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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 Establish a Standard Service Offer Pursuant To R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-0935-EL-SSO

Direct Testimony of
Michael M. Schnitzer

Director,

The NorthBridge Group, Inc.

On Behalf of Intervenors

Constellation NewEnergy, Inc.

and

Constellation Energy Commodities Group, Inc.

Dated: September 29, 2008

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I. INTRODUCTION

A. Identification of Witness

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A. My name is Michael M. Schnitzer and my business address is 30 Monument Square, Concord, MA 01742.

Q. MR. SCHNITZER, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Director of The NorthBridge Group, Inc. ("NorthBridge"). NorthBridge is a consulting firm specializing in providing economic and strategic advice to the electric and natural gas industries.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE IN THE ELECTRIC ENERGY INDUSTRY.

A. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have focused throughout this time on advising energy companies about strategic issues, particularly those relating to finance and market structure issues. In so doing, I have experience working with private sector clients in the electric utility, natural gas, private power, steel and coatings industries, as well as with public and nonprofit agencies.

I have testified before the Federal Energy Regulatory Commission ("FERC") and a number of state commissions on issues relating to competitive restructuring and wholesale market design, including Locational Marginal Pricing and Financial Transmission Rights, Regional Transmission Organizations, resource adequacy, and transmission expansion pricing. On several occasions I have been invited by FERC staff to participate as a panelist in technical conferences on these subjects. I have also testified before several state commissions, including Maryland, Illinois, Connecticut and Pennsylvania on the subject of the provision of default service to retail customers.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science degree in Management from the Sloan School of Management, of the Massachusetts Institute of Technology, which I received in 1979. My concentration was in finance. I also received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975.

B. Purpose of Testimony and Conclusions

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (collectively, "Constellation") to review the public policy and cost-benefit analysis conducted by The Toledo Edison Company, Ohio Edison Company and the Cleveland Electric Illuminating Company ("FE Companies")[1] which claimed that in the aggregate the Electric Security Plan ("ESP") is more favorable than the Market Rate Option ("MRO") filed in the companion docket Case No. 08-936-EL-SSO.

[1] FirstEnergy Corp. is a public utility holding company which owns and operates The Toledo Edison Company ("TE), Ohio Edison Company ("OE") and the Cleveland Electric Illuminating Company ("CEI"). The application for an electric security plan was filed jointly by FirstEnergy Corp. on behalf of these three Ohio electric utilities.

Q. PLEASE DESCRIBE HOW YOU CONDUCTED YOUR REVIEW OF FIRSTENERGY'S DETERMINATION THAT ITS ELECTRIC SECURITY PLAN IS MORE FAVORABLE THAN ITS MARKET RATE OPTION.

A. I reviewed the applications of the FE Companies and the testimony of FE Company witnesses Messrs. David M. Blank, Harvey L. Wagner, Gregory F. Hussing and Kevin T. Warvell and the testimony of outside experts Mssrs. Frank C. Graves and Scott T. Jones. I examined their analyses and assumptions, and, in the case of Mr. Blank, his policy arguments. I also used publicly available information about current wholesale market forward prices to update the price information contained in the FE Companies' filing.

Q. BASED ON YOUR REVIEW OF THE PUBLIC POLICY AND COST-BENEFITS ANALYSIS CONDUCTED BY THE FE COMPANIES, DO YOU AGREE THAT THE FE COMPANIES HAVE DEMONSTRATED THAT THE ESP PRODUCES BENEFITS RELATIVE TO THE MRO?

A. No, I do not. My answer is based on the following conclusions.

- First, while electricity market conditions may change in the future, current forward electricity prices are lower than they were in July 2008, and the evidence that was offered by the FE Companies in support of the ESP proposal is now out of date.
- Second, the FE Companies' quantitative comparison between the MRO and ESP is materially flawed, in part because it was not done on an "apples to apples" basis, and in part because it incorporates an incorrect risk premium analysis.
- Third, when the FE Companies' quantitative analysis is adjusted to reflect updated market conditions, and to correct the flaws in their ESP and MRO comparison, the FE claimed benefit of the ESP for the FE Companies in the aggregate is completely eliminated and the ESP is actually \$200 million to \$840 million more expensive for customers than the MRO using Mr. Blanks' own aggregate cost-benefit formulation.

When these quantitative adjustments are made on a company-by-company basis, the MRO is clearly preferable to the ESP for customers of at least two of the three FE Companies.

- Fourth, a careful analysis of the ESP structure shows that it would be highly adverse to retail competition. In contrast to the MRO structure, the ESP would significantly diminish the economic opportunity for customers to switch to competitive retail electric suppliers ("CRES"), making the customers effectively captive to the FE Companies. These "captive customer" provisions could undermine the feasibility of the ESP and deprive retail customers of the value associated with having electric pricing options.
- Finally, there are fundamental differences between the ESP and MRO structures in terms of the risks that would be assumed by the commodity suppliers (FirstEnergy Solutions ("FES") in the case of the ESP; competitive full requirements bidders in the case of the MRO) and, conversely, the risks that would be borne by customers. Because of these differences the Commission cannot conclude, on the basis of the MRO and ESP commodity price comparisons offered by the FE Companies, that the linchpin of the ESP proposal – the contract between FES and the FE Companies – is fairly priced.

Thus, the Commission does not have a basis to conclude that the ESP alternative will be less costly for customers and therefore more favorable than the expected results of the MRO alternative. Further, there are sound policy reasons why the MRO option is preferable.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first describe the difference between the MRO and ESP structures, and explain the policy problems for the ESP that are created by these differences. I then turn to the FE Companies' cost/benefit comparison of the ESP and MRO, and I correct and update that comparison.

II. <u>POLICY PROBLEMS CREATED BY THE ESP</u>

Q. PLEASE SUMMARIZE WHAT YOU BELIEVE TO BE THE MATERIAL DIFFERENCES BETWEEN THE ESP AND MRO.

A. There are two fundamental differences that I discuss. First, under the MRO structure, when customers leave for a CRES, they avoid the entire MRO price and thus the MRO price is the "shopping credit." Under the ESP, the "shopping credit" is much smaller than the full commodity charge due to several design features discussed below. Second, under the MRO structure competitive bidders commit to a fixed price for the term of their full requirements supply commitment, and their only opportunity to recover their costs is through revenues from Standard Service Offer ("SSO") customers. Thus, the risk to the affiliate supplier under the ESP structure is much lower, due on the one hand to rate riders that permit rate increases under the ESP but not the MRO; and due on the other to the lower switching risks that result from the diminished shopping credit. Also, there is a third difference as the ESP proposal includes a commitment by the FE Companies to write off certain RTC and extended RTC balances and provide miscellaneous claimed benefits. Each of these differences has policy implications, as I explain below.

Q. PLEASE EXPLAIN THE DIFFERENCE IN SWITCHING OPPORTUNITY BETWEEN THE ESP AND THE MRO.

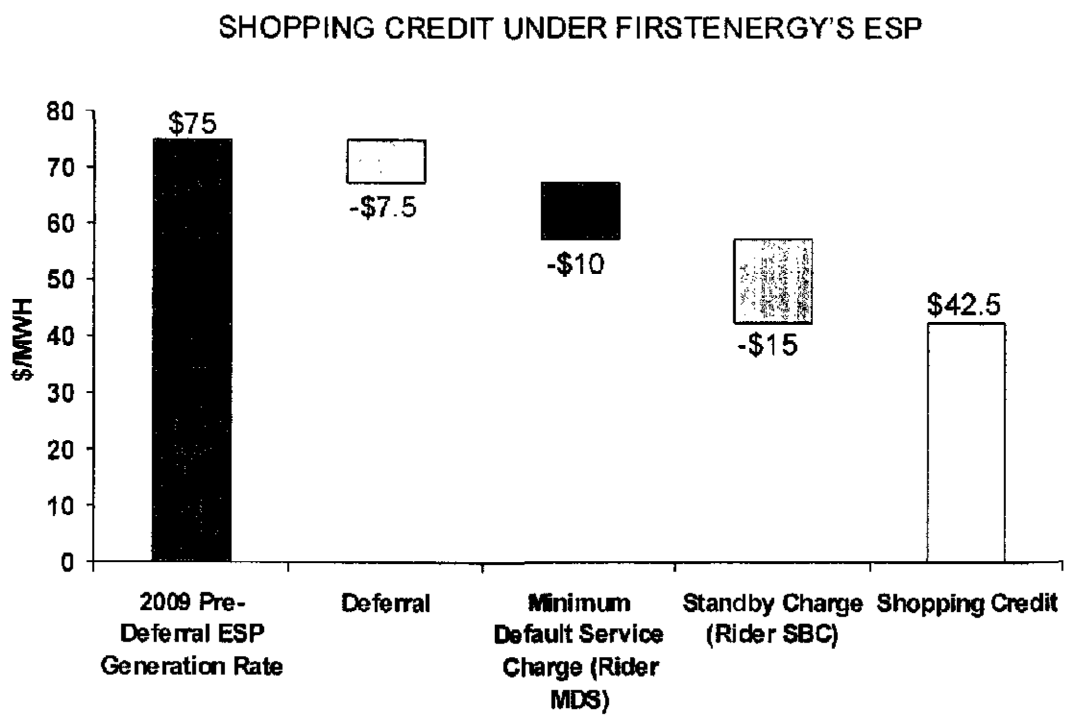
A. Under the ESP alternative, if customers switch off of SSO, their "shopping credit," the amount they avoid by switching, is much lower than the FE full commodity charge.

- The shopping credit is reduced by the generation cost deferral mechanism, the costs of which are recovered in out years under Rider DGC from all distribution customers of the FE Companies, including customers who switched away from SSO[2].
- The shopping credit is further reduced through Rider MDS – Under the ESP, if customers switch off of SSO service, the FE Companies will continue to be paid a service charge from those customers for "minimum default service."
- The shopping credit may also be reduced by Rider SBC – A standby charge rider that switching customers have to pay if they want the right to return to the ESP standard offer rate. If they do not pay this charge, then if they return to SSO service they will be charged the higher of the ESP rate or 160 percent times the then-applicable market price.

Q. WHAT IS THE EFFECT OF ALL THESE CHARGES ON THE ABILITY OF CUSTOMERS TO SHOP FOR COMPETITIVE RETAIL ELECTRIC SUPPLY?

A. The presence of these charges means that customers will have substantially fewer economic opportunities to switch to a CRES under the ESP proposal than under the MRO proposal. I have illustrated the effect of these switching charges in the following figure. I start with the full supply charge under the ESP proposal, then show what portions of it would *not* be avoided if customers switch with the right to return to the ESP price[3]. See Figure 1 below. I note that the Standby Charge increases from $15.00/MWh in 2009 to $20.00/MWh in 2010 and to $25.00/MWh in 2011, which increasingly penalizes customers wishing to shop with a CRES provider as the Shopping Credit declines.

Figure 1



Q. WHAT IS THE RESULT OF THESE SWITCHING CHARGES?

A. The result is that the amount that customers avoid when they switch away from SSO service under the ESP – the "shopping credit" – is only $42.50/MWh, not $75.00. Put

[2] The non-bypassable Rider DGC charge may not apply to certain governmental aggregation customers consistent with R.C. §4928.20(I). However, it appears that the terms of the rider would allow complete recovery for the FE Companies from customers who are subject to the charge.

[3] See Application section A.2.b, A.2.h and Direct Testimony of Mr. Warvell at p. 20.

another way, under the ESP proposal, offers from competitive suppliers would have to fall below $42.50/MWh before SSO customers would have a financial incentive to switch away from SSO service. If the SBC is not paid by a shopping customer under the ESP, a returning aggregation customer would be charged 160 percent times the then-applicable market cost of generation.[4] A returning shopping customer that was not a member of a governmental aggregation group would face the higher of 160 percent times the then-applicable market price or the SSO rate. Thus, while customers may have the legal right to switch suppliers, their actual economic opportunity to do so has been dramatically curtailed. The result is that under the ESP SSO customers are effectively captive customers.

Q. WOULD THESE CHARGES BE PRESENT UNDER THE MRO ALTERNATIVE?

A. No. It is my understanding that under the MRO alternative, if customers switch off of Standard Service, the MRO supplier will not recover any costs from those customers. Put another way, under the MRO customers switching from SSO service to competitive suppliers would avoid the entire SSO commodity charge and not face the "160 percent of market" charge upon return. It is only under the ESP that customers are effectively captive from an economic point of view. Obviously, this is very harmful to any opportunity for retail competition and to the ability of customers to have a choice of supplier and products and services.

[4] See Exhibit C of the ESP application for the method of determining the market price of generation.

Q. ARE THERE ANY OTHER RIDERS UNDER THE ESP THAT HAVE A POTENTIALLY ANTI-COMPETITIVE EFFECT?

A. Yes. Under the Economic Development Rider (EDR) the discount credits a customer receives will be forfeited if that customer switches generation service to a CRES. Similarly, under the Reasonable Arrangements Rider (RAR) customer credits are forfeited by a customer switching to a CRES. The charges under Rider EDR are also non-bypassable[5].

Q. PLEASE EXPLAIN THE DIFFERENCES IN THE RISK FACED BY COMMODITY SUPPLIERS UNDER THE MRO AND THE ESP.

A. Under the MRO, suppliers would be responsible for providing full requirements service under a fixed price that covers all supply and transmission costs, whereas under the ESP customers would be charged a stated commodity price *plus* several rate riders that provide for cost recovery for certain categories of costs or for certain cost increases. In addition, under the ESP a portion of supply costs would be deferred and recovered in later years through a non-bypassable charge.

Q. WHAT ARE THE RATE RIDERS THAT ARE PRESENT UNDER THE ESP?

A. Under the ESP alternative, the FE Companies would have riders or adders for certain costs, meaning the actual costs incurred will be passed on to retail customers through a rider that guarantees recovery of costs. These categories include:

[5] See Direct Testimony of Gregory F. Hussing at pp. 8-10.

- Rider TAS – Transmission costs including transmission service charges, transmission congestion costs, transmission net losses, other MISO charges for ancillary services[6].
- Rider CCA – Incremental capacity costs above a baseline commitment by FES.
- Rider FTE – Certain future fuel transportation costs, environmental costs and new taxes.
- Rider FCA – Certain future fuel costs.

Q. ARE THESE RIDERS PRESENT UNDER THE MRO?

A. No. It is my understanding that under the MRO alternative these costs would be included in the full requirements service for which suppliers must bid a fixed price, and there would be no comparable riders permitted[7].

Q. WHAT ARE THE IMPLICATIONS OF THESE DIFFERENCES?

A. Basically, MRO suppliers face much greater risk than faced by FES, the commodity supplier under the ESP. First, MRO suppliers absorb the risk of price changes for these costs categories during the term of their service. If an MRO supplier's cost increases during the term of its contract, it cannot pass those cost increases on to the SSO customers. Second, the MRO suppliers face greater customer switching risk than is

[6] Rider TAS appears to be the vehicle through which the FE Companies return FTR credits and losses rebates to their retail customers. It is my understanding that the FE Companies would still be the entity that receives some of those rebates even under an MRO structure. However, under an MRO structure, Rider TAS would not apply, and the FE Companies' application does not say how those rebates would be flowed through for the benefit of their customers under the MRO.

[7] The MRO provides for a separate RFP for renewable energy requirements. See MRO Application at p. 29.

present under the ESP, for the reasons described above, and they also face the risk of under-absorption of these costs due to SSO load variations.

As a whole, the ESP rate riders, as well as the economic disincentives to switch away from ESP service, mean that FES would have lower financial risk under the ESP than competitive suppliers would face in bidding on the MRO service. I discuss the order of magnitude of this risk difference in the next section of my testimony. However, the policy issue here is that this Commission can have no confidence that the transfer price that the FE Companies would be paying to FES for the supply contract under the ESP proposal is fairly priced. As further discussed below, the price estimates for MRO service that are offered by the FE Companies are not estimates for a service that is comparable to the commodity supply portion of the ESP – the MRO service is much riskier for suppliers. Only if the FE Companies were to engage in a competitive solicitation for SSO supply with comparable features to the ESP – non-bypassable recovery of a portion of supply costs, recovery riders for transmission and other cost categories, and other charges that limit the opportunity for customer switching – could the Commission be assured that the contract between the FE Companies and FES is fairly priced.

Q. WHAT ABOUT THE THIRD DIFFERENCE YOU MENTION, THE CEI WRITEOFF THAT IS PRESENT UNDER THE ESP PROPOSAL BUT NOT THE ESP?

A. It appears that the writeoff applies only to the customers of one of the FE Companies, CEI, as the customers of OE and TE will have already fully paid off their RTC and Extended RTC balances. It is my understanding that this ESP application is actually three separate applications, one for each of the FE Companies. Therefore I believe that the writeoff should not be considered in the comparison for all three FE Companies. In Part III of my testimony, in my adjustments to the FE Companies' cost-benefit analysis, I have shown my results on a company specific basis as well as a total basis.

Q. PLEASE SUMMARIZE YOUR POLICY CONCERNS WITH ESP.

A. There are significant policy concerns that are present under the ESP but not the MRO: the negative impact on customers' switching economics and retail competition under the ESP, and the lack of market testing for the appropriateness of transfer pricing under the ESP. If all else were equal between the two proposals, these two concerns alone would be sufficient reason to reject the ESP. These differences should be considered in evaluating whether the ESP proposal is in the aggregate better for customers.

III. <u>ESP HAS NOT BEEN SHOWN TO BE MORE FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS OF THE MRO</u>

Q. PLEASE ELABORATE ON YOUR SECOND CONCLUSION.

A. In this section of my testimony I discuss the quantitative cost-benefit analysis performed by Mr. Blank and:

- Summarize the main points of Mr. Blank's analysis shown in his Attachment 1, focusing on generation.
- Update the analysis to current market conditions and calculate the effect on the cost-benefit analysis of making these changes.
- Address the changes needed to make the ESP product comparable to the MRO product and calculate the effect on the cost-benefit analysis of making these changes.

- Address why the risk premia for the MRO pricing advanced by the FE Companies' witness Scott T. Jones are not appropriate for inclusion in Mr. Blank' analysis, and calculate the effect on the cost-benefit analysis of using only the market rate projections of Mr. Graves. I then calculate the cumulative effect of making all the adjustments above.
- Discuss why, even with these adjustments, the comparison of the ESP to the MRO is still not fairly made on an apples-to-apples basis.

A. Overview of Cost-Benefit Analysis

Q. PLEASE SUMMARIZE THE MAIN POINTS OF MR. BLANK'S COST-BENEFIT ANALYSIS DETAILED IN ATTACHMENT 1 TO HIS TESTIMONY.

A. Mr. Blank claims a customer net benefit of the ESP of $1.3 billion in present value for all three FE Companies together as compared to the MRO alternative. The elements of his build-up of the required revenue increases[8] associated with the ESP case and the MRO case are outlined at pp. 16-18 of his testimony and detailed in Attachment 1 of his testimony. The key element of both build-ups is the required increase in generation revenues, which are shown as the change from the existing 2008 generation rate multiplied by the forecast load in MWh, and assuming 100 percent customer retention. Both the ESP and the MRO cases assume an identical general distribution rate increase, so this has no effect on his net benefit calculation. Additionally, the analysis excludes

[8] Mr. Blank's cost-benefit analysis is denominated in terms of revenues required to be collected from customers. An increase in required revenues (costs to customers) is shown as a positive number. The Benefits to Customers is shown as the difference between present value of the required revenues under the MRO case and the ESP case, shown as "Benefits to Customers (Market – ESP)" in his Attachment 1. If this difference is positive, then there is a net benefit to customers under Mr. Blank's formulation of a cost-benefit analysis.

Network Integration Transmission Service ("NITS") and ancillary service revenue requirements, so these are effectively assumed to be equal under both cases.

Q. PLEASE DISCUSS THE ESP CASE.

A. The ESP analysis shows a total required revenue increase, on a present value basis, of $1,577.1 million for the FE Companies. As noted above, the focus of my testimony is on the generation supply-related portion of these revenues.

Q. PLEASE ELABORATE ON THE GENERATION ELEMENTS OF THE ESP CASE.

A. There are two generation elements to the ESP. The ESP generation rate of $75.00/MWh in 2009, $80.00/MWh in 2010, and $85.00/MWh in 2011 is broken into two pieces – that charged currently, and the deferred amount[9]. First, the amount charged currently is used to calculate the generation required revenue increase. Second, the deferred recovery of the generation phase-in credits ($7.50/MWh in 2009, $8.50/MWh in 2010, and $9.50/MWh in 2011), which begins in 2011, reflects the additional revenues necessary to amortize the ESP deferral. Thus, the Attachment 1 stated ESP generation rates of $67.50/MWh, $71.50/MWh, and $75.50/MWh are *after* the deduction of deferred amounts.

Q. PLEASE DESCRIBE THE MRO CASE THAT IS THE SUBJECT OF MR. BLANK'S COMPARISON.

A. The MRO analysis shows a total required revenue increase, on a present value basis, of $2,880.5 million for the FE Companies. The MRO case consists of two elements: the

[9] See Direct Testimony of Warvell at pp. 7-8.

required revenues from the distribution rate increase described above and the increase in generation required revenues from the projected results of a market solicitation for SSO service. Mr. Blank relies on the testimony of Mr. Jones and Mr. Graves to project MRO market rates of $82.57/MWh in 2009, $85.27/MWh in 2010, and $88.19/MWh in 2011 for the MRO case[10].

Q. PLEASE ELABORATE ON THE GENERATION ELEMENT OF THE MRO CASE.

A. As noted above, the required revenues for NITS and ancillary services are not considered in the cost-benefit analysis. The market rate projections used by Mr. Blank are a simple average of: 1) the rates projected by Mr. Jones for the years 2009-2011; and 2) a simple average calculated by Mr. Blank of two separate constructed cost build-ups by Mr. Graves for projecting rates. Both Mr. Jones and Mr. Graves include transmission-related costs, including NITS and ancillary services in their projected market rates, and so before calculating the averages, Mr. Blank netted these elements from their projected rates.[11] Mr. Jones' projections rely on a cost build-up from the MISO Cinergy Hub, based on forward contracts for energy as of July 15, 2008. The other elements of his build-up are summarized in Exhibit 8 to his testimony. The two estimates of Mr. Graves rely on a cost build-up from the MISO Cinergy Hub and the PJM West Hub respectively, based on forward contracts for energy as of July 15, 2008. The other elements of his build-ups are summarized in Exhibits 3 to 6 to his testimony.

[10] See Direct Testimony of Mr. Blank at p. 18, lines 10-16.

[11] See Direct Testimony of Mr. Blank at p. 18, lines 13-14. As discussed later in my testimony, both Mr. Jones and Mr. Graves apply a risk premium to their build-up of their projected cost to suppliers of providing the

B. ESP is Less Favorable as Market Prices Decline

Q. PLEASE DESCRIBE THE UPDATE YOU MADE TO MARKET PRICES.

A. Forward market prices for energy in Cinergy and PJM have fallen somewhat since the July 15, 2008 quote date used by Mr. Jones and Mr. Graves in their cost build-ups. A simple average of the 2009-2011 monthly forward quotes for energy shows an on-peak decline of $2.98/MWh at the MISO Cinergy Hub and $13.34/MWh at the PJM West Hub (off-peak the declines are $0.30/MWh and $8.03/MWh respectively) as of September 26, 2008. I have recalculated Mr. Jones' and Mr. Graves' constructed cost build-ups from the Cinergy Hub and the PJM West Hub as described in Exhibit 1 to my testimony. Exhibit 1 recalculates Exhibits 8-10 for Mr. Jones and Exhibits 3 and 5 for Mr. Graves, using the updated forward energy prices, and recalculates the average market generation rate projected by each witness.

The results of updating the market prices to September 26, 2009 are summarized in Table 1 below. The lower market generation rate decreases the MRO generation required revenue in each year of the ESP by the amounts shown below. For example, updating the market prices produces an adjustment of ($434.3 million) in 2009. The PV impact of the lowered MRO generation required revenues over the three years of the ESP is ($552.8 million) for the FE Companies together.

SSO service. The netting of the NITS and ancillary services elements by Mr. Blank also removed the risk premium associated with these elements.

Table 1

9/26/08 MARKET UPDATE OF ENERGY FORWARDS

	2009	2010	2011
7/15/08 Market Generation Rate Blank Testimony ($/MWH)	$82.57	$85.27	$88.19
Market Generation Rate Updated to 9/26/08 ($/MWH)	$74.98	$83.04	$87.24
Generation Required Revenue Adjustment from Update to 9/26/08 ($MM)	($434.3)	($128.7)	($55.0)

CHANGES TO PV OF FE CLAIMED BENEFITS TO CUSTOMERS

	TOTAL	CEI	OE	TE
PV of FE Claimed Benefits to Customers ($MM)	$1,303.4	$718.5	$409.1	$175.8
PV of Adjustments for Updated 9/26/08 Market Prices ($MM)	($552.8)	($192.9)	($255.9)	($104.0)
PV of Adjusted FE Claimed Benefits to Customers ($MM)	$750.6	$525.6	$153.2	$71.8

At market prices as of September 26, 2008, the original FE claimed customer benefit for the FE Companies of $1,303.4 million would be reduced to $750.6 million.

C. Adjustments are Needed to make ESP Comparable to MRO

Q. PLEASE DESCRIBE THE ESP COMPARABILITY ADJUSTMENTS YOU MADE.

A. The ESP estimate as presented in Mr. Blank's analysis is not appropriate for comparison to the MRO and requires two adjustments. Both of these adjustments are required to take account costs that are "in" the MRO estimates, but were not included in Mr. Blank's ESP costs. The two adjustments are for: 1) marginal transmission losses and congestion; and

2) incremental capacity costs. In my analysis, I correct Mr Blank's comparison by showing how these adjustments result in an increase in the costs associated with the ESP plan.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR MARGINAL TRANMISSION LOSSES AND CONGESTION.

A. In the FE Companies' ESP filing, the Summary of Projected Total Transmission Costs (Schedule B-1) shows projected[12] Net Losses[13] for the FE Companies totaling approximately $89 million, Congestion Expense totaling approximately $17 million and FTR Credit totaling ($22 million) for 2009. Under the ESP, the FE Companies will recover the actual amount of Net Losses and Congestion Expense (net of FTR credits) incurred from customers through Rider TAS. This cost is in addition to the $75.00/MWh ESP generation rate for 2009. The problem is that the MRO estimates used by Mr. Blank in his quantitative analysis included both marginal losses and congestion costs. So, for a valid comparison, these costs must be added to the ESP side of the ledger.

Q. HOW DO WE KNOW THAT MARGINAL TRANSMISSION LOSSES AND NET CONGESTION EXPENSE ARE INCLUDED IN THE MRO ESTIMATES?

A. The MRO projections of Mr. Blank rely on the market generation rate estimates of Mr. Jones and Mr. Graves. Mr. Jones and Mr. Graves have already included congestion and marginal transmission losses in their cost estimates for an MRO supplier. For their

[12] Schedule B-1 appears at p. 9 of 199 in Schedule 5k. The heading at the top of that page states "Schedule B-1 provides the projected transmission- and ancillary service-related costs to be charged to the Ohio Operating Companies during the 12 months in which the Rider charges will be in effect." The note at the bottom of that page states "These are placeholder expenses."

[13] The Net Losses in Exhibit B-1 are marginal transmission losses net of MISO credits for the difference between total marginal losses and average losses.

Cinergy or PJM Western Hub cost build-ups, both Mr. Jones and Mr. Graves use the 2009, 2010, and 2011 forward market prices of energy to project the costs of serving the MRO load (before risk premia are factored in). The forward prices at any MISO or PJM hub include congestion and marginal losses.

Q. PLEASE EXPLAIN.

A. The Cinergy NYMEX on-peak and off-peak forwards settle against LMPs (Locational Marginal Prices) at the Cinergy Hub, based on the average of the Cinergy Hub LMPs for the on-peak and off-peak hours of each day, as published by the MISO. The same is true for forward prices at PJM hubs; they settle at LMPs published by PJM. LMPs in MISO and PJM are composed of three elements: the real-time price, congestion, and marginal losses. Thus, by using the forward energy prices as the basis of their MRO projections, Mr. Jones and Mr. Graves have already included congestion and marginal transmission losses in their cost estimate of an MRO supplier.

Q. WHAT ABOUT THE BASIS DIFFERENTIAL THAT THEY INCLUDED IN THEIR MRO PROJECTIONS?

A. They each used an LMP-based basis adjustment to account for the cost of buying power at the Cinergy or PJM Western Hubs, where the forward prices are quoted, and the FE Load zone, where the power must ultimately be delivered. To accomplish this, they adjust the forwards based on the historic differential between LMPs at the hubs and LMPs at the FE Load zone. This "basis differential" calculation, since it is based on LMPs, also includes congestion and transmission losses. Thus the estimated MRO prices include congestion and losses for power supplied at the FE Load zone.

Q. DOES THE ESP CASE PROVIDED BY MR. BLANK INCLUDE ALL THE COSTS OF DELIVERING POWER AT THE FE LOAD?

A. No. Under the ESP, the FE Companies would take delivery of power from FES at the FES source locations, not the FE load zone.[14] The FE Companies would be responsible for the cost of moving the power from the FES locations to the FE load zone, including congestion costs and transmission losses associated with that delivery. So, to make the ESP comparable to the MRO, it is necessary to add the cost of the Net Losses and Congestion Expense (net of FTR Credits) from Schedule B-1 to the generation rate of the ESP. I have estimated approximately $80 million of annual total Net Losses and Congestion Expense (net of FTR Credits) based on the "placeholder" figures supplied by the FE Companies in Mr. Warvell's Schedule 5k, p. 9 of 199 and supported by the historical Net Losses shown in "Schedule 5k – Part 5 – B-4.xls" produced in response to OEG Set 1-9[15]. This would add approximately $1.42/MWh to the ESP rate[16].

Q. DIDN'T MR. BLANK REMOVE TRANSMISSION LOSSES AND CONGESTION FROM THE MRO PRICE ESTIMATES WHEN HE REMOVED "TRANSMISSION COSTS" FROM THOSE ESTIMATES?

A. As I just described, the MRO energy cost estimates from Mssrs. Jones and Graves included the cost of congestion and marginal losses to deliver the power to the FE Companies' load as components of the LMP. In addition to energy costs, MRO suppliers

[14] See September 25, 2008 Deposition of Kevin T. Warvell at p. 169.

[15] The projected "placeholder" costs sum to approximately $84 million. Also, in response to Constellation Set 2 – INT – 01, Mr. Warvell responded in part c) "The formula in the excel sheets links to Schedule C-1. Schedule C-1 allocates the revenue requirement necessary to achieve revenue-neutral rates based on the projections in the May 1, 2008 filing. Please see the Companies' response to OEG Set 1-9 for an interactive version of Schedule 5k." Historical Net Congestion Expense and Net Losses for the twelve months ending June 2008, total $74,621,523 as reported in columns AE through AP and Lines 122 to 126, in the Tab "Data," in Schedule 5k – Part 5 – B-4.xls.

[16] Based on 2008 sales from Mr. Blank's Attachment 1: $80 million divided by 56,471 GWh.

will also responsible for the cost of Network Transmission Service and Ancillary Services. To account for these costs, it is my understanding that Mssrs. Jones and Graves added to their full requirements cost build-ups a transmission cost figure supplied by the FE Companies of approximately \$7.50/MWh[17]. This figure appears to be based on the same set of transmission and ancillary service costs shown in the Summary of Total Projected Transmission Costs (Schedule B-1) Schedule 5k, p. 9 of 199 sponsored by Mr. Warvell, This figure includes, in addition to service charges for Network Transmission Service and ancillary services, approximately \$84 million in costs for Net Losses and Congestion Expense (net of FTR Credits). Thus when that "transmission cost" figure was added to the estimates of delivered power costs by Mssrs. Jones and Graves, there was a double count of congestion and losses, because congestion and losses were already included in the Jones and Graves delivered power costs. When Mr. Blank subtracted the "transmission cost" figure from the estimates of Mssrs. Jones and Graves, the number that was left was their estimated delivered cost of power at the FE load locations, which includes congestion and losses. Thus, to make the ESP estimates comparable to the MRO estimates, the cost of congestion and losses between the FES delivery points and the FE Companies' load zone must be added to the comparison on the ESP side of the ledger.

[17] See Jones' Direct Testimony at p, 14, lines 9-12 and Graves' Exh. 3, fn. 7 and Graves' Exh. 5, fn. 7.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR CAPACITY COSTS.

A. The FE Companies' ESP application provides that a base amount[18] of MISO capacity owned by the unregulated generation affiliate FES would be available to meet the MISO capacity obligations of the SSO load if the ESP is adopted. If capacity in excess of this base amount is needed under the ESP Rider, then Rider CCA would allow the FE Companies to recover the incremental cost of obtaining this capacity. Under the MRO, all capacity requirements are included in the price to be bid by MRO suppliers, and both Mr. Jones and Mr. Graves include capacity costs for 100% of the FE Companies' load as a part of their generation rate build-up.

To adjust Mr. Blank's analysis to make the ESP comparable to the MRO, it is necessary to add the cost of incremental capacity needed (in excess of the FES baseline MISO commitment) to the generation rate of the ESP[19]. I can quantify the impact of Rider CCA by multiplying the shortfall between the FE Companies' projected peak load and FES's committed generation portfolio by the capacity prices used by Mr. Jones and Mr. Graves in their price forecasts for the MRO. The details of the analysis are set out in Exhibit 2.

Q. WHAT IS THE NET EFFECT OF THE COMPARABILITY ADJUSTMENTS?

A. The results of making the comparability adjustments are summarized in Table 2 below. The ESP generation rate[20] must increase (e.g., from $75.00/MWh to $76.68/MWh in

[18] All of FES's power plants in MISO, including its share of two plants owned by the Ohio Valley Electric Corp., and its new 700 MW Fremont plant coming online in 2009. See Application, Attachment D and Rider CCA.

[19] By assuming 100% SSO load retention in his cost-benefit analysis, Mr. Blank is effectively assuming that incremental capacity will be needed.

[20] The gross ESP generation rate before netting the deferral credit.

2009) to make it properly comparable to the MRO market generation rate by including the costs for Marginal Transmission Losses, Net Congestion Costs and incremental capacity costs. The higher ESP generation rate increases the ESP generation required revenue in each year of the ESP by the amounts shown in Table 2 below (e.g., an increase of $96.2 million in 2009). The PV impact of the higher ESP generation required revenues over the three years of the ESP is ($247.9 million) for the FE Companies together.

Table 2

COMPARABILITY ADJUSTMENTS

	2009	2010	2011
ESP Generation Rate[21] Blank Testimony ($/MWH)	$75.00	$80.00	$85.00
ESP Generation Rate Adjusted for Comparability ($/MWH)	$76.68	$81.66	$86.72
Adjustment for Rider TAS and Rider CCA Costs Not Included ($MM)	$96.2	$96.0	$99.9

CHANGES TO PV OF FE CLAIMED BENEFITS TO CUSTOMERS

	TOTAL	CEI	OE	TE
PV of FE Claimed Benefits to Customers ($MM)	$1,303.4	$718.5	$409.1	$175.8
PV of Adjustments for Rider TAS and Rider CCA ($MM)	($247.9)	($86.5)	($114.9)	($46.6)
PV of Adjusted FE Claimed Benefits to Customers ($MM)	$1,055.5	$632.0	$294.2	$129.2

[21] Based on gross ESP generation rates before netting the deferral credits.

The impact[22] of making this comparability adjustment on the original claimed customer benefit for the FE Companies of $1,303.4 million would be to reduce it to $1,055.5 million.

D. <u>Blank's MRO Price Estimate is Too High</u>

Q. ARE THERE ANY ADDITIONAL PROBLEMS WITH MR. BLANK'S QUANTITATIVE ANALYSIS?

A. Yes. His use of an MRO price forecast obtained by averaging the results of Mr. Graves and Mr. Jones is neither appropriate nor valid, and results in a significant error in his calculations.

Q. PLEASE EXPLAIN.

A. In choosing to average Mr. Graves and Mr. Jones forecasts, Mr. Blank failed to recognize that the two forecasts were for different "MRO" products. Mr. Jones was apparently attempting to estimate the MRO price for the MRO "as filed," that is with the substantial risks from the very limited restrictions on switching and with the opportunity for aggregation that exists in Ohio. At p. 2 of his testimony Mr. Jones explains:

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

Then, at p 5 of his testimony he clarifies his understanding of the MRO estimate he is making:

[22] The impact is calculated independently of the impact of the update to market prices calculated above in sub-part B. The cumulative impact of all adjustments is calculated in sub-part D below.

> Thus, as explained in more detail below, I include a "margin" to reflect the amount of expected return that a bidder would require for accepting the substantial risks of providing full requirements service at fixed prices for the Ohio Companies' standard service offer.

In contrast, Mr. Graves was attempting to estimate an MRO price for a product that was more similar to the ESP, in that it reflected his understanding of the switching rules and incentives under the Company's ESP proposal. At pp. 3-4 he outlines the purpose of his testimony:

> My testimony addresses the expected result of a market-rate offer (MRO) for retail generation service, as well as the following issues:
>
> - What is the nature of the generation service product proposed to be supplied under the ESP by the Ohio Companies to standard-service-offer (SSO) customers?
> - What constitutes a market price for that product?
> - What are reasonable methods for determining a market price for providing generation service to SSO customers?
> - Using those methods, what are useful market pricing benchmarks based on currently available information?

Then, at p.17 he summarizes his conclusions about what constitutes a market price for that "ESP-like" product:

> I believe it is likely that customer-switching risk is greater in Ohio than has been the case in other states at the time of their auctions from which I have drawn comparables. The switching risk is higher in Ohio because governmental aggregation effectively lowers switching costs for customers and lowers customer acquisition costs for retail providers. Also, there are many large commercial and industrial customers eligible for fixed-price SSO in Ohio, and prices are generally high and volatile right now. On the other hand, I understand that a charge will be applied to any customers who wish to leave SSO with the right to return to the fixed SSO price in the future. Accordingly, the results based on the mid-level risk premium are about what I would expect a market solicitation to include.

As a result, Mssrs. Jones and Graves arrived at different conclusions about the risk premium that would be charged MRO suppliers. The risk premium estimates the additional amount an MRO bidder would require above its "direct" or "no-risk" costs to assume the SSO load risk. Mr. Graves chooses a risk premium at the 50^{th} percentile of his distribution, as he discussed in the quote above. Mr. Jones, who relied on Mr. Graves' data about risk premia in other full requirements solicitations, effectively chose a risk premium above the 75^{th} percentile in Mr. Graves' distribution. Apparently, each was choosing the risk premium he thought was appropriate for his own purpose – which were different since they were evaluating different MRO products.

Q. WHICH ESTIMATE SHOULD MR. BLANK HAVE USED IN HIS ANALYSIS?

A. Given the structure of his quantitative analysis, Mr. Blank should have used only Mr. Graves' estimate, which was intended to reflect the risk premium for an MRO product with ESP switching rules and risk. As I discuss further below, it does not appear that Mr. Graves took into account *all* of the switching and supplier risk characteristics of the ESP proposal, but Mr. Jones did not take *any* of them into account. By averaging the two, Mr. Blank used an MRO price estimate which is too high.

Q. WHAT IS THE QUANTITATIVE IMPACT OF USING ONLY MR. GRAVES' GENERATION RATE FORECAST?

A. I have calculated the decrease in the generation required revenue that would result from using only Mr. Graves July 15, 2008 forecast of market generation rates[23]. The projected

[23] This adjustment is calculated separately from the September 26, 2008 update to market prices described in sub-part B above.

impact of this comparability adjustment on the FE Claimed customer benefit calculation is shown in Table 3 below:

Table 3

7/15/08 MARKET GENERATION RATE BASED ON USING GRAVES ONLY

	2009	2010	2011
7/15/08 Market Generation Rate Blank Testimony ($/MWH)	$82.57	$85.27	$88.19
7/15/08 Market Generation Rate Adjusted to Use Graves Only[24] ($/MWH)	$83.45	$81.87	$81.39
Generation Required Revenue Adjustment from Using Graves Only ($MM)	$50.6	($195.9)	($395.8)

CHANGES TO PV OF FE CLAIMED BENEFITS TO CUSTOMERS

	TOTAL	CEI	OE	TE
PV of FE Claimed Benefits to Customers ($MM)	$1,303.4	$718.5	$409.1	$175.8
PV of Adjustments for Using Graves Only Market Generation Rate ($MM)	($429.8)	($149.9)	($199.5)	($80.5)
PV of Adjusted FE Claimed Benefits to Customers ($MM)	$873.6	$568.6	$209.6	$95.3

Under this adjustment, and relative to the original blended market generation rate, MRO generation required revenues decline on a present value basis by ($429.8 million). The impact of making this adjustment on the original FE claimed customer benefit for the FE Companies of $1,303.4 million would be to reduce it to $873.6 million.

[24] See Direct Testimony of Mr. Blank at p. 18, lines 10-16.

Q. HAVE YOU CALCULATED THE CUMULATIVE IMPACT OF ALL OF THE ADJUSTMENTS YOU MADE ABOVE?

A. Yes. The cumulative effect of making all three sets of adjustment is summarized in Table 4 below. As adjusted, the gross ESP generation rate now exceeds the MRO market generation rate calculated using Mr. Graves' forecast only (and as updated to September 26, 2008 forward market prices). The present value of FE Claimed Benefits to Customers for the FE Companies has declined from a projected positive value by Mr. Blank of $1,303.4 million to an adjusted negative value of ($246.0 million)[25]. An adjusted cost-benefit analysis adopting Mr. Blanks' formulation and in the same format as his Attachment 1, is attached as Exhibit 3.

[25] Note that the present value differences calculated in sub-parts B, C and D cannot simply be summed to obtain the cumulative effect. This is a result of Mr. Grave's relying on both PJM West Hub forwards and Cinergy Hub forwards and Mr. Jones relying only on the latter, and also of small differences in their constructed cost buildup methodologies. The effect of the change in market prices on Mr. Jones' analysis is effectively removed from the final calculation because it relies only on the market generation rate forecast of Mr. Graves.

Table 4

CUMULATIVE CHANGES TO ESP GENERATION RATE AND MRO MARKET GENERATION RATE

	2009	2010	2011
ESP Generation Rate ***Adjusted for Comparability*** **($/MWH)**	$76.68	$81.66	$86.72
9/26/08 Market Generation Rate Adjusted to Use Graves Only ($/MWH)	$73.38	$78.14	$77.95

CUMULATIVE CHANGES TO PV OF FE CLAIMED BENEFITS TO CUSTOMERS[26]

	TOTAL	CEI	OE	TE
PV of FE Claimed Benefits to Customers ($MM)	$1,303.4	$718.5	$409.1	$175.8
PV of Cumulative Adjustments to FE Claimed Benefits ($MM)	($1,549.4)	($540.6)	($717.9)	($290.9)
PV of Adjusted FE Claimed Benefits to Customers ($MM)	($246.0)	$178.0	($308.8)	($115.1)

E. <u>Adjusted Comparison of ESP and MRO is Still Biased</u>

Q. GIVEN ALL OF THE CORRECTIONS ABOVE IS THE COMPARISON NOW FAIR ON AN APPLES-TO-APPLES BASIS?

A. No. The cumulative correction accounts only for changes that can be easily quantified, but as discussed earlier in my testimony there are other differences between the MRO and the ESP that are a net detriment to customers under the ESP, but are not reflected in this analysis.

Q. PLEASE ELABORATE.

A. In Part II of my testimony I explained why the risk faced by competitive suppliers under the MRO proposal would be far greater than the risk faced by FES under the FE Companies proposal – the ESP has some features that would result in expectations of lower switching than would be expected under the MRO, and the ESP has some cost recovery features that increase the certainty of cost recovery relative to what would be the case under the MRO. I explained that given these differences, the Commission cannot be assured that the ESP supply contract with FES is fairly priced, at least based on the evidence offered by Mr. Blank.

As noted earlier in my testimony, Mr. Graves' analysis attempts to account for these differences, but it only goes part way. Specifically, Mr. Graves makes mention of only one of the three ESP "shopping credit" reductions shown in Figure 1. It is not clear that he was aware of the generation deferral aspect of the ESP proposal or of the Minimum Default Service charge, both of which reduce switching opportunities, and hence the supplier's switching risk, substantially. Nor does he make any mention of the various riders that are available to FE under the ESP which provide for "no-risk" recovery of transmission costs, ancillary service costs, losses and congestion as well as protection against cost increases in other areas. These are, of course, risks that are borne by MRO suppliers in the "comparables" in Mr. Graves database, but he does not make any adjustment to account for the fact that there is less risk in the ESP proposal in these areas, too.

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[26] Cumulative adjustments includes: 1) Market price update to September 26, 2008 described in sub-part B; 2) Adjustments to make ESP product comparable to MRO product described in sub-part C; and 3) Reliance only on Mr. Graves' estimates of MRO generation rates as described in this sub-part D.

In fact, the Commission can use Mr. Graves' analysis to get an approximation for the level of risk premium that would be charged by an MRO bidder that had the advantage of all the risk-reducing features that are found in the ESP, not just the single factor taken into account by Mr. Graves. Mr. Graves' data regarding risk premiums charged by suppliers in full requirements solicitations ranges from 9.82 percent at the 25th percentile to 27.57 percent at the 75th percentile. The lower risk premiums at the 25th percentile reflect less switching risk and more certainty for the generation supplier observed in certain solicitations with more favorable risk profiles for suppliers (e.g., shorter terms, lower switching risk due to higher proportion of residential customers). The restrictive rules of the ESP described in Part II of my testimony are risk reducing. FES, as the supplier to the FE Companies under the ESP, has arguably even less risk than the competitive bidders who rank at or near Graves' 25th percentile.

Using the 25th percentile as an estimate of the proper risk premium to use in Mr. Blank's analysis – in order to put the MRO and ESP on an apples-to-apples basis in terms of risk to suppliers – results in a further reduction of MRO costs of approximately $220 million annually[27].

For illustrative purposes, I have applied that further reduction to the cumulative changes shown above in Table 4, which yields the results shown in Table 5 below. ESP costs exceed the MRO costs for each of the three companies, and by approximately $840 million, in aggregate. The ESP generation supply rate exceeds the MRO supply rate in each year, demonstrating the amount by which the FES contract is over-priced relative to

[27] The risk differential is 6.14 percent between the 50th percentile and the 25th percentile in Mr. Graves' distribution of risk premia. Based on an updated September 26, 2008 market generation rate of $73.38/MWh from Exhibit 3 and 2008 Sales of 56,471 GWh yields, this yields approximately $220 million annually.

what competitive bidders would offer if the competitive bidders had the same risk-reducing advantages that are present under the ESP proposal. The calculations of the illustrative numbers shown in Table 5 are presented in Exhibit 4.

Table 5

ILLUSTRATIVE

CUMULATIVE CHANGES TO ESP GENERATION RATE AND MRO MARKET GENERATION RATE USING GRAVES' 25th PERCENTILE RISK PREMIUM

	2009	2010	2011
ESP Generation Rate Adjusted for Comparability ($/MWH)	$76.68	$81.66	$86.72
9/26/08 Market Generation Rate Using Graves 25th Percentile Only ($/MWH)	$69.49	$74.00	$73.82

CUMULATIVE CHANGES TO PV OF FE CLAIMED BENEFITS TO CUSTOMERS

	TOTAL	CEI	OE	TE
PV of FE Claimed Benefits to Customers ($MM)	$1,303.4	$718.5	$409.1	$175.8
PV of Cumulative Adjustments to FE Claimed Benefits ($MM)	($2,145.4)	($748.5)	($994.0)	($402.8)
PV of Adjusted FE Claimed Benefits to Customers ($MM)	($841.9)	($30.0)	($585.0)	($227.0)

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS REGARDING THE FE COMPANIES' ESP APPLICATION?

A. I recommend the Commission reject the ESP application based on the following conclusions:

- First, while electricity market conditions may change in the future, current forward electricity prices are lower than they were in July 2008, and the evidence that was offered by the FE Companies in support of the ESP proposal is now out of date.
- Second, the FE Companies' quantitative comparison between the MRO and ESP is materially flawed, in part because it was not done on an "apples to apples" basis, and in part because it incorporates an incorrect risk premium analysis.
- Third, when the FE Companies' quantitative analysis is adjusted to reflect updated market conditions, and to correct the flaws in their ESP and MRO comparison, the FE claimed benefit of the ESP for the FE Companies in the aggregate is completely eliminated and the ESP is actually \$200 million to \$840 million more expensive for customers than the MRO using Mr. Blanks' own aggregate cost-benefit formulation. When these quantitative adjustments are made on a company-by-company basis, the MRO is clearly preferable to the ESP for customers of at least two of the three FE Companies.
- Fourth, a careful analysis of the ESP structure shows that it would be highly adverse to retail competition. In contrast to the MRO structure, the ESP would significantly diminish the economic opportunity for customers to switch to a CRES, making the customers effectively captive to the FE Companies. These "captive customer" provisions could undermine the feasibility of the ESP and deprive retail customers of the value associated with having electric pricing options.
- Finally, there are fundamental differences between the ESP and MRO structures in terms of the risks that would be assumed by the commodity suppliers (FirstEnergy Solutions ("FES") in the case of the ESP; competitive full requirements bidders in the

case of the MRO) and, conversely, the risks that would be borne by customers. Because of these differences the Commission cannot conclude, on the basis of the MRO and ESP commodity price comparisons offered by the FE Companies, that the linchpin of the ESP proposal – the contract between FES and the FE Companies – is fairly priced.

Thus, the Commission does not have a basis to conclude that, in aggregate, the ESP alternative will be less costly for customers and therefore more favorable than the expected results of the MRO alternative. And there are sound policy reasons why the MRO is preferable.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

DESCRIPTION OF MARKET PRICE ADJUSTMENT TO THE MRO

In order to update the projected FE companies' cost of the MRO with current market information, I first replicated the market prices in the analyses of Mr. Jones and Mr. Graves. I used the relevant forwards from July 15, 2008, as well as the assumptions in Jones' Exhibits 3-10 and Graves' Exhibits 3-6, to reproduce their market cost-of-service build-ups. I obtained the same market rates for MRO service as Mr. Jones in Exhibits 8-10 and Mr. Graves in Exhibits 4 and 6.[1] I then replaced the July 15, 2008, forwards with those from September 26, 2008, while leaving all the other assumptions the same. The resulting market generation rates represent an MRO cost build-up that is consistent with the methodology of Mr. Jones and Mr. Graves and updated to reflect market conditions as of September 26, 2008.

[1] In preparing my analysis, I did not have access to the actual spreadsheets used in the analyses of Mr. Jones and Mr. Graves. Therefore, there are small (less than $.01/MWh) differences in the rates due to rounding error.

Forward Prices Used by Mr. Jones and Mr. Graves vs. Forward Prices on 9/26/2008

	PJM WESTERN HUB ON-PEAK		PJM WESTERN HUB OFF-PEAK		CINERGY HUB ON-PEAK		CINERGY HUB OFF-PEAK	
Contract Month	7/15/2008	9/26/2008	7/15/2008	9/26/2008	7/15/2008	9/26/2008	7/15/2008	9/26/2008
Jan-09	107.67	80.03	80.67	63.42	79.00	66.75	46.50	46.25
Feb-09	107.67	80.03	80.67	63.42	79.00	66.75	46.50	46.25
Mar-09	97.81	75.42	66.50	57.17	73.31	63.38	40.50	42.50
Apr-09	93.00	74.67	66.50	57.17	73.31	63.38	40.50	42.50
May-09	91.13	75.50	56.25	43.29	67.25	62.75	34.25	33.75
Jun-09	104.19	86.21	66.33	54.33	75.50	70.88	34.25	34.75
Jul-09	120.56	98.45	77.33	62.83	90.25	82.19	41.00	40.75
Aug-09	120.56	98.45	77.33	62.83	90.25	82.19	41.00	40.75
Sep-09	95.50	80.31	65.50	55.92	71.50	65.50	34.25	33.25
Oct-09	88.69	75.54	64.17	55.25	66.88	61.13	36.50	32.75
Nov-09	88.69	70.66	64.17	55.25	66.88	61.13	36.50	32.75
Dec-09	88.69	78.66	64.17	64.75	66.88	61.13	36.50	32.75
Jan-10	95.58	87.54	65.44	59.25	71.33	72.75	40.00	39.88
Feb-10	95.58	87.54	65.44	59.25	71.33	72.75	40.00	39.88
Mar-10	95.58	78.38	65.44	59.25	71.33	66.00	40.00	39.88
Apr-10	95.58	78.38	65.44	59.25	71.33	66.00	40.00	39.88
May-10	95.58	74.75	65.44	59.25	71.33	61.75	40.00	39.88
Jun-10	95.58	88.88	65.44	59.25	71.33	73.00	40.00	39.88
Jul-10	95.58	104.50	65.44	59.25	71.33	88.00	40.00	39.88
Aug-10	95.58	104.50	65.44	59.25	71.33	88.00	40.00	39.88
Sep-10	95.58	81.13	65.44	59.25	71.33	65.75	40.00	39.88
Oct-10	95.58	75.88	65.44	59.25	71.33	61.50	40.00	39.88
Nov-10	95.58	75.88	65.44	59.25	71.33	61.50	40.00	39.88
Dec-10	95.58	75.88	65.44	59.25	71.33	61.50	40.00	39.88
Jan-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Feb-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Mar-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Apr-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
May-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Jun-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Jul-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Aug-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Sep-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Oct-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Nov-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00
Dec-11	92.05	82.35	65.06	58.33	69.50	69.75	42.00	42.00

Mr. Graves' Constructed Cost Method (Using PJM West Forward)
Calculation of Generation Service Price (2009-2011)

	2009	2010	2011
Energy, NITS & Ancillary Costs ($)	$3,685,560,815	$3,867,917,325	$3,759,770,021
Capacity Cost ($/MW-day)	$69.17	$82.50	$95.45
Peak Capacity Plus Reserve Margin (MW)	13,327	13,530	13,736
Total Capacity Cost ($)	$336,468,544	$407,414,231	$478,542,931
Total Procurement Costs ($)	$4,022,029,359	$4,275,331,556	$4,238,312,952
Total Projected Load (MWh)	56,818,797	57,321,168	57,833,934
Total Procurement Costs ($/MWh)	$70.79	$74.59	$73.28
Estimated 25th Percentile Risk Premium (%)	9.82%	9.82%	9.82%
Projected Low Market Price ($/MWh)	$77.74	$81.91	$80.48
Estimated 50th Percentile Risk Premium (%)	15.96%	15.96%	15.96%
Projected Median Market Price ($/MWh)	$82.08	$86.49	$84.98
Estimated 75th Percentile Risk Premium (%)	27.57%	27.57%	27.57%
Projected High Market Price ($/MWh)	$90.30	$95.15	$93.49

Note: Based on Mr. Graves' Exhibit 4, with energy cost updated as of 9/26/2008.

Mr. Graves' Constructed Cost Method (Using Cinergy Forward)
Calculation of Generation Service Price (2009-2011)

	2009	2010	2011
Energy, NITS & Ancillary Costs ($)	$3,700,768,771	$3,918,087,035	$3,942,455,886
Capacity Cost ($/MW-day)	$69.17	$82.50	$95.45
Peak Capacity Plus Reserve Margin (MW)	13,327	13,530	13,736
Total Capacity Cost ($)	$336,468,544	$407,414,231	$478,542,931
Total Procurement Costs ($)	$4,037,237,315	$4,325,501,266	$4,420,998,817
Total Projected Load (MWh)	56,818,797	57,321,168	57,833,934
Total Procurement Costs ($/MWh)	$71.05	$75.46	$76.44
Estimated 25th Percentile Risk Premium (%)	9.82%	9.82%	9.82%
Projected Low Market Price ($/MWh)	$78.03	$82.87	$83.95
Estimated 50th Percentile Risk Premium (%)	15.96%	15.96%	15.96%
Projected Median Market Price ($/MWh)	$82.39	$87.50	$88.64
Estimated 75th Percentile Risk Premium (%)	27.57%	27.57%	27.57%
Projected High Market Price ($/MWh)	$90.64	$96.27	$97.52

Note: Based on Mr. Graves' Exhibit 6, with energy cost updated as of 9/26/2008.

MR. JONES' ANALYSIS OF MARKET-RATE OFFER PRICES
2009

	Residential High Shopping Risk	Residential Low Shopping Risk	Commercial High Shopping Risk	Commercial Low Shopping Risk	Industrial	Streetlight	Total
Forecast Load (MWh)	8,792,308	8,792,308	7,700,718	7,700,718	23,834,744	384,015	57,202,582
Direct Costs ($/MWH)							
Round the Clock Energy Price	$51.82	$51.82	$51.82	$51.82	$51.82	$51.82	$51.82
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.11	$5.11	$5.18	$5.18	$2.33	-$8.21	$3.91
Capacity Price	$8.18	$8.18	$5.60	$5.60	$4.40	$0.00	$5.89
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$4.95	$4.95	$4.50	$4.50	$1.02	$3.50	$3.12
Total Direct Cost per MWh	$78.26	$78.26	$75.29	$75.29	$67.77	$55.31	$72.94
Total Direct Cost	$688,057,103	$688,057,103	$579,816,075	$579,816,075	$1,615,345,569	$21,238,542	$4,172,605,717
Margin	20%	10%	20%	10%	20%	10%	17%
Total Price per MWh	$93.91	$86.08	$90.35	$82.82	$81.33	$60.84	$85.35
Total Cost	$825,668,524	$756,862,813	$695,779,290	$637,797,682	$1,938,414,683	$23,362,396	$4,882,250,895

Note: Based on Mr. Jones' Exhibit 8, with energy cost updated as of 9/26/2008.

MR. JONES' ANALYSIS OF MARKET-RATE OFFER PRICES
2010

	Residential High Shopping Risk	Residential Low Shopping Risk	Commercial High Shopping Risk	Commercial Low Shopping Risk	Industrial	Streetlight	Total
Forecast Load (MWh)	13,367,073	4,455,691	11,711,096	3,903,699	23,885,967	384,015	57,707,541
Direct Costs ($/MWH)							
Round the Clock Energy Price	$54.33	$54.33	$54.33	$54.33	$54.33	$54.33	$54.33
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.36	$5.36	$5.43	$5.43	$2.44	-$8.61	$4.10
Capacity Price	$8.41	$8.41	$5.75	$5.75	$4.19	$0.00	$5.93
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$5.15	$5.15	$4.68	$4.68	$1.06	$3.64	$3.24
Total Direct Cost per MWh	$81.45	$81.45	$78.39	$78.39	$70.22	$57.56	$75.81
Total Direct Cost	$1,088,700,225	$362,900,075	$918,033,044	$306,011,041	$1,677,346,378	$22,104,634	$4,374,631,554
Margin	30%	15%	30%	15%	30%	15%	29%
Total Price per MWh	$105.88	$93.66	$101.91	$90.15	$91.29	$66.20	$97.59
Total Cost	$1,415,310,292	$417,335,086	$1,193,442,958	$351,912,697	$2,180,550,291	$25,420,329	$5,631,643,763

Note: Based on Mr. Jones' Exhibit 9, with energy cost updated as of 9/26/2008.

MR. JONES' ANALYSIS OF MARKET-RATE OFFER PRICES
2011

	Residential	Commercial	Industrial	Streetlighting	Total
Forecast Load (MWh)	18,068,101	15,831,164	23,937,405	384,015	58,233,804
Direct Costs ($/MWH)					
Round the Clock Energy Price	$54.93	$54.93	$54.93	$54.93	$54.93
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.42	$5.49	$2.47	-$8.70	$4.15
Capacity Price	$7.33	$6.90	$4.33	$0.00	$5.96
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$5.12	$4.79	$1.07	$3.67	$3.27
Total Direct Cost per MWh	$80.99	$80.31	$71.00	$58.10	$76.51
Total Direct Cost	$1,463,371,307	$1,271,395,824	$1,699,486,159	$22,310,089	$4,455,318,138
Margin	40%	40%	40%	20%	40%
Total Price per MWh	$113.39	$112.43	$99.40	$69.72	$107.03
Total Cost	$2,048,719,830	$1,779,954,154	$2,379,280,623	$26,772,107	$6,232,482,567

Note: Based on Mr. Jones' Exhibit 10, with energy cost updated as of 9/26/2008.

ADJUSTED MARKET RATES

	$/MWH - with transmission costs				$/MWH - net of transmission costs		
Year	Mr. Graves, using Cinergy	Mr. Graves, using PJM Western Hub	Combined for Mr. Graves	Mr. Jones	Combined for Mr. Graves	Mr. Jones	Average
2009	$82.39	$82.08	$82.24	$85.35	$73.38	$76.57	$74.98
2010	$87.50	$86.49	$87.00	$97.59	$78.14	$87.93	$83.04
2011	$88.64	$84.98	$86.81	$107.03	$77.95	$96.53	$87.24

CALCULATION OF INCREMENTAL CAPACITY COSTS

USING MR. GRAVES' CAPACITY COSTS	2009	2010	2011
Projected Peak Load (MW) - Graves	13,327	13,530	13,736
Available Capacity (MW)	11,831	12,184	12,184
Shortfall (MW)	1,496	1,346	1,552
Capacity Cost ($/MW-day)	$69.17	$82.50	$95.45
Incremental Capacity Cost ($MM)	$15,835,278	$16,987,266	$22,662,145
Projected Sales (MWH)	57,202,000	57,705,000	58,211,000
Incremental Capacity Cost ($/MWH)	$0.28	$0.29	$0.39

USING MR. JONES' CAPACITY COSTS	2009	2010	2011
Projected Peak Load (MW) - Jones	13,331	13,533	13,740
Available Capacity (MW)	11,831	12,184	12,184
Shortfall (MW)	1,500	1,349	1,556
Capacity Cost ($/MW-day)	$72.33	$72.33	$72.33
Incremental Capacity Cost ($MM)	$16,602,689	$14,926,144	$17,216,869
Projected Sales (MWH)	57,202,000	57,705,000	58,211,000
Incremental Capacity Cost ($/MWH)	$0.29	$0.26	$0.30

	2009	2010	2011
AVERAGE OF TWO ESTIMATES ($/MWH)	$0.28	$0.28	$0.34

Available Capacity is an average of a low case and a high case scenario for FirstEnergy's MISO capacity.

Low range assumptions:
- Fremont plant will not become operational before May 2009.
- New wind capacity and uprates shown in Attachment D of FirstEnergy's filing will not count towards ESP capacity.

High range assumptions:
- Fremont plant will become operational before May 2009.
- New wind capacity and uprates shown in Attachment D of FirstEnergy's filing will count towards ESP capacity.

SUMMARY - TOTAL OHIO

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	73.38
2010 Market Rate average($/MWH)	78.14
2011 Market Rate average ($/MWH)	77.95

Year		2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)		57,202,000		57,705,000		58,211,000		58,744,000		59,284,445		1,451,558,323	
ESP		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$137.0		$150.0		$151.0						
Distribution Improvement Rider		2.00	$114.4	2.00	$115.4	2.00	$116.4						
ESP Generation Rate		69.18		73.16		77.22							
Generation Increase over 2008 Rate of 68.18		1.00	$57.1	4.98	$287.3	9.04	$525.8						
Economic Development Rider			$0.0		$0.0		$0.0						
AMI Study			($1.0)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			($10.0)		($10.0)		($10.0)		($10.0)		($10.0)		$0.0
Environmental Remediation & Reclamation			($15.0)		($15.0)		($15.0)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			($316.0)		($275.0)		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)		0.00	$0.0	0.00	$0.0	2.01	$117.0	2.01	$118.1	3.25	$192.7		$1,558.4
Deferral Recovery - CEI Distribution ($25M)		0.00	$0.0	0.00	$0.0	0.03	$1.7	0.03	$1.7	0.03	$1.7		$42.2
Total Revenues Per Year			($33.5)		$252.7		$887.0		$109.8		$184.4		$1,600.6
NPV of Total Revenues Per Year	$1,825.6												

Consultant Market Rates		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$137.0		$150.0		$151.0
Generation Rate		73.38		78.14		77.95	
Generation Increase over 2008 Rate of 68.18		5.20	$297.3	9.95	$574.4	9.77	$568.6
Total Revenues Per Year			$434.3		$724.4		$719.6
NPV of Total Revenues Per Year	$1,579.6						

NPV: Ohio Summary	Total Ohio	CEI	OE	TE
NPV: ESP	$1,825.6	$276.7	$1,078.5	$470.4
NPV: Market Rates	$1,579.6	$454.6	$769.7	$355.3
Benefits to Customers (Market - ESP)	($246.0)	$178.0	($308.8)	($115.1)

SUMMARY - THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	73.38
2010 Market Rate average($/MWH)	78.14
2011 Market Rate average ($/MWH)	77.95

Year		2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)		19,967,000		20,133,000		20,298,000		20,471,000		20,645,004		501,344,773	
ESP		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$21.5		$34.5		$34.8						
Distribution Improvement Rider		2.28	$45.5	2.28	$45.8	2.28	$46.2						
ESP Generation Rate		69.18		73.16		77.22							
Generation Increase over 2008 Rate of 69.02		0.16	$3.2	4.14	$83.4	8.20	$166.4						
Economic Development Rider			$16.0		$16.0		$16.0						
AMI Study			($0.3)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			($3.5)		($3.5)		($3.5)		($3.5)		($3.5)		$0.0
Environmental Remediation & Reclamation			($0.5)		($0.5)		($0.5)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			($316.0)		($275.0)		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)		0.00	$0.0	0.00	$0.0	2.02	$41.0	2.02	$41.4	3.27	$67.5		$543.9
Deferral Recovery - CEI Distribution ($25M)		0.00	$0.0	0.00	$0.0	0.08	$1.7	0.08	$1.7	0.08	$1.7		$42.2
Total Revenues Per Year			($234.2)		($99.3)		$302.0		$39.6		$65.7		$586.0
NPV of Total Revenues Per Year	$276.7												

Consultant Market Rates		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$21.5		$34.5		$34.8
Generation Rate		73.38		78.14		77.95	
Generation Increase over 2008 Rate of 69.02		4.36	$87.1	9.12	$183.6	8.93	$181.3
Total Revenues Per Year			$108.6		$218.1		$216.1
NPV of Total Revenues Per Year	$454.6						

NPV: Cleveland Electric	
NPV: ESP	$276.7
NPV: Market Rates	$454.6
Benefits to Customers (Market - ESP)	$178.0

SUMMARY - OHIO EDISON

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	73.38
2010 Market Rate average($/MWH)	78.14
2011 Market Rate average ($/MWH)	77.95

Year		2009		2010		2011		2012		2013		2014 - 2035	
Sales (MWH)		26,460,000		26,738,000		27,019,000		27,308,000		27,602,840		688,313,507	
ESP		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$75.0		$75.0		$75.5						
Distribution Improvement Rider		1.97	$52.1	1.97	$52.7	1.97	$53.2						
ESP Generation Rate		69.18		73.16		77.22							
Generation Increase over 2008 Rate of 67.92		1.26	$33.4	5.24	$140.2	9.30	$251.2						
Economic Development Rider			($8.6)		($8.6)		($8.6)						
AMI Study			($0.5)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM			($4.6)		($4.6)		($4.6)		($4.6)		($4.7)		$0.0
Environmental Remediation & Reclamation			($14.0)		($14.0)		($14.0)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits			$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)		0.00	$0.0	0.00	$0.0	2.00	$53.9	2.00	$54.5	3.23	$89.1		$725.4
Total Revenues Per Year			$132.9		$240.7		$406.6		$49.9		$84.4		$725.4
NPV of Total Revenues Per Year	$1,078.5												

Consultant Market Rates		Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions	Rate ($/MWH)	Revenue $ millions
Distribution Rates			$75.0		$75.0		$75.5
Generation Rate		73.38		78.14		77.95	
Generation Increase over 2008 Rate of 67.92		5.46	$144.5	10.22	$273.2	10.03	$271.1
Total Revenues Per Year			$219.5		$348.2		$346.6
NPV of Total Revenues Per Year	$769.7						

NPV: Ohio Edison	
NPV: ESP	$1,078.5
NPV: Market Rates	$769.7
Benefits to Customers (Market - ESP)	($308.8)

SUMMARY - TOLEDO EDISON

Model Assumptions	
2008 Sales (MWH)	56,471,000
Sales Growth Rate	0.92%
Discount Rate	8.48%
2009 Market Rate average ($/MWH)	73.38
2010 Market Rate average($/MWH)	78.14
2011 Market Rate average ($/MWH)	77.95

Year	2009		2010		2011		2012		2013		2014 - 2036	
Sales (MWH)	10,775,000		10,834,000		10,894,000		10,965,000		11,036,601		261,900,043	
ESP	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue	Rate	Revenue
	($/MWH)	*$ millions*	*($/MWH)*	*$ millions*	*($/MWH)*	*$ millions*	*($/MWH)*	*$ millions*	*($/MWH)*	*$ millions*	*($/MWH)*	*$ millions*
Distribution Rates		$40.5		$40.5		$40.8						
Distribution Improvement Rider	1.56	$16.8	1.56	$16.9	1.56	$17.0						
ESP Generation Rate	69.18		73.16		77.22							
Generation Increase over 2008 Rate of 67.28	1.90	$20.5	5.88	$63.7	9.94	$108.3						
Economic Development Rider		($7.4)		($7.4)		($7.4)						
AMI Study		($0.2)		$0.0		$0.0		$0.0		$0.0		$0.0
Energy Efficiency and DSM		($1.9)		($1.9)		($1.9)		($1.9)		($1.9)		$0.0
Environmental Remediation & Reclamation		($0.5)		($0.5)		($0.5)		$0.0		$0.0		$0.0
CEI RTC - Net of Residential Credits		$0.0		$0.0		$0.0		$0.0		$0.0		$0.0
Deferral Recovery - Generation Phase-In (10 yr)	0.00	$0.0	0.00	$0.0	2.03	$22.1	2.03	$22.2	3.28	$36.2		$289.1
Total Revenues Per Year		$67.8		$111.3		$178.3		$20.4		$34.3		$289.1
NPV of Total Revenues Per Year $470.4												

Consultant Market Rates	Rate	Revenue	Rate	Revenue	Rate	Revenue
	($/MWH)	*$ millions*	*($/MWH)*	*$ millions*	*($/MWH)*	*$ millions*
Distribution Rates		$40.5		$40.5		$40.8
Generation Rate	73.38		78.14		77.95	
Generation Increase over 2008 Rate of 67.28	6.10	$65.7	10.86	$117.6	10.67	$116.3
Total Revenues Per Year		$106.2		$158.1		$157.0
NPV of Total Revenues Per Year $355.3						

NPV: Toledo Edison	
NPV: ESP	$470.4
NPV: Market Rates	$355.3
Benefits to Customers (Market - ESP)	($115.1)

ADJUSTED MARKET RATES

	$/MWH - with transmission costs			$/MWH - net of transmission costs
Year	Mr. Graves, using Cinergy, at 25th Percentile Risk Premium	Mr. Graves, using PJM Western Hub, at 25th Percentile Risk Premium	Combined for Mr. Graves	Combined for Mr. Graves
2009	$78.03	$77.74	$77.89	$69.49
2010	$82.87	$81.91	$82.39	$74.00
2011	$83.95	$80.48	$82.22	$73.82

SUMMARY - USING MR. GRAVES' 25th PERCENTILE

NPV ($MM)	CEI	OE	TE	Total
ESP	276.7	1078.5	470.4	1825.6
Market Rates	246.7	493.6	243.4	983.7
Benefits to Customers (Market - ESP)	-30.0	-585.0	-227.0	-841.9

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and accurate copy of the foregoing document was served this 29th day of September, 2008 by regular U.S. mail, postage prepaid, or by electronic mail, upon the persons listed below.

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