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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. 08-935-EL-SSO

BRIEF OF OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY IN SUPPORT OF THEIR ELECTRIC SECURITY PLAN

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INTRODUCTION

Seven years after the restructuring of retail electric generation service in 2001, the enactment of Am. Sub. S.B. 221 ("S.B. 221") in May 2008 again radically changed regulation of electric service in Ohio. As pertains to this case, that legislation creates a new process for an electric distribution utility to make a Standard Service Offer ("SSO") available to its customers – the Electric Security Plan ("ESP"), which affords the Public Utilities Commission of Ohio ("Commission") a mechanism both to provide electric generation service to customers, and to authorize a variety of other features and benefits that can be included within the scope of such an ESP *notwithstanding* any other provision of Title 49 of the Ohio Revised Code. R.C. § 4928.143(B). These additional features can be tailored so that, overall, an ESP can provide not only generation service with stable pricing, but also provide other benefits, including, without limitation, enhancements to service reliability, energy efficiency and load management, economic development and job retention, incentives to add new capacity, and environmental benefits. Significantly, under the new legislation, the Commission may approve a proposed ESP notwithstanding any constraints of "traditional" regulatory practices, including the requirement to fix rates on a cost of service basis.[1] Equally significant, the legislation also sets out the single, specific test for the Commission to apply in determining whether to approve an ESP: whether the proposed ESP is more favorable, in the aggregate, than the expected results from a Market Rate Offer ("MRO").

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[1] While the statute gives the Commission the flexibility, in passing on an ESP, to diverge from traditional cost of service requirements, the end result of any Commission action must nonetheless afford the Companies fundamental constitutional protection. *Federal Power Comm. v. Hope Natural Gas*, 320 U.S. 591, 603 (1944).

The Electric Security Plan (the "Plan"[2]) submitted in this case by Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE") (collectively, the "Companies") unquestionably meets this test as established by the legislature. It offers price stability not only for generation but for the totality of retail electric service. It includes a waiver of RTC charges totaling $591 million that the Companies otherwise would collect from CEI customers under an MRO. It also includes, in contrast to an MRO, the Companies' commitment to spend up to $96 million of *shareholder* funds over five years to support environmental, economic development and energy efficiency improvements in Ohio. The Plan's average price increases over the Plan period reflecting all of the Plan's provisions are modest: a 5.32% increase for 2009 over current rates, a 4.01% increase in 2010, and a 5.99% increase in 2011 (Blank Testimony, p. 12), with the first year increase attributable to an increase in distribution rates, not generation rates, after well over a decade with no increase in distribution rates

Solely on a quantitative basis, the Companies' Plan is more favorable, producing customer benefits of more than $1.3 billion on a net present value basis as compared to an MRO. The Commission Staff agrees as it concludes, using its own analytical framework, that the net present value benefit to customers under the Plan exceeds $200 million dollars. And when necessary and appropriate modifications are made to the Staff's analysis, the net present value benefit exceeds $1.6 billion. Based upon these numbers alone, there can be no question that the statutory criterion for approval of the Companies' Plan has been met.[3] R.C. § 4928.143(C)(1).

[2] For purposes of this Post-Hearing Brief, the Companies use the abbreviation "ESP" to refer generally to the electric security plans authorized by R.C. § 4928.143 and use "Plan" to refer to the Companies' proposed ESP.

[3] During the hearings there was considerable attention directed to the question of revision of these analyses to account for more recent wholesale generation prices. While the issue is discussed in greater

Moreover, even though they may not be readily quantifiable, the Plan's other benefits further tip the balance towards its favorability over an MRO alternative. As explained in the pages that follow, these include incentives to enhance service reliability, economic development and job retention, energy efficiency and load management, environmental remediation, and additional generation capacity. The Plan commits *in fact* to the expenditure of one billion dollars on distribution system investments, irrespective of the pressures that may be imposed by uncertainty of current economic conditions or of access to the financial markets. The Plan also commits to a five-year stay-out period for increasing base distribution rates. The value of such *commitments* as part of the Plan must not be overlooked and, importantly, the Commission must recognize that such *commitments* do not arise under an MRO or "traditional" regulation.

In addition, the Plan provides flexibility to the Commission to shorten the Plan period if warranted and also allows for the submission and review of future electric security plans, which would be prohibited if this Plan is rejected and the Companies implement their MRO. If an ESP is rejected and retail generation pricing is established through an MRO, the Commission, under R.C. § 4928.142(F), loses any opportunity to manage that pricing in the future. Under an MRO, generation pricing is subject to the outcome of a competitive bidding process which, in turn, is dependent on the more volatile wholesale energy markets as well as the unpredictable and currently constrained credit markets. A substantial aspect of the "security" offered to customers by this Electric *Security* Plan is protection against the uncertainty of this alternative result. That security will be lost upon rejection of the Plan.

The Plan here is carefully balanced to offer considerable benefits to customers while affording the Companies the opportunity to manage their risks during the Plan term. As such,

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detail later in this Brief, we submit that upon proper consideration of the "update" issue, the Plan remains more favorable than the MRO alternative.

the Plan here is – and, intrinsically, must be – a comprehensive, indivisible package to be accepted in its totality. A substantial distinction between traditional regulation and the new regulatory paradigm here is that the Commission *cannot require* the Companies to accept a *different* ESP than the one proposed. A traditional rate case begins with a company request in its application but ends up with a Commission order having a result, generally different than the request, which a utility *must* then implement. In contrast here, while the Commission may modify the terms of a proposed ESP, the Companies are not required to accept those modifications and may instead choose to implement an MRO upon compliance with the criteria of R.C. § 4928.142 (and thus preclude the prospect of any future ESP). Some intervenors seem to suggest that the Companies should be forced to file a "better" ESP (which actually means a plan advancing that particular intervenor's interests, typically at the expense of other parties' interests), but there is no statutory basis for such a requirement. Thus, before the Commission rejects the Plan in favor of some modification which may accommodate a particular intervenor's parochial interests, it should consider the potential impact of that course in the context of potentially losing the opportunity for all customers to receive any of the benefits of this Plan or, for that matter, the benefits under any future ESP.

The State's policy of promoting diversity of suppliers and customer choice must be harmonized with the express statutory accommodation of ESP provisions that may have the effect of limiting customer shopping. *Compare* R.C. § 4928.143(B)(2)(d) *with* R.C. § 4928.02(C), (E). Several intervenors in this proceeding criticize the Companies' Plan as having the potential to limit customer shopping options.[4] But shopping is only one approach to achieve

[4] Indeed, some witnesses sponsored by the intervenors opine that the Commission's approval of any ESP that was more favorable than an MRO was "anti-competitive" because such an ESP would suppress competition. Hearing Tr., Vol. VI, pp. 103-104; Hearing Tr., Vol. V, pp. 169-170.

the goal of favorable pricing for customers – it is not the end to be sought simply in and of itself.[5] Indeed, S.B. 221 expressly authorizes terms, conditions or charges in ESPs relating to limitations on customer shopping. R.C. § 4928.143(B)(2)(d). Ohio Energy Group ("OEG") witness Baron captures the essence of this key distinction between an MRO and an ESP in stating: "The Commission has a choice: numerous high cost shopping options, or low rates." Baron Testimony, p. 24. In the context of the Plan here, that is precisely the choice before the Commission.[6]

The General Assembly's adoption of a mechanism permitting an ESP is a clear departure from the requirements of traditional regulation, which focuses on a utilities' cost of providing service. Rates under an ESP are established *notwithstanding* the traditional ratemaking statutes, including the cost based ratemaking practices used for decades and other criteria set out in Title 49. R.C. § 4928.143(B). Although the Companies will certainly incur costs to implement the Plan and bear risks under it, the Commission's review here is not directed at the impact of the Plan on the Companies.[7] Indeed, despite the substantial amount of time consumed at hearing by parties attempting to pursue other issues,[8] the ultimate question for the Commission is very

[5] Similarly, while expressing no opinion on whether the Plan is more favorable than the expected outcome of an MRO, representatives of governmental aggregation organizations appear to view their continued existence as an "end" to be sustained at all costs rather than merely an expedient available only to the extent that customers benefit. Frye Testimony, p. 3-5, 8-9, 12, 14-15; Hearing Tr., Vol. V, p. 169-170.

[6] In any rate-setting proceeding, there will be complaints from parties about the particular adverse or inequitable effects of the newly proposed rates *on them*. This case, of course, is no different in that regard. In resolving those issues the Commission must look at all of the relevant circumstances. Where, for example, unreasonable rate increase *percentages* are claimed, the Commission properly must consider whether that customer's existing rates are unreasonably low as the result of subsidization from other customers. While gradualism is certainly an appropriate consideration for the Commission to weigh, it should not be used to maintain historic subsidies at their current level.

[7] The one exception is the backward-looking application of the significantly excessive earnings test pursuant to R.C. § 4928.143(F), which only applies if, and well after, an ESP is adopted and in place.

[8] Remarkably, very few witnesses opine on the one relevant issue. *See, e.g.*, Hearing Tr., Vol. IV, pp. 23-24 (Commercial Group witness Gorman did not look at the Plan in the aggregate or review the MRO

limited and precise: *Is the Plan more favorable to customers than the expected results of an MRO?* On the record here, we submit the answer is clearly "Yes."

Consistent with Staff witness Fortney's observation that "[t]his is not your traditional rate case" (Fortney Testimony, p. 9), this Brief necessarily departs from the framework for discussion of the issues in a "traditional" rate case to one more suited to the singular nature of an ESP. Accordingly, we divide this brief and discuss the issues raised in four broad categories:

- The Plan Benefits Customers
- The Plan Helps Achieve Important State Policy Goals
- The Plan Balances Customer Benefits with Key Risk Mitigation Measures
- The Plan Allows Commission Management of Important Provisions

I. THE PLAN BENEFITS CUSTOMERS.

The General Assembly established one specific standard – starkly different from any previously expressed – for the Commission's review and approval of ESPs:

> [T]he Commission by order *shall* approve or modify and approve an [ESP] application . . . if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is *more favorable in the aggregate* as compared to the expected results that would otherwise apply under Section 4928.142 of the Revised Code.

R.C. § 4928.143(C)(1) (emphasis added).[9] This standard requires a comprehensive analysis of the entirety of the Plan. It does not require that the Plan incorporate any specific provisions, or

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results), 84 (Kroger Co. witness Higgins does not offer testimony on the favorability of the Plan); Hearing Tr., Vol. VII, pp. 108-109 (City of Cleveland witness Courtney has no opinion on whether the Plan should be approved); Hearing Tr., Vol. V, p. 168 (NOPEC/NOAC witness Frye has no opinion on whether the Plan is more favorable than the expected results of an MRO). Interestingly, however, Mr. Higgins also testified in the Companies' MRO proceeding and, in that proceeding, testified that the Companies' MRO plan "appeared to be unattractive in light of the [C]ompanies' estimate that it would cost customers about $1.3 billion more than the ESP." Hearing Tr., Vol. IV, p. 84.

[9] If the Commission approves the ESP application with modifications, the Companies may reject the

specific bases for its terms. Rather, it involves a consideration of the quantitative and qualitative benefits to customers of all of the Plan's proposed terms.

As demonstrated below, the Plan includes a number of benefits to customers over an MRO:

- Customers will realize a savings of $1.3 billion in net present value over an MRO;
- The Plan will result in over a half billion dollars in waived CEI RTC charges;
- The Plan will stabilize distribution rates;
- The Plan will promote improvement to the quality of customer's service;
- The Plan will stabilize generation rates;
- The Plan will minimize and phase-in increases in rates;
- The Plan will promote energy efficiency and load management;
- The Plan will allow interruptible service credits for those customers who wish to receive such service;
- The Plan is consistent with the State's policy goals and will promote Ohio's economy and help improve Ohio's environment.

A. The Plan Represents Significant Net Present Value Savings To Customers Over The Expected Results Of An MRO.

The projected aggregate quantitative benefits alone represent an estimated $1.3 billion in net present value savings to customers as compared to the expected results of an MRO, including savings across each of the Companies and comparative average savings of $600 per customer. Blank Testimony, pp. 5-6, 16, Att. 1. The analysis to determine the value of the Plan was

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changed plan and file a new ESP or proceed with an MRO. R.C. § 4928.143(C)(2)(a).

conducted by Mr. Blank, and the expected cost of the outcome of an MRO was based on the work of two well-established economics experts. The most difficult aspect of the R.C. § 4928.143(C)(1) standard is the needed comparison to an uncertain value – specifically, the "expected results" of an MRO. The complexity of predicting the "expected results" of an MRO requires extensive education and experience in economics, risk assessment and quantification, and wholesale energy pricing, bidding processes and trends. In order to ensure a reasoned estimate of the results of an MRO, the Companies retained *two* experts: Dr. Jones and Mr. Graves.[10] Mr. Blank then compared the outcome of his calculation of the cost of the Plan to customers (approximately $1.6 billion on a net present value basis) to the expected cost to customers of an MRO ($2.9 billion on a net present value basis), and determined that the Plan results in an approximate $1.3 billion benefit to customers on a net present value basis. Blank Testimony, Att. 1, p.1.

1. On A Net Present Value Basis, The Amount Customers Will Pay For All Of The Plan's Components Is $1,577,100,000.

To assess whether the Plan is quantitatively more favorable than the MRO alternative, the Companies conducted a thorough analysis that incorporates the Plan's projected impact. Blank Testimony, Att. 1. Mr. Blank calculated the value of all applicable components of the Plan as proposed by the Companies, taking into account the appropriate recovery periods, and applied a discount rate to derive the cost of the Plan on a net present value basis. This net present value for each Company individually, and for all three Companies combined, is set forth on

[10] Dr. Jones holds a Ph.D. in economics and has over 30 years of experience in forecasting and market-price determination in the energy industry. Jones Testimony, pp. 1-2. Mr. Graves, a Principal of The Brattle Group, has degrees in mathematics and finance, and has worked for over 20 years in the energy industry, including assisting utilities in price forecasting, risk management, financial simulation, and valuation assessments. Graves Testimony, pp. 2-3.

Attachment 1 to Mr. Blank's prefiled direct testimony. The cost of the Plan is $1,577,100,000 on a net present value basis.

The Companies' calculation of the Plan's net present value cost reflects the estimated costs to customers of the Companies' distribution rate case, Case No. 07-551-EL-AIR (the "Distribution Case") and the Plan's Delivery Service Improvement Rider, base generation rates (taking into account deferral amounts), along with other deferrals, and the value of other non-rate benefits.[11] *See* Blank Testimony, pp. 16-17, Att. 1.

The Companies' calculation of net present value properly accounts for costs incurred by suppliers and the Companies. For example, certain costs properly were excluded from both the Plan and MRO estimates because they would be expected to be similar and, thus, cancel each other out. These excluded costs include: transmission costs; the 2011 fuel rider; the rider impact for new environmental costs; new taxes; purchased reserve capacity; and the fuel transportation surcharge. Blank Testimony, pp. 18-19. Further, both estimates assume that there was no shopping, thus preventing the results from being skewed by any differences in shopping. Blank Testimony, pp. 18-19.

2. On A Net Present Value Basis, The Expected Amount Customers Will Pay Resulting From An MRO Is $2,880,500,000.

The next step in the process of comparing the Plan to the expected result of an MRO is, in fact, determining the expected cost resulting from an MRO. The testimonies of Dr. Jones and Mr. Graves address the expected result of an MRO for retail generation service and provide: (1) the nature of the generation service product proposed to be supplied under the ESP by the Companies to SSO customers; (2) reasonable methods for determining a market price for providing generation service to SSO customers; and (3) useful market pricing benchmarks. Mr.

[11] The specifics of these Plan provisions are discussed *infra*.

Blank relies upon the results of both Dr. Jones' and Mr. Graves' analyses to arrive at $2,880,500,000 as the expected cost to customers resulting from an MRO, again on a net present value basis. Blank Testimony, Att. 1, p. 1.

The relevant product for establishing a market price benchmark is the expected cost of electricity supply for retail electric generation service to SSO customers in the Companies' service territory over the next three years, 2009-2011. The components of that service include generation, capacity, and ancillary services, together with all transmission and transmission-related services including network services, congestion costs, and other costs incurred in delivering electric generation to the Companies' service territory. Graves Testimony, p. 4.

Mr. Graves discusses two methodologies for determining a market price benchmark for supplying electric generation service to SSO customers: (1) a "comparables" method that relies upon prices for providing generation service to SSO-equivalent customers obtained from competitive procurements held in other jurisdictions (adjusting the results to align with the market conditions in the Companies' service territories); and (2) a "modified constructed cost" method that determines a market price benchmark by adding up the prices of the individual cost components of generation service (e.g., energy, capacity, ancillary services, network service) and then adding an appropriate premium for pricing and volumetric risk. Graves Testimony, pp. 8-10, 11-14.

Mr. Graves notes the significant pricing and volumetric risks associated with supplying retail electric generation service to SSO customers. These risks include the prospect of opportunistic customer switching between SSO and competitive retail electric supply, as facilitated by governmental aggregation programs. Graves Testimony, pp. 5-6. More specifically, to provide electric generation service sufficient to meet SSO customer load, the supplier is subject to: (1) *pricing risk* due to volatility in electric power prices; and (2) *volumetric risk* that stems from load uncertainty produced by changes in weather, economic conditions, and customer switching. *Id.* In Ohio, the presence of governmental aggregation facilitates customer switching, and thereby raises the cost of providing the SSO product.[12] *Id.*

Dr. Jones' methodology for calculating the expected MRO price includes deriving "direct cost components" of full requirements service. Jones Testimony, p. 5. These direct costs include costs for procurement of energy from the wholesale market, and of transmission services from the Midwest ISO ("MISO"). *Id.* He also includes 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 Companies' SSO.[13] *Id.* Dr. Jones calculates separate margins for each year for customers representing relatively low shopping risk and for customers representing relatively high shopping risk. He then creates a single MRO price for each year based on a weighted average of all customer classes. *Id.* The direct cost components include the

[12] *See* Graves Testimony p. 10. In fact, Mr. Graves notes that his results were conservative estimates of a benchmark SSO market price. In particular, the results of his comparables analysis are based mainly on procurement results pertaining to *residential* customers in other jurisdictions. Customer-switching risk (particularly with respect to residential customers) will be greater than that reflected in the adjusted comparables used due to the presence of governmental aggregation programs and, as a result, the premium Mr. Graves develops to capture this particular risk undoubtedly understates it. In addition, the Companies' SSO load obligation extends to industrial and commercial customers. Industrial customers in most jurisdictions have switched to competitive retail suppliers far more than residential customers, supporting the conclusion that the switching risk associated with these customers is higher than for residential customers only. Because the customer-switching risk faced by the Companies is greater than that of the comparables used in his analysis, the expected results of an MRO would be even higher than the estimates provided, in order to reflect that additional risk. Dr. Jones' testimony supports this fact: "Government aggregation substantially increases the shopping risk faced by a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligations." Jones Testimony, p. 19.

[13] Dr. Jones relies on publicly available analyses of recent solicitations as evidence of the competitive margin that would be included in a market-clearing offer. Jones Testimony, p. 23.

price for round-the-clock energy;[14] location cost adjustments;[15] load-shaping costs;[16] capacity costs;[17] transmission and ancillary services costs;[18] and distribution losses. *Id.* at 6.

Moreover, Dr. Jones accounts for the fact that the commitment to meet the Companies' SSO load represents a substantial commitment of capital resources, and that these capital resources are exposed to substantial risk. Jones Testimony, p. 15. Potential suppliers will not make such a commitment without an expectation of earning a margin to compensate for these risks. *Id.* The supplier must have adequate capital to function efficiently in energy markets. This would include the ability to enter forward contracts and other derivative instruments to

[14] The round-the-clock price, the price for wholesale energy at a traded wholesale energy hub such as the Cinergy hub, is equal to the average price that a buyer would pay at the hub if purchasing an equal amount of energy in every hour of the day over some time period. The round-the-clock wholesale energy price is calculated using forward peak and off-peak contract prices, weighted by the number of peak and off-peak hours. For this analysis, both Dr. Jones and Mr. Graves use prices for calendar peak and off-peak as those forward prices were stated on July 15, 2008. Jones Testimony, p. 6.

[15] Location cost adjustments must be made because transmission congestion between the Cinergy Hub and the Companies' load zones results in differences in the prevailing prices in the two areas. In calculating round-the-clock wholesale energy prices, the forward wholesale market price data for contracts that deliver into Cinergy Hub were used. The Cinergy Hub was used because it is a liquid trading location in the MISO area, and prices for transactions at the Cinergy Hub are reported in the trade press. Jones Testimony, p. 7.

[16] Load shaping costs are incurred to more accurately reflect the cost of serving customers' actual load. The round-the-clock energy price is calculated based on the cost of providing an equal amount of energy in each hour of the year. While the round-the-clock price is a useful indicator of the cost of energy, it is only a beginning step to calculating the cost of serving load. Consumers do not use electricity at constant rates throughout the year. Instead, their consumption varies minute by minute in response to numerous factors. Jones Testimony, pp. 8-9.

[17] MISO requires load serving entities to demonstrate that they have sufficient capacity in the form of generation resources both to serve load and to meet reserve margin requirements. It is uncertain how the MISO's resource adequacy program will operate. Nevertheless, a wholesale supplier would assume that it would be required to procure adequate capacity to comply with MISO's reserve margin, or resource adequacy, requirement. Accordingly, Dr. Jones assumes that a supplier would be required to demonstrate resources adequate to meet 113.5% of projected annual peak load measured at the load zone. He thus calculates capacity costs using a capacity requirement based on the projected peak load for the Companies. Whether MISO's methodology will lead to higher capacity requirements for load serving entities is a source of risk to a supplier of full requirements electric service. *See* Jones Testimony, pp. 10-13.

[18] As part of the full requirements service needed to meet the Companies' SSO load, the wholesale supplier would be required to procure transmission and ancillary services from MISO. Jones Testimony, p. 14.

obtain sufficient, diversified generation supply and to hedge any costs or risk associated with providing the standard service offer. *Id.* at 16. Also, the supplier must have adequate capital to fund the delay between when expenses are incurred and when revenues are collected. *Id.* As Dr. Jones explains, the main risks for a wholesale supplier include shopping risk,[19] load variability risk,[20] price variability risk,[21] regulatory risk,[22] and bidding risk.[23] *Id.* at 17.

Based upon their own methodology, as described above, both Dr. Jones and Mr. Graves derive an expected market price, excluding transmission, that would be expected to result from an MRO conducted for the service territories of the Companies for the Plan period. Dr. Jones concludes that such market prices would be $81.69/MWh for 2009, $88.66/MWh for 2010 and

[19] Shopping risk exists because customers have the right at any time to elect to receive retail electric service from alternate competitive suppliers. Moreover, customers who shop have the right to return to their SSO provider. This means that the wholesale supplier of full requirements service to supply the Companies' SSO load may diminish if market prices drop sufficiently to enable successful entry by competitive suppliers. Conversely, the wholesale supplier is exposed to further risk in that retail customers may switch from alternative suppliers to the SSO if market conditions make such movement attractive. Jones Testimony, p. 17.

[20] Load variability risk arises because real time customer demand is driven by factors that are unpredictable and outside of the control of the participants in the marketplace. These factors include, for example, weather and changing macroeconomic conditions. Because of these factors, the wholesale supplier cannot be certain of future load for any customer taking SSO service. Jones Testimony, p. 21.

[21] Price variability risk arises both because electricity prices are volatile and because wholesale suppliers of the standard service offer are unable to hedge their future needs perfectly due to shopping risk and load variability. A wholesale supplier bidding to provide full requirements electric service to meet SSO service obligations can be fairly certain that the actual market price at the time the service is delivered will be higher or lower than the market price expected at the time the bid was prepared. Jones Testimony, p. 21.

[22] Wholesale suppliers of full requirements service for the Companies' SSO face regulatory risk because the costs incurred to provide the service can be affected by changes in regulatory policies. Well-recognized sources of such risk in the Companies' service territories include the possibility of future environmental regulations, such as controls on greenhouse gas emissions, and the possibility that MISO will institute changes to the design of its markets or rules. Jones Testimony, p. 22.

[23] Bidding risk arises because once an offer is submitted the bidder is typically required to keep the offer "open" for some period of time for review and acceptance by the regulator. During the time the bid is kept open, market prices may change substantially, making it difficult or impossible for the winning bidder to hedge the price that it offered. Jones Testimony, p. 23.

\$94.99/MWh for 2011.[24] Blank Testimony, p.18. Mr. Graves' expected market prices are \$83.45/MWh for 2009, \$81.87/MWh for 2010, and \$81.39/MWh for 2011. *Id.* Mr. Blank combines these expected market prices to derive a Market Rate Average for each year. Blank Testimony, Att. 1, p. 1.

3. The Plan Is More Favorable Than The Expected Result Of An MRO.

Once the value of the Plan is calculated and the expected market pricing for an MRO is derived, a comparison can be made to determine which approach, the Plan or an MRO, is more favorable. In making this comparison, Mr. Blank uses the Market Rate Averages of \$82.57/MWh for 2009, \$85.27/MWh for 2010, and \$88.19/MWh for 2011 calculated by Dr. Jones and Mr. Graves to compute the difference between the expected cost of the MRO and the value of the Plan based upon the difference in generation pricing under each approach. Blank Testimony, p. 18.[25] The result of Mr. Blank's analysis shows that the cost of an MRO on a net present value basis is \$2,880,500,000 for all three Companies across the three-year Plan period. Similarly, the cost of the Plan on a net present value basis as proposed by the Companies is \$1,577,100,000 over the same period. The result is that there is a net present value benefit of over \$1.3 billion dollars to customers under the Plan as proposed by the Companies.

This analysis is summarized in the following table, which is drawn from Attachment 1 to Mr. Blank's testimony:

[24] Dr. Jones updated his calculation for 2010 slightly (*see* Cos. Ex. 10 (errata)), but this change has no material impact on the Companies' resultant calculation.

[25] Mr. Graves provides two estimates calculated under two different methodologies. *See, generally,* Graves Testimony. The average of those two estimates is then combined with Dr. Jones's estimate. Blank Testimony, p. 18, n.2. The expected cost of the MRO and the value of the Plan both include the estimated cost of the Distribution Case.

ESP & MRO Net Present Value (NPV) Summary				
($ Millions)	Total Ohio	CEI	OE	TE
NPV: ESP	$1,577.1	$189.9	$963.4	$423.8
NPV: MRO	$2,880.5	$908.5	$1,372.4	$599.6
Benefits to Customers (MRO - ESP)	$1,303.4	$718.5	$409.1	$175.8

The Commission Staff also compared the Plan to an MRO, albeit through a different methodology, and concluded that there is a positive net present value of approximately $200 million to the benefit of customers. See Johnson Testimony, Ex. 9D. When Staff's approach is properly modified, as explained in the rebuttal testimony of Mr. Blank, the positive net present benefit is in excess of $1.6 billion compared to the expected result of an MRO.

These measures of the obvious financial benefit of the Plan are conservative because comparing only generation prices between the ESP and MRO does not take into account the Plan's numerous qualitative benefits and other benefits that are not readily capable of quantification. *See* Blank Testimony, pp. 15-16. These benefits, described in further detail throughout this Brief, are not reflected in the Companies' calculation of net present value. For example, most obviously, the Plan provides predictable and relatively stable prices for three years, with only limited ability for adjustments. In contrast, an MRO is open to fluctuation and volatility even beyond what may be experienced in the initial bid due to additional competitive bids that will occur in the future for generation supply in 2010 and 2011. The impact of such stability on customers and the State's economy are significant and increases the Plan's value. Nor does the quantitative estimate incorporate the secondary and tertiary benefits of additional commitments by the Companies to spend up to $96 million in various demand-side management, AMI, energy efficiency, job retention, economic development, and environmental remediation efforts. *See* Blank Testimony, p. 9. The aggregate quantitative benefits of the Plan, even without consideration of the qualitative benefits discussed in further detail *infra*, are more favorable than an MRO alternative and, as such, the Plan should be approved.

4. The Companies' Market Price Estimates Are Conservative In Nature.

The calculations by Dr. Jones and Mr. Graves are conservative, further supporting the conclusion that the Plan is more favorable in the aggregate. *See* Blank Testimony, p. 5. For example, the estimates of market prices incorporate retail prices that were derived at a time when the market for those prices likely was artificially low based on a number of factors, including the recent rejection of Clean Air Interstate Rules ("CAIR"), external downward pressure on MISO reported prices, the delay in impact of rising fuel costs, and the determination to incorporate the added costs of renewable energy resources. Warvell Testimony, pp. 6-7. As a result, the experts' MRO estimate is conservative, and the true difference between the Plan's aggregate price and the MRO would be even greater than the Companies' estimate. Also, if certain of the excluded costs specifically were included in the analysis, the quantitative benefits of the Plan likely would be greater. Blank Testimony, p. 19. The fuel transportation surcharge and new environmental costs would be higher for the MRO rates – increasing the benefits of the Plan. *Id.* Moreover, the Plan incorporates riders, the value of which are set at zero initially and adjusted only if the costs are indeed incurred – the riders may never apply if the risk event does not occur. *See* Section I.B.4 *infra* (describing Riders FTE and FCA). On the other hand, under an MRO, suppliers build the risks of certain future costs into their prices and, thus, customers will pay the cost of suppliers assuming this risk regardless of whether any events ever actually occur. In making its determination, the Commission must appropriately consider the conservative nature of the market price estimates included in the Plan.

5. The Use Of Updated Market Forwards Requires Consideration Of Other Factors That Will Increase Expected MRO Prices.

At the hearing, intervenors made much of more recent fluctuations in wholesale energy prices subsequent to the Companies' submission of the Plan, suggesting using more recent wholesale market forward prices than those used by Dr. Jones and Mr. Graves to reflect perceived trends and changes in pricing from the date of the Companies' filed Application. Kollen Testimony, p. 11; OEG Ex. 2a (October 21, 2008 update to Mr. Kollen's analysis); Schnitzer Testimony, pp. 16-17. This assertion is misplaced and inappropriate. The recent changes only highlight the uncertainty and volatility of wholesale energy prices, rather than counseling in favor of a downward adjustment in the calculation of the expected results of an MRO. "[T]he trend in prices for 2009 has been down, '10 has been down a little bit, and '11 has not moved as much, but those prices can as easily move up and down based on what we just talked about, not only natural gas markets and oil markets but also issues to do with credit and other items that are affecting us today." Hearing Tr., Vol. I, p. 103.

The proponents of using more recent wholesale market forward prices ignore other factors that have also changed, such as credit constraints and rising risk parameters that would *increase expected MRO bid prices*. Further, the forward prices utilized by Dr. Jones and Mr. Graves appropriately provide for a *contemporaneous* comparison of the terms and conditions of the ESP as filed by the Companies and the expected results of an MRO. Hearing Tr., Vol. III, p. 86. Arbitrarily selecting dates to obtain forward prices that reflect only certain perceived trends eliminates the contemporaneous nature of the data that is essential in making a fair and accurate comparison between the ESP and MRO.[26] Moreover, by the time the actual bidding process would take place, prices could easily be trending significantly upward. Hearing Tr., Vol. III, p. 109.

[26] As Dr. Jones aptly notes, "July 15 is the date where we have a constant set of analyses that the Commission can feel confident that will allow them to make a comparison in the aggregate." Hearing Tr., Vol. III, p. 106.

The reality that risks are much different now than they were several months ago must frame any discussion of updating prices to account for perceived recent trends. The continuing lack of credit and the associated credit crisis are particularly relevant to power markets, where credit forms such an important business element. Bidders and suppliers alike must increase bids because of challenges induced by the crisis. These challenges include increased cost of credit, fewer and less creditworthy counterparties and increased risk premiums. Hearing Tr., Vol. III, pp. 85-88, 104-109, 136-137.

Furthermore, the necessary fundamentals for participating in an MRO, such as access to short and long term capital markets, are now significant hurdles. Some financial institutions that tended to be among the participants in historic auctions either no longer exist or exist in a different form, and those that do participate find themselves severely capital constrained. Hearing Tr., Vol. III, pp. 87-88.

Dr. Jones explains that a supplier would require compensation for bearing the significant risk associated with committing to supply MRO service. Jones Testimony, pp. 15, 23. Dr. Jones further testifies that while energy-only costs may have declined recently, a number of other costs and risks have increased dramatically since July due to turmoil in the financial markets and subsequent capital market restrictions. Hearing Tr., Vol. III, pp. 85-88, 104-109, 136-137. These increasing risks and costs, particularly the significant capital costs required for participating in an MRO, would push prices in an MRO substantially upward, particularly if conducted in the midst of a severe financial crisis.[27] *Id.* Moreover, the costs of letters of credit, which typically are required to participate in market offers, have increased dramatically. *Id.* Dr.

[27] Mr. Graves supports the view provided by Dr. Jones indicating that any updating would have to include and account for the substantial increases in the price of risk premiums, poor liquidity and cost of credit. Hearing Tr., Vol. III, pp. 205-208.

Jones agrees that it would be inappropriate to update the analysis with current forward prices for power without also adjusting the margins required to compensate bidders for capital costs and bearing of risk, which are both many times what they were in July. Hearing Tr., Vol. III, p. 105.

In fact, the crisis has indeed had a substantial impact on recent bid prices as evidenced in Maryland where prices were higher than the typical levels seen and beyond the levels anticipated based on other market factors. Procurement results included a substantial premium that has not appeared in Maryland procurements in the past. *See State of Maryland Public Service Commission, In the Matter of the Competitive Selection of Electricity Supplier/Standard Offer or Default Service*, Order No. 82279, Case Nos. 9056/9064, Oct. 24, 2008, pg. 2 ("The Bid Monitor further testified that the bids were conducted in the most severe financial crisis in generations and the Bid Monitor concluded that the crisis had a substantial impact on bid prices."). As this real life experience aptly illustrates, the margins that are demanded in the current financial environment are substantially higher than those demanded in previous solicitations.

Recent events in Pennsylvania similarly support the conclusion that ongoing turmoil in the financial markets has had an upward effect on risk premiums. In particular, Mr. Blank notes the results of the Pennsylvania Power & Light POLR procurement process that has taken place this year. Hearing Tr., Vol. VII, pp. 80-82. These procurements took place in March 2008 and again in October 2008. Between March and October, the winning bid price in those RFP arrangements *went up* even though the round-the-clock wholesale energy price for forwards for the relevant time *went down*.[28] *Id.* Moreover, the premium provided by winning bids over the round-the-clock wholesale energy price went from 51% in March to 66% in October.

[28] For example, in March 2008, the price for residential service for the winning bids was $108.80/MWh at the same time that the round-the-clock wholesale energy price at the PJM West Hub for forwards for 2010 was $72.24/MWh. In October, the winning bid for POLR supply for residential was $112.51 while the round-the-clock wholesale energy forwards for 2010 for the contemporaneous period were $67.92.

As Mr. Blank indicates, this was caused by a number of factors. One being the credit market issues discussed previously. *Id.* Another fact is that the Clean Air Interstate Rule ("CAIR") was overturned by the United States Court of Appeals for the D.C. Circuit this summer. *North Carolina v. EPA*, 531 F.3d 8964 (D.C. App. 2008). While this decision creates a near term uncertain regulatory vacuum and an economic environment which may tend to depress wholesale prices, there is a strong expectation that, in the longer term, the CAIR rule will be reinstated in some form and, hence, increase market prices. Hearing Tr., Vol. VII, p. 82; *see* Order, *North Carolina v. EPA*, Case No. 05-1244 *et al.*, slip op. (D.C. App. Oct. 21, 2008) (seeking briefing on whether any party is seeking *vacatur* of CAIR, and whether the court should stay its mandate until EPA promulgates a revised rule).

The issues discussed above provide strong support and evidence that the market price analyses supplied as part of the Plan do not need to be updated for the Commission to render a reasoned and accurate decision regarding whether the Plan is more favorable than the expected result of an MRO.[29] Further, the foregoing certainly establishes that the use of more recent market forwards cannot be done in a vacuum and must be accompanied by, and requires consideration of, credit market conditions, regulatory rulings, and increased risk premiums that all will have the effect of increasing expected MRO prices.

B. The Plan Provides Other Tangible Benefits To Customers Over The Expected Result Of An MRO.

The Plan provides significant benefit through the waiver of collection of the remaining balance of CEI RTC charges, and reduces uncertainty and risk by committing to no further

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So, although there was a 6% reduction in the wholesale energy price, there was a 3.4% increase in the price for POLR service. Hearing Tr., Vol. VII, pp. 80-82.

[29] As was stated during the hearing regarding the record being kept open, the Companies continue to assert their right to be heard and respond to any additional evidence that may be submitted in the record.

increases in distribution rates through December 31, 2013, while promoting service quality and reliability. The Plan brings stability and certainty to generation rates over the Plan period, utilizing credits and deferrals to manage price increases for customers. The Plan's price provisions notably exclude significant expenditures that the Companies commit to absorb without passing on the costs to customers, including costs of required renewable energy resources and promoting and implementing energy efficiency and demand-side management programs. *See* Hearing Tr., Vol. I, p. 53; Blank Testimony, p. 9. Plus, the Plan includes credits for energy efficiency, programs to assess the delivery systems' abilities to incorporate advanced metering technology, and options for interruptible service.

1. The Plan Waives RTC Charges Of Over Half A Billion Dollars.

The Companies' current rate plan requires that RTC charges be paid by CEI customers through the end of 2010. Blank Testimony, p. 7. Under the Plan, however, RTC charges are waived for CEI customers as of January 1, 2009.[30] Application, ¶ A.1.; Hussing Testimony, p. 8. The Transition Rate Credits will also terminate at this same time under the Plan. *Id.* The Companies' agreement to waive these RTC charges constitutes a $591 million benefit to CEI customers. Blank Testimony, pp. 7-8.

It is noteworthy that none of the testimony of the other parties' witnesses addresses this particular aspect of the Plan, which represents one of its most significant, quantifiable customer benefits. As proponents solely for their respective interests, we should, perhaps, not be surprised that these witnesses largely just criticize the Plan and/or simply "want more" than the benefits it already offers. In omitting any mention of a feature of the Plan that is worth over half a billion dollars to CEI customers, however, these presentations can hardly be characterized as presenting

[30] The Plan includes a Regulatory Transition Charge and Residential Transition Rate Credit Rider to transition those charges into the new proposed rate classifications. Hussing Testimony, pp. 7-8.

any sort of a balanced view. But such a benefit cannot simply be ignored as this Plan component alone will save a CEI residential customer using 750 kWh per month nearly $200 over the two year period the RTC charge would otherwise remain in place if the ESP is not approved.

2. The Plan Provides For Stable Distribution Rates.

Resolving the Companies' pending Distribution Case, the Plan includes new distribution rates and a commitment not to increase distribution rates until 2014. *See* Application, ¶ A.3.b. The new distribution base rates will be effective on a service-rendered basis starting January 1, 2009 for OE and TE customers and starting May 1, 2009 for CEI customers. *See id.* The distribution rates reflect revenue increases of $75 million for OE, $34.5 million for CEI, and $40.5 million for TE. *Id.* The Companies may, however, implement revenue-neutral changes in rate design or new service offerings, both as approved by the Commission. *Id.*

The Commission's approval of the Plan will resolve the following distribution rate case issues:[31] (1) the allowed rate of return on equity for each of the Companies will be established at 10.5%, together with the necessary accounting authority to effectuate the proposed distribution base rate increase; and (2) approval of the revenue distribution and rate design stipulation and the proposed tariffs as described in the Application. Application, ¶ A.3.d. Moreover, approval of the Plan will acknowledge the Companies' understanding reached with Staff that the Companies will continue to work with Staff to ensure it is provided sufficient information to effectively continue its audits. *Id.* The Plan commitment regarding maintaining distribution rate levels will allow customers to budget over a five-year horizon related to electricity distribution costs. Further, the time and resources otherwise expended on intervening distribution rate cases can be avoided to the benefit of customers and the Commission.

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[31] Although the Commission may address these issues in the context of the Distribution Case, they remain essential elements of the Plan.

3. The Plan Promotes Service Quality And Reliability.

(a) The Companies will invest significant resources into improving their delivery systems under the Plan.

Under the Plan, the Companies commit to invest at least $1 billion from 2009 through 2013 in making improvements to their distribution energy delivery system. Application, ¶ A.3.g; Schneider Testimony, p. 10. The investment will be implemented using a value-of-service analysis to assure that capital is invested in projects that benefit customers the most. Schneider Testimony, p. 10. The significance of this Plan provision is that the Companies are *committing* to spend this amount toward improving their delivery systems over the specified period. Such a *commitment* provides substantial value to customers as it is not simply a projection or estimate or budget for what is planned to be spent; it is a commitment that a minimum $1 billion *will* be spent to improve the Companies' delivery systems over the next five years. Staff supports this extraordinary commitment by the Companies; Staff witness Roberts states:

> This funding level, along with the Companies' current budget for operation and maintenance . . . should enable each operating company to maintain a satisfactory level of service reliability.

Roberts Testimony, p. 4.[32]

(b) The Companies will conduct a comprehensive Smart Grid study.

The Plan also commits the Companies to conduct a comprehensive Smart Grid study by the end of the Plan's first year. Application, ¶ A.4.f, Att. E; Schneider Testimony, p. 11. The study will assess what steps are required to implement Smart Grid technology. This Study will include an analysis of the Companies' electric distribution system and define a first estimate of

[32] OCC witness Cleaver attempts to minimize the significance of the Companies' commitment, asserting that the Companies had already committed to $424 million of the $1 billion. Cleaver Testimony, p. 37. Mr. Cleaver, however, concedes that his $424 million number included funding for transmission and, therefore, his comparison is inaccurate. Hearing Tr., Vol. IV, p. 80.

the scope, logical sequence, and cost of the major investments necessary to implement Smart Grid technology. The Study will serve as a planning document to recognize the key changes/upgrades that may be needed to deploy Smart Grid, frame potential solutions for further study, and present a first-level prioritization of key investments. *See* Application, Att. E; Schneider Testimony, p. 11. Not surprisingly, no witnesses raise any complaints about the Smart Grid study.[33]

(c) The Companies will obtain continued and increased generating capacity under the plan to meet present and future needs.

In the proceedings leading to Senate Bill 221, concerns were raised regarding current generating capacity. The Companies, through the Plan, have sought to ensure increases in capacity in response to these concerns. FES will be required to increase capacity by 1000 MW from January 1, 2007, through 2011. Application, ¶ A.2.l, Att. D. The increases will be accomplished through any or all of: (1) new and/or upgraded existing generation; (2) maintenance of existing generation that would otherwise be shutdown; and (3) purchases of additional generation. Application, ¶ A.2.l; Blank Testimony, pp. 10-11. The increased capacity will help assure customers that adequate generation will be available to meet growing demands and alleviate the burdens of capacity constraints.

4. The Plan Will Produce Stable Generation Rates.

One of the most significant concerns underlying S.B. 221 was the potential volatility and uncertainty of electric generation prices as the State continues its transition to a full market-based system during turbulent economic times. Indeed, the state, national, and even international

[33] In fact, NRDC witness Sullivan describes the study as "comprehensive" and requests additional funding for it. Sullivan Testimony, p. 13.

economies have proved even more volatile and uncertain since the passage of S.B. 221. *See* Hearing Tr., Vol. III, p. 204-207.

The Plan provides certainty, stability, mitigated increases in generation rates and options for customers to control their usage and costs. The Companies commit to provide a specific base generation price for each year of the Plan with only limited possibilities for adjustment. *See* Application, ¶¶ A.2.a, A.2.b., Scheds. 3a, 3b, 3c. The average base generation price is fixed through the generation charge Rider ("Rider GEN") at 7.5¢/kWh in 2009, 8.0¢/kWh in 2010, and 8.5¢/kWh in 2011. Application, ¶ A.2.b. Rider GEN rates are seasonal and voltage-level adjusted, applied across eight rate classifications. Scheds. 3a, 3b, 3c; Hussing Testimony, p. 3.[34]

Rider GEN rates also include all of the costs associated with the Companies' requirements for renewable energy resources as set forth in S.B. 221. Application, ¶ A.2.d.; Warvell Testimony, p. 7. As explained by witness Kevin Warvell, the Companies will meet the statute, and in meeting that statute any risk involved in the pricing of renewable energy would be assumed by the Companies. Hearing Tr., Vol. I, p. 53. This Plan provision relieves the customers of risk associated with the cost of meeting the renewable energy resource requirement in S.B. 221 during the Plan period.

As an added benefit to customers, the Companies have proposed not to implement the full base generation price. Instead, customers will pay a lower price, with the differential to be deferred and recovered at a later date. Through this mechanism and the anticipated terms of a wholesale power supply agreement with FirstEnergy Solutions ("FES"), customers will experience minimal yearly average increases: a 0.06% increase for 2009 over current rates, a 4.01% increase in 2010, and a 5.79% increase in 2011. Application, p. 5; Hearing Testimony,

[34] The rate classifications were originally proposed in the Companies' Distribution Case, and Staff opines that the voltage-based classifications are reasonable. *See* Fortney Testimony, p. 4.

Vol. I, p. 21. These price increases reflect mitigation of the base generation prices of ten percent or more as the result of phase-in credits implemented through the Generation Phase-In Rider ("Rider GPI"). The actual average base generation price for customers in 2009 is 6.75¢/kWh, 7.15¢/kWh in 2010, and 7.55¢/kWh in 2011. Application, ¶ A.2.b, Attachment A. The prices were established after an assessment of wholesale market prices, cleared auction prices, and the attendant risks associated with wholesale generation market prices. *See* Hearing Tr., Vol. I, p. 26. The offsetting credit was determined by balancing the size of the rate impact on customers and the use of the deferral mechanism. Warvell Testimony, p. 8. Thus, the fixed base prices provide significant benefits to customers in the form of certainty and stability. Customers will be better able to plan their energy budgets and requirements during the Plan period. And, customers will be protected from increases and volatility in the wholesale energy market over the next three years.

The only potential adjustments to base generation charges may be made in the context of three riders, all of which are designed only to pass through certain incremental potential future costs above a baseline level. Each of these orders deal with specific costs that could increase substantially and unpredictably over the term of the Plan. Notably, customers potentially would only pay a portion of these increases and then, only in the later years of the Plan. The costs sought to be recovered through the riders would be subject to Commission review and would be reconciled annually via filings with the Commission. *See* Application, ¶ A.2.i., Att. B. The riders that would potentially adjust base generation charges include Rider FTE, Rider FCA and Rider CCA. Each of these riders is discussed below.

(a) Rider FTE will increase base generation prices only if the fuel transportation surcharges or certain environmental costs rise above a specific annual threshold.

The bypassable Fuel Transportation Surcharge, Environmental Control and New Taxes Rider ("Rider FTE") includes two components for the Companies' cost recovery. Both components establish significant thresholds below which the Companies will bear all such costs. Indeed, Rider FTE provides that the Companies will bear up to $110 million over the Plan period for these costs before the rider is triggered. *See* Warvell Testimony, pp. 13-14. If they exceed the substantial threshold and dollars are actually recovered, Rider FTE's two components will be reconciled quarterly. *Id.*; Hearing Tr., Vol. II, p. 126.

The first component of Rider FTE provides for the recovery of fuel transportation surcharges above $30 million in 2009, $20 million in 2010, and $10 million in 2011. Application, Att. B. As explained by Mr. Warvell, the recovered costs include those "incurred by FES to move the fuel-related sources, be it coal, via train or barge, to the particular unit." Hearing Tr., Vol. I, p. 159. The initial threshold of $30 million is based on FES' budgeted amount for fuel transportation charges for 2009. To the extent that fuel transportation costs are below or at the threshold for the year, customers will pay nothing for the FT portion of the Rider FTE. Hearing Tr., Vol. I, pp. 160-161.

The decreasing threshold levels in the FT component of Rider FTE represent the risk the Companies are willing to bear. They also reflect the Companies' attempt to decrease customers' prices in the near term. Staff, in fact, "recognize[s] and appreciate[s] that the Companies are attempting to phase-in the FT surcharge costs gradually for ratepayers with minimal cost recovery in the first part of the ESP plan." Turkenton Testimony, pp. 5-6. Significantly, while the risk of customers potentially paying for fuel transportation surcharges under Rider FTE is greatest in 2011, the Companies have provided that the Commission may terminate the Plan effective December 31, 2010. Thus, any increases in rates from fuel transportation surcharges through Rider FTE in 2011 may occur only if the Commission determines in its discretion that the Plan remains in customers' best interests and will continue for its third year. *See* Application, ¶ A.7.e.; Section IV.A., *infra.*

Although the competitive supplier intervenors allege that they will not be able to compete without information regarding the bases for the fuel transportation charges, it is clear after cross-examination that this information has competitive value and, without such information, the real risk CRES suppliers run is setting their prices too low. *Compare* Garvin Testimony, p. 21 (Rider FTE limits CRES suppliers' abilities to set "price[s] to beat" and, thus, prejudices government aggregation groups) *with* Hearing Tr., Vol. V, pp. 153-154 (Mr. Garvin admits that FES' fuel transportation costs were important because he had "a concern that if [Gexa] didn't know the price to beat . . ., [Gexa] would set [its] price too low."). As for these intervenors' concerns about "transparency" for the benefits of customers, fuel transportation surcharge costs for 2006 and 2007 have been provided to Staff. Hearing Tr., Vol. IX, pp. 208-209. Further, the Companies produced their budget forecasts for these costs for each year of the Plan to the Commission. Hearing Tr., Vol. IX, pp. 209-210. The supporting information produced to the Commission, in combination with Staff's audit and review process, provides a solid foundation for the FT portion of Rider FTE. Moreover, under the Plan, the Commission will have the opportunity to review all fuel transportation costs sought to be recovered under this rider.

The second component of Rider FTE (specifically, the "E" portion) will recover any costs incurred in excess of $50 million due to new taxes, new environmental laws or new interpretations of existing laws that take effect after January 1, 2008.[35] Application, Att. B.

[35] As described in Section I.B.4 *supra*, the Companies' will absorb the costs of renewable energy resource requirements, incurred as a result of S.B. 221, as part of the base generation rates. Thus, the adjustment

Since the $50 million dollar threshold is a significant hurdle to overcome before any dollars are collected from customers, that threshold should give the Commission comfort that the intent of this component of the Rider is meant to address environmental issues of significant proportion. The Companies cannot offer the fixed generation prices included in the Plan without such provisions to allow the Companies to manage this type of risk. Staff recognizes the potential risks facing the Companies and their supplier and supported this provision of Rider FTE. "Based on possible legislative action regarding any new carbon tax, new environmental or renewable laws, or new taxes I believe it is appropriate in this ESP proceeding to approve, as a placeholder rider, the E portion of Rider FTE." Turkenton Testimony, p. 7. As with other cost recovery under this rider, all environmental costs will be subject to Commission review.

(b) Rider FCA may recover only incremental increased fuel costs in 2011.

The Fuel Cost Adjustment Rider ("Rider FCA") is also bypassable and will allow the Companies to recover only the incremental costs of fuel in 2011 that exceed the costs for 2010. Application, Att. B. The entire cost of fuel for 2009 and 2010, including all increases in those costs, are absorbed as part of the base generation charges under Rider GEN. Hearing Tr., Vol. I, p. 86. Rider FCA accounts for the uncertainty in fuel costs in 2011. Hearing Tr., Vol. I, p. 85; *see* Hearing Tr., Vol. IX, p. 206 (Staff witness Turkenton recognizes that fuel prices have been volatile in recent years). There is significant precedent for the Companies' ability to use a fuel recovery mechanism to recover such costs; it is similar to that approved by the Commission in the Companies' RSP and subsequent cases. Hearing Tr., Vol. IX, p. 207. Moreover, because Rider FCA may *only* recover 2011 costs, customers will not be subject to any Rider FCA costs if

may be made only in the face of new requirements or changes in existing requirements, not because of requirements in S.B. 221. *See* Application, ¶¶ A.2.d (describing the renewable energy resource costs built in to the base generation rates), A.2.i. (description of allowable adjustments).

the Commission exercises its discretion to terminate the Plan effective January 1, 2011 or if the fuel costs in 2011 are equal to or less than the fuel cost level experienced in 2010. *See* Application, ¶ A.7.e.[36]

As with Rider FTE, the Companies produced supporting information for Rider FCA for 2006, 2007, and 2008 to Staff. Hearing Tr., Vol. IX, pp. 205-206. Both Staff and the OCC appear to want explicit future projections for such costs, but such information is not available. *See* Turkenton Testimony, pp. 2-4; *see also* Yankel Testimony, p. 38 (costs recovered under Rider FCA "are not known and measurable"); Hearing Tr., Vol. IX, p. 206 (Staff had no reason to believe that the Companies have not produced all available information). Specific cost projections are neither contemplated by S.B. 221 nor consistent with recent Commission approvals for recovery of increased fuel costs through riders in the Companies' RSP and subsequent cases. In any event, and as Ms. Turkenton recognizes, given the volatility in fuel costs such projections may not be accurate when used to predict costs two or three years in the future. Hearing Tr., Vol. IX, p. 206.

(c) Rider CCA will recover only certain capacity costs necessary to meet MISO's planning reserve requirements and above those levels already committed to under the Plan.

The Plan will require FES to commit to adding 1000 MW of capacity from January 1, 2007 through December 31, 2011. Application ¶A.2L.; Warvell Testimony, pp. 12-13. These commitments will be made at no additional charge to customers. *Id.* To the extent that these capacity additions and other plant commitments made by FES[37] are insufficient to meet MISO's

[36] To the extent the intervenors suggest that FES could somehow manipulate its fuel transportation charges in order to recover under the Rider FTE, this suggestion is baseless because the Commission will retain the ability to review and audit charges recovered under it. Application, Att. B; Hearing Tr., Vol. II, p. 126.

[37] The Plan calls for FES to commit all of its generation within MISO (including capacity associated with Ohio Valley Electric Corp. but excluding the PJM assets of Beaver Valley and Seneca) to serve the

planning reserve requirements for the Companies' load, FES will purchase such additional capacity. *Id.*

If such purchases are required, the Capacity Cost Adjustment Rider ("Rider CCA") will recover part of the costs of such purchases. The Plan, however, mitigates those potential costs in two ways. First, Rider CCA is only necessary if FES' committed capacity is insufficient to meet the planning reserve requirement. Warvell Testimony, p. 12. Second, Rider CCA – if implemented at all – will only reimburse for costs necessary to meet the requirement during the months of May through September. Warvell Testimony, p. 13.[38]

Staff presents no concerns regarding Rider CCA. Because the Commission will have the opportunity to review and approve costs passed through Rider CCA, any legitimate concerns regarding Rider CCA should be resolved. *See* Hearing Tr., Vol. VII, pp. 77-78.[39] As with Rider FTE and Rider FCA, Rider CCA charges are bypassable.

5. The Plan Further Mitigates Increases In Generation Rates.

As noted, a major concern underlying S.B. 221 was that the continuing transition to market-based generation rates would lead to prices for electricity that would be significantly

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Companies' load and to meet any planning reserve requirements associated with that load. Warvell Testimony, pp. 12-13.

[38] In addition, in the event any penalties are levied by MISO against FES for failure to meet any capacity requirement, the cost of any such penalties would not be passed on to customers. *See* Hearing Tr., Vol. II, pp. 24-25, 27-28.

[39] Other concerns relating to Rider CCA expressed by intervenor witnesses are likewise without merit. For instance, FPL witness Garvin admits that his proposal for the Companies to manage all of the capacity within their service territory has, to his knowledge, never been attempted elsewhere. *See* Garvin Testimony, pp. 17-18; Hearing Tr., Vol. V, pp. 152-153. We suggest that the Commission would be ill-advised to attempt a maiden voyage here, especially as the Companies do not purport to have the expertise necessary to carry out such a new assignment. Another example is OEG witness Baron's proposal that Rider CCA should not apply to his large industrial clients because planning reserves are not calculated based on interruptible loads. But he admits on cross-examination that his clients' firm load requirements are, in fact, included in the capacity reported to MISO. *See* Baron Testimony, p. 32; Hearing Tr., Vol. VI, p. 59. Thus, Rider CCA properly applies to all customers in the recovery of the Companies' planning reserve costs.

higher than the current prices. A major benefit under the Plan is mitigating rate increases that would otherwise occur by engineering increases in a measured fashion in each year of the Plan by employing the regulatory principle of gradualism in the design of generation rates and certain riders. Hussing Testimony, p. 5. The fixed base generation rates are reduced for a more gradual transition via a phase-in that spreads the impact of such increases via amortization over 10-year deferral periods. Application, ¶ A.2.b.; Warvell Testimony, p. 9 (deferred amounts for 2009 and 2010 will be recovered starting in 2011, and deferred amounts for 2011 will be recovered starting in 2013). The Companies determined an appropriate phase-in credit for each year by balancing a rate increase to customers against the burden resulting from the Companies foregoing cash obligations. Hearing Tr., Vol. I, p. 72. And while we recognize certain criticisms relating to the customer impact of future recovery of the phase-in deferrals, the fact is that an important balance struck in the design of the Plan is that such phase-in-deferral recovery is only fully implemented in 2013 as the DSI Rider charges terminate (*see* Section III.C *infra*), thus providing gradualism as well as price stability.

(a) Through credits and deferrals, the Plan reduces increases in rates during the Plan period.

Some of the intervenor witnesses who testified regarding the Companies' proposed rate design acknowledged that gradualism is a recognized and reasonable rate design strategy. Hearing Tr., Vol. VI, pp. 15-16 (OEG witness Mr. Baron recognized that gradualism and consistency is a "legitimate goal" for the Companies);[40] Hearing Tr., Vol. VIII, pp. 19-20 (Nucor witness Dr. Goins recognizes that reasonable minds can differ about rate design and gradualism

[40] Mr. Baron also acknowledges that "the Commission has considered and relied on gradualism as a ratemaking principle historically." Hearing Testimony, Vol. VI, p. 19.

is a consideration). Gradualism is, indeed, a useful tool in managing overall customer impacts resulting from rate design objectives.

The positive impact of the phased-in structure of the Plan's generation costs cannot be minimized. The structure results in a reduction of generation pricing of over ten percent during the Plan's three years. Application, ¶ A.2.a. Indeed, the Plan's use of phase-in riders will defer the impact of $430 million in the first year alone. Warvell Testimony, pp. 8-9. The phase-in deferral works to the benefit of customers by spreading out the increase in rates to future years that otherwise would have to be paid in full by customers commencing on January 1, 2009, and because the carrying charges on the deferral are less than the Companies' overall cost of capital. The accrued deferrals will be subject to a carrying charge set at an interest rate that is also very favorable for customers. Blank Testimony, p. 11.

While challenged primarily by competitive supplier intervenors, the phase-in of generation prices, along with other deferrals, is expressly authorized as part of an ESP by R.C. § 4928.144, which allows the phase-in of charges and authorizes their deferral. This section then directs that such deferrals plus carrying charges be collected through a *nonbypassable* surcharge on the rates of an electric distribution utility (except as provided in R.C. § 4928.20(I) specifically related to governmental aggregation programs). The arguments against the permissibility of such phase-in deferrals, and the recovery thereof, are really a quarrel with S.B. 221 as enacted, as opposed to the Plan.

As specifically authorized by R.C. § 4928.144, therefore the Plan provides credits through Rider GPI, which credits are deferred and then recovered through the Deferral Generation Credit Rider ("Rider DGC"). Application, ¶ A.2.e.; Warvell Testimony, p. 8. The Companies estimate that these deferrals would be $430 million in 2009, $490 million in 2010 and $550 million in 2011. *Id.* These amounts represent what customers *won't* pay during the Plan period.

S.B. 221 expressly authorizes ESPs to include an option to securitize any phase-in amounts. R.C. § 4928.143(B)(2)(f). As a possible alternative for future implementation, the Plan sets forth a reasonable framework under which these securitization provisions could be accomplished by the Companies and reviewed by the Commission. *See* Application, ¶ A.2.g. Recovery under either option may not exceed ten years and would be non-bypassable except for certain governmental aggregation customers, consistent with R.C. § 4928.20(I). Application, ¶ A.2.e.

(b) Rider EDR reduces rate increases for certain customers.

Through the Economic Development Rider ("Rider EDR"), the Plan will mitigate the increases in rates experienced for customers presently served under discounted rates. Rider EDR provides credits to customers taking service under the following rate schedules: RS, GT, STL, TRF and, for interruptible customers. These customers mostly represent residential heating customers taking service under non-standard residential rates, political subdivisions taking street lighting and traffic lighting service rates, and customers taking service under transmission service rates. Application, Sched. 3a (*e.g.*, OE Sheet 108). The credits available to these customers will be funded through non-bypassable Rider EDR charges to customers taking service under rate schedules GP and GS.

The credits and charges in Rider EDR are designed to moderate the potential rate increases to those customer classes which would have otherwise received the largest increases.[41]

[41] Some intervenors complain that certain customer classes will receive much larger increases than others. For example, OEG witness Baron and Nucor witness Goins both point to the GT rate class for Toledo Edison as one class that would experience increases over 30%. Baron Testimony, p. 17; Goins Testimony, p. 9. But both of these witnesses admit that their rate increase figures were based on revenues

Hearing Tr., Vol. IV, p. 269. The Rider further contemplates that these credits would be paid for by charges to those customer classes which would receive reductions or increases below the system-wide average increase.[42] Thus, Rider EDR promotes gradualism by spreading out the increases across customer classes.

6. The Plan Promotes Energy Efficiency.

The General Assembly has determined that the State should "[e]ncourage innovation and market access for cost-effective supply- and demand-side retail electric service, including, but not limited to, demand-side management, time-differentiated pricing, and implementation of advanced metering infrastructure." R.C. § 4928.02(D). In furtherance of this policy, the Plan includes several components that encourages customers to manage and reduce consumption.

(a) The Companies will commit to make significant investments in DSM/EE programs at no cost to customers.

The Plan commits the Companies to provide up to $25 million of shareholder funds from 2009 through 2013 for customer demand-side management/energy efficiency improvements. Application, ¶ A.4.g.; Blank Testimony, p. 9. In contrast, because an MRO is limited to setting retail generation pricing through a competitive bidding process, an equivalent commitment of shareholder funds is not possible in an MRO proceeding. The broad authorization in S.B. 221

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generated by those customers and thus reflect special contract and other discounts that customers in that class currently enjoy. Hearing Tr., Vol. VI, p. 26; Hearing Tr., Vol. VIII, p. 34. Further, both agree that some of the increases result: (1) from the fact that there are different rates among the Companies for similar customers; and (2) from the Companies' desire to develop uniform rates. Hearing Tr., Vol. VI, p. 16; Hearing Tr., Vol. VIII, p. 21. Both witnesses admit that a goal of achieving some consistency among the Companies' rates was reasonable in designing rates. Hearing Tr., Vol. VI, p. 16; Hearing Tr., Vol. VIII, pp. 21-22.

[42] The charges for customers in the GS and GP rate classes are non-bypassable for two reasons. First, Rider EDR is designed to be revenue neutral to the Companies. Thus, the Companies must be able to recover the amounts provided as credits under the Rider. Second, because Rider EDR acts as a way to keep rates low for customers, particularly for industrial customers, the Rider benefits society as a whole. Hussing Testimony, pp. 8-9.

for developing ESPs that are not cost-based makes it possible for the Companies to commit these shareholder funds. No witness seriously contests the value of this commitment.

Nevertheless, several parties and Staff demand additional details and additional spending commitments. *See* Gunn Testimony, pp. 3-4, 9-10 (seeking defined processes and increased spending in 2009 of $28 million); Sullivan Testimony, pp. 3-11 (complaining that ESP should include additional detail regarding energy efficiency and demand management plans and also include a customer charge of at least $32.5 million for 2009 program costs); Gonzalez Testimony, pp. 5-8; Scheck Testimony, pp. 13-14 ($25 million commitment unlikely to meet benchmarks); Hearing Tr., Vol. IX, p. 27 (Mr. Sullivan estimating maximum cost for energy efficiency programs in 2009 of $63 million); *see also* Alexander Testimony, pp. 20-24 (describing as "insufficient" the Companies' proposal to commit up to $25 million in shareholder funds). All of the issues these witnesses raise are premature and best reserved for, and can be addressed in, a future proceeding dedicated to reviewing the Companies' benchmark report that will be filed pursuant to O.A.C. 4901:1-39-03 and R.C. § 4928.66. Indeed, Mr. Gunn concedes that a detailed DSM/EE program review has always occurred, in his experience, in a regulatory proceeding dedicated to DSM/EE or integrated resource planning, and not in an SSO proceeding. Hearing Tr., Vol. IX, pp. 22-23.

The Companies do not intend to suggest, by committing to spend up to $25 million of shareholder funds on DSM/EE programs, that this is the upper limit of what will be spent to meet the benchmarks set forth in R.C. § 4928.66. *Nothing* in the Plan limits the Companies' spending on such programs or constrains the types of programs that will be funded. The nature of the programs to be funded will be determined in compliance with R.C. § 4928.66 and any relevant Commission rules.[43]

(b) The Plan offers a time-of-day pricing option for generation rates.

Rider GEN includes an option for time-of-day pricing. Customers who have qualifying metering and who elect the time-of-day option will be charged on-peak and off-peak rates by rate schedule. On-peak is defined as 6:00 a.m. to 10:00 p.m. EST, Monday through Friday, excluding holidays. Application, Sched. 3a, Original Sheet 88. Commercial Group witness Gorman notes that the "TOD price structure will encourage customers to improve more efficient power demands on the utility because more accurate price signals are transmitted to retail customers." Gorman Testimony, p. 7.

(c) The Plan includes a pilot Advanced Metering Infrastructure program to assess the readiness of the Companies' current infrastructure.

The Plan includes a proposal for an Advanced Metering Infrastructure ("AMI") pilot program that will examine the Companies' infrastructure's readiness for demand-side tools. Application, ¶¶ A.4.a, A.4.b, Att. F. Staff "supports" the notion that the Companies are proposing to offer an AMI pilot in conjunction with some form of dynamic pricing to residential customers during the ESP period." Scheck Testimony, p. 7.

For the pilot study, the Companies will select approximately 500 participants who will receive Dynamic Peak Pricing along with a control group of customers similar to the participants.[44] Application, ¶¶ A.4.a, A.4.c; Hussing Testimony, pp. 16-17. The participants'

[43] Therefore, to the extent that Ms. Alexander recommends that efforts be directed to at-risk customers and that Mr. Millard recommends that small business entities also be eligible for programs, the Companies are free to institute such programs and will consider those recommendations going forward. *See* Alexander Testimony, pp. 23-24; *see, generally,* Millard Testimony.

[44] The scope of the program is similar to a program undertaken by Baltimore Gas & Electric. Hearing Tr.,

service will incorporate advanced metering technology, real-time usage information and enhanced billing data summaries in their monthly bill. Application, ¶ A.4.c, Att. F; Hussing Testimony, p. 17. The participants' generation rates will decrease during off-peak times in order to encourage usage during those times. Hussing Testimony, p. 17. The on-peak generation rates (which will be higher than off-peak rates) will further increase during Critical/Dynamic Peak conditions, which may occur up to 12 times per year. Application, Att. F. Participants will receive notification of the Critical/Dynamic Peak events on the prior day to encourage participants' selective use of energy during that time. Application, Att. F; Hussing Testimony, pp. 17-18. The resultant data from the study will help determine the potential benefits of such technology. The Plan calls for the Companies to engage a group of stakeholders to discuss the proposed AMI pilot program, assess the potential for such technologies, and assist the Companies in implementing any other agreed-upon programs to the extent they are cost effective. Application, Att. F; Hussing Testimony, p. 17.

The Companies will pay for the first $1 million in costs associated with the AMI/Dynamic Peak Pricing Program without passing on those costs to customers. Application, ¶ A.4.a, Att. F. To the extent that the size and scope of the program may change after the consultation with the collaborative group, the costs of a pilot study could conceivably exceed $1 million. To the extent that occurs, only costs beyond $1 million will be recovered via the Demand Side Management and Energy Efficiency Rider ("Rider DSE"). Hussing Testimony, p. 17; *see* Application, Att. F. If the cost estimates offered by Staff witness Scheck prove correct (*see* Scheck Testimony, pp. 2-3), it is likely the total cost of the pilot program will be absorbed by the Companies' shareholders.

Vol. IV, p. 21.

(d) The Plan encourages customers to undertake their own energy efficiency measures.

Rider DSE allows the Companies to recover costs associated with energy efficiency and demand-side management programs while also encouraging customers' own energy efficiency and demand-side management efforts.[45] Application, ¶ A.4.i.; Sched. 5o. Rider DSE includes two components. The first, DSE1, is a 0.0193¢/kWh charge, which is updated semi-annually via a filing with the Commission, to recover costs associated with the interruptible, demand-side management options. *See* Application, Sched. 3a, p. 74. The second component, DSE2, is a separate charge that reimburses the Companies for past and future costs incurred in complying with energy efficiency and peak demand reduction requirements in R.C. § 4928.66, including costs incurred for programs approved in Case No. 05-1125-EL-ATA. Application, Scheds. 3a, pp. 74-76, 5o, p. 17. The DSE2 charge also will be updated semi-annually through requests for approval to the Commission.[46] *Id.*

The structure of Rider DSE supports the Companies' demand-side management and energy efficiency efforts and encourages customers to institute their own such efforts. The

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[45] Rider DSE allows the Companies to recover lost revenues. Hussing Testimony, p. 10. S.B. 221 expressly recognizes the Companies' right to recover such lost revenues. R.C. § 4905.31(E); R.C. § 4928.66(C). Such lost revenues have not been calculated and thus are not presently included in the Rider DSE charge. Hearing Tr., Vol. IV, pp. 210-211. Thus, Mr. Gorman's suggestion that the DSE Rider be rejected on the basis that it recovers such lost revenue should be rejected. *See* Gorman Testimony, pp. 11-12.

[46] IEU witness Murray incorrectly suggests that the DSE2 charge will be set at 0.00¢ for non-residential customers until 2010 and that this will not provide an incentive to customers to establish their own programs. Murray Testimony, p. 5. Likewise, OCC Witness Yankel misunderstands the initial 0.00¢ charge and complains that the charge will be applied inconsistently. *See* Yankel Testimony, p. 38. However, costs to be recovered as part of the DSE2 charge for non-residential customers will be included in that rider beginning as early as mid-2009 and updated semi-annually on January 1 and July 1 of each year. Hearing Tr. IV, p. 221. If estimates of certain parties are accurate, the cost of implementing programs starting in 2009 to secure compliance with the energy efficiency and peak reduction requirements in R.C. § 4928.66 will result in a material incentive to avoid the DSE2 charge. *See* Gunn Testimony, pp. 4-10; Sullivan Testimony, p. 9; Hearing Tr., Vol. IX, p. 27 (cost of DSM/EE programs in 2009 estimated at $30 million to $63 million).

DSE2 charge is avoidable by non-residential customers who implement programs at their terminus and who otherwise satisfy the requirements set forth in Rider DSE. Hussing Testimony, pp. 10-11; *see* Application, Sched. 3a, pp. 75-76, 5o, pp. 1-2 (sample application). Participating customers must achieve reductions over their current usage in increasing amounts over 5 years, culminating in reductions of 4.8% for service in 2013. *See* Application, Sched. 5o, p. 1. The Companies set the annual reductions required to qualify for avoidance of the DSE2 charge at 1½ times the statutory minimums imposed on the Companies systemwide by R.C. § 4928.66 so that these reductions would contribute an amount in excess of the energy efficiency requirement for that particular customer to the Companies' efforts to meet the statutory minimums. Hearing Tr., Vol. IV, pp. 204-205. In other words, customers who implement these measures will provide energy efficiency sufficient to meet the statutory minimum for their load, as well as provide an additional energy efficiency amount that the Companies may apply toward meeting their overall requirement for energy efficiency. As such, Rider DSE promotes the state's policy of encouraging energy efficiency by incentivizing customers to implement measures that make the most sense for them.[47]

7. The Plan Provides Credits For Interruptible Customers.

The benefits of an option for interruptible service as proposed by the Companies are significant for customers that have a significant amount of load that can be interrupted. As explained by Nucor witness Goins:

> For electricity-intensive manufacturing customers such as Nucor that can interrupt their manufacturing processes, lower electricity

[47] This incentive mechanism also has intervenor support. *See, e.g.*, Gorman Testimony, p. 9 ("I agree with the Compan[ies'] proposal that customers that undertake DSM/EE programs on their own should be able to opt out or avoid paying the DSM/EE Rider charges."); Hearing Tr., Vol. IV, pp. 37-38 (Gorman acknowledges that high load-factor customers, such as his clients, want the option to opt-out of the DSE2 charge); Hearing Tr., Vol. IX, pp. 24-25 (OEC witness Gunn believes that a rate package that includes energy efficiency measures is more favorable than one without such measures), 29.

> prices afforded by interruptible rates help reduce their financial and business risks by making their products more cost-competitive. Moreover, including interruptible rates in the ESP recognizes not only the role such rates can play in economic development and job retention, but also the potential benefits of interruptible service in enhancing system reliability and reducing all customers' costs for generation and transmission services.

Goins Testimony, p. 16. Under the Plan, customers who can designate a contract firm load and be subject to interruption for their realizable curtailable load ("RCL") are eligible to receive a credit. Application, Scheds. 5s, 5t; Warvell Testimony, p. 22. The credit offered for emergency interruptions is $1.95/kW/month, an amount derived from the bilateral market price of capacity of MISO designated network resource. Warvell Testimony, p. 22. This amount effectively represents the avoidable cost for the Companies if customers commit to interrupt during a system emergency, whether called by MISO or the Companies. Customers eligible for economic interruptions may receive an additional credit of $6.05/KW/month. Hearing Tr., Vol. II, p. 65.

The Plan's interruptible options are incorporated into two riders: the Economic Load Response Program Rider ("Rider ELR") and the Optional Load Response Program Rider ("Rider OLR"). *See* Application, Scheds. 5s (ELR), 5t (OLR); Warvell Testimony, p. 23. Rider ELR is available to customers currently receiving an interruptible credit as of July 31, 2008. Warvell Testimony, p. 23. Rider ELR customers will be subject to both emergency and economic interruptions. Economic interruptions may be triggered when the market price of power increases above Rider GEN's rates. During economic interruptions, customers may buy-through the interruption by paying the market rate.

Rider OLR is available for any customers seeking an interruptible credit after the effective date of the tariff. Warvell Testimony, p. 23. Rider OLR customers will receive credit for emergency interruptions only. The Companies "offered the OLR rider for any new customers that would arrive, and in offering that rider, our belief was they would get the same interruptible credit, emergency interruptible credit, and then based on their criteria, they could apply for a reasonable arrangements rider in which they could get additional credits for items that could lead to economic interruption." Hearing Tr., Vol. I, p. 56.

No witness seriously challenges the wisdom of including interruptible rates in the Plan. Indeed, to the extent there is testimony by intervenors about Riders ELR and OLR, it largely amounts to asking for bigger credits, restrictions on the Companies' ability to interrupt service, or greater freedom to participate in interruptible programs. The short answer to these proposals is that if such objectives are indeed warranted and desirable under particular circumstances, they can be readily pursued through the special contract mechanism and do not require changes to the Plan.

For example, both OEG witness Baron and NuCor witness Goins want to increase the Realizable Curtailable Load ("RCL"), one of the components for calculating the interruptible credit. The Companies' proposed RCL takes the customer's average hourly demand during peak hours and subtracts the customer's contract firm load. Warvell Rebuttal, p. 3. Mr. Baron and Dr. Goins suggest using the customer's monthly peak rather than the average hourly peak period demand, but the resulting RCL greatly overcompensates interruptible customers. Goins Testimony, p. 8; Baron Testimony, p. 31. Indeed, even the Companies' proposal provides interruptible customers a credit that is greater than the value of power likely to be interrupted in an emergency or required to be bought through as part of an economic interruption. Warvell Rebuttal, p. 7.

Mr. Baron and Dr. Goins also suggest that the per kW credits provided under Riders ELR and OLR are too low. Goins Testimony, p. 20; Baron Testimony, p. 30. But the Companies' proposed credit for emergency interruptions, $1.95/kW, is based, reasonably, on the bilateral market contract price for designated network resources ("DNR"), a measure of capacity requirements within MISO.[48] Hearing Tr., Vol. II, pp. 53-54.

Both of these witnesses also suggest limiting the number of hours in which the Companies could economically interrupt customers (Baron Testimony, p. 30 (1000 hours per year); Goins Testimony, p. 20 (250 hours per year)), but Mr. Baron admits that this suggestion would put the Companies at risk of potentially being unable to economically interrupt customers. Hearing Tr., Vol. VI, pp. 54-55. Further, placing time limitations on the ability to economically interrupt customers would reduce the value of the right to interrupt and thus require a reduction of the customer's interruptible credit. Warvell Rebuttal, p. 8.

Dr. Goins also argues for giving customers options to be interrupted for either emergencies or economic reasons, suggesting that without separating the two options customers would be unlikely to choose to receive interruptible service. Goins Testimony, pp. 20-21. Yet, Dr. Goins' view is belied by the fact that the Companies' interruptible customers *currently* receive service that includes *both* emergency and economic interruptible provisions and customers do indeed choose to take advantage of this service. Warvell Testimony, p. 22.

II. THE PLAN HELPS ACHIEVE IMPORTANT STATE POLICY GOALS.

The Plan includes terms that benefit all citizens through the promotion of the State's economy and improvement of the State's environment. R.C. § 4928.02(N) reflects a State policy of "[f]acilitating the state's effectiveness in the global economy" in the Commission's regulation of electric service. Also, it is this State's policy to "[p]rovide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential

[48] The credit received by customers receiving service via Rider ELR also includes a credit under Rider EDR of $6.05/kW. Hearing Tr., Vol. II, p. 65. This represents, in effect, the economic interruption credit; it is only available to customers who can be economically interrupted. This value is greater than the values for economic interruption credits proposed by Mr. Baron or Dr. Goins. Baron Testimony, p. 30 ($2.20/kW); Goins Testimony, p. 26 ($2.60/kW).

environmental mandates." R.C. § 4928.02(J). The Plan furthers both the State's economic and environmental health.

A. The Plan Will Benefit The State's Economy.

The Plan will "[f]acilitat[e] the state's effectiveness in the global economy." R.C. § 4928.02. First and foremost, the Plan provides a significant positive net present value to the Companies' customers over the expected results of an MRO. These savings thus allow customers to invest in other aspects of the State's economy – a particularly significant benefit given the current financial challenges facing the State and the nation. As noted, the Companies conservatively estimate that the Plan will result in savings of an average of $600 per customer. *See* Blank Testimony, pp. 5-6. The Plan also allows for certain customers to enter into reasonable arrangements that will help assure the customers' continued participation in the State's economy. And, the Plan commits the Companies to make significant direct investments in economy-enhancing initiatives.

1. The Plan Encourages Economic Growth By Allowing The Companies To Provide Service Under Reasonable Arrangements.

The Plan's Reasonable Arrangements Rider ("Rider RAR") implements tariff discounts pursuant to R.C. §§ 4905.31 and 4905.34, and the Commission's proposed rules under O.A.C. 4901:1-38. Application, ¶ A.4.i; Hussing Testimony, pp. 9-10. Reasonable arrangements most often serve as a mechanism to retain existing businesses in the State and, to a lesser degree, serve to attract new businesses. Blank Rebuttal, pp. 16-17. Thus, Rider RAR "provides a means of encouraging energy efficiency and economic development, including job creation and retention, capital investment and incremental and retained load." Hussing Testimony, p. 10.

The Companies will assist customers who seek a reasonable arrangement in establishing an application procedure and reviewing the application to determine completeness. Then, the applications will be filed with the Commission, which will retain the authority to review and approve or reject such applications. Hearing Tr., Vol. IV, pp. 133-135. The discounts from these contracts or arrangements would be forfeited if customer switches to a CRES supplier for generation service. Application, ¶ A.4.i; Hussing Testimony, p. 10. As discussed in Section III.B *infra*, the discounts made available to customers with special arrangements will be recovered through the Delta Revenue Recovery Rider ("Rider DRR").

2. The Companies Will Invest Millions Of Dollars For Economic Development And Job Retention.

The Plan commits the Companies to spend up to $5 million annually for five years – $25 million – for economic development and job retention initiatives. Application, ¶ A.4.h; Blank Testimony, p. 9. No recovery of these funds will be sought from retail customers. Application, ¶ A.4.h. While the Application did not dictate how these funds must be used, they do provide flexibility for Companies to address individual customer needs when a typical special contract may not be the best solution, but the benefit to State's economy and customers justifies some supportive measure. This is a significant commitment of *shareholder* funds and represents a benefit to customers and the State's economy not achievable under an MRO or traditional regulatory mechanisms.

B. The Plan Will Help Achieve State Environmental Goals.

The Plan continues the Companies' commitment to environmental stewardship through provisions that will allow for additional customer involvement in renewable energy resources and will commit the Companies' supplier to environmental remediation efforts. As a result, it is clear that the Plan provides significant qualitative benefits to customers and the environment that would not otherwise be found in the expected results of an MRO

1. Under The Plan, Customers Can Purchase Renewable Energy Credits.

The Plan extends the Green Resource program, which was approved previously by the Commission in Case No. 06-1112-EL-UNC. Application, ¶ A.2.d.; Hussing Testimony, p. 8. The Green Resource Rider ("Rider GRN") offers customers the option to purchase, on a monthly basis, renewable energy credits ("RECs") under a REC-acquisition program. Blank Testimony, p. 10; Hussing Testimony, p. 8. The cost of the RECs will be set by a competitive bidding process, previously approved by the Commission, plus administrative costs. Hussing Testimony, p. 8.

Not surprisingly, there is no opposition to this important rider. Indeed, Staff recommends the approval of Rider GRN and "appreciates and fully supports the Companies' efforts to continue to make this voluntary green product offering available during the ESP plan period . . . ." Turkenton Testimony, pp. 12-13.

2. Significant Environmental Remediation Measures Will Be Undertaken.

Under the Plan, the Companies will also require FES to support and/or undertake efforts for environmental remediation and reclamation of existing retired generating plants and/or manufactured gas plant sites in Ohio that the Companies own and are obligated to remediate. Application, ¶ A.2.m. FES will be required to cover such costs up to $15 million each year during the Plan period. Application, ¶ A.2.m. There is no opposition to this significant commitment.

III. OTHER PLAN PROVISIONS BALANCE CUSTOMER BENEFITS WITH KEY RISK MITIGATION MEASURES FOR THE COMPANIES.

As an integrated package, the Plan can offer the substantial customer benefits discussed above only because it also contains important measures that permit the Companies to manage and mitigate several significant risks. First, the Plan addresses the risks imposed on the Companies by S.B. 221 as providers of last resort of generation service. Second, the Plan addresses the risk associated with compensation for discounts that customers receive to reduce the size of their electric bills as a part of economic development efforts. Third, the Plan allows the Companies to manage serious challenges associated with their infrastructure and workforce in order to maintain and improve system reliability for customers. Fourth, the Plan continues the current practice of recovery of the Companies' MISO transmission costs as a pass through only. Finally, the Plan addresses recovery of certain cost deferrals. Each of these Plan features is discussed in turn.

A. The Plan Mitigates Significant Risks Borne By The Companies As Providers Of Last Resort Service.

The Plan identifies and mitigates four specific risks that arise from the Companies' status as POLR suppliers of generation service: (1) the risk of shopping customers; (2) the risk of returning customers; (3) the risk of increased non-distribution uncollectible expense; and (4) the risk relating to uncollectibles of PIPP customers.

1. The Plan Will Permit The Companies To Manage Shopping Risks.

As POLR generation service suppliers, the Companies must commit to obtain adequate generation resources to supply their customers' retail load, even though all of their customers are free to switch to alternative generation suppliers at any time. The uncertainty of how much load the Companies will actually have to serve creates "shopping risk," a reflection of the potential cost that arises if customers shop in larger numbers than anticipated when market prices decline, and the Companies are forced to sell power initially committed to serve those customers at a loss because of those lower market prices. The other element of shopping risk is that a POLR generation supplier has a risk of opportunity costs when it commits to sell power for POLR service at a certain price for a designated period of time and market prices increase above that price. Hearing Tr., Vol. V, p. 149. That supplier expects compensation for that risk of foregone profit in the price it charges to the electric distribution utility due to foregoing the ability to sell power at a higher price if power prices increase. Warvell Testimony, p. 11. Mr. Warvell states the issue succinctly: "If more customers shop than anticipated, for any variety of reasons, then the Companies have procured generation that they do not need to serve their retail load." Warvell Testimony, p. 11. Conversely, "[i]f fewer customers shop than anticipated, the Companies may find themselves short generation and be forced to go to the market to acquire power to serve the unanticipated load." *Id.* The design of the base generation charge in the Plan is set at a level necessary to compensate the Companies for this risk associated with non-shopping customers. For customers who shop, however, a 1¢/kWh minimum default service charge is applied through a separate Minimum Default Service charge ("Rider MDS") to compensate the Companies for this risk. Application ¶¶ A.2.h, Sched. 5a (Rider GEN); Warvell Testimony, pp. 10-12; *see* R.C. § 4928.143(B)(2)(3) (providing for the inclusion of "[t]erms, conditions, or charges relating to . . . default service"). The minimum default service charge serves "to account for shopping risk, opportunity costs, and some back office and front office administration charges." Hearing Tr., Vol. I, pp. 27-28.

Several intervenor witnesses acknowledge these risks. *See* Baron Testimony, p. 26 ("I do not dispute [Mr. Warvell's] testimony on this issue."); Hearing Tr., Vol. VII, pp. 113-117 (Mr. Courtney recognizes the risks associated with POLR responsibilities, including shopping and opportunity risks); Hearing Tr., Vol. V, pp. 146-149 (Mr. Garvin recognizes that there are two risks associated with customers leaving); Hearing Tr., Vol. VIII, pp. 80-81 (Mr. Murray recognizes that there may be opportunity costs for POLR providers). Moreover, many witnesses concede these risks give rise to costs for which the Companies should be compensated. Hearing Tr., Vol. VII, p. 117 (Ms. Ringenbach believes it is appropriate for the Companies to be compensated for the risks of customers leaving); *see* Hearing Tr., Vol. VII, pp. 118-119 (Mr. Courtney recognizes the costs associated with the POLR risks); Hearing Tr., Vol. VIII, p. 81 (Mr. Murray acknowledges that there can be costs associated with hedging for risks).

Although several intervenor witnesses criticize Rider MDS charge because the Companies have no specific calculation of costs to support the charge, that criticism is misdirected. *See* Courtney Testimony, p. 4; Garvin Testimony, p. 13; Ringenbach Testimony, p. 9; Frye Testimony, p. 5; Goins Testimony, p. 32; Yankel Testimony, p. 34; Hearing Tr., Vol. I, pp. 120-121, 136-140, 214-215. As noted earlier, an ESP is not a cost-based vehicle and, therefore, such a calculation is not a prerequisite. Moreover, as Staff witness Fortney states, a specific dollar value for shopping risk is "incalculable." Hearing Tr., Vol. VIII, p. 164. Mr. Warvell, providing the basis for the charge, explains that the level of the Rider MDS charge reflects a judgment and estimates of what value fairly compensates a POLR supplier for the real risks arising from a customer's ability to shop. Warvell Testimony, pp. 10-12. The Companies are able to offer the fixed base generation prices in the Plan only if they can be compensated for these recognized risks via the minimum default service charge.

2. The Plan Helps The Companies Manage The Risks Created By Returning Customers.

Beyond the risk of customers who leave the system and shop, the Companies also face another, separate risk: from customers who shopped for generation service but then return to the Companies' SSO generation supply. The problem here arises because the Companies will have secured their POLR generation supply based upon the amount needed to serve customers who have not shopped but instead remained on the system. If a (former) shopping customer then returns to the Companies, the POLR obligation requires that the Companies provide that customer generation service, even if the added costs of securing the required generation exceeds what the customer will pay for it – creating a loss for the Companies. S.B. 221 acknowledges this risk of returning shoppers as it establishes a utility's right to include in an ESP "[t]erms, conditions, or charges relating to limitations on customer shopping" and "standby . . . service." R.C. § 4928.143(B)(2)(d).

Consistent with S.B. 221, the Plan provides for a standby charge ("Rider SBC") that is bypassable for all customers.[49] Application, ¶ A.2.k. The Rider SBC charge is 1.5¢/kWh in 2009, increases to 2.0¢/kWh in 2010 and 2.5¢/kWh in 2011. Application, ¶ A.2.k.; Warvell Testimony, pp. 20-22. Customers who elect to pay Rider SBC while receiving service from another supplier can return to the Companies' SSO at the same generation rates paid by customers that never shopped. Application, ¶ A.2.k (returning customers must pay such SSO prices for the shorter of 12 consecutive months or the remainder of the Plan period).[50] If a customer chooses not to pay the standby charge, a non-governmental aggregation customer will pay the higher of the market-priced SSO or the standard SSO upon return to the utility for retail generation service.[51] *See* Application, ¶ A.2.k, Att. C. Companies' witness Warvell supports this charge. Warvell Testimony, pp. 21-22. But, he is not alone. IEU witness Murray

[49] Notably, S.B. 221 only addresses whether standby charges should be bypassable for customers served through governmental aggregations. R.C. § 4928.20(J). The Plan goes further, however, allowing the standby charge to be waived by non-governmental aggregation customers.

[50] Under R.C. § 4928.20(J), governmental aggregation customers who return to the utility must pay the market-priced SSO for the remainder of the Plan, unless the Commission shortens the period to not less than two years.

[51] Some intervenor witnesses, particularly Competitive Supplier witnesses Frye and Ringenbach, complain about the market price charged to returning customers, calling the 160% markup on wholesale market forward prices a "penalty." Frye Testimony, p. 5; Ringenbach Testimony, pp. 9-10. But neither of these witnesses know the relationship of their own companies' retail rates to the current wholesale rates. *See* Hearing Tr., Vol. VII, p. 179. Accordingly, neither has any basis to know if a 60% difference between wholesale and retail rates is within the norm in the industry.

recognizes that the SBC Rider can provides a value to customers (Hearing Tr., Vol. VIII, pp. 81-82) and Competitive Suppliers witness Ringenbach acknowledges that the Companies should be allowed to recover the costs associated with shopping customers returning to the Companies (Hearing Tr., Vol. VII, p. 177).

3. The Plan Allows The Companies To Recover Non-Distribution Uncollectibles For Which They Bear An Increased Risk.

Compared to the Companies, Competitive Retail Electric Service ("CRES") suppliers can better manage uncollectible expenses. Hussing Testimony, p. 13. Unlike these suppliers, the Companies, having POLR responsibility, cannot select who they will serve. *Id.* Additionally, although the Companies are subject to collection practice rules propounded by the Commission, CRES suppliers are free to establish their own, self-protecting collection policies. Hussing Testimony, p. 12; Hearing Tr., Vol. VII, p. 181. Further, the Companies are also subject to partial payment priority that gives CRES suppliers the first dollars collected. Although they promote certain state goals, the collection rules and policies impose costs on the Companies in the form of increased uncollectible expenses that arise from the rules' requirement for substantial notice periods, seasonal shutoff moratoria and CRES suppliers' priority for partial payments. Hussing Testimony, p. 12; *see* O.A.C. 4901:1-18; Case No. 02-1944-EL-CSS.

The Plan incorporates a Non-Distribution Uncollectible Rider ("Rider NDU"), applicable to all customers.[52] Application, ¶ A.2.j. The impact of Rider NDU is limited because the costs recovered under this rider include only those costs that are associated with non-distribution services. The rider will be adjusted annually to insure that only actual non-distribution uncollectible expenses are recovered. Application, ¶ A.2.j; Hussing Testimony, p. 13.

[52] This mechanism was previously discussed by Staff in conjunction with the Companies' Distribution Case. Hussing Testimony, pp. 13-14. Distribution-related collectibles, of course, are addressed in the context of distribution rates.

Rider NDU is non-bypassable for several reasons. First, the uncollectible costs recovered by the rider result from the societal and state policy benefits associated with the Companies' role as default service providers – benefits which are enjoyed, and should be borne, by all. Second, the incurred uncollectible costs are not limited to non-shopping customers. Hussing Testimony, p. 13.

While the Companies would prefer not to have any uncollectible expense, recovery of non-distribution uncollectible expense through Rider NDU makes sense. Contrary to Commercial Group witness Gorman's argument that Rider NDU will cause the Companies to sit back and let the amount of uncollectibles increase at the expense of customers (Gorman Testimony, p. 13-14) the Companies, like any business, would rather collect monies due now, not later. Hearing Tr., Vol. IV, pp. 262-263.[53]

4. The Plan Protects The Companies In The Event The State Places An Increased Uncollectible Burden On The Companies Relating To PIPP Customers.

The Plan also includes a PIPP Uncollectible Recovery Rider ("Rider PUR") in the event that the State requires the Companies to bear uncollectible costs associated with PIPP customers. Application, ¶ A.2.j; Hussing Testimony, p. 15. OPAE witness Alexander argues that such costs should be recovered by the Companies in base rates. She ignores, however, that the Rider PUR is a much more flexible and accurate mechanism to capture the expense than is base rate

[53] In a self-serving change in position, Competitive Suppliers witness Ringenbach asserts that the Companies should be required to purchase CRES receivables if the Companies recover under Rider NDU. *See* Ringenbach Testimony, pp. 10-11. The Competitive Suppliers apparently want to maintain their current priority for partial payments (rules that were changed in their favor by stipulation just a few years ago) and force the Companies to purchase their receivables. *Id.*; *see* Case No. 02-1944-EL-CSS. But the stipulation that changed the partial payment priority not only provides protection to the CRES suppliers (so that partial payments are first applied to amounts past due to the suppliers), but that stipulation also put the suppliers at little to no risk of incurring uncollectible expenses. In fact, the changes in the stipulation to give CRES suppliers priority for partial payments were preferred by CRES suppliers as compared to the purchase of receivables, as was testified to by a witness for Ms. Ringenbach's company in a prior case before the Commission. Hearing Tr., Vol. VII, pp. 183-187, Co. Ex. 16.

inclusion. Moreover, Rider PUR is merely a placeholder for additional costs if and only if the State makes changes that require the Companies to bear uncollectible costs for PIPP customers. Thus, the separate mechanism for recovery of these costs,[54] if they occur, is appropriate.

B. The Plan Allows For Mitigation of Risks Resulting From Special Contracts And Arrangements.

S.B. 221 authorizes utilities to recover delta revenue associated with reasonable arrangements (special contracts). *See* R.C. § 4905.31(E). Pursuant to this authority, the Plan establishes a Delta Revenue Recovery Rider ("Rider DRR") to insure the Companies' complete recovery of revenue foregone as a result of discounts provided in reasonable arrangements between the Companies and customers. Application, ¶ A.4.i; Hussing Testimony, pp. 11-12. The reasonable arrangements include continuing CEI special contracts, service under Rider RAR, and unique contracts. *See* Hussing Testimony, p. 12.

Rider DRR will recover lost revenue associated with reasonable arrangements and other discounts (including those offered by Rider RAR). CEI will recover its costs for special contracts continuing past December 31, 2008, from its customers. *See* Application, Sched. 5n. Any subsequent delta revenue arising from reasonable arrangements entered into by the Companies and approved by the Commission after January 1, 2009, will be recovered from all customers in accordance with R.C. § 4928.143(B)(2)(i). Hussing Testimony, p. 12. Because all customers benefit from reasonable arrangements, Rider DRR is non-bypassable. Hussing Testimony, pp. 11-12.

Importantly, this rider will recover only lost revenues resulting from reasonable arrangement discounts; it is not a source of additional revenue. The "recovery of revenue

[54] These uncollectible costs can also be reviewed by the Commission's Staff.

foregone as a result" of reasonable arrangements is expressly authorized by R.C. § 4905.31(E).[55] Moreover, the amount recovered from customers will be the difference between the price set in the reasonable arrangement and the associated tariff rate. Hussing Testimony, p. 12. The Commission has control over the discounted price (and, thus, the amount recovered under Rider DRR) because each reasonable arrangement requires prior review and approval by the Commission in accordance with R.C. § 4905.31.[56] This is also the response to concerns regarding what customers will receive such reasonable arrangements and whether adequate criteria for justification will be applied. Such a reasonable arrangement – and hence any resulting delta revenue recovery – will only take place if the Commission approves it. The Companies do not seek an independent, discretionary role in the process. If this device, intended to advance the joint economic interests of the state and customers, is utilized, the Companies seek only to be made whole.

Further, the recovery of this revenue is necessary to maintain the Companies' financial health because they have no alternative source from which to absorb the effect of revenue foregone by reasonable arrangements or continuing special contracts. Hussing Testimony, p. 11. Mr. Hussing explains the impact of such lost revenue on the Companies:

> I think it's best explained in an example. If I look at an industrial customer's total bill and I looked at the distribution portion of that bill, the distribution portion of that bill for a transmission customer is about 1 percent of the bill. To a – maybe a general service primary or subtransmission customer that may be 5 percent . . . of the total bill. So if, for example, a special arrangement were granted and it's 5 percent off the total bill for the transmission customer, the utility not only has zero distribution revenue, it's losing money on the transaction. And for the 5 percent discount,

[55] The allowable recovery is not limited to 50% as suggested by intervenors' witnesses. *See* Gonzalez Testimony, p. 26.

[56] Thus, to the extent City of Cleveland witness Courtney seeks Commission review, that review is already built into the rider. *See* Courtney Testimony, pp. 6-7.

> on 5 percent of the distribution total bill then they have zero distribution revenue.

Hearing Tr., Vol. IV, p. 146. As a result, the Companies require the Rider DRR to recover the lost revenues and enable the Companies' ability to offer such reasonable arrangements to its customers who play a vital role in the State's economy.

C. The Plan Addresses Risks Associated With Significant Challenges Presented By An Aging Infrastructure And Workforce.

The Delivery Service Improvement Rider ("DSI Rider") is an incentive mechanism proposed under the Plan addressing significant issues presented by an aging distribution infrastructure and a workforce approaching retirement in disproportionate numbers. While, in part, it is a mechanism which allows the Companies to afford the expense associated with these factors, it is also designed with incentive characteristics which align the Companies' and customers' expectations with respect to distribution reliability.

The way that the Companies must do business to maintain and improve their delivery systems has changed and is continuing to change. Equipment suppliers now require that the Companies order and pay for equipment in advance to secure a position on a waiting list for the equipment. Schneider Testimony, p. 4; Hearing Testimony, Vol. III, p. 228-229 (issues have arisen with the Companies' suppliers for transformers and trucks). This shift in the timing of purchasing outlays thus demands the Companies predict their needs further in advance and invest capital upfront. *See id.*

Further, the Companies employ thousands of energy delivery and customer service employees who play a central role in insuring reliability and responsiveness in service. Schneider Testimony, p. 3. The members of that workforce, including linestaff, however, are approaching retirement in disproportionate numbers. *See* Schneider Testimony, p. 3. Therefore, the Companies will be required to hire and train a significant number of new employees, a process that typically takes nearly five years. Schneider Testimony, p. 3. During that period, however, the Companies will also need to retain current experienced employees in unprecedented numbers to assist in training the new employees. This training and necessary overlap of personnel will impose costs upon the Companies significantly above normal levels over the next three to five years. These costs will not be recoverable through traditional rate cases during that period.[57] Therefore, the Companies face significant near-term financial burdens relating to their workforce.

These challenges occurring at the same time as significant cost increases are expected in the cost of materials and supplies support the need for additional distribution revenues over the Plan period. Costs for the Companies' materials, supplies and equipment have jumped in price and suppliers are placing more onerous terms on the Companies' purchasing. These increases and purchasing challenges are made all the more important because the Companies' infrastructure is aging and will require large investments in the near term. *See* Schneider Testimony, p. 3. Indeed, substantial price increases have hit the Companies on numerous fronts, including an over 70% increase in the price of wire and over 40% increase in transformer prices over the past five years. *Id.*[58] And, the price of fuel for the Companies' trucks has shown considerable volatility. *Id.* at pp. 3-4.

The Plan's DSI Rider allows the Companies to respond to these challenges in a timely manner. Application, ¶ A.3.e; Schneider Testimony, p. 4. This is not a cost-based proceeding and the DSI Rider is not based upon historically incurred costs but rather takes advantage of the

[57] Under the Plan, the stay-out period precludes distribution rate increases during some of this period. Even apart from this factor, however, traditional ratemaking mechanisms are ill-suited to address these extraordinary circumstances because they may not capture the associated costs, thereby depriving the Companies recovery of these costs.

[58] The impact the price increase for transformers is particularly noteworthy considering the Companies' network includes 533,000 distribution transformers. *Id.*

express provisions of R.C. §4928.143 to implement an incentive based distribution charge. As stated in R.C. §4928.143(B), such charges may be implemented notwithstanding any other provision of Title 49.[59] Application, ¶ A.3.e; Schneider Testimony, pp. 4-5.

In order to align customers' and the Companies' interests, the Plan, through the DSI Rider, implements an important incentive to achieving a level of service reliability. R.C. §4928.143(B)(2)(h) authorizes the Companies to incorporate such incentives in "provisions regarding the utility's distribution service" in their ESP. Accordingly, the DSI Rider provides an incentive for the Companies to achieve top decile performance and, hence, promote customers' interests in reliable service.

The Plan sets up a bandwidth around a uniform 120-minute System Average Interruption Duration Index ("SAIDI") target: at the low-end, 90 minutes and, at the high end, 135 minutes. Application, ¶ A.3.f, Att. E; Schneider Testimony, p. 8. The range is skewed in favor of customers in that a greater improvement in performance is required in order to increase the DSI Rider (at 89 minutes, which is 31 minutes from the target), as compared to a narrower trigger that would decrease the DSI Rider (at 136 minutes, which is 16 minutes from the target). Application, ¶ A.3.f; Schneider Testimony, pp. 8-9. In so functioning, the DSI Rider aligns customer expectations for, and the Companies' interests in, maintaining and improving service reliability and assuring that customer dollars are spent in the most cost effective manner, while providing the Companies' the ability to carry out such efforts.

Notably, the Companies' proposed bandwidth is very conservative. In order for any one of the Companies to receive any additional incentive revenue under the DSI Rider, it would have to: (1) achieve top decile performance; (2) continue to pay exceptional attention to detail; (3)

[59] The DSI Rider shall not be considered a contribution in aid of construction, nor shall it be considered in the test for significantly excess earnings. Application, ¶ A.3.f.

drive for continuous improvement; and (4) maintain focus on strategic capital planning. Schneider Testimony, pp. 8-9. Notably, OCC witness Cleaver agrees that a SAIDI of 89 for CEI and Ohio Edison would be exemplary.[60] Hearing Tr., Vol. IX, p. 77. On the opposite side of the proposed incentive bandwidth, even the ceiling of the SAIDI target range represents above-average performance; it would be within the second quartile of performance among utilities as measured by industry leaders. Schneider Testimony, p. 9. In fact, it represents a significantly more aggressive SAIDI target than the Staff approved SAIDI targets for other electric utilities. Staff witness Roberts confirms that other investor-owned utilities in Ohio have approved SAIDI targets as high as 163.5, 174, and 218.6. Hearing Tr., Vol. VII, pp. 306-307. Thus, by operation of the DSI Rider, the Companies, which have performance that is already among the best in the State, will have incentives to achieve "exemplary," top-decile service.

The Plan proposes two adjustments to CEI's SAIDI target which reflect the age, system design, service area geography and historical system performance of CEI. First, the Companies propose to modify CEI's SAIDI target from 95 minutes to 120 minutes. Application, ¶ A.3.f. Second, the Companies propose to multiply customer outage minutes by a factor of 0.5 on CEI circuits where fifty percent or more of the premises are served by rear lot facilities. *Id.*, Att. E.

Both adjustments are appropriate. CEI has the most aged distribution system of the three Companies. It also has the most challenging system design and service area geography. Schneider Testimony, p. 6; *see* Hearing Tr., Vol. III, p. 237. Yet, CEI's current SAIDI target is

[60] Mr. Cleaver agrees using SAIDI alone is an appropriate metric for the performance measure in the DSI Rider. Cleaver Testimony, pp. 21-22. While he agrees that a CEI or OE SAIDI of 89 would be exemplary, he is oddly inconsistent in not applying the same standard for TE. *See* Hearing Tr., Vol. IX, p. 77.

more aggressive – 95 minutes – than both TE and OE, which have targets of 120. *See* Schneider Testimony, p. 6. Thus, a SAIDI target of 120 minutes for CEI is more than reasonable.[61]

Even with this proposed adjustment to CEI's SAIDI target, a 120-minute target fails to reflect fully the disparate conditions faced by CEI. CEI's service area contains a significant number of rear-lot facilities. Schneider Testimony, p. 6; Hearing Tr., Vol. III, pp. 254-255. In fact, CEI estimates that it has 439 circuits where over 50% of the homes are served by rear lot facilities. Hearing Tr., Vol. III, p. 254. The special service restoration issues associated with rear lot service facilities, including restrictions on the use of equipment and the additional time and labor required give rise to the problem. Hearing Tr., Vol. III, p. 255. As Mr. Schneider explains: CEI experiences significant issues associated with crews being able to restore service timely to customers served on rear lot circuits based on the number of such customers and the need to manually haul poles and other equipment to such sites. Schneider Testimony, p. 7. Further due to those concerns and "the number of obstructions at such sites including trees, fences, garages, etc., service restoration times are roughly double for rear lot circuits as compared to facilities located adjacent to streets. Application, Att. E. Their disproportionate numbers and additional service requirements make rear lot facilities a legitimate factor to consider in measuring CEI's SAIDI performance.

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[61] That CEI's pre-existing SAIDI target is simply too aggressive for its current system capabilities is illustrated by CEI's difficulties in reaching the target over the past several years, despite OE's and TE's successes in reaching their target of 120 minutes. *See* Cleaver Testimony, p. 23. Further, even with an amended target of 120 minutes, the DSI Rider would provide an incentive for performance from CEI that is "exemplary" and discourage performance at higher levels (for instance, 163 minutes, a SAIDI level that, while in the "penalty" range under the Companies' proposal, is nonetheless more reliable than the Staff-approved SAIDI targets for three other investor-owned utilities). *See* Hearing Tr., Vol. VII, pp. 306-307.

D. The Plan Continues The Current Practice Permitting Pass Through Recovery Of Transmission Costs.

The Companies propose to recover transmission service related costs through the Transmission & Ancillary Services Rider ("Rider TAS"). Application, ¶ A.5.a., Sched. 5k. Rider TAS mirrors the current mechanisms of recovery of all transmission and transmission-related costs, through a reconcilable rider. *See* Application, ¶ A.5.a. These costs include those imposed by FERC, MISO and other transmission organizations. Warvell Testimony, p. 23. Under this framework, the Plan best ensures that the Companies recover their costs under the tariffs or agreements with MISO or other regional transmission organizations and also ensures that customers receive transmission service at no more than its cost. The Commission retains its right to audit those costs and assure that the costs are properly represented in the Rider TAS. Hearing Tr., Vol. I, p. 59-60.

E. The Plan Mitigates Risks Related To Deferred Cost Recovery.

Deferrals associated with the phase-in of generation costs have been addressed earlier in this brief. In addition to those deferrals, however, the Plan also proposes deferral mechanisms to mitigate risk arising from storm damage and certain other distribution related costs and, as well, addresses a group of previously authorized "legacy" deferrals. Much like the DSI Rider, these deferral mechanisms are of benefit both to the Companies and customers. The Plan's ability to moderate the increases in customer prices is based, in part, on the deferral of certain costs and expenses. Yet, the Companies' earned return on these deferrals will be less than their costs of capital. Hearing Tr. Vol. II, p. 306. Thus, the deferrals represent a "win-win" resolution.[62] In the context of these general principles, we address the two remaining groups of deferred costs.

[62] Notably, Staff believes that, without a distribution rate stay-out to help ensure customer price stability, the deferral of certain costs is unnecessary. Fortney Testimony, pp. 7-8. The Companies, however, have

As to the first group, the Plan establishes a non-bypassable Storm Damage and Distribution Enhancement rider ("Rider SDE") to permit deferral and subsequent recovery of three categories of costs: (1) costs in excess of an established baseline that result from storm damage; (2) costs related to line extensions that, as a result of new rules and/or policies under R.C. § 4928.151, are in excess of those reflected in the Companies' application in Case No. 07-551-EL-AIR; and 3) depreciation, property tax obligations and post-in-service carrying charges on gross plant distribution capital investments placed in service after December 31, 2008, and made to improve reliability and/or enhance the efficiency of the distribution system. Application, ¶ A.3.h. Rider SDE will recover the deferred amounts, including interest at a rate of 0.7083 percent, over a ten-year period beginning in 2014, thereby providing customers rate relief during the Plan period. Application, p. 22; Wagner Testimony, pp. 4-5. The post-in-service interest will be recovered on only the net of depreciation balance recorded in the first year of the Plan, i.e., gross plant additions occurring after January 1, 2009. Hearing Tr., Vol. II, pp. 290-291. As explained by Mr. Wagner at hearing, the Companies "are seeking authorization [via Rider SDE] to defer costs that under the [P]lan we know we are going to incur, not unlike other requests for deferral of costs that [the Companies have] made before the Commission." Hearing Tr., Vol. II, p. 302.

As to the second group, the Commission has previously approved the deferral of certain costs associated with the Companies' provision of electric service. While the benefits (i.e., service) attributable to those deferred costs already have been and continue to be enjoyed by customers, the deferrals themselves have not yet been recovered by the Companies. Wagner Testimony, pp. 5-6; Hussing Testimony, pp. 14-15.

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proposed a distribution rate stay-out. *See* Application, ¶ A.3.c. Thus, the deferral of these and the other costs are appropriate.

The Plan establishes specific mechanisms to recover those costs, including the non-bypassable Deferred Distribution Costs Recovery and Deferred Transmission Costs Recovery riders ("Rider DDC" and "Rider DTC"). Application, ¶¶ A.6.b, A.6.c, Att. G. We recognize that the recovery of certain of these costs coincide with issues in the Companies' pending distribution rate case.[63] We also acknowledge the Attorney Examiners' declaration that resolution of the issues presented in the Distribution Case will be made upon the record and arguments there. Certain of the deferrals at issue here, however, relate to accruals made in the period which is subsequent to the date certain in that case. We will not burden this brief with restating the underlying issues which were argued in that case. Suffice it to say that the Companies adhere to the calculation methodology for the post-date certain deferrals here that they used for calculations in the rate case and (re)urge adoption of that methodology here. Staff (Tufts Testimony, p. 3) also recommends recovery of the post-date certain accruals, albeit upon its own, earlier-proposed methodologies, recognizing, however, that a Commission decision on these methodological issues in the Distribution Case should apply to the post-date certain period accruals here. Hearing Tr., Vol. IX, pp. 186-189. Similarly, OCC appears to adhere to its own Distribution Case positions with respect to methodology.

The Plan also establishes a non-bypassable rider to recover the accumulated deferred balance of fuel costs authorized under the Companies' RSP, and then RCP, ("Rider DFC"). Application, ¶ A.6.d. Rider DFC serves to recover dollars associated with increased fuel costs incurred by the Companies in 2006 and 2007 over the 2002 baseline. Warvell Testimony, p. 16.

[63] Those deferrals relate to transition taxes arising in Case No. 99-1212-EL-ETP, line extensions in Case No. 01-2708-EL-COI, and distribution-related costs from Case No. 05-1125-EL-ATA. Other deferrals were not addressed in the Distribution Case – for example, the deferral of $25 million of CEI distribution costs in 2009 and the costs captured in the DTC Rider. The support for the authorization for deferral and recovery is in the testimonies of Mr. Blank (Testimony, p. 2), Mr. Hussing (Testimony, p. 14) and Mr. Wagner (Testimony, p. 16).

Rider DFC would recover the 2008 year-end balance of these deferrals plus interest and adjustments for the Commercial Activity Tax ("CAT"). Warvell Testimony, p. 18; Application, Sched. 6a. A Rider DFC charge would be established for each of the Companies. The charge will continue until the deferred amounts are recovered. Warvell Testimony, p. 19 (but the recovery period will not extend past 25 years). The Rider DFC charge for OE will be 0.0375¢/kWh, 0.0339¢ for CEI, and 0.0260¢ for TE. *Id.* Because Rider DFC would recover past costs, Rider DFC is appropriately non-bypassable because the Companies have already incurred the cost and customers have already benefited from the fuel that was purchased, and, at least in part, these fuel costs were added to customers' shopping credits in the past.[64] In other words, these are no longer avoidable costs for the Companies if customers shop in the future.

The Commission previously approved the recovery of these costs in the Companies' Rate Certainty Plan. Warvell Testimony, pp. 16-17; *see* Turkenton Testimony, p. 14. Rider DFC would resolve the Companies' request for an alternative recovery mechanism in Case No. 08-124-EL-ATA. Warvell Testimony, pp. 17-18. Staff has recognized the Companies' right to receive the deferred amounts, but suggested that the deferred amounts be reduced by $9,135,561 for fuel cost and generation MWh adjustments. *See* Turkenton Testimony, pp. 15-16.

Staff's position, which was articulated in its report in Case No. 08-124-EL-ATA is incorrect for two reasons. First, Staff would deny the Companies recovery for losses on coal re-sales that led to Synfuel purchases that, in turn, ultimately reduced fuel costs to customers. As Mr. Warvell explains, these coal re-sale losses were incurred as part of a multi-part transaction to

[64] Thus, the government aggregation and competitive supplier witnesses' complaints about the DFC Rider's non-bypassability fail. *See* Fein Testimony, p. 9; Ringenbach Testimony, pp. 7-8, 12. So, too, does Ms. Ringenbach's argument that the DFC Rider charge is improper under *Elyria Foundry*. *See* Ringenbach Testimony, pp. 7-8, 12. Ms. Ringenbach misstates the court's holding as applied to the DFC Rider: The DFC Rider is a generation cost recovered as a generation charge; it is not a generation cost recovered through a distribution rate.

achieve savings for customers. Warvell Rebuttal, pp. 10-11. Second, Staff would require the Companies to record profits on certain emission allowance sales and use those profits to reduce recoverable fuel costs. Staff overlooks that emission allowances are only charged as fuel costs when they are consumed, and are only booked on a weighted average cost basis of all similar emission allowances. *Id.* at pp. 13-14. In other words, customers never paid for the emission allowances that were sold for a profit. Therefore, it would be inappropriate to flow that profit through to customers via reducing recoverable fuel costs by that amount.

IV. THE PLAN ALLOWS COMMISSION MANAGEMENT OF IMPORTANT PROVISIONS.

A. The Commission Can Terminate The Plan After Two Years.

The Plan will allow the Commission flexibility to control the duration of the Plan, thus giving the Commission the opportunity to consider the Plan in light of future conditions which are not now known. This flexibility is consistent with the State's policy to "[r]ecognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment." R.C. § 4928.02(G). Specifically, the Commission can terminate the Plan after two years by issuing a final order to that effect on or before December 31, 2009. Application, ¶ A.7.e. With such an order in place, the Plan would be terminated effective December 31, 2010. Application, ¶A.7.f; Warvell Testimony, p. 3. Depending on when and how it ends, the Plan carefully details which of its provisions also end, including, significantly, generation charges, which would then be determined pursuant to a competitive bid as set forth in an MRO.[65] *See* Application, ¶¶ A.7.e, A.7.i; Warvell Testimony, p. 3; Blank Testimony, p. 8. However, as also carefully detailed in the Plan, other provisions and

[65] Unless the Companies entered into another ESP after the termination of this Plan.

riders, including those relating to deferral recovery, survive the Plan's termination. *See* Application, ¶ A.7.f.

B. The Commission Can Defer Certain Reserve Capacity Costs.

As discussed above, Rider CCA allows the Companies to separately recover charges incurred by its supplier to provide needed capacity over and above the levels required by FERC, NERC, MISO or other applicable standards. Application, ¶ A.2.n.; Warvell Testimony, pp. 12-13. However, the Companies have built into the Plan a valuable tool for the Commission to control the impact of this charge on customers. In its own discretion, the Commission may adjust the generation phase-in credit to mitigate the impact on customers and manage the gradual transition to Plan rates. At any point in time, if the excess capacity costs are greater than 1.5% of customers' total rate, the Commission may increase the generation phase-in credit and the associated deferred phase-in dollar amount. Application, ¶ A.2.o; Warvell Testimony, p. 13.

C. The Plan Incorporates A Reasoned Test For Assessing Whether Revenues Are "Significantly Excessive."

S.B. 221 establishes a requirement that the Commission determine whether significantly excessive earnings result from an approved ESP. R.C. § 4928.143(F). Since the statute provides only limited guidance as to how the test is to be performed, the Plan sets forth a framework under which a test for significantly excessive earnings ("SEE") should be administered. Application, ¶ A.7.d, Att. H. The proposed test compares the Companies' earnings for a prior annual period to the average earned return of companies with comparable business risk after making appropriate adjustments for differences in capital structures. *See* Application, Att. H; Vilbert Testimony, p. 2. If the Companies' earnings are greater than a threshold that is significantly higher than the average return by comparable companies, the earnings may be significantly excessive.[66] *Id.* In line with the statute's recognition that the earnings should be refunded only if "significantly excessive," the Companies submit the threshold be set at 1.28 standard deviations above the sample's mean earned return on total capital. Application, Att. H; Vilbert Testimony, p. 14. Therefore, if a utility's earned rate of return on total capital exceeds the sample mean earned return on total capital by more than 1.28 standard deviations, significantly excessive earnings may be deemed to have occurred. Vilbert Testimony, p. 14.

Four parties (the Staff and three intervenors – OCC, OEG, and the Commercial Group) filed testimony addressing the SEE test proposed by the Companies and, in some respects, offered alternative formulations. Before addressing the merits of the proposals themselves, however, preliminary issues require attention.

The first of these is whether the SEE methodology will actually be established in this case. The Companies propose a comprehensive SEE methodology, as do OCC, OEG and the Commercial Group.[67] Staff alone, however, proposes that a decision on the first part of the methodology – the limited aspect of determining the comparable companies and associated ROE – be postponed and deferred to a technical conference, the details of which, in particular its timing, are unknown.[68] Such postponement is unwarranted. The Companies' SEE proposal is

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[66] R.C. § 4928.143(F) also requires that consideration be given to the capital requirements of future committed investments in this State.

[67] Although, as discussed below, the Commercial Group proposal impermissibly departs from the requirements of the statute.

[68] Conversely, and somewhat opportunistically during his cross examination, OEG's Mr. King suggests we postpone decision on the last aspect of the SEE process – determining the increment above the baseline that defines "significantly excessive" – until mid-2010 when the SEE evaluation would actually be performed. Mr. King's prefiled testimony, however, presents a full, albeit flawed, methodology both for determining the ROE of the comparable group as well as definitively establishing the increment for the SEE threshold. That prefiled testimony, which was not corrected or updated at the time that Mr. King took the stand, contains no suggestion whatsoever that the Commission should wait until mid-2010 to decide the latter point. Mr. King's change of heart on the matter may be influenced by prolonged exposure to the suggestion repeatedly made at hearing that the economy was entering a recessionary period. But, whatever the cause, the newly adopted position is contradicted by Mr. King's own OEG

expressly part of the Plan package, and therefore must be fully decided and approved here. OEG witness Kollen, too, expressly urges resolving the matter now. Kollen Testimony, p. 23. The various approaches presented here by other parties will undoubtedly be the same as what they present in the other ESP cases. Staff, not offering a specific methodology of its own, has nonetheless agreed with much of Dr. Vilbert's approach and deemed it appropriate for the Companies here.[69] Postponing a decision on the methodology as to the sample of comparable companies to a future technical conference only unnecessarily impedes resolution of this case. The issue has been comprehensively explored on this record and a decision can and should be made here.[70]

A second preliminary issue is Mr. Cahaan's odd foray out of economics (his area of expertise) into the law (which he acknowledges is not); more specifically, into the legal issue of burden of proof. He suggests, essentially, that a proper statutory interpretation requires that the Companies prove that they are *not* comparable to a sample group of companies which *do* have significantly excessive earnings. As with the prior issue, he stands alone with a position opposite to that advanced by all the other witnesses on the SEE question. At the outset, and despite the latitude which has been afforded witnesses on this record to testify on legal issues, the Companies submit that interpretation of the statute on the formulation of burden of proof is

colleague, Mr. Kollen, who makes clear that the SEE issue, *in its entirety*, should be decided at this time. Kollen Testimony, p. 23.

69 According to Mr. Cahaan, "[i]f the Commission had a strict up or down choice right now based upon the record of this case without such a technical conference, we have no objection to adopting Dr. Vilbert's method. And everybody can argue anything they want, but we happen to think Dr. Vilbert's method has much to commend it." Hearing Tr., Vol. IX, p. 119.

70 Moreover, Staff's recommendation that the question of the proper methodology to consider the comparable companies should be kicked to a technical conference so the participants in the AEP and Duke cases can weigh in is strangely inconsistent with its position that the issue of the definition of what constitutes "significantly excessive" should be resolved here and apply in the other cases. Hearing Tr., Vol. IX, p. 165.

clearly an issue of law – not fact or expert economic opinion – which determination, in the first instance, rests with the Commission. Even beyond that threshold issue, however, as a practical matter of its application, Mr. Cahaan's proposed approach is illogical. It requires starting with an assumption about the very factor (i.e. the threshold for what is significantly excessive and what "comparable" companies exceed it) which is the ultimate point of the SEE exercise. Vilbert Rebuttal, pp. 4-5. Mr. Cahaan's proposal is both inappropriate as a matter of law and unworkable.

The final preliminary matter, Mr. Gorman's proposed SEE test, requires only brief attention. Mr. Gorman recommends setting a ceiling of a Commission-approved return of equity over which no increases in rates or rider are permitted. Gorman Testimony, pp. 18-19. That approach, however, fails to determine SEE by comparison to the earnings of a set of companies, including utilities, of comparable risk. Hearing Tr., Vol. XI, pp. 37-38. Moreover, under his approach, there is no distinction between earnings which simply exceed a target allowed return and earnings which are "significantly excessive." In both respects his proposal is inconsistent with the requirements of the statute and cannot be accepted. Vilbert Rebuttal, pp. 3-4.

Moving to the merits of properly applying the statutory requirements for the SEE test, the first step requires the determination of the earnings (i.e., return) of companies of comparable risk, both utilities and non-utilities. Dr. Vilbert approaches this exercise by first considering the underlying character of the assets of the utilities, next selecting a group of industries where the underlying assets exhibit similar business risk characteristics, and then applying some further screens to obtain an appropriate sample. To accommodate properly considerations of financial risk,[71] he determines the overall return on total capital for each company in the sample (using

[71] Dr. Vilbert derives the comparative rates of return ("ROEs") of the sample's members by application of their accounting-based capital structures to the overall return, thus accounting for financial risk. Vilbert

accounting rather than market measures[72]) and then averages those overall returns to arrive at a representative value. Dr. Vilbert explains the methodology in depth and, significantly, according to Mr. Cahaan, it has features the "Staff likes very much" and has "much to commend it." *See* Vilbert Testimony, pp. 2-14, Appx. B; Hearing Tr., Vol. II, p. 174; Cahaan Testimony, p. 4; Hearing Tr., Vol. IX, p. 107.

Both OCC witness Woolridge and OEG witness King also determine an average return for their respective groups of "comparable" companies, but their approaches have serious shortcomings. For starters, neither uses a selection process which actually considers comparability of business *and* financial risk characteristics. Both rely heavily upon use of beta,[73] a market-based (rather than accounting-based) risk measure which inherently captures only the *aggregate* of business and financial risk – what Mr. Cahaan calls a "black box." Use of beta thus obscures the distinction between business and financial risk making impossible any meaningful comparative analysis of both of these risk characteristics as the statute requires.[74] *See* Hearing Tr., Vol. IX, p. 107. Companies with identical betas may have very different business risk. Vilbert Rebuttal, p. 7. Moreover, in addition to beta potentially being a highly subjective

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Testimony, pp. 5-8; Cahaan Testimony, p. 5. As Mr. Cahaan states, "[t]he part that I like about Dr. Vilbert's approach is that it focuses on the business risk which is the area which is, I think, hardest to deal with and then it, as a secondary measure, it corrects for the financial risk. The financial risk part is easy, it can be corrected for just by a calculation. The business risk part cannot be corrected by any calculation whatsoever." Hearing Tr., Vol. IX, p. 116.

[72] The importance of this distinction should not be overlooked. Unlike the forward looking perspective of a rate case where investor expectations make it appropriate to use market measures in the analysis of sample proxies, the SEE retrospectively looks at *earnings* – an accounting concept – thus making accounting measures the proper gauge. Vilbert Testimony, pp. 4-5. While neither Mr. King nor Dr. Woolridge take issue with this concept, in practice both of them erroneously employ market measures, including beta, in their calculations. Vilbert Rebuttal, p. 10.

[73] By definition, beta measures the relative sensitivity of a stock's price to overall fluctuations in the stock market. Woolridge Testimony, p. 7. A beta value less than 1.0 means a stock's price is less volatile than the overall market. A value greater than 1.0 implies it is more volatile.

[74] OCC's suggestion during cross examination of Mr. Cahaan that Dr. Vilbert somehow employed beta in his methodology is simply wrong, as a review of his testimony shows. Hearing Tr., Vol. IX, p. 157.

criterion,[75] even using a single standard source for beta introduces variability depending on the given week during which the value is taken to apply the SEE test. Dr. Vilbert explains the problem in detail and Mr. Cahaan concurs in the criticism.[76] Vilbert Rebuttal, pp. 6, 13-14; Hearing Tr., Vol. IX, p. 107.

A next step in the SEE examination is determining the earnings of the Ohio utility under consideration, an exercise which should exclude the effects of non-Ohio jurisdictional operations as well as nonrecurring items. Wagner Testimony, pp. 6-9; Vilbert Testimony, pp. 8-9. Both Mr. King and Dr. Woolridge appear now to concur with excluding non-Ohio jurisdictional operations. Hearing Tr., Vol. VII, p. 209; Hearing Tr., Vol. V, p. 25. As to excluding non-recurring items, although Dr. Woolridge seems to take issue with the notion, the fact is that Value Line – which he uses for sample company data – *does* adjust for these extraordinary items in its reported earnings. In order to have a valid comparison, therefore, consistency would require making a comparable adjustment for any of the Companies' non-recurring items, as Dr. Vilbert recommends. Hearing Tr., Vol. VII, p. 209; Hearing Tr., Vol. V, p. 25; Vilbert Rebuttal, p. 15.

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[75] Mr. King, despite being one of the beta proponents, nonetheless acknowledges that "[t]here are as many estimates of beta for a given company as there are analysts making the measurement." Hearing Tr., Vol. VII, p. 218.

[76] We will not burden this brief with extensive discussion of the various other methodological flaws in the King and Woolridge approaches, the problems of which are comprehensively addressed in Dr. Vilbert's rebuttal testimony. *See* Vilbert Rebuttal, pp. 6-17, 22-23. They include, however, in particular as to Mr. King, his use of *separate* utility and non-utility sample groups, contrary to the statutory language, with his non-utility group being admittedly riskier and thus, by definition, not comparable to the Companies here. *Id.* at pp. 7-9. Intuitively, his non-utility sample group is inherently suspect when the reported ROE's of its members is a spread of 224 basis points, a range which exceeds the 200 basis point increment he offers as the appropriate "adder" for what should be considered "significantly excessive." *Id.* at pp. 8-9. Not only are the members of this group not comparable to the Companies here, they are not even comparable among themselves. To attempt to compensate, Mr. King makes an adjustment for risk using the CAPM methodology in a fashion quite different than he applied it in other proceedings. Not surprisingly, he produces a result more adverse to the Companies here. He thus provides the point of his own "brilliant" adage that "CAPM results can be made to conform to the preferences of any analyst simply through the judicious selection of different inputs." Hearing Tr., Vol. VII, p. 224; Vilbert Rebuttal, pp. 10-11.

One other aspect of the SEE proposed by the Companies is exclusion of DSI Rider revenues from application of the test. Application, ¶ A.3.f. The supporting rationale is that the Rider is designed as an incentive which, if included in the SEE calculation, would undermine its purpose and make its incentive character illusory.[77] Co. Exh. 1, pp. 23-25; Vilbert Rebuttal, pp. 18-19; Hearing Tr., Vol. XI, pp. 91-94. Moreover, because S.B. 221 directs the Commission to consider in its application of the SEE the impact of future committed capital investment in this state in its application of the SEE, this approach is well within the Commission's authority and discretion.

Having determined the returns both for the comparative companies as well as the utilities under examination in a given period, the final aspect of the SEE process is determination of the threshold above the return of the comparable companies at which the utility's earnings will be considered significantly excessive. Dr. Vilbert determines this increment by use of a statistical confidence measure. This is one of the approaches also used by Dr. Woolridge, as well as, according to Mr. Cahaan, the witnesses addressing the SEE issue in the ESP plans proposed in the AEP and Duke cases.[78] Cahaan Testimony, p. 8. The underlying rationale for use of a statistical measure derives from the statute itself. R.C. § 4928.142(F) requires, effectively, an economic analysis and, as it imposes the criterion of "significantly" on the measure of what are "excessive earnings," suggests a measure well grounded in economics, i.e., testing statistical significance at some confidence interval. Vilbert Testimony, p. 3; Vilbert Rebuttal, p. 6.

[77] Additionally, the closer the threshold is set to the mean of the sample group, the more important it is not to include the incentive rider revenues in the calculation since the problem of potential asymmetry gets worse, the tighter the threshold. Vilbert Rebuttal, pp. 18-19; Hearing Tr., Vol. XI, pp. 91-94.

[78] Even Mr. King (who initially proposed using the FERC incentive adder, but as his cross examination developed, became somewhat less clear about whether he had a proposal at all) finally acknowledges his earlier testimony that there could be *some* statistical confidence level that would be sufficient to determine SEE. Hearing Tr., Vol. VII, pp. 228-229, 231-232.

The alternative measure of the threshold increment – "significantly excessive" – offered, at least initially, by Mr. King[79] and used, in part, by Dr. Woolridge[80] is the so-called "adder" used by FERC in setting an allowed ROE, developed to provide an incentive to construct risky transmission projects. Of course, that intended purpose – to encourage future behavior – has nothing whatever to do with a retrospective look to see if, under the unique characteristics of the Ohio statutory test, a utility may have earned a return on equity considered "significantly excessive" in a prior period. Vilbert Rebuttal, p. 17. There is nothing in the FERC orders addressing the adder that suggests it is appropriate for use here, a fact its proponents acknowledge. Hearing Tr., Vol. V, p. 29; Hearing Tr., Vol. VII, p. 226. To the contrary, if FERC uses the adder as a component of an allowed rate of return, that reflects the reasonable regulatory expectation (on the part of FERC) that the applicant in question will, on average, have a fair opportunity to earn that allowed return. In that context, therefore, if a reasonable expectation is that a company may at times earn a little more than the allowed return, how can that be considered "significantly excessive"? The short answer is that it cannot, a point fully explained by Dr. Vilbert. Vilbert Rebuttal, p. 17.

Mr. Cahaan, too, refers to the FERC adder, but uses it as the lower bound of a recommended range for the Commission to consider in setting the value of the appropriate adder.

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[79] Mr. King makes no distinction between "excessive" and "significantly excessive," deeming the difference to be a mere "matter of semantics." *See* Hearing Tr., Vol. VII, p. 226. This view runs afoul of the tenet of statutory construction that every word in a statute is presumed to have some effect. *Shump v. First Continental-Robinwood Assoc.*, 741 N.E.2d 232 (Montgomery Cty. App. 2000); *State v. Linner*, 77 Ohio Misc. 2d 22 (Ohio Mun. 1996). In any event, as noted, he may have abandoned his earlier reliance on the FERC adder entirely. Hearing Tr., Vol. VII, pp. 228-229.

[80] While Dr. Woolridge only uses a single standard deviation from the mean (as distinguished from Dr. Vilbert's factor of 1.28) to set the parameters of his confidence level, at least he is on the right track in using a statistical measure. Why, then, he chooses to impair this analysis by averaging it with the 150 basis of his FERC adder is not entirely clear, although this step does achieve biasing his end result downward. In any event, introducing an unsuitable factor (the FERC adder) into an averaging calculation does not make the end result any less unsuitable or, as Dr. Vilbert put it, "garbage in, garbage out." Vilbert Rebuttal, p. 20.

His reliance on it, however, even simply as one boundary of a range, is no more relevant or justified than its use by its other proponents. For his upper bound, he uses what he approximates is the spread between allowed returns on equity and a utility's corresponding debt cost – 400 basis points. Cahaan Testimony, pp. 23-24. Irrespective of the accuracy of his approximation (and he made no underlying analysis to validate it), this number too bears no logical relationship to a measurement of significantly excessive earnings. Vilbert Rebuttal, p. 22. It follows, that any range created by Mr. Cahaan's combining these two arbitrary boundaries is his own "giraffapotamus" that is no more appropriate than relying on either of them separately. Moreover, by its nature any threshold based upon a fixed increment cannot reflect the economic conditions prevailing at the time and therefore lacks the flexibility inherent in using a measure of variation from the sample. Vilbert Testimony, p. 12. Accordingly, this proposal, too, should be rejected by the Commission.

In sum, the Companies' SEE proposal is both well-reasoned and well-supported. The intent of the statute is properly captured and applied it in a way that is fair both to the Companies and customers. It should be adopted.

CONCLUSION

S.B. 221 establishes a straight-forward standard for the approval of ESPs. If the aggregate effect of the ESP is more favorable than the expected results of an MRO, the ESP "shall" be approved, or approved with modifications. The Companies' Plan exceeds that standard and therefore passes the singular statutory test. It represents significant net present value benefit above a conservatively low MRO price estimate. It stabilizes prices for electric service over the next three years and, thus, provides an incalculable benefit to customers and the economy during a period of expected turbulence in costs and prices. The Plan also includes other unquantifiable benefits in the form of commitments to the Companies' customers, their service, and the State. Its package of terms aligns the Companies' and customers' interests in the provision of electric service. It also includes important incentives for the Companies to improve service and for customers to adapt their usage. The Plan provides the Companies with financial flexibility to maintain and improve their service while providing appropriate checks by the Commission to manage the Plan's impact, including the Plan's term. As a result, the Companies' Plan is consistent with and furthers State law and policy in the provision of electric service. The Plan, as a whole, clearly is more favorable than the expected results under a MRO and should, therefore, be approved.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The foregoing *Brief of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company In Support Of Their Electric Security Plan* was served via electronic mail on this 21st day of November, 2008, upon all parties of record.

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