**BEFORE**

**THE PUBLIC UTILITIES COMMISSION OF OHIO**

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| In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company For Authority to Provide for a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan | )  )  )  )  )  )  ) | Case No. 12-1230-EL-SSO |

**REBUTTAL TESTIMONY OF**

**ROBERT B. STODDARD**

**ON BEHALF OF**

**OHIO EDISON COMPANY,   
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND   
THE TOLEDO EDISON COMPANY**

# Introduction, Purpose and summary of conclusions

Q. What is your name, business address, and position?

A. My name is Robert B. Stoddard. I am a vice president of Charles River Associates (“CRA”), where I lead the firm’s Energy & Environment practice. My business address is 200 Clarendon Street, T-33, Boston, Massachusetts 02116-5092.

Q. What are your educational and professional qualifications?

A. I have over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. My recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and the PJM Interconnection (“PJM”).[[1]](#footnote-1) I have submitted testimony to the Federal Energy Regulatory Commission (“FERC”) as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and have testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts.

I was the lead economist for capacity suppliers in developing the capacity markets both in PJM and New England. I represented Mirant (now d/b/a GenOn) and other generation owners throughout the settlement discussions of the PJM Reliability Pricing Model (“RPM”)—including the Fixed Resource Requirement (“FRR”) Alternative—and developed many of the particular features of the market design. Following the settlement discussions, I was a member of a small team chosen by the settlement judge to draft revisions to the Tariff and RAA language consistent with the discussions. Furthermore, PJM filed affidavits from me and two other economists to provide the record on which FERC could accept the RPM settlement. Subsequent to the adoption of RPM, I participated actively in PJM’s Capacity Market Evolution Committee and served as a capacity market advisor to several utilities, generation owners, and financial market participants. I have also testified on capacity market issues in the New York, Midwest, and California markets. In related areas, I served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut’s standard offer energy auction. I hold degrees in economics from Amherst College and Yale University. A summary of my experience is attached as Exhibit RBS-1 to this testimony.

Q. Have you previously testified before the public utilities commission of Ohio?

A. Yes. I testified in Case 10-2929-EL-UNC, involving the setting of the capacity charge by AEP Ohio to CRES providers, and in Case 11-346-EL-SSO, in which AEP Ohio is seeking approval of its modified Electric Security Plan (“ESP”). In both cases I testified on behalf of FirstEnergy Solutions Corp.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company (collectively, “the Companies”).

Q. What Is The Purpose Of Your Testimony In This Proceeding?

A. The Stipulation and Recommendation (“Stipulation”) proposes to extend the provisions of the Companies’ current Electric Security Plan (“ESP”) with certain changes (referred to as “ESP 3”). Specifically, the Stipulation proposes to change the product solicited in the upcoming supply auctions to be conducted in October 2012 and January 2013 from a one-year to a three-year full requirements product. The purpose of my testimony is to address matters raised by Mr. James F. Wilson, testifying on behalf of the Office of the Ohio Consumers’ Counsel, who challenges parts of the Stipulation.[[2]](#footnote-2) In particular, I rebut Mr. Wilson’s conclusions about the prudence of the Companies’ proposal to extend their ESP to include a multi-year procurement in the upcoming auctions.

Q. Please briefly summarize your overall conclusions.

A. The Companies should be authorized to extend their ESP to procure a portion of their customers’ requirements throughout the proposed ESP 3 period. While it is true that the recently announced deactivations of coal-fired generators throughout PJM, including several in the American Transmission Systems, Incorporated (“ATSI”) zone, will substantially affect PJM’s markets, I disagree with Mr. Wilson’s statement that this “uncertainty” implies that the Companies should procure only short-term hedges of the Companies’ customers’ requirements.[[3]](#footnote-3) I concur with the Companies’ proposal to purchase a portion of the SSO requirement under three-year contracts; this laddered approach is a reasonable form of risk management frequently used by utilities. These contracts impose no undue level of risk that potential auction participants will be unable to manage at reasonable cost.

Mr. Wilson greatly overstates the degree of uncertainty in the PJM markets during the Company’s proposed ESP 3 period. On the capacity side, PJM has completed the primary auctions for the entire proposed ESP 3 period, and so capacity prices are known to a high degree of certainty, as even Mr. Wilson acknowledges. On the energy side, Mr. Wilson flags uncertainty about transmission and generation changes that could affect the future price of energy. While there is always uncertainty about future conditions, Mr. Wilson overstates the relevance of this uncertainty in designing a risk management program. With respect to transmission, the PJM Board of Managers has recently approved extensive transmission upgrades to address future reliability needs of the region. With respect to generation additions and retirements, the PJM capacity market has effectively fixed the set of generation that will serve the market throughout the proposed ESP 3 period. There is no basis, therefore, to lead the Commission to believe that the remaining uncertainty in the market is extraordinary or likely to reduce competitive participation in the Companies’ procurement auctions.

Notwithstanding the foregoing, to the extent that the Commission believes that the future market risks are high, this argues *for* obtaining greater certainty, not *against*, contrary to Mr. Wilson’s testimony. Insurance is valued most in risky situations. If, as Mr. Wilson suggests, consumers face a risk of adverse outcomes that could drive up prices (beyond what could reasonably be foreseen, given the announced generation deactivations), then there is a clear benefit to having secured a hedge against this outcome. Mr. Wilson believes that this hedge will come at a substantial price, owing to the high uncertainty that he sees, but he fails to recognize four points:

First, Mr. Wilson tacitly assumes that risks decline as we approach the 2015/16 delivery year. While this may be true for some risks, new risk factors could easily arise, or become more prominent, over the next several years. It is instructive to refer to Mr. Wilson’s testimony in the Companies’ earlier SSO filing:[[4]](#footnote-4) the primary risk factors Mr. Wilson now identifies are almost completely different than those he identified in 2010.

Second, delay allows resolution of some risks, but the result may be that prices increase. A multi-year hedging strategy avoids trying to “time the market.”

Third, Mr. Wilson is viewing the proposed ESP 3 plan solely as a hedge against potentially higher costs to consumers in the future. While that is true in part, it is also true that the ESP 3 contracts hedge energy supplier from potentially lower prices in the future. The risk is symmetric. Forward contracts are not always biased in the favor of the seller, as Mr. Wilson implies.

Finally, Mr. Wilson’s concerns about the lack of liquidity in the auction are also overstated and without solid foundation. Procurement of three-year forward full-requirements contracts is common in eastern markets and, even despite uncertainties and a lack of complete hedging products, participation has been robust and prices in line with reasonable expectations.

# Fundamental Shifts Drove Generation Deactivations

Q. Mr. Wilson states that “enormous changes in the past year” in the ATSI zone have “resulted in extraordinary uncertainty about future market conditions and prices.”[[5]](#footnote-5) Do you Agree?

A. While I concur with Mr. Wilson that there have been considerable changes in the past year, I disagree with his conclusion that these changes have created “extraordinary uncertainty.”

Q. What are these changes in the ATSI zone?

A. As Mr. Wilson discusses in his testimony, generation owners have announced deactivations of a significant quantity of coal-fired generation in PJM generally and the ATSI zone particularly. Announced deactivations total 1,549 MW this summer, and an additional 1,952 MW by June 1, 2015.[[6]](#footnote-6) These units represent approximately one-fifth of the generation resources located in the ATSI zone.

Q. Why are these units being deactivated?

A. The United States Environmental Protection Agency (“EPA”) has recently promulgated regulations that place substantial burdens on existing and new coal-fired generation:

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (“CSAPR”). CSAPR requires states to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states. This rule replaces a 2005 rule known as the Clean Air Interstate Rule (“CAIR”). Unlike CAIR, CSAPR provides much more limited opportunity for trading emissions credits across state lines and, consequently, places higher compliance costs in states—like Ohio—that have a high proportion of generation from coal-fired facilities. Final supplements to CSAPR were published on December 15, 2011.

On December 16, 2011, the EPA finalized the Mercury and Air Toxics Standard (“MATS”). “These rules set technology-based emissions limitation standards for mercury and other toxic air pollutants, reflecting levels achieved by the best-performing sources currently in operation.”[[7]](#footnote-7) Unlike other pollution regulation, MATS sets a standard that *each generation unit* must meet or exceed; unlike CSAPR, for example, over-compliance at one facility cannot be used to offset under-compliance at another. Under MATS, therefore, any generator that will remain in operation in 2015 must have installed a suite of pollution control equipment to reduce emissions of heavy metals (including mercury, arsenic, chromium and nickel) and acid gases.

Compliance with these two new regulations will require significant capital expenditures to add the necessary pollution control equipment to many existing coal-fired generation. Owners of these facilities, therefore, needed to consider closely whether the millions or billions of required expenditures makes commercial sense, in light of the reasonably expected future profitability of those plants.

Q. Besides these new EPA regulations, are there other factors that owners of these coal-fired generators would have considered in deciding upon deactivations?

A. Yes. The owners would have assessed the economics of each generation facility and unit, weighing not only the retrofit capital costs but also the expected future revenues. An important factor for coal-fired generators is the fundamental shift in the price of natural gas, which have fallen from above $12/MMBtu in mid-2008 to about $2.50/MMBtu today. Thus, an efficient gas-fired generator with an incremental energy cost of $84/MWh in 2008 would only cost about $17/MWh today. This cost shift is primarily the result of fundamental changes in the technology of gas extraction to include hydro-fracturing, a technology that brings decades’-worth of reserves of non-conventional gas into play. There is no serious debate, therefore, that this cost shift will be long-lived. Although there has been some decline in coal prices over this time, as well, these declines have not been enough to offset the two fundamental changes wrought by the sharp decline in gas prices.

First, lower gas prices result in lower energy prices. In PJM, as in all competitive wholesale power markets in the U.S., energy prices are set by the most costly units needed to operate the system. When gas-fired units are on the margin, as they frequently are in PJM, the sharp reduction in natural gas prices means that the energy price paid to *all* generating units declines. Coal-fired generators, therefore, have had their operating margins severely compressed by the downward step-change in gas prices.

Second, there has been a reshuffling of the “merit order” of generating units. “Merit order” is the supply stack of generating units, ordered by their offer prices into the market. Before 2008, coal-fired generators in Ohio were generally less costly to operate (at least at the margin) than the gas-fired generation in the state. After 2008, the picture is more complicated, with only the most modern, efficient coal-fired generation able to compete directly with the better gas-fired generation. Consequently, less-efficient coal generation, including the sub-critical coal facilities slated for deactivation, can expect to operate much less frequently, and to earn lower margins, than they had historically.

Q. Are the deactivations announced for the ATSI zone out of line with deactivations elsewhere?

A. No. These same two forces—new EPA regulations imposing costly retrofits on coal plants combined with sharply eroded unit profitability from lower gas prices—have led generation owners to announce large amounts of deactivations throughout the country. For example, GenOn Energy announced that it will deactivate PJM generation totaling 3,140 MW, of which 1,856.5 MW is outside of the ATSI zone. Overall, PJM suppliers have filed to deactivate over 16,000 MW by June 1, 2015; it is my judgment that substantially all of these are the consequence of low energy prices, increased emissions control requirements, or both. This is approximately one-tenth of PJM’s generation capability. The ATSI zone—with approximately one-fifth of its generation slated for deactivation—is relatively harder hit because of the higher proportion of older, sub-critical coal generation in the zone.

Q. Mr. Wilson states that PJM “scRambled” to manage the deactivation announcements. Do you believe that the Commission should be concerned with the timing of these announcements relative to the PJM capacity auction held in May?

A. No, PJM proceeded in a timely and orderly way to address reliability challenges posed by the numerous unit deactivations across its footprint. The timeline was necessarily short. The final MATS rule was published at the end of December, 2011, and contained material changes from earlier draft rules. The changes materially altered the compliance costs for many power plants. FirstEnergy Generation announced its deactivations only a month later, in January 2012; GenOn Energy, only two months later, in February 2012. Given the importance of these decisions—involving hundreds of millions of dollars in capital assets—it was not unreasonable that these generation owners took a month or two to assess the EPA’s final rules and evaluate their fleet’s future economics under different alternatives. PJM promptly began its review of the implications for reliability of the announced deactivations in the ATSI zone and elsewhere in the PJM footprint.

Q. What actions were taken to respond to the announced generation deactivations in the ATSI zone?

A. As a general matter, deactivation of generation resources may trigger the need for additional transmission, capacity resources, or some combination of both.

On the transmission side, PJM expedited the consideration of new transmission to ensure that reliability standards could be met after these generators were deactivated. Mr. Wilson summarizes these actions in his testimony, but he omits to underscore the expedited nature of the evaluation. Transmission planning is usually an activity that takes many months, and sometimes years. PJM was able to preliminarily identify transmission upgrades and include them into the RPM Base Residual Auction for Delivery Year 2015/16 very quickly. That action had a material effect on the outcome of the Base Residual Auction: with the originally posted system parameters, there was a substantial risk that the ATSI zone would clear at the cap of $537/MW-day. Because of the swift inclusion of additional transmission, the auction actually cleared at $357/MW-day for annual resources in the ATSI zone, resulting in a load price of $294/MW-day (plus scaling factors).

On the capacity resource side, FirstEnergy Generation Corp. proposed to build four 231 MW gas fired turbines at its Eastlake site. In addition to this proposed generation, there was a substantial increase in participating bids from demand-side resources, which ultimately were shown to be a more economic means of meeting the reliability needs of the ATSI zone than the proposed Eastlake generation. For Delivery Year 2015/16, 1,808 MW of demand-side resources located within the ATSI zone cleared in the Base Residual Auction, out of the ATSI resource requirement of 14,940 MW.

Q. Mr. Wilson notes that not all of the transmission expansion projects that have now been identified were included in the Base Residual Auction parameters. What bearing does this observation have on the case?

A. It has no bearing whatsoever. PJM proceeded at an expeditious pace to develop transmission, and when it published the final parameters for the Base Residual Auction, it included the transmission that had progressed sufficiently far in the review process. PJM has an obligation under its tariff to finalize the auction parameters prior to the auction, and it would have been imprudent for PJM to include transmission that had not yet been properly vetted. So not only is Mr. Wilson’s critique of PJM baseless, it is irrelevant to the Commission’s decision regarding the Companies’ proposed ESP 3. The Federal Energy Regulatory Commission oversees PJM and the conduct of the RPM auctions. For the purposes of this proceeding, the RPM auction results should be taken as given.

# Outcomes of the 2015/16 Base Residual Auction Provide certainty about capacity prices

Q. Mr. Wilson states that “PJM determined that the ATSI ZOne will be a separate pricing zone for RPM purposes.” Wilson direct at 4. Could you please clarify how this determination was made?

A. Yes. PJM determines two key parameters for 25 potentially constrained subareas of PJM: the Capacity Emergency Transfer Limit (“CETL”) and the Capacity Emergency Transfer Objective (“CETO”). The CETL is the ability to import capacity assistance into that area, while the CETO is the required amount of emergency import capability into a defined area.[[8]](#footnote-8) If the CETO is close to, or above, the CETL, then the subarea requires additional internal resources to ensure reliability. PJM considers announced deactivations in computing the CETO, and so the announced deactivations in the ATSI zone triggered an assessment of the CETO and CETL for the ATSI zone. PJM determined that the CETO exceeded the CETL and, consequently, the ATSI zone would be modeled as a separate pricing zone to allow prices to reflect the cost of that new entry.

Q. Mr. Wilson notes that the ATSI capacity resource price cleared at $357/MW-day. Is this the price that ATSI zone customers will pay for capacity?

A. No. The capacity payments by load are, in effect, a blended average of the capacity price paid to in-zone resources and the resource price paid to imported resources external to the ATSI zone. The $357/MW-day figure is the price that will be paid to Annual Resources within the ATSI zone for their 2015/16 capacity, but ATSI-zone Limited Resources will be paid only $305/MW-day, and ATSI-zone Extended Summer Resources will be paid $322.[[9]](#footnote-9) So, the weighted average price paid to resources within the ATSI zone is $342/MW-day, not $357. Furthermore, annual external resources deliverable to the ATSI zone are paid the RTO capacity prices of $136/MW-day. To reflect the use of these external resources to support reliability in the ATSI zone, PJM credits all customers in the ATSI zone with the value of Capacity Transfer Rights, which are similar to Financial Transmission Rights in the PJM energy markets. In the ATSI zone for the 2015/16 Planning Year, these Capacity Transfer Rights are worth $48/MW-day, bringing the average resource price down to $294/MW-day. This figure will be scaled up based on losses and other factors, and adjusted up or down to reflect purchases or sales in the Incremental Auctions, to arrive at the final Zonal Capacity Price.

# The Uncertainty in ATSI zone is Not Extraordinary

Q. Is there significant uncertainty as to capacity prices during the ESP 3 Period?

A. No. As Mr. Wilson acknowledges, the Base Residual Auctions establishes the clearing price for “well over 90% of supply.”[[10]](#footnote-10) The remaining supply will be purchased over the next three years in Incremental Auctions, but recent rule changes to these auctions have improved the convergence of their clearing prices to the price set in the Base Residual Auction. Consequently the price of capacity for SSO suppliers is known with a high level of confidence.

Q. Is it reasonable to assume, as mr. Wilson asserts, that the incremental auctions will clear at lower prices?

A. No. The introduction of a 2.5% “holdback” for short lead-time resources and other changes to the incremental auction design were explicitly intended to remove this systematic difference between the results of the Incremental Auctions and the corresponding Base Residual Auction. Since those changes were implemented, Incremental Auction prices have been both above and below the corresponding Base Residual Auction price. While there have been more Incremental Auction prices below the Base Residual Auction prices than *vice versa*, it must be noted that PJM used two of the four new-design Incremental Auctions to sell back resources that were no longer required because of lower reserve requirements caused by macroeconomic changes. As the economy picks up, there is a growing risk that Incremental Auctions will clear above the Base Residual Auctions, imposing costs on the Companies should they have needed to secure replacement capacity. Purchasing some of the SSO requirements before the first Incremental Auction for the 2015/16 Delivery Year hedges against this risk.

Q. Mr. Wilson avers that “prices for the ATSI zone must be considered highly uncertain at this time.” Do you agree?

A. No, Mr. Wilson overstates the riskiness introduced by the recent developments discussed above. He identifies three primary sources of uncertainty in the energy market: (1) “the large amount of plant retirements,” (2) “the numerous planned transmission upgrades,” and (3) “the uncertain market reaction to provide new generation, demand response, and energy efficiency capacity.”[[11]](#footnote-11) A thoughtful examination of each of these three elements shows that the risks are not extraordinary.

With regard to plant retirements, there is no reason to believe that there are additional generator deactivations in the ATSI zone that have not yet been announced. More to the point, substantially all of the existing generating units in the ATSI zone—other than those with announced deactivations—participated in and cleared the Base Residual Auction and consequently have committed to participate in the market through at least May 31, 2016. If any of these generators subsequently is deactivated before then, its owner will be responsible for securing replacement capacity or be subject to a substantial penalty.

With regard to transmission upgrades, the PJM Board of Managers has approved a slate of transmission upgrades aimed at addressing reliability concerns related to plant deactivations throughout the PJM footprint. Many of these upgrades address ATSI zone reliability. The set of transmission upgrades and the expected timing is now well known to the market.

With regards to new capacity resources, Mr. Wilson makes much of little. The time to bring any substantially sized new resource to the market is before the Base Residual Auction, when the resource could secure its capacity payment. Furthermore, no new generator or repowering is in the interconnection queue for the ATSI zone, other than the proposed new gas fired turbines at the Eastlake site, which did not clear in the auction. I do not expect, therefore, that any new generation or major repowering would have a commercial on-line date much before June 2016. Although I concur that some additional demand resources will likely enter the market during the proposed ESP 3 period, beyond those already cleared in a Base Residual Auction, these are likely to be relatively small and their effect on energy market outcomes reasonably predictable.

So, looking across the three primary factors identified by Mr. Wilson, I agree that there have been substantial *changes* in the market, but I see relatively low *risk* about what those changes will be. This is not to say that there are not substantial risks about future energy prices—there are. But these risks are the risks that energy marketers are used to managing, and risks that are not necessarily going to be resolved prior to the delivery year. There is certainly no assurance that the risks will resolve in favor of the lower prices to customers.

Moreover even the level of risk may not decline; some issues that are not viewed as material risks this year might become important in two or three years. For example, in 2009 Mr. Wilson warned the Commission about numerous risks he saw facing potential suppliers for the Companies’ SSO load. Mr. Wilson discussed risks of zonal prices, fuel prices, customer migration, customer usage patterns, rules and policies, and PJM integration.[[12]](#footnote-12) Comparing these risks to Mr. Wilson’s current list makes clear how in the passage of time some risks resolve themselves (e.g., PJM integration), some risks continue (e.g. zonal pricing), and some risks are heightened (federal rules and policies). One reason why laddering is considered a normal and prudent risk management approach is that no utility can know whether risks will increase or decrease over time, nor whether a future risk will resolve itself so as to result in lower prices.

Q. Mr. Wilson expresses his opinion that it is “unclear” whether “all of these transmission upgrades” will be constructed. How do you respond?

A. I disagree with Mr. Wilson’s implication that these transmission elements are a major uncertainty. While system conditions always change, and approved transmission upgrades have subsequently been tabled as load conditions vary, I view these transmission upgrades as high likely to be installed because these facilities are needed to meet mandatory reliability standards. As I just discussed, I disagree with Mr. Wilson’s view that major repowerings or new generation construction could obviate the need for the new transmission. To the contrary, the announcement of these transmission upgrades is likely to make any such generation expansion *less* likely to occur. PJM overall is not short of capacity, and the ATSI zone does not have extensive gas pipeline infrastructure to support the rapid and cost-effective development of gas-fired generation. Faced with competition from external supply brought into the ATSI zone by expanded transmission, it seems unlikely that new generation in the zone will be economic before June 2016. This opinion is confirmed by the fact that the proposed new gas-fired turbines at the Eastlake site did not clear the most recent Base Residual Auction.

Q. Do prospective SSO suppliers have any means of hedging the energy price risk?

A. Yes. Much of the price risk in the ATSI zone is related to overall market conditions and fuel costs; these can be hedged using conventional and well-established hedging tools, such as natural gas and PJM West forward contracts. The basis risk between PJM West and the ATSI zone can be hedged either through acquiring Financial Transmission Rights into the ATSI zone or financial over-the-counter contracts.

# Purchasing Multi-Year Products is Reasonable

Q. Mr. Wilson concludes that “significant uncertainty and risk” implies that “a three-year product may not be in the interest of consumers at this time.” Wilson direct at 7. Do you concur with his logic?

A. No. In the first instance, and as I discussed above, I disagree with Mr. Wilson’s conclusion that conditions in the ATSI zone are significantly more risky than power markets are familiar with and able to manage efficiently. Thus, the predicate of his conclusion is flawed.

Even if one were to accept his predicate, however, Mr. Wilson’s logic does not follow. The three-year product that the Companies propose to secure are a form of insurance against unknown future prices. Insurance is most valuable in times of uncertainty, so if (as Mr. Wilson suggests) the risk premium on the insurance is higher for the three-year product because of greater future uncertainty, the value of the insurance is also higher.

Mr. Wilson fails to recognize, though, that this insurance creates value not only to consumers but also to energy suppliers: the SSO contracts provide consumers with a hedge against price increases, but they also provide suppliers with a hedge against price decreases. Many of the risk factors identified by Mr. Wilson could result in *lower* prices than are currently foreseeable: additional transmission, additional demand-side resources, or repowerings could all move energy prices down. For generation owners, a reduction in prices could seriously and adversely affect their income and ability to fund required updates to existing facilities to meet new EPA regulations. Consequently, generation owners may be willing to *pay* a premium to avoid being exposed to these risks, leading them to *lower* their offer prices in the SSO auctions to ensure revenue stability throughout the proposed ESP 3 period.

Furthermore, I disagree with Mr. Wilson’s assessment that delay is the best strategy for hedging in this matter. Some risks do decline as we approach delivery, but if the goal of the ESP program was to minimize the amount of risk premium paid to suppliers, the Companies should simply buy in the spot markets and pay no risk premium at all. Such a program, however, would also maximize the risk borne by customers. Delaying procurement of power shifts risks to consumers, and that risk may ultimately result in higher SSO prices. Moreover, total risk does not always decline as we approach delivery. Risks that today seem unimportant may, two years from now, be in the forefront of people’s minds, just as compliance with EPA regulations were not significant enough to merit specific mention by Mr. Wilson in 2009.

Q. Is there precedent for the commission to use laddered multi-year procurements?

A. Yes. The PUCO has approved the use of multi-year SSO procurements for the Companies and for Duke Energy Ohio. In both cases, the procurement proceeded without issue.

Q. Looking to other states, is there precedent for using a three-year product?

A. Yes. In particular, I believe that the PUCO should look to New Jersey as a precedent. Each year since 2002, the New Jersey Board of Public Utilities oversees an annual auction, conducted by the state’s four electric utilities collectively, for Basic Generation Service (“BGS”). BGS is essentially the same product as the Companies’ SSO service. Each auction secures three-year forward commitments for one-third of the BGS load, with auction tranches specifying the particularly utility delivery zone in the state.

Q. Does New Jersey face a similar degree of uncertainty as the ATSI zone?

A. Yes. Like the ATSI zone, New Jersey faces material changes in what generating resources will serve load there in the future, with older units being replaced by new gas-fired units. As in ATSI (in the future), there are transmission constraints into and within New Jersey that can materially affect delivered energy pricing.

Q. Despite these factors, Have the three-year BGS auctions in New Jersey functioned well?

A. Yes. The auctions have produced results that are fully consistent with competitive outcomes. For example, regarding the most recent auction, the New Jersey Board of Public Utilities approved a three-year procurement for fixed-price service “to mitigate the risk to ratepayers.” The Board found that “the Auctions appear to have generated a result that is consistent with competitive bidding, market-determined prices, and efficient allocation of the [two types] of load.” [[13]](#footnote-13)

Q. Are there other states that use Laddered three-year procurements for standard service successfully?

A. Yes. The Delaware Public Service Commission authorized Delmarva Power (the primary Delaware electric utility) to conduct competitive auctions to purchase full-requirements wholesale electric power supplies for its Standard Offer Service (“SOS”) (non-shopping) customers. Supply for Residential and for Small Commercial & Industrial customers is secured under 36-month contracts.[[14]](#footnote-14)

In District of Columbia, the Public Service Commission has also approved the use of a laddered, multi-year SOS procurement for its investor-owned electric utility. As in Delaware, the utility is required to solicit offers annually to serve about one-third of the residential and small commercial load for a three-year period. I note that both D.C. and Delaware are in portions of PJM that have historically been affected by transmission constraints that raise capacity and energy prices.

The Maine Public Service Commission conducts an annual Request for Proposal for one-third of the SOS load for residential and small commercial customers, laddering procurement of a 36-month full requirements product.

Q. Are there other states that use laddered procurements for standard service?

A. Yes, laddering is very common among those states that have market-based procurement to meet the full requirements of non-shopping customers. In addition to New Jersey, Delaware, the District of Columbia, and Maine, multi-year laddering is used in Illinois, Maryland, Pennsylvania and Rhode Island.

Q. What benefits accrue to the Companies’ customers from using a three-year procurement, instead of shorter terms?

A. The limited amount of three-year procurement proposed by the Companies in this proceeding will have the effect of mitigating rate impacts that may be caused by energy and capacity prices in the last year of the proposed ESP 3 period, by blending these later-year prices in with prices for the earlier part of the proposed ESP 3 period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

**CERTIFICATE OF SERVICE**

I hereby certify that a copy of the foregoing was served this 6th day of June 2012 by the Commission’s DIS System as well as electronic mail upon the following:

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/s/ Carrie M. Dunn

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1. I use the term “PJM” both to refer to the Regional Transmission Organization and to the geographic region for which it is responsible. [↑](#footnote-ref-1)
2. Direct Testimony of James F. Wilson, Wilson Energy Economics, on behalf of The Office of the Ohio Consumers’ Counsel, Case No. 12-1230-EL-SSO, filed May 21, 2012 (“Wilson Direct”). [↑](#footnote-ref-2)
3. Wilson Direct, p. 7. [↑](#footnote-ref-3)
4. Direct Testimony of James F. Wilson on behalf of the Office of the Ohio Consumers’ Counsel, Case No. 09-906-EL-SSO. (December 7, 2009) [↑](#footnote-ref-4)
5. Wilson Direct, 3:22-23. [↑](#footnote-ref-5)
6. PJM, Pending Deactivation Requests, available at <http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (as of May 30, 2012).. [↑](#footnote-ref-6)
7. EPA, <http://www.epa.gov/mats/basic.html>. [↑](#footnote-ref-7)
8. A useful tutorial on CETO and CETL can be found on the PJM website at <https://www.pjm.com/~/media/committees-groups/subcommittees/raas/20110324/20110324-item-03-2011-ceto-tutorial-raas.ashx>. [↑](#footnote-ref-8)
9. Limited Resources and Extended Summer Resources are demand response supply resources that have limitations on the frequency, duration, and/or season when PJM can activate them. [↑](#footnote-ref-9)
10. Wilson Direct, p.34. [↑](#footnote-ref-10)
11. Wilson Direct, p.17. [↑](#footnote-ref-11)
12. Direct Testimony of James F. Wilson on behalf of the Office of the Ohio Consumers’ Counsel, Case No. 09-906-EL-SSO, p. 7-8. (December 7, 2009) [↑](#footnote-ref-12)
13. See, e.g. Board of Public Utilities, *In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2012,* Decision and Order, Docket No. EO11040250, available at <http://nj.gov/bpu/pdf/announcements/2012/2-9-12-2A.pdf> . [↑](#footnote-ref-13)
14. Delmarva Power DE SOS, Overview, <http://www.pepcoholdings.com/business/suppliers/sos/dplderfp/overview/> (accessed June 5, 2012). [↑](#footnote-ref-14)