BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP)
REBUTTAL TESTIMONY
OF DONA R. SEGER-LAWSON

- ■ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- ■ **RATES AND TARIFFS**
- ■ **OTHER**

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dona R. Seger-Lawson. My business address is 1065 Woodman Drive, Dayton, Ohio 45432.

II. DP&L RATE HISTORY

Q. Does DP&L have a history of providing below-market generation rates to customers?

A. Yes. After SB 3 was passed in 1999, DP&L filed its Electric Transition Plan, Case No. 99-1687-EL-ETP. SB 3 provided for a five-year Market Development Period (MDP) (Ohio Rev. Code 4928.40(A)), but DP&L, its customers, CRES providers and Staff expected competition in the generation markets to develop quickly. The parties thus agreed to a Stipulation that created a three-year MDP for DP&L. June 1, 2000 Stipulation and Recommendation, VII.

As the end of DP&L's three-year MDP approached, CRES Providers were not able to beat DP&L's then-existing prices, and competition therefore was not developing in DP&L's service territory. Customers thus faced the prospect of significant rate increases if the price freeze associated with the MDP were to expire and they were to be charged market rates. DP&L filed an application to extend its MDP to five years, Case No 02-2779-EL-ATA. The parties eventually entered into a Stipulation that extended DP&L's MDP to five years, and created a three-year Rate Stabilization Period (RSP) for DP&L through December 31, 2008. May 27, 2003 Stipulation and Recommendation, II, IX. The Commission cited to the facts that "[d]uring that MDP, the Commission anticipated that competition would develop" and "the failure of competition to develop according to expectations" as reasons supporting its approval of the Stipulation. Opinion and Order, p. 3.

In 2005, competition still had not developed as expected and customers and the Commission's Staff expressed concerns to DP&L that there would be significant rate increases if DP&L's RSP expired as scheduled after 2008. With Staff's encouragement, DP&L thus entered into a Stipulation that extended its RSP to December 31, 2010. November 3, 2005 Stipulation and Recommendation, I.A. (Case No. 05-276-EL-AIR). It was undisputed that that Stipulation provided $262 million in savings compared to projected market rates over the period 2006-2010. Nov. 14, 2005 Testimony of D. Seger-Lawson, Attachment B.

SB 221 was passed in 2008, and pursuant to that statute, DP&L filed an Electric Security Plan, Case No. 08-1094-EL-SSO. Yet again, parties expressed concern about the failure of competition to develop sufficiently in DP&L's service territory. The parties entered into yet another Stipulation that extended DP&L's rate plan through December 31, 2012. Feb. 24, 2009 Stipulation and Recommendation, ¶ 1. In approving the Stipulation, the Commission relied upon that fact that it was undisputed that "the rates contained in the ESP proposed in the Stipulation are more favorable in the aggregate than the equivalent market rates." June 24, 2009 Opinion and Order, p. 11.

DP&L thus has a long history of providing below-market rates to customers. The Staff signed the Stipulations that I review here, and encouraged DP&L to take the actions described here.

Q. Is that history pertinent to this proceeding, and if so how?

A. Yes. Due to the recent decreases in the price for generation, competition has developed rapidly in DP&L's service territory over the last few years. As DP&L witness Chambers explains, those events are jeopardizing DP&L's financial integrity and corresponding ability to provide stable and reliable service. In evaluating DP&L's requests in this case, and its need to preserve its financial integrity, including its requests for the Service Stability Rider (SSR) and Switching Tracker (ST), the Commission should consider DP&L's long history of providing below-market rates to customers.

Q. Several intervenors have criticized DP&L for not transferring its generation assets after DP&L's 1999 ETP case. Does the history that you describe undermine that criticism?

A. Yes. Under SB 3 market development periods for all Ohio electric distribution utilities (EDUs) were supposed to end in 2005, after which the price of retail generation service would be market-based and set through a competitive bid process. I recall that the Commission's Staff was concerned that if all Ohio EDUs implemented full legal separation and conducted competitive bid auctions to supply SSO, customers would experience "rate shock" because market prices at that time were higher than the cost-based SSO rates established through Rate Stabilization Plans (RSPs). This concern is depicted in PUCO Chairman Schriber's testimony before the House Public Utilities and Energy Committee on February 23, 2005:

> "The PUCO has worked to ensure that Ohio's electric customers do not face 'sticker shock' from electric rates when the market development period ends at

> the end of 2005. The PUCO worked with the electric companies on establishing rate stabilization plans (RSP) in their service territories. A RSP provides rate stability for customers, financial stability for electric utilities to ensure reliable service for customers, and promotes further development of competitive markets. The establishment of these plans was supported by the Ohio legislature . . . ."

Just prior to that on September 1, 2004 in Case No. 04-1371-EL-ATA, First Energy had announced its intent to transfer its generation assets and filed to set rates based on either an RSP or a Competitive Bid. A competitive bid was conducted, the results of which were rejected by the Commission as it would have increased FE SSO rate by over 25%.[1] Further, Monongahela Power transferred its generation assets and attempted to conduct a competitive bid to serve the SSO load which would have resulted in double-digit increases to its SSO customers. Had DP&L transferred its generation assets at an earlier date, then DP&L would not have been able to offer the below-market rates that it has long provided to customers. The fact that DP&L has not previously transferred its generation assets was thus a significant customer benefit.

Now that market prices for generation have declined, it is convenient for some intervenors to criticize DP&L for not moving more rapidly toward structural separation. Parties were too glad to be silent when market prices for generation made it in their self-interest to be silent. Now, suddenly, they want to claim that DP&L should have been structurally separating faster – forgetting the actual history of the slow development of competition in DP&L's service territory and of the concerns about rate shock.

[1] Confidential Post-Auction Staff Report Submitted December 9, 2004.

Q. Is there any other evidence that parties to this proceeding did not want DP&L, or other Ohio EDUs, to go further with structure separation at an earlier date?

A. Yes. In his July 2007 prepared remarks before the Ohio General Assembly, Sam Randazzo spoke on behalf of Industrial Energy Users of Ohio, stated on page 12 of his "Electricity Post 2008 A Common Sense Blueprint for Ohio" statement. Mr. Randazzo asks the Ohio legislature to repeal the corporate separation section of SB 3 that allows a utility to transfer generation without PUCO approval. He goes on to ask that any PUCO granted authority to transfer that has not yet been acted on be voided. He states specifically:

> "Under this federal law, the PUCO has granted permission for generation asset transfers to AEP, CG&E and FE and FE has exercised such authority to push control over certain generating assets to an unregulated affiliate. It is reasonable to expect that AEP and CG&E may also exercise such authority. **We recommend that Sec. 4928.17(E) be repealed and that any unused generation asset transfer permission that the PUCO may have granted under federal law be declared void as contrary to the public interest in order to manage the risks presented by the claims and schemes like those of Monongahela Power**"

IEU takes an inconsistent position in this proceeding.

III. RECONCILIATION RIDER

Q. Several intervening parties state in their pre-filed testimony that DP&L's Reconciliation Rider (RR) should be implemented on a bypassable basis. Do you agree?

A. No. DP&L's proposed RR is designed to recover 1) administrative costs associated with implementing the Competitive Bid auction, 2) costs associated with implementing computer programming changes associated with Competitive Retail Enhancements, and 3) costs if any that exceed a 10% threshold for the FUEL, RPM , TCRR-B, AER and the CBT Rider. If the Commission finds that one of those costs, such as the administrative costs associated with implementing the Competitive Bid auction, should be recovered on a bypassable basis, that does not mean that the entire RR should be made bypassable. Instead the Commission should direct the Company to seek recovery of the administrative costs associated with the Competitive Bid Process (CBP) through the bypassable Competitive Bid rate that is designed to recover the cost of generation supply that results from the auction.

Q. Several witnesses for intervening parties state that DP&L should not be permitted to recover deferral balances from bypassable charges through the nonbypassable RR. Has the Commission ever allowed a bypassable charge to become a non-bypassable charge?

A. Yes. In both Duke's and FE's ESP proceedings the Commission has allowed a "circuit breaker" provision to be put in place, such that if the cost of a given rider exceeds a certain percentage then the rider would become nonbypassable. Duke Case No. 11-3549-EL-SSO, Opinion and Order dated November 22, 2011, page 12, paragraph (d) ("Rider SCR shall be avoidable by shopping customers during the time that they purchase retail electric generation service from a CRES Provider, as long as the balance of said Rider is less than 10% of Duke's overall actual SSO revenue . . .") FE Case No. 12-1230-EL-SSO Opinion and Order dated July 18, 2012, page 9, paragraph (8) ("The Generation

Cost Reconciliation Rider (Rider GCR) will be avoidable by customers during the period that the customer purchases retail electric generation service from a CRES provider unless the allowed balance of Rider GCR reaches five percent of the generation expense in two consecutive quarters.")

Q. Is DP&L's proposal consistent with these Commission orders?

A. Yes. DP&L's proposal seeks recovery of costs associated with the FUEL Rider, the RPM Rider, TCRR-B, AER and the CBT Rider on a bypassable basis from non-shopping customers unless and until such time as the deferred balances associated with these riders exceed 10% of the underlying costs. Further, DP&L's plan does not propose that ALL of a given bypassable rider should become nonbypassable, only the amount that exceeds the 10% threshold should become nonbypassable as it is moved to the RR. Thus, DP&L's position is more moderate than the "circuit breaker" provisions that the Commission approved in other utilities' cases.

Q. What is the purpose of DP&L's proposal to transfer the deferral balances exceeding 10% in the FUEL Rider, the RPM Rider, TCRR-B, AER and the CBT Rider to the non-bypassable RR?

A. The purpose of this proposal is to mitigate rate impacts on all customers and avoid experiencing the growing deferral balances as described in Witness Rabb's testimony on page 13 lines 4 through 14. It is not reasonable for bypassable deferrals to accumulate over time such that the remaining few SSO customers are paying for the majority of the deferral.

Q. Did you review Staff Witness Patrick Donlon's pre-filed testimony in this case?

A. I did.

Q. On page 10, starting on line 1 Mr. Donlon suggests that DP&L should apply for recovery of the deferral balances of the RPM, CBT, FUEL, TCRR-B, and AER when the Company is at 100% CBP. Does it make sense to wait until the Company is at 100% CBP to address the death spiral issue?

A. No. Growing unrecovered balances have already become a significant issue in DP&L's Transmission Cost Recovery Rider (TCRR). In DP&L's 2012 TCRR filing (Case No. 12-524-EL-RDR), DP&L sought recovery of $8.3 M in deferred costs associated with TCRR. While the Company attempted to recover that deferral over the course of the year, due to volatile PJM charges and a decrease in DP&L's SSO load from 7.5 GWh in 2011 to 5.9 GWh in 2012, DP&L still had a deferral balance of $8.2 M when it filed its 2013 TCRR filing (Case No. 13-404-EL-RDR). DP&L must now seek to recover that same deferral balance from even fewer SSO sales, ultimately increasing the rate for SSO customers. The $8.2 M deferral represents approximately 38% of the base TCRR costs. Thus, DP&L and its customer are already struggling with growing unrecovered balances with respect to its TCRR rate design. Unless the Commission allows DP&L to implement a different rate design and/or a resolution to the perpetually growing unrecovered balances, DP&L's TCRR-B costs will far exceed the market value of these transmission-related costs and the remaining SSO customers may experience much higher TCRR-B rates.

Q. Why is DP&L making a proposal to move these deferral balances to the RR now instead of once the Company is at 100% competitive bid?

A. The Company does not want to let these deferral balances and carrying costs continue to accumulate over the next few years. Such a result would burden customers. Instead, DP&L's proposal addresses the issue now through this balanced approach of seeking to recover all costs from the bypassable rider and transferring only the deferral balance over 10% to the non-bypassable rider.

Q. Are you aware of an instance where the Commission ruled in a similar manner?

A. Yes. In AEP's 2012 TCRR Filing, the Commission found that AEP could recover the current TCRR deferral on a non-bypassable basis over three years in order to minimize the rate impact that would otherwise occur. Specifically, page 6 of the Commission's October 24, 2012 Order in Case No. 12-1046-EL-RDR, states: "We also find that OP should be authorized to establish a separate nonbypassable rate as part of the TCRR, in order to collect the under-recovery of approximately $36 million, plus carrying charges at the Company's long-term cost of debt rate, evenly over a three-year period. The separate nonbypassable rate should terminate once the full amount of the under-recovery has been collected. We agree with Staff and OP that the three year collection period is necessary in order to avoid the significant rate impact that would otherwise result from collecting the under-recovery over just one year, in combination with the other projected cost increases." Therefore the position that DP&L should not be able to transfer bypassable deferrals to a nonbypassable rider to avoid significant rate impacts to customers is contrary to the protection of customers in AEP's recent TCRR case.

Q. Have you reviewed the pre-filed direct testimony of IEU-OH witness Joseph G. Bowser regarding the Company's proposal to implement the Reconciliation Rider (RR) on a nonbypassable basis?

A. Yes I have.

Q. On page 7 starting at line 7 Mr. Bowser implies that DP&L's position is that the deferral balances that exceed 10% would be recovered over the next quarter. Is that DP&L's intent?

A. No. Mr. Bowser misconstrues DP&L's proposal. The Company seeks to recover any amount that exceeds the 10% over an appropriate period of time; however it would begin recovery the following quarter through the Reconciliation Rider.

Q. Did you review the testimony of Sharon L. Noewer, witness for First Energy Solutions?

A. Yes, I did.

Q. On page 17 starting on line 1, Ms. Noewer takes the position that DP&L's proposal to transfer unrecovered balances from bypassable charges to nonbypassable charges is anticompetitive and "will disrupt the underlying economic value of the contract shopping customers entered into with CRES Providers." And further she claims that it would be difficult "to predict whether or not one or more of the riders would trigger the 10% provision." Do you agree with her position?

A. No, I do not. DP&L's proposal is less disruptive than the "circuit breaker" provisions First Energy has implemented in its own service territory. As discussed above, First

Energy has a Commission-approved provision that allows it to make its entire Generation Cost Recovery (GCR) rider non-bypassable when a 5% threshold is reached, which means the entire bypassable rider may become a nonbypassable rider under certain conditions. DP&L's proposal is not that the entire bypassable rider becomes non-bypassable, but that only the amount that exceeds 10% becomes nonbypassable.

In addition, First Energy's trigger is set at 5%, compared to DP&L's more reasonable trigger at 10%. Since FES serves customers through CRES contracts in First Energy's service territory, and since this provision has been in place since July 2012 in First Energy's service territory, FES has been able to overcome any risks associated with this conditional provision and its potential impact on its CRES contracts with customers.

IV. ALTERNATIVE ENERGY RIDER – NONBYPASSABLE (AER-N)

Q. On page 10 of IEU-OH Witness Mr. Bowser's pre-filed testimony he states at line 10, that "the Commission must have determined that there is a need for the facility based on resource planning projections in the proceeding" implying that the finding of need must be in the ESP proceeding. Do you agree?

A. No. First of all, Mr. Bowser misconstrues the requirements of ORC §4928.143 (B)(2)(c). That section states that no surcharge should be authorized unless "there is a need for the facility based on resource planning projections submitted by the electric distribution utility." The electric distribution utility is required to submit its resource planning projections through its annual Long-term Forecast Report filed under OAC §4901:5-5-05. Resource planning projections are not a requirement of an ESP filing.

Second, the section of the OAC that establishes the components of an ESP filing specifically states at OAC §4901:1-35-03(C)(9)(b)(i) that if an electric distribution utility is seeking a non-bypassable charge under ORC §4928.143(B)(2)(c), "[t]he need for the proposed facility must have already been reviewed and determined by the commission through an integrated resource planning process filed pursuant to rule 4901:5-5-05."

The Company first sought the Commission's finding of need in the Company's 2010 Long-term Forecast Report and that finding of need was announced by the Commission in its April 19, 2011 Opinion and Order in Case No. 10-505-EL-FOR on page 5, paragraph (11): "There is a need for a 1.1 MW solar generation facility known as Yankee 1, and for additional solar generation facilities during the LTFR planning period." The Company now simply seeks a placeholder rider for the AER-N until such time as cost support can be filed in a separate case which will allow the Commission Staff and intervening parties to review DP&L's prudently incurred costs before establishing the level of the non-bypassable charge.

Q. On page 11 of Mr. Bowser's testimony at lines 1 – 4 he claims that DP&L's AER-N is contrary to ORC 4928.64(E). Do you agree?

A. No. ORC §4928.64 (E) requires renewable <u>compliance</u> costs to be bypassable. Compliance costs are costs such as administrative costs associated with purchasing renewable energy credits (RECs), and the cost of the RECs themselves to demonstrate that the EDU has met the renewable benchmarks of SB 221. DP&L's AER-N is to recover the cost of a new generation facility that meets the requirements of ORC 4928.143(B)(2)(c), which so happens to be a renewable generation resource. The cost of the Yankee Solar facility is not a renewable compliance cost and therefore does not violate ORC 4928.64(E) as Mr. Bowser suggests.

Q. On page 50, line 6 FES Witness Mr. Lesser says there is no longer a "need" for the Yankee facility and thus DP&L's AER-N should be denied. Do you agree?

A. No. Ohio Revised Code 4928.143 (B)(2)(b) states that a nonbypassable charge can be established to recover costs of new generation "for the life of the facility." There is no mention of a subsequent determination of continuing need. Such a requirement would discourage any new generation construction as markets change over time. Further, once a facility is built, it cannot be unbuilt. So, while the availability of Ohio Solar RECs may be greater now, the fact is that the Commission found that there were insufficient SRECs at the time Yankee was built[2] and it found a need for the facility through the Company's 2010 Long-term Forecast Report proceeding before the Commission.

V. COMPETITIVE RETAIL ENHANCEMENTS

Q. Did you review the testimony of Stephen E. Bennett, witness for Retail Energy Supply Association (RESA)?

A. Yes, I did.

Q. On page 3, starting on line 23 he states that DP&L should raise the threshold for interval meters from 100 kW to 200 kW for all customers. Should the Commission adopt that suggestion?

[2] March 17, 2010 Finding and Order in Case No. 09-1989-EL-ACP at paragraph (7) "we find that there was an insufficient quantity of the Ohio-based soar energy resources reasonably available in the market . . ."

A. No, the Commission should not adopt that recommendation for several reasons. First, there are important business reasons underlying the 100 kW threshold. Utilities develop load profiles that are used to create hourly load shapes for any customer group that does not have an interval meter installed. Increasing the interval metering threshold to 200 kW would require DP&L to conduct a new load research meter sample, to monitor the usage of customers that have demands between 100 kW and 200 kW and to develop, monitor and maintain load profiles for customers that fit this demand bandwidth. Second, an increase to 200 kW would result in less accurate assignment of CRES Providers' loads in PJM. This could cause PJM to assign too much load to the CRES Provider, increasing the CRES Provider's cost of doing business. The most accurate assignment of load is done through the use of an interval meter. Third, although Mr. Bennett states that requiring customers to install interval meters is a "discriminatory cost for shopping customers," all shopping customers larger than 100 kW are required to install the interval meters and thus it is not discriminatory.

Q. Is the cost of an interval meter a significant barrier for customers to shop?

A. No. DP&L charges a one-time $570 charge for interval meter installation. Customers that have 100 kW will have a typical SSO generation bill of between $2,000 and $3,000 per month. If the customer expects to save 10% on its generation bill, then the investment in an interval meter has a payback period of only 2 to 3 months. Thus, the cost of an interval meter is not a barrier that would cause the customer not to take service from a CRES provider.

Q. On page 9 line 21 Mr. Bennett states that DP&L should transition to supplier consolidated billing. Do you agree?

A. No. DP&L already offers three types of billing options for CRES Providers: 1) dual billing, 2) EDU consolidated rate ready billing, or 3) EDU consolidated bill ready billing. The Company has spent a significant amount of capital updating its billing systems to provide these functions. Supplier consolidated billing would also require further costly reprogramming of DP&L's billing system for limited or no value to customers. Before any Ohio EDU offers supplier consolidated billing, there are many rules, regulations, notices, payment agreements and other issues that would have to be fully vetted and developed through PUCO-ordered OAC rule changes.

Q. On page 9, line 22 of his testimony Mr. Bennett suggests that supplier consolidated billing would allow "product/offering innovation that would no longer be constrained by utility billing systems." Do you agree?

A. No. Bill ready billing means that a CRES Provider calculates its own portion of the bill and sends the EDU the charges that are then placed on the bill. Through bill ready billing, CRES Providers have an opportunity to offer different prices for different months, or different days of the week, or any other pricing option. Their innovation in product offering is not limited in any way through bill ready billing. DP&L has been providing bill ready billing since May 2012.

Q. On page 20 of her testimony FES Witness Noewer at line 22 states "A CRES provider in DP&L's service territory is essentially precluded from offering customers percentage-off PTC billing. . . ." Do you agree with this statement?

A. No. As I noted above, through bill ready billing CRES providers can offer any kind of pricing option they choose. They can calculate the monthly charges and send it through to be placed on the EDU's consolidated bill. If FES wants to offer percentage-off Price to Compare (PTC) billing it has ample access to DP&L's rates and tariffs, and customer monthly demand and energy amounts and can calculate it's rates based on percentage-off PTC or any other pricing option it would like to offer.

Q. On page 22, line 1 FES Witness Noewer states that DP&L's per billing fee is excessive. On page 14 of RESA witness Bennett on line 10 has a similar complaint. Are these complaints well founded?

A. No. DP&L's per bill fee was a result of a Commission order approving an October 14, 2004 Stipulation in Case No. 03-2405-EL-CSS. In that case the Commission fully considered the Company's costs and although below cost, the Company committed to charge only $0.20/bill for consolidated billing and $0.12/bill for dual billing. Today, DP&L's cost for rendering a consolidated bill is $0.35/bill; therefore if the Commission finds that DP&L's per bill fee should be modified, it should be increased not decreased nor eliminated. Billing is a cost of doing business and CRES providers should be required to pay their fair share of that cost.

Q. On page 6, line 11 Staff Witness Donlon states that Staff recommends that the cost of the competitive enhancements be split among CRES providers, the Company and the customers. He goes on to state that the Company should be assessed 15% of the costs. Is it appropriate for the Company to be assigned a portion of the costs of the six competitive enhancements that the Company has agreed to implement?

A. No, DP&L and its shareholders should not be required to pay for Competitive Retail Enhancements from which DP&L receives no benefit. As explained in my pre-filed testimony on page 15, line 1 DP&L and its shareholders do not benefit from implementing any of the six Competitive Retail Enhancements that the Company has proposed. The Company proposed them because it received feedback from CRES Providers in its earlier MRO case that these are some of the enhancements that they would like to see. Further, intervenors in this case suggest additional Competitive Retail Enhancements beyond those which DP&L has agreed to implement. To the extent that the Commission finds that DP&L should implement these six items or any other CRES enhancements, neither DP&L nor its shareholders caused the costs to be incurred, and they should not be required to subsidize CRES service.

VI. STORM COST RECOVERY RIDER

Q. Have you reviewed the pre-filed direct testimony of Staff witness David Lipthratt?

A: Yes I have.

Q. Do you agree with his recommendations?

A. No, I disagree with Mr. Lipthratt's testimony on storm cost recovery in several respects. First, the introduction of a storm cost recovery mechanism into this ESP case is inappropriate, especially as the Company has already filed a separate case No. 12-3062-EL-RDR to recover those costs. Second, Mr. Lipthratt's calculation of a baseline for DP&L unreasonably penalizes the Company for its extraordinary efforts during severe storms. Finally, his position on storm capital expenditures is inconsistent with Commission precedent.

Q. Please explain why Staff witness Lipthratt's establishment of a storm cost recovery mechanism is inappropriate in this ESP case.

A. Mr. Lipthratt's testimony is the first introduction of a storm cost recovery rider in this ESP case, and it came just before the hearing started in this case. The Company never proposed a storm rider in the ESP, but rather through a separate case for a Storm Cost Recovery Rider (Case No. 12-3062-EL-RDR). Inserting this new topic into this ESP case one week before the hearing is scheduled to begin does not give parties a chance to thoroughly examine, much less dispute, Mr. Lipthratt's position on storm costs. Further, Mr. Lipthratt addresses a Storm Rider only in the context of storm costs on a going-forward basis. He fails to mention the fact that in Case No. 12-3062-EL-RDR DP&L is also seeking recovery of historical storm costs. The subject of storm recovery should not be considered in the context of this ESP proceeding. The Company should be given ample opportunity to present the facts in the case that it filed to recover storm damage.

Q. If the Commission chooses to consider a storm cost recovery mechanism in this case, why is Mr. Lipthratt's calculation of the storm baseline unreasonable?

A. Mr. Lipthratt calculates DP&L's 10-year and 3-year major averages as $3.98 M and $3.70 M, respectively, and from those figures he establishes a $4 M major storm baseline for DP&L. In his calculation, Mr. Lipthratt includes three extraordinary storms (Hurricane Ike, the 2011 Ice Storm, and the 2005 Ice Storm) in his calculated averages and still rounds up from there. That logic would mean that the Company should be refunding money even when faced with record storm damage.

In reality, the Company should be made whole, not penalized, for its response in extraordinary weather events. The Commission has recognized that Hurricane Ike and the 2005 Ice Storm were severe weather events that fell outside the normal scope of storms. DP&L has also been nationally praised for its strong response in storm restoration. Including such extraordinary storms in the baseline is a clear distortion of the average, and unduly punishes the Company for its good faith efforts in those storms.

Q. Are you aware of any other Commission precedent in calculating storm baselines?

A. Yes. In Case No. 11-346-EL-SSO, Staff calculated a major storm baseline for AEP that was adopted by the Commission. In their review of AEP's major storm costs, Staff specifically identified and discarded exceptional years from the calculation (see Staff Witness Jeff Hecker's testimony in Case No. 11-346-EL-SSO, page 2, lines 16-22). However, Mr. Lipthratt made no attempt to normalize DP&L's storm costs. Rate making principles usually consider "normalized" costs in a given test year, such that anomalies are smoothed over. Mr. Lipthratt should have identified and removed any years (or even individual storms) that sustained an unusual level of storm expenses for the Company. DP&L's major storm costs, as presented in Attachment A to Mr. Lipthratt's testimony, include three obvious outliers: 2005, 2008, and 2011 (due to the three major storms already mentioned). Removing these three years from the calculation generates a major storm baseline of $1.10 M.

Q. Is the calculated $1.10 M baseline reasonable?

A. Yes. It accounts for the extraordinary storm events, as I just described. In addition, it is reasonable in comparison to AEP-Ohio and Duke-Ohio's storm thresholds. For example, the 2011 FERC Form 1 for DP&L and AEP-Ohio show that AEP-Ohio's distribution O&M expenses are 340% of DP&L's distribution O&M expenses. Applying a simple ratio using AEP-Ohio and DP&L's distribution O&M expenses reduces DP&L's major storm baseline to $1.46 M. It is also noteworthy that DP&L's base distribution rates are similar to or lower than Duke's current base distribution rates, which include only $1.58 M in storm costs (see the January 11, 2011 Opinion & Order in Case No. 09-1946-EL-RDR, page 6). Duke's distribution O&M expenses according to its 2011 FERC Form 1 are 145% of DP&L distribution O&M; similarly applying this ratio provides a major storm baseline of $1.09 M for DP&L.

Q. Are there alternative options for establishing a level of storm expenses as a baseline?

A. Yes. Duke's proposal (discussed by William Don Wathen's testimony in Case No. 12-1682-EL-AIR, pages 13-14) allows for the deferral of any (not just major) storm costs above or below the amount provided for in their distribution rates. DP&L believes that this approach is a more comprehensive view of storm costs, and a more evenhanded approach for the utility and customer alike. There may be some years where DP&L experiences very little non-major storm expense, but just enough major storm expense to pass the $1.1 M baseline. Other years may cause unusual levels of non-major storm expenses with few, if any, major storms. In the first situation the customer may unnecessarily compensate DP&L for storm expenses, while in the second situation DP&L may unnecessarily refund money to customers. If a baseline is set in this proceeding, DP&L recommends that a baseline is set by a reasonable average of its total storm expenses, and it will recover/refund the difference. Excluding the same three years (2005, 2008, 2011) as exceptions, DP&L's storm baseline would be $1.99 M.

Q. On page 8, line 20 Staff Witness Lipthratt recommends capital costs incurred due to a major storm should not be included in the Storm Damage Recovery Rider. Are you aware of any Commission precedent regarding the inclusion of capital costs in a storm cost recovery rider?

A. Yes. In Case No. 05-1090-EL-ATA, the Company was allowed recovery of the capital costs associated with the 2005 Ice Storm. Additionally, DP&L's ESP Stipulation (Case No. 08-1094-EL-SSO) states that DP&L may apply to recover "the cost of storm damage." Capital costs are not excluded from that stipulated permission to recover storm damage. Based on past Commission precedent and DP&L's Stipulation, recovery of capital costs through a storm cost recovery rider is appropriate.

Q. Does DP&L have a distribution investment rider (DIR) in place to recover capital costs associated with storm damage as well as any new investments in its distribution system?

A. No, it does not.

Q. Does DP&L have any other mechanism to obtain timely recovery of capital investments in its distribution system?

A. No, it does not.

VII. OTHER

Q. Have you read Staff Witness Raymond W. Strom's testimony?

A. Yes.

Q. Do you see on page 4 line 18 where Mr. Strom states that he is concerned that DP&L's participation in its own auction may have a negative impact on participation of other potential bidders?

A. Yes.

Q. Is this concern consistent with the Commission's order in the AEP ESP case?

A. No. Page 40 of the Commissions August 8, 2012 Order in Case No. 11-346-EL-SSO, states "[i]n addition, nothing within this Order precludes AEP-Ohio or any affiliate from bidding into any of these auctions." Therefore Staff's position that DP&L should be prohibited from participating in its own auction is contrary to the Commission's handling of the issue in AEP's recent ESP case.

Q. Did you review the testimony of Industrial Energy Users of Ohio Witness Kevin Murray?

A. I did.

Q. On page 38 of his pre-filed testimony Mr. Murray encourages the Commission not to adopt the Company's proposal with respect to the Transmission Cost Recovery Rider – Nonbypassable (TCRR-N). If the Commission adopts DP&L's proposal should the Commission address the contractual relationship between customers and their CRES Providers?

A. The Commission should adopt DP&L's proposal to implement the TCRR-N and if the Commission is concerned about existing contractual relationships between customers and their CRES Providers, the Commission could encourage all CRES providers who are parties to this case to remove the non-market based transmission and ancillary service costs from their price.

Q. As a factual matter, does the Service Stability Rider (SSR) meet the elements of Ohio Rev. Code § 4928.143(B)(2)(d)?

A. Yes.

Q. Is the SSR a term, condition, or charge?

A. Yes, it is a charge.

Q. As a charge, to what does the SSR relate?

A. The SSR charge relates to several items in that subsection. First, it relates to default service, since DP&L will be providing SSO service during the SSO term. Second, the non-bypassable nature of the SSR means that it relates to bypassability.

Q. Is the SSR a charge that would have the effect of stabilizing or providing certainty regarding retail electric service?

A. Yes it is. It would stabilize retail electric service provided by DP&L because it would help to assure DP&L's financial integrity, which is important to the company's ability to provide stable, safe, and reliable electric service. It would provide certainty regarding retail electric service because it would help to strengthen DP&L's financial integrity, and because the SSR is important to allowing a multi-year ESP, which itself provides certainty regarding retail electric service.

VIII. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.