

U.S. House Subcommittee on Energy
Hearing on Powering America: Examining the State of the Electric Industry
Through Market Participant Perspectives
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Written Testimony of
Lisa G. McAlister
Senior Vice President and General Counsel of Regulatory Affairs,
American Municipal Power, Inc. (AMP)

Summary Points:

- American Municipal Power, Inc. (AMP) is the non-profit wholesale power supplier and service provider for 135 member municipal electric systems across nine states – with a majority of AMP’s members being load-serving entities within the PJM region.
- AMP supports competitive markets, reliability and affordability but believes that the current capacity constructs in PJM are flawed and need a comprehensive review (in conjunction with the energy and ancillary services markets) of the cumulative impacts of PJM’s overall market design on consumers.
- PJM’s current capacity construct is a complex rules-driven administrative mechanism for pricing and procuring capacity that relies on distinctly non-market features. Over time, PJM’s capacity construct has become less flexible and is incapable of accommodating state and public policy decisions.
- It is time to consider alternatives to the current capacity construct and AMP supports the broader use of bilateral contracting for load-serving entities, like AMP, to satisfy most or all of their capacity needs.
- AMP supports appropriate transmission infrastructure build-out to replace aging infrastructure. However, there needs to be more transparent transmission planning, equitable treatment, better oversight to ensure the most cost-effective and efficient grid expansion, and rates of return that reflect current economic conditions and risks.
- We support Congressional oversight and commend this Subcommittee for taking up these important matters.

Good morning, Chairman Upton, Vice Chairman Olson, Ranking Member Rush and distinguished members of the Subcommittee. My name is Lisa McAlister and I'm the Senior Vice President and General Counsel for Regulatory Affairs of American Municipal Power, Inc. (AMP). I'm pleased to have the opportunity to appear before you this morning to discuss the state of the electric markets in the Eastern Regional Transmission Organizations (RTOs) and my focus will be on the PJM Interconnection, LLC (PJM).

AMP has a unique vantage point on the state of the wholesale energy and capacity markets, the transmission planning that PJM oversees, and the impact of these policies on electric consumers. AMP is the non-profit wholesale power supplier and service provider for 135 member municipal electric systems across nine states – with a majority of AMP's members being load-serving entities (LSEs) within the PJM region. We are an active participant in the PJM stakeholder process and an active litigant in many of the administrative cases before the Federal Energy Regulatory Commission (FERC) that address the myriad changes to the PJM markets. AMP commends the Subcommittee for holding this hearing and appreciates the opportunity to share its perspective, and looks forward to discussing these matters further during the hearing.

The electric industry has experienced a number of changes throughout the past few decades – principally driven by regulatory actions. However, a discussion of the state of the electric industry must recognize that technology developments will be the principal driver to the changes confronting our industry going forward – be those grid modernization, customer-sited generation, shale gas, energy storage or cyber. While my remarks today will not focus on those technologies, AMP recognizes those drivers and

we're working with our member municipal electric systems to ensure they have the tools needed to be prepared to meet their customer needs.

AMP is a member-focused organization and our members are customer-focused—therefore, the lens through which we view the impact of market changes is to ensure that the benefits of regulatory changes to improve reliability justify the costs to consumers.

I. Background

As you know, in the 1990s, the government decided to restructure the electricity industry, breaking vertically integrated utilities into generation and wires businesses and introducing competition in the generation sector. As the competitive market for generation began to emerge, it became clear that an impartial “traffic cop” with the authority to enforce grid reliability and operate the electric grid in a nondiscriminatory basis was needed to mitigate market power resulting from continued vertical integration of investor-owned utilities. FERC’s landmark Orders 888, 889 and 2000 created independent system operators (ISOs), which have since become known also as regional transmission organizations (RTOs). Additional reforms by FERC and Congress continued the progress towards electricity market restructuring. With that progress came evolution of the RTOs and the development of RTO-run centralized wholesale markets.

Specifically, PJM began using locational marginal pricing (LMP) to set prices for energy purchases and sales in the PJM market and to price transmission congestion costs in 1997. FERC’s basis for approving this market design was that LMP would send the proper price signals as to where generators should locate on the system, and where new transmission facilities should be constructed to relieve substantial and continuing congestion. But over time, it became evident that PJM’s LMP energy market was not

sending these signals—or at least that these signals were not being adequately responded to by market participants, chiefly generators and transmission owners. Electric generation owners in particular claimed that the existence of the \$1,000 price cap prevented them from earning sufficient revenues to permit them to make the necessary investments. The “missing money problem” was repeatedly cited as justification for providing a separate locational capacity revenue stream for generation owners separate from energy market revenues. Accordingly, PJM developed its administrative capacity construct, called the Reliability Pricing Model (RPM). Again, the justification for RPM came down to the lack of a requirement for a long-term forward commitment for capacity as an obstacle to capacity resources being able to project an adequate revenue stream going forward. Consequently, PJM argued that the then-current, energy-only construct did not provide meaningful price signals to capacity resources of the true value of the level of reliability that they provide to the system.

In spite of the combined revenue that generators can obtain from the energy market and RPM capacity construct, as well as PJM’s various ancillary services markets, the capacity constructs in particular have rapidly morphed beyond their intended purpose and require constant modifications to achieve desired outcomes. The capacity constructs are becoming increasingly complicated, bringing increased volatility and so much “rules churn” that any long-term planning and coordination is extremely difficult. For example, PJM’s most recent changes add performance requirements that are overly restrictive and unnecessary. Further, what used to be an administrative construct to recover “missing money” is becoming a major source of revenue – and consumer costs – for many units. We are moving away from markets.

Due to market volatility and the constant rules churn, AMP embarked on a generation asset development effort a number of years ago to reduce its market exposure. As a result, today AMP has assets of more than \$6.7 billion, including coal, gas and hydropower projects. Although AMP does own generation assets, AMP and its members remain net short on generation capacity and rely on market purchases to meet load obligations. Further, because AMP members are transmission-dependent and AMP does not own transmission, we rely on PJM and the transmission owners to plan and build and provide nondiscriminatory access to the transmission system to get our generation to our load.

II. Capacity Constructs

On May 1st and 2nd of this year, FERC held a technical conference to discuss the role of state policies in shaping the quantity and composition of resources needed to cost-effectively meet future reliability and operational needs in the Eastern RTOs and ISOs. The conference was a forum where FERC and the participants, including AMP, had a policy-level conversation about whether centralized capacity constructs are sufficiently flexible and robust to integrate state policies, while also satisfying reliability goals and meeting the needs of market participants and electric consumers in the face of an evolving resource mix.

Let me be clear at the outset: AMP supports competitive markets. Truly competitive markets are important to public power because they offer opportunities for our members to serve their customers at a lower cost. But, PJM's current administrative capacity adequacy construct is not a market in any meaningful sense. Rather, RPM is a complex rules-driven administrative mechanism for pricing and procuring capacity—one that relies

on such distinctly non-market features as an artificial demand curve, price caps and minimum offer price requirements, and obstacles to competition from certain types of resources. And while the purpose of a true market is to arrive at the most efficient utilization of economic resources, RPM's acknowledged goal is to provide a stream of revenues to suppliers to make up for "missing money." RPM is a "market" in name only, and, as time has gone on, fewer and fewer PJM market participants use that term to describe it.

Another factor that sets RPM apart from a normal market is that RPM's rules are in constant flux. During the ten years RPM has been in effect, PJM has been in a near-constant state of developing, filing or defending some new set of RPM rules, some of which fundamentally changed the nature of RPM. In fact, since 2010, there have been 27 significant filings made to modify RPM. According to PJM, the 2016 Base Residual Auction (BRA) was the first BRA with no rule changes from the prior year. While PJM may view each set of rule changes as necessary to address some unforeseen events or to provide market design improvements, the constant "rules churn" that is RPM has a number of negative impacts. The ongoing accumulation of rules and patches to rules, for example, has produced an unduly complicated mechanism; at this point, in fact, RPM's complex web of rules, exceptions, and exceptions to exceptions is such as to confound many market participants while, at the same time, providing a cloak for gaming behavior by others. Furthermore, the ever-changing nature of RPM's rules makes long-term resource planning and coordination next to impossible. These dysfunctional attributes are manifest in the fact that, even after more than a decade of operation and countless tweaks and patches, RPM still falls woefully short in terms of its ability to:

- ensure reasonable, transparent and stable capacity prices;
- incent required levels of electric infrastructure development;
- promote fuel diversity (PJM has grown heavily dependent on natural gas generation); or
- provide any assurance that in the long term sufficient resources will be built to meet the region's reliability needs.

During FERC's September 25, 2013 Technical Conference on Centralized Capacity Constructs, PJM delivered a report on RPM's goals and its claimed successes in several areas, including that of bringing forth the right capacity investments in the right locations. Yet, less than a year later, PJM believed it necessary to propose a fundamental overhaul of RPM in the form of its Capacity Performance (CP) proposal. Touted as a response to the polar vortex of early 2014, CP was rich in features that were uniquely disruptive and burdensome for stakeholders, such as unreasonable operational performance requirements, a paradigm shift for seasonal resource participation, penalties disconnected from the value of performance at the time and with the potential to exceed capacity revenue, and a near complete unwinding of the market mitigation rules governing offer caps, to name a few. Rather than seeking to meet the challenge of extreme demands by adding flexibility to PJM's capacity construct, CP instead adopted an inflexible product definition that discourages fuel and technology diversity by imposing strict performance requirements which disregard the fact that, even among the most well-managed units, there will be variations in forced outage rates, fuel supply arrangements, ramping rates and minimum load levels, and environmental restrictions, among other things. And because CP imposes unduly discriminatory restrictions and requirements on the use of renewable and demand response resources, a whole family of resources that historically provided significant value to the region now are greatly hampered in the value

they can bring. For example, as a result of feedback and strategic direction from our members and their customers, AMP made decisions to develop four new hydroelectric facilities totaling over 300 MW at an investment cost of nearly \$3 billion. Those local decisions were reached in furtherance of a power supply strategy that incorporates long-lived (80-100 year) emission-free resources to avoid market volatility, and were pursued irrespective of RPM price signals or its three-year look-ahead. However, as a result of the move to CP, AMP cannot get full value for its hydroelectric infrastructure as they cannot guarantee 24/7/365 operation. This is the case because AMP cannot control the river flows and cannot practically back up the hydroelectric plants with an alternative generation resource. In making PJM's capacity construct less flexible, CP also has made it less capable of integrating the diversity of resources that may be an element of implementing important state policies.

Another example of the unreasonable effect of CP on AMP specifically has been to put AMP at risk of not being able to use its coal resource in one RTO (MISO) to serve its load in another RTO (PJM). With FERC's acquiescence, and against AMP's protests, FirstEnergy and Duke Energy withdrew from MISO to participate in PJM. A sizable number of AMP's members are served from the transmission facilities owned by FirstEnergy and Duke, so prior to those companies' RTO "realignment," a considerable portion of AMP's member load was located within MISO. That was the situation that existed when AMP negotiated the purchase of its 368 MW share of the Prairie State Generating Campus (Prairie State). When FirstEnergy and Duke moved into PJM, however, the interconnected AMP members were compelled as a practical matter to move into PJM, as well. Consequently, AMP found itself in the situation in which Prairie

State and other supply resources remained within MISO while most of its load was located in PJM. That outcome was one over which AMP had no control and it is the situation that continues to this day. However, today PJM's new CP rules require all capacity resources physically located outside of PJM to pseudo-tie into PJM to qualify as capacity resources. Thus, in order to utilize Prairie State for its intended purpose — namely, providing long-term power supply service to AMP's members in an economical and reliable manner (and not to take advantage of more advantageous market conditions in one RTO or the other), AMP is required to use a pseudo-tie arrangement to offer AMP's Prairie State share into PJM's capacity auctions. However, the pseudo-ties are currently under attack from competitive generators and other RTOs, among others. If AMP's use of that pseudo-tie becomes burdened to the point that it is rendered uneconomic, AMP's members would be deprived of the intended benefits of a resource in which AMP has invested significant capital and resources to serve its members.

More recently, PJM has faced another development it seems to view as a challenge to RPM—namely, the efforts by some states and LSEs to take a direct role in guiding the resource mix in order to implement state policies. These efforts have taken the form of legislatively required affiliate power purchase agreements (Ohio) that some market participants have opposed as “out of market threats” to RPM. FERC's questions in the April 13 Notice of Technical Conference suggest that it, too, has concerns about the impacts that policy-implementing payments to capacity resources may have on current RTO capacity constructs. An effort to distinguish between state actions that are “inside” versus “outside” the market would be misplaced, however, especially if the purpose of the distinction is to insulate the current capacity constructs from the “outside”

influence of state policies. The reality is that, today, there already are factors at work that could be portrayed as “out of market” subsidies or advantages, such as state or local tax incentives, differing access to certain financing methods or vehicles, and variations in the cost of financing. Each of these factors ultimately has its roots in a particular state or local policy that may have differing effects across the spectrum of market participants and resources. Given this history, it is reasonable to expect that state and local governments, who are closer to and likely to take their cues from ultimate consumers, will continue in their efforts to guide asset decisions toward those that comport with relevant policies (as well as their long-term planning goals) regardless of the short-term and volatile signals produced by RPM and for reasons unrelated to the administrative determination of net Cost of New Entry (CONE) or Energy and Ancillary Services offsets. In a true market, nothing is truly “out of market.”

AMP and its members, for example, retain the obligation to serve customers and, thus, AMP makes long-term strategic decisions, like whether to add distributed generation or deploy Advanced Metering Infrastructure, based upon the feedback and direction of our members and their customers. AMP is not alone; each state has valid environmental, political and policy goals that factor in a plethora of local and state considerations beyond the ability of a mechanistic administrative construct to accommodate. Consumers, and by extension their elected officials, are the parties best positioned to assign value to externalities in resource decision making. Self-supply is at the very core of public power’s organizational model, and AMP’s existence. An administrative construct that fails to accommodate those choices (because it can’t) will always be “missing money.”

PJM needs a resource adequacy construct that is robust enough to withstand the effect of external events without the need to adopt another set of complex rule changes in response to each event. There are alternatives to the current centralized capacity constructs that, in concert with the energy and ancillary services markets and shortage pricing, would be more resilient to external events. Simpler, more robust alternatives to RPM and centralized capacity constructs exist.

One such alternative is for LSEs to satisfy most or all of their capacity needs through bilateral arrangements, in a real marketplace where willing buyers and willing sellers negotiate arrangements tailored to meet the parties' individual wants and needs (e.g., as to contract term, fuel type and resource flexibility, location on the grid, and financial terms), with a capacity auction available to satisfy any residual needs. Under such an approach, the RTO would retain its role of developing and specifying resource adequacy requirements for its footprint and Local Distribution Companies (LDCs) of concern. Each LSE, LDC or other Relevant Electric Retail Rate Authority (RERRA) would be responsible for securing capacity to meet its peak load obligation plus a predetermined reserve margin and would face significant penalties for failing to do so. LSEs, LDCs and RERRAs could procure resources bilaterally on a long-term portfolio basis in compliance with their respective resource adequacy requirements. The RTO could then conduct a residual auction to accommodate LSEs and supply that did not enter into long-term arrangements. This alternative has numerous advantages over current capacity constructs, including the following:

- **Fewer Moving Parts and Administrative Judgments.** Because the primary procurement construct is decentralized and bilateral, it eliminates the onerous stakeholder processes, disputes and subsequent litigation over discrete features of mandatory capacity constructs.

- **Harmonization with State and Local Public Resource Policies.** This proposal appropriately honors state and local resource portfolio and public policy choices, and does not bias market rules toward or against specific resource types.
- **Avoidance of Jurisdictional Disputes.** By appropriately involving state and local authorities in the resource adequacy, constrained zone mitigation and market power issues, this alternative sidesteps controversy over respective limits of state and federal jurisdiction in the capacity market area created by recent court decisions.
- **Flexibility for Individual States.** This proposal provides each individual state within an RTO region with the flexibility to address resource adequacy issues for its retail customers that may result from the state's prior decisions regarding retail access. An RTO-administered, centralized voluntary capacity market still would be available to satisfy residual needs.
- **Improved Product Differentiation and Resource Performance.** Bilateral contracting and other customized arrangements to procure electric resources enables the development of tailored products and services that will meet specific needs rather than relying solely on generic, lowest common denominator-type capacity products. For example, resources with desirable characteristics, such as those with dual fuel capability or firm gas transportation contracts that allow for certainty during winter peaks, could be appropriately valued and supported without complex and costly performance penalties.
- **Choice of Business Models for Merchant Generators.** This proposal provides merchant generators and resource suppliers a choice as well: they can enter into individualized bilateral supply arrangements with LSEs, rely on sales into the residual capacity auction (and/or the energy and ancillary services markets) to obtain their revenues, or pursue any combination of these approaches.

In evaluating the viability of the bilateral contracting model, we believe the benchmark should be the value bilateral contracting would bring to market efficiency and reliability and its amenability to implementing varying state policies, rather than its implications for existing centralized capacity constructs. Moreover, in considering this alternative to centralized capacity constructs, the policy concerns that might lead LSEs, states or local regulatory bodies to favor local generation over distant generation; newer, more efficient resources over older, less efficient ones; lower-emitting resources over higher-emitting resources, *etc.*, are legitimate concerns deserving of recognition and

weight, and, second, policymakers will continue pursuing policies at the direction of their constituents. Market rules imposed by RTOs to protect administratively derived prices under centralized capacity procurement constructs should not erect barriers to meeting such policy goals. And, it bears noting, these prices, developed as they are in isolation from local consumer input, will be wrong. Capacity is not fungible and not all MWs of capacity are created equal. Consumers are in a better position to determine the value of a particular fuel or resource. Long-term contracts support legitimate public policy and should be encouraged, rather than being considered “out-of-market” subsidies. RTO market rules that effectively penalize long-term contracting and self-supply should be reformed.

As a second-tier alternative, and a minimum step to reform the capacity construct, public power systems’ unfettered ability to self-supply their own loads with their own resources at their own costs should be restored. Although the original settlement that created PJM’s capacity construct guaranteed that capacity resources of public power LSEs and other self-supply entities, like AMP, would clear, over time the PJM rules have changed and have stripped away guaranteed clearing for self-supply. This has resulted from modification of the minimum offer price rules (MOPR) that were deemed necessary to mitigate buyer-side market power. Buyer-side market power, also known as monopsony power, is defined as the power of a buyer facing many sellers and little to no competition from other buyers. *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 84 (3d Cir. 2014). The MOPR in PJM, in its original form, had a basis in economic theory: it targeted a limited set of new or uprated resources (new gas-fired resources) but did not apply to new nuclear, coal, hydroelectric, renewable, or energy storage resources, because these

resources cannot be developed on a timeframe and at a size that could allow the exercise of buyer-side market power. The PJM MOPR has always been applied only to new entrants into the capacity market. It properly does not include existing resources as existing units have sunk costs that new units do not have. Initially, public power entities were exempted from MOPRs in PJM on the basis that they have no incentive to attempt to manipulate the market through below market offers. This is true because public power's business model effectively prohibits anything other than legitimate self-supply as they are non-profit entities whose purpose is to secure long-term supply arrangements at the lowest possible cost and they use tax-advantaged and tax-exempt financing to do that. There are real obligations that come with using such financing, including: 1) a prohibition on both the municipal LSE and any participants in a project financed with tax-advantaged obligations against using the project for anything other than the governmental purposes of the municipal LSE or project participant; and, 2) a prohibition against the municipal LSE or any project participant using their interest in the project for any activities that constitute a "private use" for the entire term the obligations remain outstanding. If a public power entity fails to comply with the requirements, the tax status of obligations issued by the municipal LSEs could be jeopardized and result in significant economic harm. In other words, the federal tax requirements on tax-advantaged obligations that are critical to the longstanding business models of public power entities serve as effective barriers against such entities building generation as merchant generation, market manipulation, or anything other than legitimate self-supply. Nonetheless, due to pressure from competitive generators, the MOPR rules were modified to include self-supply entities.

Most recently, on July 7, 2017, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded back to FERC prior orders that accepted PJM's revisions to the MOPR in PJM's capacity auction rules with respect to several aspects of a PJM-proposed rate structure: the self-supply exemption, the competitive entry exemption, unit-specific review, and the mitigation period, on the basis that FERC exceeded the limits of its Federal Power Act Section 205 authority by suggesting modifications to PJM's proposal, which PJM accepted.

As a result of this decision, self-supply entities are squarely at risk of having to pay twice to satisfy the same capacity obligation - once for the resource procured outside of PJM's resource adequacy construct and a second time to procure through RPM to replace self-supply that failed to clear the auction. The decision also does nothing to promote consumer welfare as any blanket proposal that replaces lower cost offers with higher, administratively determined offers has more to do with maintaining existing seller-side market power than tailoring a real solution to a real problem.

It is worth noting also that there have been a number of calls, mostly from merchant generators, for FERC and/or RTOs to expand the application of MOPR to existing units in addition to new gas-fired units. AMP strongly believes that applying MOPR to existing units defies rational economic theory; takes more of the auction process behind closed doors as PJM and the Independent Market Monitor determine units' costs; and, introduces unwarranted uncertainty as generation resources could no longer know whether they will clear the market or not, resulting in the unintended consequence of severely damaging the bilateral market.

Finally, the consumer impacts of market reform alternatives must not be ignored. Market participants wishing to protect their economic interests dominate FERC adjudicative dockets and RTO stakeholder processes. In these fora, the interests of “load”—retail consumers and those charged with protecting them—often are drowned out by the self-interested concerns of larger and better-financed participants.

III. Energy Markets

Of the two wholesale electricity markets, the energy markets are better able to value or select additional attributes than the capacity constructs. As a result of FERC’s last technical conference on this subject in the fall of 2013, FERC has done an admirable job in trying to improve price formation. This is the right track. And, while there are new technologies with different operating parameters and capabilities we need to address (distributed resources, energy storage), we must not lose sight of improving our current price formation processes regarding transparency of operator decisions, modeling all known constraints, and more accurate price formation rules during periods of transmission congestion and volatile fuel prices.

Improved energy market rules will be essential to address the rapidly changing technological demographic of intermittent resources with a zero energy cost. New energy products will be needed to allow RTOs to properly dispatch and balance the system, even at high levels of penetration by intermittent resources. For that reason, new energy products also must incentivize the retention of sufficient non-variable resources to ensure load continues to be served when intermittent resources are not generating.

IV. Transmission

AMP would be remiss to not touch on the third largest (and growing) component of wholesale electric bills: transmission. Nationally, transmission costs have increased drastically. According to the Edison Electric Institute's (EEI) December 2016 Transmission Projects at a Glance, increases in year-over-year total transmission investment by EEI's members reached approximately \$20.1 billion in 2015 and are expected to increase through 2017 to a peak of approximately \$22.5 billion in 2017. The Brattle Group, in a 2015 presentation to a JP Morgan Investor Conference, demonstrated these costs have been increasing exponentially since 1995. The build-out trend is expected to continue at a rate of \$5 to \$10 billion annually as infrastructure built in the 1960's reaches the end of its life and is replaced. According to Navigant, global spending on large-scale transmission system infrastructure for renewable energy integration is expected to grow from \$36.7 billion in 2016 to \$46.7 billion in 2025.

Locally, AMP's members have experienced similar increases over the past eight years. In four of AMP members' transmission zones, annual revenue requirements have increased by a range of 99 percent to 214 percent from 2009 through 2016.

AMP's members are willing to pay their share of costs, but must work to make sure these costs lead to the most cost-effective and efficient grid expansion. The transmission grid must be planned for the future, rather than piecemeal replacement of the grid of the past. The transmission planning process must be open and transparent, must provide equitable treatment, and take into account the changing resource mix and configuration of the future. This can be accomplished by a number of steps.

More robust planning processes for transparency and replicability are required. In PJM, since 2005, almost \$19B in projects have been proposed absent transparent criteria and models that stakeholders can review and comment on prior to the plans being finalized, despite the fact that the transmission owners have turned over the planning and operation of their facilities to PJM. These supplemental projects are not needed to address any established NERC, PJM or even individual transmission owner criteria.

In addition to a lack of consistent planning criteria among transmission owners, different planning criteria and processes between different organized markets (RTOs/ISOs) hinder inter-regional projects from being built. The interregional planning process needs to move away from compartmentalized and multiple threshold evaluations and evaluate interregional projects based on their combined benefits across all regions.

In 2016, AMP and other public power organizations in PJM sponsored a new stakeholder effort to address the PJM Transmission Owners' use of Supplemental Projects to replace aging transmission infrastructure. This effort was placed on a hiatus when FERC issued a show cause order (EL16-71) with the concern that the PJM planning process is not providing stakeholders with the opportunity for early and meaningful input and participation in the transmission planning process, as required by Order No. 890. The stakeholders agreed to put their effort on hold to enable PJM and the Transmission Owners to prepare their responses to this order. With the subsequent lack of a FERC quorum, this hiatus was extended until just this month when AMP led a group of stakeholders to ensure efforts started back again. The PJM Transmission Owners have consistently opposed formation of this group and its returning to work.

More robust planning models that account for changing grid drivers are also required. We need better models via improved software to generate a common model that can accurately include all known system constraints. New drivers that must be considered include distributed intermittent renewables, smart grid/micro grid opportunities, aging transmission facilities, generation retirements and future environmental requirements. These drivers could reduce the need for transmission investments and failure to consider these factors could result in unnecessary investments and higher electric rates. The U.S. Department of Energy (DOE) and FERC must continue their focus in this area and fully engage the industry in this endeavor.

While it is essential for developers to earn a fair rate of return on their investments in transmission infrastructure, these rates should reflect current economic conditions and risks, and not have the unintended consequence of encouraging building or over-building for the sake of revenue generation. Return on Equity (ROE) rates must reflect current economic conditions and additional incentives must be awarded judiciously to reflect actual levels of risk.

V. Conclusion

AMP supports Congress playing a more active role in encouraging FERC to refocus on its statutory mandate to ensure “just and reasonable” rates for customers in a meaningful way, and to examine whether net customer benefits exist for the multitude of RTO market mechanisms deployed, proposed and on the horizon in the Eastern RTOs.

Enhanced congressional oversight is critical to ensure that FERC is responsive to the real needs of consumers. Congress can be helpful by:

- Insisting that keeping costs to consumers as low as possible be a central part of the RTO mission, in addition to promoting electric system reliability;

- Reiterating that LSEs, through their obligation to serve their customers, have a right to make generation resource decisions that are not subject to rejection by the RTO or FERC;
- Insisting that resource adequacy constructs have the flexibility and capability to accommodate state and public policy decisions;
- Ensuring that RTO governing boards are truly representative and open, transparent stakeholder boards (i.e., meaning they reflect all load-serving entities and hold open meetings);
- Ensure that RTO governing boards are independent from RTO management and act solely in the interest of the RTO, are free from conflicts that compromise judgment and are able to take positions in opposition to management;
- Requiring RTOs to demonstrate that proposed market changes benefit consumers (i.e., stop the creation of new markets and products for the sake of creating markets and products);
- Requiring FERC to consider real-world outcomes in its decision-making (including balancing consumer, financial, environmental and other impacts);
- Directing FERC and the RTOs to develop robust and consistent planning criteria among transmission owners and RTOs; and,
- Encouraging FERC to ensure that ROE rates for transmission investments reflect current economic conditions and actual risk levels for the investments.

In closing, I want to stress that AMP supports both competitive markets and transmission infrastructure build-out. However, the current capacity constructs are not competitive markets. They can and should be simplified to ensure they are achieving the policy goals for which they were designed: ensure resource adequacy; balance the numerous goals of safety, resource adequacy, consumer affordability, environmental sustainability, and financial stability to provide less price volatility to consumers; be consistent with the needs of wholesale customers and consumer preferences (and operate within the constraints) as reflected through applicable state environmental

programs and all other jurisdictional policy objectives; accommodate all types of business platforms (merchant or competitive entries, investor owned utilities, and public power self-supply); facilitate trade to include bilateral contracting and not have market rules that restrict the use of available capacity; and produce just and reasonable rates.

In order to ensure that the right transmission is getting built at just and reasonable rates, transmission infrastructure must be designed and built in accordance with FERC direction and principles of coordination, openness, transparency, information exchange and comparability. Customers and transmission-dependent utilities like AMP and our members must have the ability to ensure that planned facilities are indeed necessary and economical and must have a meaningful opportunity for review and input after reviewing the transmission owners' transparent criteria, assumptions and models.

Thank you again for the opportunity to appear before you today; I would be happy to respond to any questions.