1.2**	**$417.7**
MRO Savings per Year	**44.0**	**106.0**	**115.8**	**22.1**	**22.1**	**22.1**	**$332.1**
Present Value Summary							
(19) NPV: ESP	**$617**						
(20) NPV: MRO	**$352**						
(21) Benefits to Customers (MRO - ESP)	**($266)**						
(1) $72.2 Million Smart Grid Cost from Case No. 09-1820-EL-ATA and with federal match (Distributed according to Response to OCC Set 1 DR 25)							
(2) Assumes Lost Revenue Recovery occurs through distribution rate case and decoupling with 5 percent annual adjustment							
OCC Assumptions							
Rate Case Reduction Percentage	0.6						
PIPP Percentage Reduction from Competitive Bid	0.935						
Lost Revenue Adjustment Factor	0.05						
Smart Grid Operational Savings Factor	0.9						

Schedule WG - 1B

Present Value Costs of ESP Compared to MRO and Separate Cases

Case Three: DCR, Zero Distribution Rate Case Recovery and Revenue Decoupling Scenario

TOTAL OHIO

FE Assumptions							
(1) CBP Price ($/MWH) 61.50							
(2) RS Retail Generation Rate (Non-Seasonal) ($/MWH) 63.23							
(3) PIPP RS Generation Discount 6%							
(4) PIPP RS Retail Generation Rate (Non-Seasonal) ($/MWH 59.44)							
(5) Net Present Value Discount Rate 8.48%							
Sales Forecast	June 11 - May 12	June 12 - May	June 13 - May	June 14 - May	June 15 - May 16	June 16 - May 17	
	(MWH)	(MWH)	(MWH)	(MWH)	(MWH)		
(6) RS PIPP	1,193,396	1,202,877	1,200,378	1,194,670	1,188,591		
(7) Total	52,521,450	53,274,861	54,175,960	54,818,825	54,685,040		
ESP Provisions	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue	
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	
(8) Delivery Capital Recovery (DCR) Rider $2.34/MWH	51.3	124.5	127.0				
(9) PIPP RS Generation Revenue $ 59.44/MWH	70.9	71.5	71.3				
(10) Economic Development Funds	-1.0	-1.0	-1.0				
(11) Fuel Fund ($0.5) ($0.5) ($0.5)	-0.5	-0.5	-0.5				
(12) MISO Exit Cost Estimate	0.0	0.0	0.0	0.0	0.0		
(13) PJM Integration Cost Estimate ($5.0)	0.0	0.0	0.0	0.0	0.0		
(14) RTEP Estimate	0.0	0.0	0.0	0.0	0.0		
Lost Revenue Collected Under ESP (Assumes 6 year provision of last stip.)	6.8	14.6	23.3	23.3	23.3	23.3	
Smart Grid Cost (1)	8.5	14.7	12.9				
(15) Total Revenues Per Year	**136.0**	**223.9**	**232.9**	**23.3**	**23.3**	**23.3**	**$662.6**
MRO Provisions	Revenue	Revenue	Revenue	Revenue	Revenue		MRO Savings
	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions	$ millions
(16) Distribution Rate Case (Zero dollars approved)	0.0	0.0	0.0				302.8
(17) PIPP RS Generation Revenue Discounted .5 Percent	70.6	71.2	71.0				1.0
Estimated Lost Revenue Collected Under MRO (2)	0.3	0.7	1.2	1.2	1.2	1.2	*108.8*
Smart Grid Cost Discounted 10% by Operational Savings	7.6	13.3	11.6				3.6
(18) Total Revenues Per Year	**$78.6**	**$85.2**	**$83.7**	**$1.2**	**$1.2**	**$1.2**	**$250.9**
MRO Savings per Year	**57.5**	**138.7**	**149.2**	**22.1**	**22.1**	**22.1**	**$411.7**
Present Value Summary							
(19) NPV: ESP	**$545**						
(20) NPV: MRO	**$213**						
(21) Benefits to Customers (MRO - ESP)	**($332)**						

(1) $72.2 Million Smart Grid Cost from Case No. 09-1820-EL-ATA and with federal match (Distributed according to Response to OCC Set 1 DR 25)

(2) Assumes Lost Revenue Recovery occurs through distribution rate case and decoupling with 5 percent annual adjustment

OCC Assumptions	
Rate Case Reduction Percentage	0
PIPP Percentage Reduction from Competitive Bid	0.935
Lost Revenue Adjustment Factor	0.05
Smart Grid Operational Savings Factor	0.9

Schedule 2

FirstEnergy Case No. 10-388-EL-SSO Estimated Lost Distribution Revenues	2012	2013	2014	2015	2016	2017
Baseline (MWh)[1]	53642614	53642614	53642614			
Targeted % reduction from baseline	0.8	0.9	1			
Targeted MWh savings	429140.912	482783.526	536426.14			
Residential/Residential Low Income Sector Incremental Savings (MWh)[2]	195635	222080.422	246756.0244			
Residential/Residential Low Income Sector Cumulative Savings (MWh)	195635	417715.422	664471.4464	664471.4464	664471.4464	664471.4464
Lost Revenue Recovery (as a result of this agreement)[3]	**$6,783,448**	**$14,483,865**	**$23,039,883**	**$23,039,883**	**$23,039,883**	**$23,039,883**
2009-2011 Residential/Reseidential Low Income Savings Eligible for Lost Revenue Collection[4]	409377	409377	409377	204688.5		
Total Lost Revenue Recovery	**$ 20,978,186**	**$ 28,678,603**	**$ 37,234,621**	**$ 30,137,252**	**$ 23,039,883**	**$ 23,039,883**

Combined "Program Year 2012 MWh Saved" "Baseline", from Case No. 09-1947-EL-POR, Exhibit FE-GLF-2, assumed same baseline 2012-2014

Projected in 2013 and 2014 assuming the Residential and Residential Low Income sectors contribute the same percentage to 2013 and 2014 compliance as they did in 2012 (46%)

Assumes $.032334/kWh distribution rate, plus $.00234/kWh DCR rider

Assumes 2009-2011 Savings are eligible for lost revenue collection until mid-year 2015, per Stipulation and Recommendation in Case No. 08-935-EL-SSO

Schedule 3

ESP Estimated Rate Impacts - per Company Schedule 1	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
RESIDENTIAL SERVICE (RS) - TOTAL	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 PROPOSED AVERAGE RATES	Increase (Decrease)	MAY 2011 PROPOSED REVENUE	MAY 2012 PROPOSED REVENUE	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED AVERAGE RATES	Increase (Decrease)	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 PROPOSED AVERAGE RATES	Increase (Decrease)
	(a)	(b)		(a)	(b)		750 kWh (c)			750 kWh (c)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	$ 0.1191	$ 0.1150	-3.4%	$ 584,286,839	$ 564,187,198	-3.4%	$ 94.84	$ 89.44	-5.7%	$ 93.12	$ 96.64	3.8%
OHIO EDISON COMPANY	$ 0.1132	$ 0.1105	-2.3%	$ 921,351,517	$ 899,987,487	-2.3%	$ 92.01	$ 89.94	-2.3%	$ 94.50	$ 97.15	2.8%
THE TOLEDO EDISON COMPANY	$ 0.1208	$ 0.1224	1.3%	$ 251,186,755	$ 254,491,784	1.3%	$ 91.50	$ 92.67	1.3%	$ 96.98	$ 99.88	3.0%

Sources:
(a) OCC Set 1 RPD-17 Current Schedules 1
(b) Schedules 1 - Errata.
(c) Applicable Rates applied to usage, see detail for each utility

ESP Estimated Rate Impacts - No ESP (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
RESIDENTIAL SERVICE (RS) - TOTAL	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 AVERAGE RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED REVENUE	MAY 2012 REVENUE - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 AVERAGE RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 AVERAGE RATES - No ESP	Increase (Decrease)
	(a)	(b)		(a)	(b)		750 kWh (c)			750 kWh (c)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	$ 0.1191	$ 0.1098	-7.8%	$ 584,286,839	$ 538,528,398	-7.8%	$ 94.84	$ 85.51	-9.8%	$ 93.12	$ 92.72	-0.4%
OHIO EDISON COMPANY	$ 0.1132	$ 0.1071	-5.4%	$ 921,351,517	$ 871,838,573	-5.4%	$ 92.01	$ 87.35	-5.1%	$ 94.50	$ 94.56	0.1%
THE TOLEDO EDISON COMPANY	$ 0.1206	$ 0.1184	-2.0%	$ 251,186,755	$ 246,267,681	-2.0%	$ 91.50	$ 89.70	-2.0%	$ 96.98	$ 96.91	-0.1%

Sources:
(a) OCC Set 1 RPD-17 Current Schedules 1
(b) Schedules 1 -Errata with no ESP rate changes, see detail for each utility
(c) Applicable Rates applied to usage, see detail for each utility

ESP Estimated Rate Impacts - No ESP with D Increase (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
RESIDENTIAL SERVICE (RS) - TOTAL	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 AVERAGE RATES - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED REVENUE	MAY 2012 REVENUE - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 AVERAGE RATES - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED AVERAGE RATES	MAY 2012 AVERAGE RATES - No ESP, D Incr	Increase (Decrease)
	(a)	(b)		(a)	(b)		750 kWh (c)			750 kWh (c)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	$ 0.1191	$ 0.1121	-5.9%	$ 584,286,839	$ 549,937,989	-5.9%	$ 94.84	$ 87.26	-8.0%	$ 93.12	$ 94.46	1.4%
OHIO EDISON COMPANY	$ 0.1132	$ 0.1084	-4.2%	$ 921,351,517	$ 882,827,908	-4.2%	$ 92.01	$ 88.36	-4.0%	$ 94.50	$ 95.57	1.1%
THE TOLEDO EDISON COMPANY	$ 0.1208	$ 0.1201	-0.8%	$ 251,186,755	$ 249,638,091	-0.6%	$ 91.50	$ 90.92	-0.6%	$ 96.98	$ 98.13	1.2%

Sources:
(a) OCC Set 1 RPD-17 Current Schedules 1
(b) Schedules 1 -Errata with no ESP rate changes (see detail for each utility) and Distribution Rate case revenue increase at 60% granted of a $ 114 million rate case request ($124 million (DCR revenue in Schedule 1) x 92% (% of DCR revenue shown as distribution rate case in WRR Attachment 1)
(c) Applicable Rates applied to usage, see detail for each utility

ESP Estimated Rate Impacts - per Company Schedule 1	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.00	$4.00		$ 32,036,435	$ 32,036,435		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.029510	$0.029510		$ 144,751,448	$ 144,751,448		$ 22.13	$ 22.13		$ 22.13	$ 22.13	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 56,763,651						$ 34.41		
OVER 500 kWh	$0.078818			$ 50,545,659						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 216,820,351			$ 47.29					
				$ 324,130,071								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005662			$ 27,723,998			$ 4.24			$ 4.24	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.002964			$ 14,538,912			$ 2.22			$ 2.22	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064145 (c)			$ 94,045,469						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054573 (c)			$ 187,678,034			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 324,130,071	$ 323,986,412	$ (143,659)	$ 47.29	$ 47.55	$ 0.27	$ 54.11	$ 54.76	$ 0.65
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000686	$0.000419	$ 1,309,679	$ 3,364,944	$ 2,055,265	$ 0.20	$ 0.51	$ 0.31	$ 0.20	$ 0.51	$ 0.31
(DSE2), PER kWh	$0.002088	$0.002088		$ 10,241,987	$ 10,241,987		$ 1.57	$ 1.57		$ 1.57	$ 1.57	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000300	$0.000300		$ 1,471,550	$ 1,471,550		$ 0.23	$ 0.23		$ 0.23	$ 0.23	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004680	$0.004680		$ 21,688,356	$ 21,688,356		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 1,044,703	$ 1,044,703		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 8,276	$ 8,276		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017000)	($0.017000)		$ (8,369,857)	$ (8,369,857)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 471,374	$ 471,374		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (566,672)	$ (566,672)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	*($0.019000)*	*($0.019000)*		*$ (7,193,592)*	*$ (7,193,592)*							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 12,611,162		$ (12,611,162)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DELIVERY CAPITAL RECOVERY (DCR), PER kWh		$0.004217	$0.004217		$ 20,686,085	$ 20,686,085		$ 3.16	$ 3.16		$ 3.16	$ 3.16
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (6,006,832)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.011634		($0.011634)	$ 23,252,630			$ 5.82					
OVER 500 kWh	$0.014952		($0.014952)	$ 21,536,089			$ 3.74					
				$ 38,781,887		$ (38,781,887)	$ 8.56		$ (8.56)			
DEFERRED GENERATION COST (DGC)												
ALL SUMMER kWh, PER kWh		$0.001178	$0.001178		$ 1,727,111						$ 0.88	$ 0.88
ALL WINTER kWh, PER kWh		$0.001178	$0.001178		$ 4,051,174			$ 0.88	$ 0.88			
					$ 5,778,286	$ 5,778,286						
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000446	$0.000446		$ 2,187,704	$ 2,187,704		$ 0.33	$ 0.33		$ 0.33	$ 0.33	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000345	$0.000345		$ 1,694,092	$ 1,694,092		$ 0.26	$ 0.26		$ 0.26	$ 0.26	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003557	$0.003557		$ 17,447,675	$ 17,447,675		$ 2.67	$ 2.67		$ 2.67	$ 2.67	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.000878	$0.000878		$ 4,306,736	$ 4,306,736		$ 0.66	$ 0.66		$ 0.66	$ 0.66	
USR												
FIRST 833k kWh, PER kWh	$0.001951	$0.001951		$ 9,571,450	$ 9,571,450		$ 1.46	$ 1.46		$ 1.46	$ 1.46	
OVER 833k kWh, PER kWh	$0.000568	$0.000568		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.04200)	($0.04200)		$ (23,335,644)	$ (23,335,644)							
(EDR) - AUTOMAKER CHARGE PROVISION, PER kWh		$0.00007	$0.00007		$ 347,902	$ 347,902		$ 0.05	$ 0.05		$ 0.05	$ 0.05
(EDR) - INFRASTRUCTURE IMPROVEMENT PROVISION, PER kWh		$0.00052	$0.00052		$ 2,570,549	$ 2,570,549		$ 0.39	$ 0.39		$ 0.39	$ 0.39
TOTAL - RS	$0.1191	$0.1150	($0.0041)	$ 584,286,839	$ 564,187,198	$ (20,099,641)	$ 94.84	$ 89.44	$ (5.41)	$ 90.12	$ 93.64	$ 3.53
Percentage Increase/Decrease May 2012 vs May 2011			-3.4%			-3.4%			-5.7%			3.8%

Sources:
(a) OCC Set 1 RPD-17-CEI Current Schedule 1
(b) Schedule 1 - CEI_Errata
(c) For calculation of bills, May 2012 RS Generation Charges per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - per Company Schedule 1	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
OHIO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 44,491,512	$ 44,491,512		$ 4.00	$ 4.00		$4.00	$4.00	
ENERGY CHARGE, PER kWh	$0.031898	$0.031898		$ 259,734,033	$ 259,734,033		$ 23.92	$ 23.92		$ 23.92	$ 23.92	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 72,921,426						$ 34.41		
OVER 500 kWh	$0.078818			$ 82,158,308						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 380,843,977			$ 47.29					
				$ 535,923,711								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005856			$ 47,683,319			$ 4.39			$ 4.39	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004548			$ 37,032,741			$ 3.41			$ 3.41	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064129 (c)			$ 134,799,622						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054559 (c)			$ 329,571,059			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 535,923,711	$ 549,066,740	$ 13,163,030	$ 47.29	$ 48.90	$ 1.61	$ 54.11	$ 56.10	$ 1.99
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000686	$0.000419	$ 2,174,086	$ 5,585,853	$ 3,411,768	$ 0.20	$ 0.51	$ 0.31	$ 0.20	$ 0.51	$ 0.31
(DSE2), PER kWh	$0.001889	$0.001889		$ 15,381,453	$ 15,381,453		$ 1.42	$ 1.42		$ 1.42	$ 1.42	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000170	$0.000170		$ 1,384,249	$ 1,384,249		$ 0.13	$ 0.13		$ 0.13	$ 0.13	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 35,378,926	$ 35,378,926		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 2,282,268	$ 2,282,268		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640	-	$ 26,215	$ 26,215		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017700)	($0.017700)		$ (31,926,425)	$ (31,926,425)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 782,487	$ 782,487		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	$0.000000	$0.000000		$ -	$ -							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (32,703,576)	$ (32,703,576)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 20,934,736		$ (20,934,736)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DELIVERY CAPITAL RECOVERY (DCR), PER kWh		$0.002443	$0.002443		$ 19,892,477	$ 19,892,477		$ 1.83	$ 1.83		$ 1.83	$ 1.83
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (8,342,159)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.004592		($0.004592)	$ 14,265,380			$ 2.30					
OVER 500 kWh	$0.012202		($0.012202)	$ 35,828,017			$ 3.05					
				$ 41,741,238		$ (41,741,238)	$ 4.35		$ (4.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000212	$0.000212		$ 1,726,240	$ 1,726,240		$ 0.16	$ 0.16		$ 0.16	$ 0.16	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000362	$0.000362		$ 2,948,939	$ 2,948,939		$ 0.27	$ 0.27		$ 0.27	$ 0.27	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003354	$0.003354		$ 27,310,425	$ 27,310,425		$ 2.52	$ 2.52		$ 2.52	$ 2.52	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.001006	$0.001006		$ 8,191,499	$ 8,191,499		$ 0.75	$ 0.75		$ 0.75	$ 0.75	
USR												
FIRST 833k kWh, PER kWh	$0.002025	$0.002025		$ 16,490,481	$ 16,490,481		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
OVER 833k kWh, PER kWh	$0.001046	$0.001046		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.03900)	($0.039000)		$ (30,920,981)	$ (30,920,981)							
(EDR) - AUTOMAKER CHARGE PROVISION, PER kWh		$0.00007	$0.00007		$ 577,522	$ 577,522		$ 0.05	$ 0.05		$ 0.05	$ 0.05
(EDR) - INFRASTRUCTURE IMPROVEMENT PROVISION, PER kWh		$0.00052	$0.00052		$ 4,267,147	$ 4,267,147		$ 0.39	$ 0.39		$ 0.39	$ 0.39
TOTAL - RS	$0.1132	$0.1105	($0.0026)	$ 921,351,517	$ 899,987,487	$ (21,364,031)	$ 92.01	$ 89.94	$ (2.07)	$ 94.50	$ 97.15	$ 2.65
Percentage Increase May 2012 vs May 2011			-2.3%			-2.3%			-2.3%			2.8%

Sources:
(a) OCC Set 1 RPD-17-OE Current Schedule 1
(b) Schedule 1 - OE_Errata.
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - per Company Schedule 1	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE TOLEDO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 PROPOSED RATES	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 13,156,549	$ 13,156,549		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.035595	$0.035595		$ 74,017,397	$ 74,017,397		$ 26.70	$ 26.70		$ 26.70	$ 26.70	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 21,746,516						$ 34.41		
OVER 500 kWh	$0.078818			$ 20,521,524						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 94,763,805			$ 47.29					
				$ 137,031,847								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005804			$ 12,069,026			$ 4.35			$ 4.35	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004421			$ 9,193,171			$ 3.32			$ 3.32	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064094 (c)			$ 36,941,627						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054529 (c)			$ 81,960,688			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 137,031,847	$ 140,164,512	$ 3,132,666	$ 47.29	$ 48.76	$ 1.48	$ 54.11	$ 55.97	$ 1.86
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000686	$0.000419	$ 555,208	$ 1,426,491	$ 871,282	$ 0.20	$ 0.51	$ 0.31	$ 0.20	$ 0.51	$ 0.31
(DSE2), PER kWh	$0.002032	$0.002032		$ 4,225,407	$ 4,225,407		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000210	$0.000210		$ 436,681	$ 436,681		$ 0.16	$ 0.16		$ 0.16	$ 0.16	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 9,309,494	$ 9,309,494		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 339,917	$ 339,917		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 2,745	$ 2,745		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017600)	($0.017600)		$ (4,753,463)	$ (4,753,463)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 199,828	$ 199,828		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (424,625)	$ (424,625)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (3,518,025)	$ (3,518,025)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 5,346,221		$ (5,346,221)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DELIVERY CAPITAL RECOVERY (DCR), PER kWh		$0.002941	$0.002941		$ 6,115,611	$ 6,115,611		$ 2.21	$ 2.21		$ 2.21	$ 2.21
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	$0.00		$0.00	$ -			$ -					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.001600		($0.001600)	$ 1,543,593			$ 0.90					
OVER 500 kWh	$0.001600		($0.001600)	$ 1,161,926			$ 0.45					
				$ 2,705,519		$ (2,705,519)	$ 1.35		$ (1.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000818	$0.000818		$ 1,700,976	$ 1,700,976		$ 0.61	$ 0.61		$ 0.61	$ 0.61	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000120	$0.000120		$ 249,532	$ 249,532		$ 0.09	$ 0.09		$ 0.09	$ 0.09	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000257	$0.000257		$ 535,184	$ 535,184		$ 0.19	$ 0.19		$ 0.19	$ 0.19	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003472	$0.003472		$ 7,219,769	$ 7,219,769		$ 2.60	$ 2.60		$ 2.60	$ 2.60	
GENERATION COST RECONCILIATION (GCR), PER kWh	($0.000515)	($0.000515)		$ (1,070,908)	$ (1,070,908)		$ (0.39)	$ (0.39)		$ (0.39)	$ (0.39)	
USR												
FIRST 833k kWh, PER kWh	$0.002243	$0.002243		$ 4,663,543	$ 4,663,543		$ 1.68	$ 1.68		$ 1.68	$ 1.68	
OVER 833k kWh, PER kWh	$0.000561	$0.000561		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.02210)	($0.02210)		($742,042)	($742,042)							
(EDR) - AUTOMAKER CHARGE PROVISION, PER kWh		$0.00007	$0.00007		$ 147,485	$ 147,485		$ 0.05	$ 0.05		$ 0.05	$ 0.05
(EDR) - INFRASTRUCTURE IMPROVEMENT PROVISION, PER kWh		$0.00052	$0.00052		$ 1,069,725	$ 1,089,725		$ 0.39	$ 0.39		$ 0.39	$ 0.39
TOTAL - RS	$0.1206	$0.1224	$0.0018	$ 251,186,755	$ 254,491,784	$ 3,305,029	$ 91.50	$ 92.67	$ 1.16	$ 96.98	$ 99.88	$ 2.89
Percentage Increase/Decrease May 2012 vs May 2011			1.3%			1.3%			1.3%			3.0%

Sources:
(a) OCC Set 1 RPD-17-TE Current Schedule 1
(b) Schedule 1 - TE_Errata
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.00	$4.00		$ 32,036,435	$ 32,036,435		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.029510	$0.029510		$ 144,751,448	$ 144,751,448		$ 22.13	$ 22.13		$ 22.13	$ 22.13	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 58,763,851						$ 34.41		
OVER 500 kWh	$0.078818			$ 50,545,869						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 216,820,351			$ 47.29					
				$ 324,130,071								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005652			$ 27,723,998			$ 4.24			$ 4.24	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.002964			$ 14,538,912			$ 2.22			$ 2.22	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064146 (c)			$ 94,045,469						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054573 (c)			$ 187,678,034			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 324,130,071	$ 323,986,412	$ (143,659)	$ 47.29	$ 47.55	$ 0.27	$ 54.11	$ 54.76	$ 0.65
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000267	$0.000000	$ 1,309,679	$ 1,309,679	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.002088	$0.002088		$ 10,241,987	$ 10,241,987		$ 1.57	$ 1.57		$ 1.57	$ 1.57	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000300	$0.000300		$ 1,471,550	$ 1,471,550		$ 0.23	$ 0.23		$ 0.23	$ 0.23	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 21,688,356	$ 21,688,356		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 1,044,703	$ 1,044,703		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 8,276	$ 8,276		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017000)	($0.017000)		$ (8,369,857)	$ (8,369,857)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 471,374	$ 471,374		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (568,672)	$ (568,672)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (7,193,592)	$ (7,193,592)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 12,611,182		$ (12,611,182)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DELIVERY CAPITAL RECOVERY (DCR), PER kWh		[illegible]	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (8,006,832)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.011634		($0.011634)	$ 23,252,630			$ 5.82					
OVER 500 kWh	$0.014952		($0.014952)	$ 21,536,089			$ 3.74					
				$ 36,781,887		$ (36,781,887)	$ 8.56		$ (8.56)			
DEFERRED GENERATION COST (DGC)												
ALL SUMMER kWh, PER kWh		$0.001178	$0.001178		$ 1,727,111						$ 0.88	$ 0.88
ALL WINTER kWh, PER kWh		$0.001178	$0.001178		$ 4,051,174			$ 0.88	$ 0.88			
					$ 5,778,285	$ 5,778,286						
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000446	$0.000446		$ 2,187,704	$ 2,187,704		$ 0.33	$ 0.33		$ 0.33	$ 0.33	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000345	$0.000345		$ 1,694,092	$ 1,694,092		$ 0.26	$ 0.26		$ 0.26	$ 0.26	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003557	$0.003557		$ 17,447,675	$ 17,447,675		$ 2.67	$ 2.67		$ 2.67	$ 2.67	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.000878	$0.000878		$ 4,306,736	$ 4,306,736		$ 0.66	$ 0.66		$ 0.66	$ 0.66	
USR												
FIRST 833k kWh, PER kWh	$0.001951	$0.001951		$ 9,571,450	$ 9,571,450		$ 1.46	$ 1.46		$ 1.46	$ 1.46	
OVER 833k kWh, PER kWh	$0.000568	$0.000568		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.04200)	($0.042000)		$ (23,335,644)	$ (23,335,644)							
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1191	$0.1098	($0.0093)	$ 584,286,839	$ 538,526,398	$ (45,758,442)	$ 94.84	$ 85.51	$ (9.33)	$ 93.12	$ 92.72	$ (0.40)
Percentage Increase/Decrease May 2012 vs May 2011			-7.8%			-7.8%			-9.8%			-0.4%

Sources:
(a) OCC Set 1 RPD-17-CEI Current Schedule 1
(b) Schedule 1 - CEI_Errata with no ESP rate changes (highlighted items) for Rider DSE1; Rider DCR; Rider EDR automaker charge and Rider EDR infrastructure improvement charge
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
OHIO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 44,491,512	$ 44,491,512		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.031898	$0.031898		$ 259,734,033	$ 259,734,033		$ 23.92	$ 23.92		$ 23.92	$ 23.92	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 72,921,426						$ 34.41		
OVER 500 kWh	$0.078818			$ 82,158,308						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 380,843,977			$ 47.29					
				$ 535,923,711								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005856			$ 47,683,319			$ 4.39			$ 4.39	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004548			$ 37,032,741			$ 3.41			$ 3.41	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064129 (c)			$ 134,799,622						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054659 (c)			$ 329,571,059			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 535,923,711	$ 549,086,740	$ 13,163,030	$ 47.29	$ 48.90	$ 1.61	$ 54.11	$ 56.10	$ 1.99
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	[illegible]	$0.000000	$ 2,174,086	$ 2,174,086	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.001889	$0.001889		$ 15,381,453	$ 15,381,453		$ 1.42	$ 1.42		$ 1.42	$ 1.42	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000170	$0.000170		$ 1,384,249	$ 1,384,249		$ 0.13	$ 0.13		$ 0.13	$ 0.13	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 35,378,926	$ 35,378,926		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 2,282,268	$ 2,282,268		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 26,215	$ 26,215		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017700)	($0.017700)		$ (31,926,425)	$ (31,926,425)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 782,487	$ 782,487		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	$0.000000	$0.000000		$ -	$ -							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (32,703,676)	$ (32,703,676)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 20,934,736		$ (20,934,736)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
[illegible] (DCR), PER kWh		[illegible]	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (8,342,159)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.004592		($0.004592)	$ 14,255,380			$ 2.30					
OVER 500 kWh	$0.012202		($0.012202)	$ 35,828,017			$ 3.06					
				$ 41,741,238		$ (41,741,238)	$ 4.35		$ (4.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000212	$0.000212		$ 1,726,240	$ 1,726,240		$ 0.16	$ 0.16		$ 0.16	$ 0.16	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000362	$0.000362		$ 2,948,939	$ 2,948,939		$ 0.27	$ 0.27		$ 0.27	$ 0.27	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003354	$0.003354		$ 27,310,425	$ 27,310,425		$ 2.52	$ 2.52		$ 2.52	$ 2.52	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.001006	$0.001006		$ 8,191,499	$ 8,191,499		$ 0.76	$ 0.76		$ 0.75	$ 0.75	
USR												
FIRST 833k kWh, PER kWh	$0.002025	$0.002025		$ 16,490,481	$ 16,490,481		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
OVER 833k kWh, PER kWh	$0.001046	$0.001046		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.039000)	($0.039000)		$ (30,920,981)	$ (30,920,981)							
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1132	$0.1071	($0.0061)	$ 921,351,517	$ 871,838,573	$ (49,512,944)	$ 92.01	$ 87.35	$ (4.66)	$ 94.50	$ 94.56	$ 0.06
Percentage Increase/Decrease May 2012 vs May 2011			-5.4%			-5.4%			-5.1%			0.1%

Sources:
(a) OCC Set 1 RPD-17-OE Current Schedule 1
(b) Schedule 1 - OE_Errata with no ESP rate changes (highlighted items) for Rider DSE1; Rider DCR; Rider EDR automaker charge and Rider EDR infrastructure improvement charge
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE TOLEDO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 13,156,549	$ 13,156,549		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.035595	$0.035595		$ 74,017,397	$ 74,017,397		$ 26.70	$ 26.70		$ 26.70	$ 26.70	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 21,746,518						$ 34.41		
OVER 500 kWh	$0.078818			$ 20,521,524						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 94,763,805			$ 47.29					
				$ 137,031,847								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005804			$ 12,069,028			$ 4.35			$ 4.35	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004421			$ 9,193,171			$ 3.32			$ 3.32	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064094 (c)			$ 36,941,627						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054529 (c)			$ 81,960,688			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 137,031,847	$ 140,164,512	$ 3,132,665	$ 47.29	$ 48.76	$ 1.48	$ 54.11	$ 55.97	$ 1.86
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	[illegible]	$0.000000	$ 555,208	$ 555,208	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.002032	$0.002032		$ 4,225,407	$ 4,225,407		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000210	$0.000210		$ 438,681	$ 438,681		$ 0.16	$ 0.16		$ 0.16	$ 0.16	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 9,309,494	$ 9,309,494		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 339,917	$ 339,917		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 2,745	$ 2,745		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017600)	($0.017600)		$ (4,753,483)	$ (4,753,483)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 199,828	$ 199,828		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (424,625)	$ (424,625)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (3,518,025)	$ (3,518,025)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 5,346,221		$ (5,346,221)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
[illegible] DELIVERY CAPITAL RECOVERY (DCR), PER kWh		[illegible]	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	$0.000		$0.00	$ -			$ -					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.001800		($0.001800)	$ 1,543,593			$ 0.90					
OVER 500 kWh	$0.001800		($0.001800)	$ 1,161,926			$ 0.45					
				$ 2,705,519		$ (2,705,519)	$ 1.35		$ (1.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000818	$0.000818		$ 1,700,976	$ 1,700,976		$ 0.61	$ 0.61		$ 0.61	$ 0.61	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000120	$0.000120		$ 249,532	$ 249,532		$ 0.09	$ 0.09		$ 0.09	$ 0.09	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000257	$0.000257		$ 535,184	$ 535,184		$ 0.19	$ 0.19		$ 0.19	$ 0.19	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003472	$0.003472		$ 7,219,789	$ 7,219,789		$ 2.60	$ 2.60		$ 2.60	$ 2.60	
GENERATION COST RECONCILIATION (GCR), PER kWh	($0.000515)	($0.000515)		$ (1,070,908)	$ (1,070,908)		$ (0.39)	$ (0.39)		$ (0.39)	$ (0.39)	
USR												
FIRST 833k kWh, PER kWh	$0.002243	$0.002243		$ 4,663,543	$ 4,663,543		$ 1.68	$ 1.68		$ 1.68	$ 1.68	
OVER 833k kWh, PER kWh	$0.000561	$0.000561		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.02210)	($0.02210)		($742,042)	($742,042)							
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1208	$0.1184	($0.0024)	$ 251,186,755	$ 246,267,681	$ (4,918,074)	$ 91.50	$ 89.70	$ (1.80)	$ 96.98	$ 96.91	$ (0.07)
Percentage Increase/Decrease May 2012 vs May 2011			-2.0%			-2.0%			-2.0%			-0.1%

Sources:
(a) OCC Set 1 RPD-17-TE Current Schedule 1
(b) Schedule 1 - TE_Errata with no ESP rate changes (highlighted items) for Rider DSE1; Rider DCR; and Rider EDR automaker charge and Rider EDR infrastructure improvement charge
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP with D Increase (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP, D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP, D Incr	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.00	$4.00		$ 32,036,435	$ 32,036,435		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.029510	$0.029510		$ 144,751,448	$144,751,448		$ 22.13	$ 22.13		$ 22.13	$ 22.13	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 56,763,851						$ 34.41		
OVER 500 kWh	$0.078818			$ 50,545,869						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 216,620,351			$ 47.29					
				$ 324,130,071								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005662			$ 27,723,998			$ 4.24			$ 4.24	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.002964			$ 14,538,912			$ 2.22			$ 2.22	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064145 (c)			$ 94,045,469						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054573 (c)			$187,678,034			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 324,130,071	$323,986,412	$ (143,659)	$ 47.29	$ 47.56	$ 0.27	$ 54.11	$ 54.76	$ 0.65
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000267	$0.000000	$ 1,309,679	$ 1,309,679	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.002086	$0.002086		$ 10,241,987	$ 10,241,987		$ 1.57	$ 1.57		$ 1.57	$ 1.57	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000300	$0.000300		$ 1,471,550	$ 1,471,550		$ 0.23	$ 0.23		$ 0.23	$ 0.23	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 21,688,356	$ 21,688,356		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 1,044,703	$ 1,044,703		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 8,276	$ 8,276		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017000)	($0.017000)		$ (8,369,857)	$ (8,369,857)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 471,374	$ 471,374		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (588,672)	$ (588,672)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.018000)	($0.018000)		$ (7,193,592)	$ (7,193,592)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 12,611,182		##########	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DISTRIBUTION RATE CASE INCREASE, PER kWh		[illegible]	$0.002326		$ 11,409,571	$11,409,571		$ 1.74	$ 1.74		$ 1.74	$ 1.74
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (6,006,832)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.011634		($0.011634)	$ 23,252,630			$ 5.82					
OVER 500 kWh	$0.014952		($0.014952)	$ 21,536,089			$ 3.74					
				$ 38,781,887		##########	$ 8.56		$ (8.56)			
DEFERRED GENERATION COST (DGC)												
ALL SUMMER kWh, PER kWh		$0.001178	$0.001178		$ 1,727,111						$ 0.88	$ 0.88
ALL WINTER kWh, PER kWh		$0.001178	$0.001178		$ 4,051,174			$ 0.88	$ 0.88			
					$ 5,778,286	$ 5,778,286						
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000446	$0.000446		$ 2,187,704	$ 2,187,704		$ 0.33	$ 0.33		$ 0.33	$ 0.33	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000345	$0.000345		$ 1,694,092	$ 1,694,092		$ 0.26	$ 0.26		$ 0.26	$ 0.26	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003557	$0.003557		$ 17,447,676	$ 17,447,676		$ 2.67	$ 2.67		$ 2.67	$ 2.67	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.000878	$0.000878		$ 4,306,736	$ 4,306,736		$ 0.66	$ 0.66		$ 0.66	$ 0.66	
USR												
FIRST 833k kWh, PER kWh	$0.001951	$0.001951		$ 9,571,450	$ 9,571,450		$ 1.46	$ 1.46		$ 1.46	$ 1.46	
OVER 833k kWh, PER kWh	$0.000588	$0.000588		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.04200)	($0.042000)		$ (23,335,644)	$ (23,335,644)							
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1191	$0.1121	($0.0070)	$ 664,266,839	$549,937,969	##########	$ 94.84	$ 87.28	$ (7.69)	$ 93.12	$ 84.46	$ 1.35
Percentage Increase/Decrease May 2012 vs May 2011			-5.9%			-5.9%			-8.0%			1.4%

Sources:
(a) OCC Set 1 RPD-17-CEI Current Schedule 1
(b) Schedule 1 - CEI_Errata with no ESP rate changes (highlighted items) for Rider DSE1; Rider EDR automaker charge and Rider EDR infrastructure improvement charge
Instead of Rider DCR, revenue increase reflected for Distribution Rate case increase at 60% granted of a $ 114 million request ($124 million (DCR revenue in Schedule 1) x 92% (% of DCR revenue shown as distribution rate case in WRR Attachment 1))
Distribution revenue increase allocated in manner as DCR Revenue (per OCC INT-20) for CEI 51.9% and for RES 32.14%
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP with D Increase (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
OHIO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 44,491,512	$ 44,491,512		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.031898	$0.031898		$ 259,734,033	$ 259,734,033		$ 23.92	$ 23.92		$ 23.92	$ 23.92	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068816			$ 72,021,426						$ 34.41		
OVER 500 kWh	$0.078818			$ 82,158,308						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 380,843,977			$ 47.29					
				$ 535,923,711								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005856			$ 47,663,319			$ 4.39			$ 4.39	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004546			$ 37,032,741			$ 3.41			$ 3.41	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064129 (c)			$ 134,799,622						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054559 (c)			$ 329,571,059			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 535,923,711	$ 549,086,740	$ 13,163,030	$ 47.29	$ 48.90	$ 1.61	$ 54.11	$ 56.10	$ 1.99
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	$0.000267	$0.000000	$ 2,174,086	$ 2,174,086	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.001689	$0.001689		$ 15,381,453	$ 15,381,453		$ 1.42	$ 1.42		$ 1.42	$ 1.42	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000170	$0.000170		$ 1,384,249	$ 1,384,249		$ 0.13	$ 0.13		$ 0.13	$ 0.13	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 35,378,928	$ 35,378,928		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 2,282,268	$ 2,282,268		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 25,215	$ 25,215		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017700)	($0.017700)		$ (31,926,425)	$ (31,926,425)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 782,487	$ 782,487		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	$0.000000	$0.000000		$ -	$ -							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (32,703,576)	$ (32,703,576)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 20,934,736		$ (20,934,736)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
DISTRIBUTION RATE CASE INCREASE, PER kWh (b)		$0.001350	$0.001350		$ 10,989,336	$ 10,989,336		$ 1.01	$ 1.01		$ 1.01	$ 1.01
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	($1.00)		$1.00	$ (8,342,159)			$ (1.00)					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.004592		($0.004592)	$ 14,255,380			$ 2.30					
OVER 500 kWh	$0.012202		($0.012202)	$ 35,828,017			$ 3.05					
				$ 41,741,238		$ (41,741,238)	$ 4.35		$ (4.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000212	$0.000212		$ 1,726,240	$ 1,726,240		$ 0.16	$ 0.16		$ 0.16	$ 0.16	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000362	$0.000362		$ 2,948,939	$ 2,948,939		$ 0.27	$ 0.27		$ 0.27	$ 0.27	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003354	$0.003354		$ 27,310,425	$ 27,310,425		$ 2.52	$ 2.52		$ 2.52	$ 2.52	
GENERATION COST RECONCILIATION (GCR), PER kWh	$0.001006	$0.001006		$ 8,191,499	$ 8,191,499		$ 0.75	$ 0.75		$ 0.75	$ 0.75	
USR												
FIRST 833k kWh, PER kWh	$0.002025	$0.002025		$ 16,490,481	$ 16,490,481		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
OVER 833k kWh, PER kWh	$0.001046	$0.001046		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.039000)	($0.039000)		$ (30,920,981)	$ (30,920,981)							
(EDR) - AUTOMAKER CHARGE PROVISION, PER kWh		$0.00000	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
(EDR) - INFRASTRUCTURE IMPROVEMENT PROVISION, PER kWh		$0.00000	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1132	$0.1084	($0.0047)	$ 921,351,517	$ 882,827,908	$ (38,523,609)	$ 92.01	$ 88.36	$ (3.65)	$ 94.50	$ 95.57	$ 1.07
Percentage Increase May 2012 vs May 2011			-4.2%			-4.2%			-4.0%			1.1%

Sources:
(a) OCC Set 1 RPD-17-OE Current Schedule 1
(b) Schedule 1 - OE_Errata with no ESP rate changes (highlighted items) for Rider DSE1; Rider EDR automaker charge and Rider EDR infrastructure improvement charge
Instead of Rider DCR, revenue increase reflected for Distribution Rate case increase at 60% granted of a $ 114 million request ($124 million (DCR revenue in Schedule 1) x 92% (% of DCR revenue shown as distribution rate case in WRR Attachment 1))
Distribution revenue increase allocated in manner as DCR Revenue (per OCC INT-26) for OE 35.6% and for RES 45.13%
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-56, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

ESP Estimated Rate Impacts - No ESP with D Increase (b)	Rate per kWh			Annualized Revenue			RS Customer Bill (Winter)			RS Customer Bill (Summer)		
THE TOLEDO EDISON COMPANY	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP D Incr	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)	MAY 2011 PROPOSED RATES	MAY 2012 RATES - No ESP	Increase (Decrease)
RESIDENTIAL SERVICE (RS) - TOTAL	(a)	(b)		(a)	(b)		750 kWh x Applicable Rate			750 kWh x Applicable Rate		
DISTRIBUTION CHARGES												
CUSTOMER CHARGE												
BILLS, PER MONTH	$4.000	$4.000		$ 13,156,549	$ 13,156,549		$ 4.00	$ 4.00		$ 4.00	$ 4.00	
ENERGY CHARGE, PER kWh	$0.035595	$0.035595		$ 74,017,397	$ 74,017,397		$ 26.70	$ 26.70		$ 26.70	$ 26.70	
TRANSMISSION CHARGES												
TRANSMISSION & ANCILLARY SVC (TAS), PER kWh	$0.000000			$ -			$ -			$ -		
GENERATION CHARGES												
ALL SUMMER kWh, PER kWh												
FIRST 500 kWh	$0.068818			$ 21,746,518						$ 34.41		
OVER 500 kWh	$0.078818			$ 20,521,524						$ 19.70		
ALL WINTER kWh, PER kWh	$0.063047			$ 94,763,805			$ 47.29					
				$ 137,031,847								
GENERATION CAPACITY CHARGES												
GENERATION CAPACITY CHARGE, PER kWh		$0.005804			$ 12,069,026			$ 4.35			$ 4.35	
NON-MARKET-BASED SERVICES RIDER (NMB), PER kWh		$0.004421			$ 9,193,171			$ 3.32			$ 3.32	
GENERATION ENERGY CHARGES												
ALL SUMMER kWh, PER kWh		$0.064094 (c)			$ 38,941,827						$ 48.30 (c)	
ALL WINTER kWh, PER kWh		$0.054529 (c)			$ 81,960,668			$ 41.09 (c)				
GENERATION AND TRANSMISSION CHARGES				$ 137,031,847	$ 140,164,512	$ 3,132,666	$ 47.29	$ 48.76	$ 1.46	$ 54.11	$ 55.97	$ 1.86
RIDERS												
DSM / ENERGY EFFICIENCY												
(DSE1), PER kWh	$0.000267	[illegible]	$0.000000	$ 555,208	$ 555,208	$ -	$ 0.20	$ 0.20	$ -	$ 0.20	$ 0.20	$ -
(DSE2), PER kWh	$0.002032	$0.002032		$ 4,225,407	$ 4,225,407		$ 1.52	$ 1.52		$ 1.52	$ 1.52	
DEMAND SIDE MANAGEMENT (DSM), PER kWh	$0.000210	$0.000210		$ 436,681	$ 436,681		$ 0.16	0.16		$ 0.16	0.16	
STATE kWh TAX (SKT)												
FIRST 2,000 kWh, PER kWh	$0.004660	$0.004660		$ 9,309,494	$ 9,309,494		3.50	3.50		3.50	3.50	
NEXT 13,000 kWh, PER kWh	$0.004200	$0.004200		$ 339,917	$ 339,917		-	-		-	-	
ABOVE 15,000 kWh, PER kWh	$0.003640	$0.003640		$ 2,745	$ 2,745		-	-		-	-	
RESIDENTIAL DISTRIBUTION CREDIT (RDC), PER kWh	($0.017600)	($0.017600)		$ (4,753,483)	$ (4,753,483)							
AMI / MODERN GRID (AMI), PER kWh	$0.000096	$0.000096		$ 199,828	$ 199,828		$ 0.07	$ 0.07		$ 0.07	$ 0.07	
DELTA REVENUE RECOVERY RIDER (DRR), PER kWh	$0.000000	$0.000000		$ -	$ -		$ -	$ -		$ -	$ -	
ECONOMIC DEVELOPMENT (EDR)												
WATER HEATING, PER kWh	($0.005000)	($0.005000)		$ (424,625)	$ (424,625)							
SPACE HEATING & LOAD MANAGEMENT, PER kWh	($0.019000)	($0.019000)		$ (3,518,025)	$ (3,518,025)							
DELIVERY SERVICE IMPROVEMENT (DSI), PER kWh	$0.002571		($0.002571)	$ 5,346,221		$ (5,346,221)	$ 1.93		$ (1.93)	$ 1.93		$ (1.93)
[illegible]		[illegible]	$0.001621		$ 3,370,410	$ 3,370,410		$ 1.22	$ 1.22		$ 1.22	$ 1.22
RESIDENTIAL DEFERRED DISTRIBUTION COST (RDD)												
CUSTOMER CHARGE	$0.000		$0.00	$ -			$ -					
ALL WINTER kWh, PER kWh												
FIRST 500 kWh	$0.001800		($0.001800)	$ 1,543,593			$ 0.90					
OVER 500 kWh	$0.001800		($0.001800)	$ 1,161,926			$ 0.45					
				$ 2,705,519		$ (2,705,519)	$ 1.35		$ (1.35)			
NON-DISTRIBUTION UNCOLLECTIBLE RIDER (NDU), PER kWh	$0.000818	$0.000818		$ 1,700,976	$ 1,700,976		$ 0.61	$ 0.61		$ 0.61	$ 0.61	
DISTRIBUTION UNCOLLECTIBLE RIDER (DUN)	$0.000120	$0.000120		$ 249,532	$ 249,532		$ 0.09	$ 0.09		$ 0.09	$ 0.09	
DEFERRED FUEL COST RECOVERY RIDER (DFC), PER kWh	$0.000257	$0.000257		$ 535,184	$ 535,184		$ 0.19	$ 0.19		$ 0.19	$ 0.19	
ALTERNATIVE ENERGY RESOURCE RIDER (AER), PER kWh	$0.003472	$0.003472		$ 7,219,789	$ 7,219,789		$ 2.60	$ 2.60		$ 2.60	$ 2.60	
GENERATION COST RECONCILIATION (GCR), PER kWh	($0.000515)	($0.000515)		$ (1,070,908)	$ (1,070,908)		$ (0.39)	$ (0.39)		$ (0.39)	$ (0.39)	
USR												
FIRST 833k kWh, PER kWh	$0.002243	$0.002243		$ 4,663,543	$ 4,663,543		$ 1.68	$ 1.68		$ 1.68	$ 1.68	
OVER 833k kWh, PER kWh	$0.000561	$0.000561		$ -	$ -							
RESIDENTIAL GENERATION CREDIT (WINTER kWh)	($0.02210)	($0.02210)		($742,042)	($742,042)							
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
[illegible]		[illegible]	$0.00000		$ -	$ -		$ -	$ -		$ -	$ -
TOTAL - RS	$0.1208	$0.1201	($0.0007)	$ 251,186,755	$ 249,638,091	$ (1,548,664)	$ 91.50	$ 90.92	$ (0.59)	$ 98.98	$ 98.13	$ 1.14
Percentage Increase/Decrease May 2012 vs May 2011			-0.6%			-0.6%			-0.6%			1.2%

Sources:
(a) OCC Set 1 RPD-17-TE Current Schedule 1
(b) Schedule 1 - TE_Errata, with no ESP rate changes (highlighted items) for Rider DSE1; Rider DCR; and Rider EDR automaker charge and Rider EDR infrastructure improvement charge
Instead of Rider DCR, revenue increase reflected for Distribution Rate case increase at 60% granted of a $ 114 million request ($124 million (DCR revenue in Schedule 1) x 92% (% of DCR revenue shown as distribution rate case in WRR Attachment 1))
Distribution revenue increase allocated in manner as DCR Revenue (per OCC INT-20) for TE 12.5% and for RES 39.42%
(c) For calculation of bills, May 2012 RS Generation Charge per OCC INT-55, which do not incorporate PIPP discounts shown on Schedule 1 Winter $ 0.05479 Summer $ 0.06440

Attachment 1

From:	"McNamee, Thomas" <Thomas.McNamee@puc.state.oh.us>
To:	<burkj@firstenergycorp.com>, <Amy.Spiller@Duke-Energy.com>, <aporter@szd...
CC:	"Lesser, Steve" <Steve.Lesser@puc.state.oh.us>, "Turkenton, Tammy" <Tamm...
Date:	2/23/2010 7:53 AM
Subject:	RE: Meeting on February 25, 2010

The FirstEnergy meeting will be in Room 11-B and the phone-in number is 614.644.1099.

-----Original Message-----
From: burkj@firstenergycorp.com [mailto:burkj@firstenergycorp.com]
Sent: Monday, February 22, 2010 3:36 PM
To: Amy.Spiller@Duke-Energy.com; aporter@szd.com; beitingm@firstenergycorp.com; cmiller@szd.com; cmooney2@columbus.rr.com; cynthia.brady@constellation.com; 'David A. Kutik'; dane.stinson@baileycavalieri.com; david.fein@constellation.com; 'David Boehm'; dmancino@mwe.com; 'Dave Rinebolt'; 'Debbie Ryan'; Luckey, Duane; 'Ed Hess'; elmiller@firstenergycorp.com; 'Garrett Stone'; gdunn@szd.com; 'Glenn Krassen'; 'Greg Lawrence'; 'Grant W Garber'; haydenm@firstenergycorp.com; 'John W. Bentine'; 'Joe Bowser'; 'Joe Clark'; Lang, Jim; 'Art Korkosz'; 'Lance Keiffer'; 'Lisa McAlister'; mdortch@kravitzllc.com; mhpetricoff@vorys.com; 'Mike Lavanga'; 'Michael Kurtz'; mparke@firstenergycorp.com; 'Kevin Murray'; 'Matthew Warnock'; 'Matthew White'; 'Mark S. Yurick'; nmoser@theOEC.org; nolan@theOEC.org; Strom, Ray; 'Richard Sites'; robinson@citizenpower.com; rtriozzi@city.cleveland.oh.us; 'Sam Randazzo'; sbeeler@city.cleveland.oh.us; 'JEFF SMALL'; smhoward@vssp.com; smhoward@vorys.com; steven.huhman@morganstanley.com; Turkenton, Tammy; teresa.ringenbach@directenergy.com; 'Tom Froehle'; McNamee, Thomas; 'Thomas O'Brien'; trent@theOEC.org; 'Vicki Leach-Payne'; will@theOEC.org; williams.toddm@gmail.com; wis29@yahoo.com; henryeckhart@aol.com; mvincel@lasclev.org; gthomas@gtpowergroup.com; laurac@chappelleconsulting.net; burkj@firstenergycorp.com; jpmeissn@lasclev.org; Fortney, Bob; lmcbride@calfee.com
Subject: Meeting on February 25, 2010

A meeting will be held on Thursday, February 25, 2010 at 10:00 a.m. in the offices of the PUCO on the 11th floor. The purpose of the meeting will be to continue the discussions that were held at the PUCO on December 1, 2009 following the prehearing conference in the MRO. Staff will provide the number for a bridge line. All parties are invited to attend or call-in.

****

James W. Burk
Senior Attorney
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Email: burkj@firstenergycorp.com

From: "Wright, Bill" <bill.wright@puc.state.oh.us>
To: "Keeton, Kim" <Kim.Keeton@puc.state.oh.us>, "Andre Porter" <aporter@szd....
CC: "Turkenton, Tammy" <Tammy.Turkenton@puc.state.oh.us>
Date: 11/24/2009 4:39 PM
Subject: RE: 11-24-2009 ESP ALTERNATIVE

This email was inadvertently sent to the wrong service list. It was meant for parties in Case No. 09-906. Please disregard and destroy. Thank you.

From: Keeton, Kim
Sent: Tuesday, November 24, 2009 4:01 PM
To: Andre Porter; Arthur Korkosz; Barth Royer; Beth Hixon; Brian Ballenger; Christopher Miller; Craig Goodman; Craig Smith; Cynthia Fonner; D Sullivan; Damon Xenopoulos; Dane Stinson; David A. Muntean; David Boehm; David Fein; David Rinebolt; Douglas Mancino; E. Brett Breitschwerdt; Ebony Miller; Eric Weldele; F. Mitchell Dutton; Garrett Stone; Glenn Krassen; Greg Dunn; Greg Lawrence; Henry Eckhart; Howard Petricoff; James Burk; Jeff Small; John Bentine; Jones, John H.; Joseph Clark; Joseph Meissner; Lance Keiffer; Langdon Bell; Larry Gearhardt; Leslie Kovacik; Lisa McAlister; Mark Hayden; Mark Yurick; Matthew White; Maureen Grady; Ned Ford; Nicholas York; Nolan Moser; Pirik, Christine; Price, Greg; Richard Sites; Sam Randazzo; Sean Vollman; Sheilah McAdams; Steve Howard; Steve Millard; Teresa Ringenbach; Theodore Robinson; Wright, Bill
Cc: Turkenton, Tammy
Subject: 11-24-2009 ESP ALTERNATIVE
Importance: High

Attached is an ESP alternative proposal to be discussed at the December 1, 2009 pre-hearing. This proposal was referenced in Staff comments filed today in Case 09-906-EL-SSO.

PM Please consider the environment before printing this e-mail

Attachment 2

OCC Set 2
Witness: Ridmann

Case No. 10-0388-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C.§ 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

OCC
Set 2-62

Referring to page 16 of the Stipulation that provides "Staff and Signatory Parties shall at their discretion conduct an annual audit" of Rider DCR filings:

a) How will a Signatory Party provide notice that it wishes to conduct an annual audit?

b) If the Staff does not provide notice that it wishes to conduct an annual audit, will there be no further PUCO action regarding the Rider DCR filings?

c) What matters would be considered in the annual audit related to Rider DCR?

d) How does this provision provide for an audit to review the reasonableness of the Company's expenditures for capital additions included in the DCR Rider?

e) How does this provision provide for an audit to review the prudence of the Company's expenditures for capital additions included in the DCR Rider?

f) How much of the costs associated with the annual audits related to Rider DCR would be borne by the Company's retail customers?

Response:

a) The Companies anticipate that Signatory Parties interested in performing an audit would notify them of their intent to do so via a filing on the docket under which the applicable quarterly Rider DCR filing is made that prompts such an audit. Signatory Parties must file their recommendations and/or objections within the timeframes listed on page 16 of the Stipulation.
b) The Companies cannot predict PUCO actions.
c) The audits would be of a technical nature primarily involving reviews for accuracy, consistency with the Stipulation, mathematical errors, and correctness of supporting calculations.
d) Please see response to part (c) above.
e) Please see response to part (c) above.
f) The Stipulation does not contemplate that the Companies would absorb the costs associated with an annual audit.

Attachment 3

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

RESPONSES TO DATA REQUESTS

OCC-INT-4 Referring to paragraph 49 of the Application:

a. How was the level of 400,000 kilowatts determined as the limit for the load response program?

b. What is the reason for limiting entry into the program rather than attracting more than 400,000 kilowatts for the load response program?

Response: a. 400,000 kW approximately represents the current level of interruptible load on the FE Ohio system for the customers that would qualify for the proposed Optional Load Response Program Rider on 1/1/2009.

b. As this is a new program, an initial limit was set in order to study the effectiveness of the program.

Attachment 4

OCC Set 2
Witness: Ridmann

Case No. 10-0388-EL-SSO
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C.§ 4928.143 in the Form of an Electric Security Plan.

RESPONSES TO REQUEST

OCC Set 2-26 Regarding the amount of ATSI's RTEP obligation for the period from June 1, 2011 to May 31, 2016 if ATSI becomes a member of PJM:

a) What is the total monetary amount projected for the obligation, by calendar year?

b) What assumptions are used in reaching the projected amount for the obligation?

c) What portion of the obligation do you project would be assignable to service to customers of OE, CEI, and TE for each calendar year?

d) What assumptions are used in reaching the projected assignment of the obligation to OE, CEI, and TE?

Response: For parts a.) and b.), please see attachment OCC Set 2-26 Attachment 1 that provides the estimated annual revenue requirements to be allocated to load in the ATSI zone, by calendar year, for RTEP projects that were approved by PJM prior to ATSI's planned integration. An estimate of the revenue requirements for projects approved by PJM after ATSI's integration has not been developed.

For parts c.) and d.), the portion of the obligation assignable to service to customers of OE, CEI, and TE has been estimated to be 85% of the amounts shown in OCC Set 2-26 Attachment 1 The portion is based on OE's, CEI's, and TE's share of the 2009 peak load for the ATSI footprint, and it assumes that the companies' peak load ratio share does not change over time.

Exhibit Set 2-26 Attachment 1

ATSI Share of Annual Revenue Requirements for Major RTEP Approved Projects

(MAPP and PATH Delayed to 2016)

Estimated Annual Share of Revenue Requirements w/ Depreciation ($M-yr)

Project and Sponsor Company	Voltage level:	Original Projected ISD	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Carson-Suffolk		2011	$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Dominion	500 kV												
TrAIL		2011	$ 14	$ 14	$ 13	$ 13	$ 13	$ 12	$ 12	$ 12	$ 12	$ 11	$ 11
Allegheny Energy and Dominion	500 kV												
Susquehanna – Roseland		2011	$ 19	$ 24	$ 24	$ 23	$ 23	$ 22	$ 22	$ 21	$ 21	$ 20	$ 20
PSEG and PPL Electric	500 kV												
Branchburg to Roseland to Hudson		2013	$ -	$ -	$ 18	$ 18	$ 17	$ 17	$ 16	$ 16	$ 16	$ 15	$ 15
PSEG	500 kV												
MAPP		2014	$ 1	$ 6	$ 13	$ 19	$ 19	$ 23	$ 22	$ 21	$ 20	$ 20	$ 20
Dominion, PEPCO and BG&E	500 kV												
PATH		2014	$ 2	$ 2	$ 6	$ 11	$ 15	$ 17	$ 17	$ 17	$ 17	$ 16	$ 16
Allegheny Energy and AEP (WV)	765 kV												
		Sub-Total	$ 38	$ 48	$ 77	$ 87	$ 90	$ 94	$ 92	$ 89	$ 87	$ 85	$ 85
Other Eligible Projects	500 kV		$ 2	$ 2	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4
		Total	$ 40	$ 50	$ 80	$ 91	$ 93	$ 98	$ 95	$ 93	$ 91	$ 88	$ 88
Estimated OE, CEI, TE Portion			85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Estimated OE, CEI, TE Revenue Requirements			$ 20	$ 43	$ 68	$ 77	$ 79	$ 83	$ 81	$ 79	$ 77	$ 75	$ 75

Assumptions:

ATSI load has a load ratio share of 8.46% for all years
Revenue Requirements calculated based on PJM Schedule 12 methodology
Calculated annual Revenue Requirements as projected net plant of project multiplied by Fixed Charge Rate for constructing TO
Fixed Charge Rates (FCR) and Depreciation Rates are taken from constructing TOs formula rates
All projects besides Branchburg-Roseland-Hudson, have been approved for cost recovery during construction.
MAPP and PATH were delayed based on PJM currently analyzing the needed in-service dates for the RTEP backbone projects
details at: http://www.pjm.com/planning/rtep-upgrades-status/backbone-status.aspx

Attachment 5

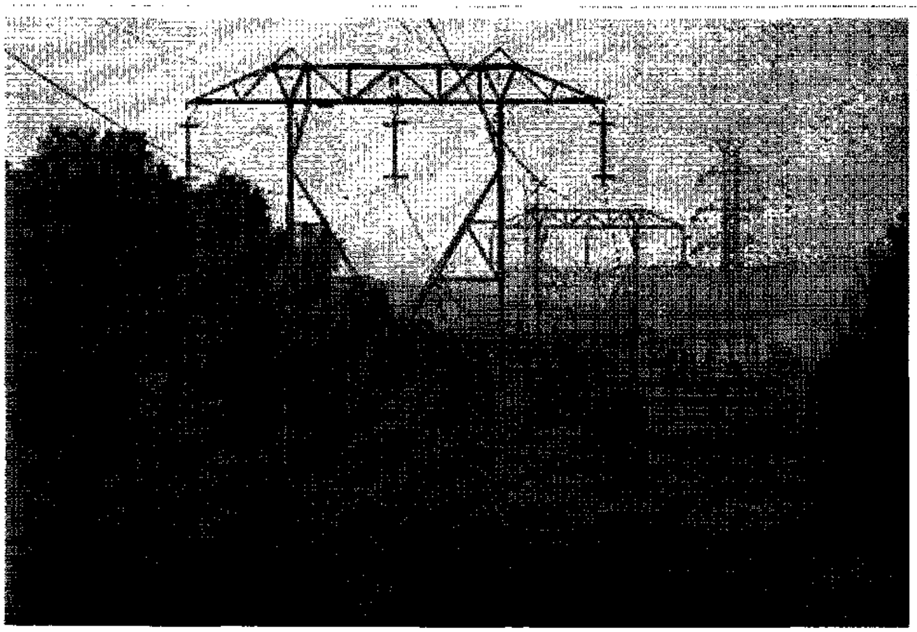
nj.com Everything Jersey

State postpones decision on N.J. Susquehanna-Roseland power line project

By Lawrence Ragonese/The Star-Ledger
January 15, 2010, 1:35PM

NEWARK -- The state Board of Public Utilities has postponed a decision on a massive North Jersey power line project, voting unanimously to consider new evidence on the need for the project, particularly if there is truly a demand for the additional power.

The BPU, however, at a hearing this morning in Newark, said it would only be a short delay and expects to rule on PSE&G's proposed Susquehanna-Roseland high voltage line within 30 days.



Jerry McCrea/The Star-Ledger

A view of PSE&G's Susquehanna-Roseland transmission line in Montville. A proposal by PSE&G would more than triple the line's current size and capacity.

At issue is a 45-mile, $750 million high-voltage line that would cut through Morris, Essex, Sussex and Warren counties, which Public Service Electric & Gas contends is needed to maintain reliability of the regional electricity grid.

N.J. Susquehanna-Roseland power line is approved in Pennsylvania

Opponents of the project in New Jersey say it would harm the environment to provide power that would go to places outside of New Jersey, solely to generate profits for the power company.

The BPU was poised to decide the fate of the 45-mile, $750 million project today but agreed to consider a recent decision by a related power provider in the mid-Atlantic region to withdraw a similar power line project application.

PATH Allegheny Virginia Transmission Corp. has asked for permission from a Virginia regulatory agency to withdraw its proposal to build a 276-mile, $1.8 billion high-voltage transmission line from West Virginia, through Virginia and to Maryland, due to a weak economy and growing energy conservation movement.

BPU Commissioner Joseph Fiordaliso, in a recommendation made today and accepted by his colleagues, said his agency has an obligation to determine if similar factors may be in play for the New Jersey application.

"This board would be remiss in not taking the opportunity to review this information," Fiordaliso said to a packed hearing room.

Previous coverage:

- **PSE&G offers money to 16 N.J. towns to support power line**

- **Vote on proposed massive N.J. power line postponed**

- **PSE&G amends power line proposal in northern N.J.**

- **March 3, 2009: Citizens group asks N.J. to block power-line project**

- **Dec. 22, 2008: Highlands Council draft report recommends against high-voltage line**

Attachment 6

News Releases

March 3, 2010 - PECO harnesses solar power - Company purchases 6 megawatts of solar credits

Contact: Cathy Engel 215-841-5555

PHILADELPHIA (March 3, 2010) – PECO has signed 10-year agreements to purchase 6 megawatts, or 80,000 solar energy credits, in support of Pennsylvania's Alternative Energy Portfolio Standards (AEPS). The purchases were made at an average price of $256.57 per megawatt hour.

Enough energy to power nearly 1,000 homes for 10 years, it would take about eight football fields of solar panels to produce the 6 megawatts purchased. Once complete, the company's purchases could result in the same environmental benefit as planting more than 48,000 acres of trees or not driving more than 133 million miles.

The first utility in the state to buy and bank green energy credits, these solar purchases are in addition to more than 450,000 megawatt-hours of wind and other renewable energy credits already purchased by PECO since 2008.

"These purchases underscore our strong environmental focus and commitment to renewable energy for our customers," said Denis P. O'Brien, PECO president and CEO. "By acting now PECO is helping to increase demand for renewable energy resources and promote clean energy technologies."

The AEPS legislation requires that by 2011, 3.5 percent of the energy sold to PECO customers is generated from renewable resources such as wind, landfill gas, and solar. These requirements are measured by renewable energy credits. Credits are sold by electric generators on a one-to-one basis each time they produce one megawatt-hour of renewable energy.

PECO's support of alternative energy is part of a broader environmental initiative to preserve the environment and help customers become more environmentally responsible. Totaling more than $15.3 million of work, the comprehensive program also includes the installation of a green roof and new energy efficient Crown Lights system at the company's Center City headquarters; the opening of PECO's first 'green building' in West Chester, recently awarded silver certification for Leadership in Energy and Environmental Design (LEED); improvements to secure LEED certification for many other company work sites; the increased use of hybrid and biodiesel vehicles; support for community environmental projects; and enhanced tools and programs to help customers use energy more efficiently.

PECO's efforts are a component of Exelon 2020: A Low-Carbon Roadmap, the comprehensive environmental plan of PECO's parent company. Exelon 2020 sets the goal of reducing, offsetting or displacing more than 15 million metric tons of greenhouse gas emissions per year by 2020. This is more than the company's 2001 carbon footprint and is equivalent to taking nearly 3 million cars off American roads and highways.

PECO completed the solar credit purchase through a competitive Request for Proposal (RFP) process launched in October 2009. The RFP process was overseen by independent monitor Navigant Consulting, and approved by the Pennsylvania Public Utility Commission (PUC).

For more information visit www.peco.com/AEPS

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Based in Philadelphia, PECO is an electric and natural gas utility subsidiary of Exelon Corporation (NYSE: EXC). PECO serves 1.6 million electric and 486,000 natural gas customers in southeastern Pennsylvania and employs about 2,400 people in the region. PECO delivered 84.3 billion cubic feet of natural gas and 38.1 billion kilowatt-hours of electricity in 2009. Founded in 1881, PECO is one of the Greater Philadelphia Region's most active corporate citizens, providing leadership, volunteer and financial support to numerous arts and culture, education, environmental, economic development and community programs and organizations.

If you are a member of the media and would like to receive PECO news releases via e-mail please send your e-mail address to PECO.Communication@exeloncorp.com

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing the *Direct Testimony of Wilson Gonzalez on Behalf of the Office of the Ohio Consumers' Counsel* has been served electronically this 15th day o f April 2010.

Jeffrey L. Small
Assistant Consumers' Counsel

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