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January 10, 2003

Magalie Roman Salas, Secretary
Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Remedying Undue Discrimination
Through Open Access Transmission Service
and Standard Electricity Market Design
Docket No. RM01-12-000

Dear Secretary Salas:

Please find for e-filing, the Mid-Atlantic and Midwestern Consumer Advocates' Supplemental Comments on Specific Issues, in the above referenced proceeding.

Very truly yours,

- Filed Electronically -

Denise C. Goulet
Senior Assistant Consumer Advocate

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	:	
Through Open Access Transmission Service	:	
and Standard Electricity Market Design	:	Docket No. RM01-12-000

MID-ATLANTIC AND MIDWESTERN CONSUMER ADVOCATES' SUPPLEMENTAL COMMENTS ON SPECIFIC ISSUES

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Dated: January 10, 2003

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EXECUTIVE SUMMARY TO
SUPPLEMENTAL COMMENTS ON SPECIFIED ISSUES
OF MID-ATLANTIC AND MIDWESTERN CONSUMER ADVOCATES

These Supplemental Comments address five issues reserved by the Commission for comment on January 10, 2003 in the Standard Market Design ("SMD") Notice of Proposed Rulemaking ("NOPR"): a) through and out rates; b) congestion management; c) regional planning; d) resource adequacy; and e) Regional State Advisory Committees ("RSACs").

A. <u>Through and Out Rates</u>

Mid-Atlantic and Midwestern Consumer Advocates[1] urge the Commission to undertake a cost and benefit impact analysis before eliminating Through and Out Rates for any region. The Commission premises its proposal to eliminate these cross-border rates on the presumption that consumers will benefit from increased transactions across those borders. However, it is not clear that these benefits exist. If they do, it is also not clear that such benefits will in fact ultimately reach the end use consumer. Contracts often reflect both the cost of generation and the cost of transmission, but may also contain fixed rate terms for

[1] For purposes of these Supplemental Comments, the Mid-Atlantic and Midwestern Consumer Advocates include the Pennsylvania Office of Consumer Advocate ("Pa. OCA"), Maryland Office of People's Counsel ("MPC"), Office of People's Counsel of the District of Columbia ("DC OPC"), and the Ohio Consumers' Counsel ("OCC").

the buyer. Thus any reduction in the transmission component may not be passed on to the buyer. While this, in and of itself, will not necessarily harm consumers, the Commission's proposal contains the prospect of increasing costs to consumers during transition periods that may allow transmission owners to recover revenues allegedly lost as a result of the elimination of these through and out rates. The resulting increase in costs to transmission customers from this lost revenue recovery mechanism could be substantial and could result in significant cost shifts among consumers. Even the existence of retail rate caps does not protect consumers from the potential for harm, as any increase in transaction costs for competitive suppliers could dampen the robustness of such retail competition in those regions. Additionally, a policy of eliminating these rates between regions over the long term could distort price signals associated with distance factors. The Commission should undertake a study of the costs and benefits of a policy of eliminating through and out rates between regions before embarking on this course.

B. Congestion Management and LMP

Mid-Atlantic and Midwestern Consumer Advocates support the use of Locational Marginal Pricing ("LMP") to manage congestion within an ITP, RTO or ISO. However, since LMP could raise the cost of electricity for transmission customers, we also support the development of a system of financial rights proposed by the Commission as Congestion Revenue Rights ("CRRs") to hedge against such potential cost increases. At the same time, we disagree with three elements of the Commission's proposal in the SMD NOPR related to CRRs: attaching scheduling priority rights to CRRs, allowing the sale of CRR options, and use of CRR auctions.

First, we urge the Commission not to attach scheduling priority rights to holders of CRRs. Such a policy would convert the nature of the CRRs from a financial hedge to a physical right to capacity and would unnecessarily complicate and confuse the congestion management process. In fact, some transmission customers who are unable to obtain the appropriate mix of CRRs would not only find themselves unable to financially hedge themselves, but may also find themselves unable to access firm service. Instead, the problem of scheduling priority lies not with the nature of CRRs, but rather with the Commission's proposal to eliminate non-firm service. The Commission should revisit the wisdom of that proposal rather than attempt a remedy whose solution may be worse than the problem to be solved.

Second, the Commission should leave the sale of CRR options to a secondary market. The Commission notes in the SMD NOPR that two types of CRRs are potentially feasible: obligations or options. Obligations compel the CRR holder to pay congestion costs when congestion occurs in the opposite direction from that specified by the CRR. However, the holder of a CRR option is not required to pay in that situation. The ITP, RTO or ISO would be taking on considerable financial risk in administering a market for CRR options since the options would only be called where they appear to have value and not where a liability is likely to be incurred. There would be no guarantee of revenue sufficiency in the sale of CRR options. Private interests in a secondary market may be better able to bear the risk of such "congestion derivatives."

Third, the Commission should require ITPs, RTOs or ISOs to allocate CRRs in a manner that requires CRRs to follow load rather than allow auctions for these financial rights. The outcome of an auction, at best, should have the same expected value outcome as an allocation scheme, but with a higher variance between auction revenues and congestion costs than would be produced by an allocation scheme. The result for consumers is the potential for not being able to fully hedge themselves from congestion and a consequent higher increase in financing costs. If the Commission nevertheless decides to allow the use of auctions, a transition period will be required for regions that do not currently use LMP in order to allow market participants in those regions to assess the value of CRRs.

C. Regional Planning

Mid-Atlantic and Midwestern Consumer Advocates fully support the Commission's proposals in the SMD NOPR requiring the ITP, RTO or ISO to undertake a regional planning process that considers both reliability and economic outcomes. Each ITP, RTO or ISO should be required to immediately undertake its own planning process, as well as coordinate with other ITPs, RTOs or ISOs across broader regions. However, the Commission's proposal places too great an emphasis on market solutions to planning concerns. Relying only on private investment for expansion of the system may not provide adequate, efficient or timely expansion. While the planning process should incorporate merchant projects, consumers should not be harmed by delays attendant to seeking merchant solutions that may be a long time coming. Consequently, it is imperative that the ITP, RTO or ISO have explicit authority to direct that necessary system enhancements be implemented.

The ITP, RTO or ISO should incorporate a process that allows for a Request for Proposal to determine the lowest cost alternative for an upgrade. The ITP, RTO or ISO should determine cost responsibility on a case specific basis that identifies benefits to the system as a whole and to specific beneficiaries where appropriate.

D. Long Term Resource Adequacy

The continued reliability of the electric supply system must be the bedrock upon which SMD rests, consequently a long term resource adequacy system that ensures reliability is critical. The SMD NOPR proposed system of penalties and curtailments will not accomplish this goal, particularly in retail choice states. The SMD system could substantially increase the risk of adverse financial consequences for competitive suppliers. Moreover, the penalties and curtailment proposed in the SMD NOPR may be infeasible.

Mid-Atlantic and Midwestern Consumer Advocates recommend instead that for the region they serve, the Commission should adopt a capacity market model that: a) provides reasonable assurance to consumers that there will be sufficient generation resources to protect reliability; b) effectively mitigates market power; c) produces reasonable prices; d) does not unnecessarily limit the portfolio choices of buyers and sellers; e) allows all resources (generation, demand and transmission) to participate; and f) accommodates both bundled native load and retail choice programs. Mid-Atlantic and Midwestern Consumer Advocates propose a model in these comments that satisfies these basic principles.

We urge the Commission to adopt a capacity market model for the Mid-Atlantic and Midwestern region that provides for centralized procurement by the ITP of sufficient capacity to meet the resource needs of the region twelve to eighteen months ahead of the time period in which the resources will actually be needed. This proposal requires the ITP, RTO or ISO to forecast demand on a longer term planning horizon, as well as assess the adequacy of resources to meet that forecast. However, the proposal accommodates the uncertainty of load growth, as well as the shorter lead time required by demand resource participation, by requiring a shorter term lead time, *i.e.* twelve to eighteen months ahead of the targeted period. The proposal provides for market based pricing in the auction, while protecting against the potential exercise of market power through the use of bid caps. This proposal better balances the competing needs of retail choice programs and demand resource participants with the longer term needs for resource adequacy.

Our proposal mitigates the potential for market power that could be exercised by generators by incorporating bid caps on generator offers, imposing mandatory bid-in requirements for all generation not sold as capacity outside the region; and incorporating a pay as bid requirement for generation combined with an average pricing for load serving entities. Bilateral contracts are encouraged. Generators would bid these contracts into the centralized auction, would privately inform the ITP, RTO or ISO of the quantities, and the contracts would then settle out as contracts for differences. This system ensures that suppliers are unable to game long or short positions by knowing the residual amounts required for the auction.

We have designed the proposal to incorporate a daily balancing mechanism that allows load serving entities in retail choice programs that are uncertain about their load demands to trade imbalances at the auction price. In essence, capacity reserves acquired in the auction follow load as switches between competing suppliers occur. In retail choice states, competitive suppliers often do not know their load requirements months ahead of time, let alone a year or more in advance. This daily balancing mechanism accommodates this uncertainty by providing an automatic means for load serving entities with excess capacity reserves resulting from lost load to sell that excess to load serving entities that find themselves short due to the acquisition of new customers.

Our proposal also incorporates a backstop mechanism in the event of market failure that would require the ITP, RTO or ISO to construct or contract for the construction of necessary generation if market solutions are not forthcoming in a timely manner to prevent shortages. This backstop mechanism is a critical component of any long term resource adequacy system if we are to ensure that generation resources are always adequate to meet demand.

E. Regional State Advisory Committees

Mid-Atlantic and Midwestern Consumer Advocates support the proposal in the SMD NOPR for the development of Regional State Advisory Committees ("RSACs") to ensure an effective forum for participation by state representatives in the ITP, RTO or ISO operations. Many of these state representatives may be reluctant to vote or participate directly in ITP, RTO or ISO meetings and stakeholder processes due to the quasi-judicial nature of their statutory responsibilities. The RSAC provides an effective forum for the ITP, RTO or ISO to obtain the valuable and critical input of these state representatives.

However, we caution that the RSAC process should not become a super stakeholder sector in the ITP, RTO or ISO, should not compromise ITP, RTO or ISO independence, and should not serve as a process to circumvent state of federal regulatory or statutory requirements. Additionally, at least for the Mid-Atlantic region, Mid-Atlantic and Midwestern Consumer Advocates do not support the SMD NOPR proposal that would have the RSAC establish resource adequacy reserve requirements, resource adequacy planning horizons, or establish regional rate design methodologies. We believe that state representatives have valuable input into each of these areas, but they should not control any of these areas. Within PJM, the RTO currently establishes reserve requirements and planning horizons on a regional basis. PJM has an existing Memorandum of Understanding ("MOU") with the state regulatory commissions within its region that provides a basis for the development of a strong RSAC process that does not compromise the RTO's regional operations. We urge the Commission to require ITPs, RTOs and ISOs to consider using the PJM MOU process as a starting point in developing an effective RSAC process and to expand upon the MOU by strengthening the state representatives' role in regional planning, development of demand resources, development of resource adequacy requirements, and market monitoring. Improved access to data is essential to allow these state representatives to effectively participate in this process and ensure the continued availability of electricity in their region at reasonable prices.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	:	
Through Open Access Transmission Service	:	
and Standard Electricity Market Design	:	Docket No. RM01-12-000

SUPPLEMENTAL COMMENTS ON SPECIFIED ISSUES
OF MID-ATLANTIC AND MIDWESTERN CONSUMER ADVOCATES

Pursuant to the Commission's Order dated October 2, 2002, in the above-captioned docket, the Pennsylvania Office of Consumer Advocate ("Pa. OCA"), Maryland Office of People's Counsel ("MPC"), Office of People's Counsel of the District of Columbia ("DC OPC"), and the Ohio Consumers' Counsel ("OCC"), (hereinafter referred to "Mid-Atlantic and Midwestern Consumer Advocates") submit supplemental comments on the following specified issues: Transmission Pricing relating to Through and Out Rates, Congestion Management and LMP; Transmission Planning; Long Term Resource Adequacy; and Regional State Advisory Committees.[1] Once again, we note that we are submitting these comments only on behalf of the offices listed above. We submit that our recommendations are appropriate for the Mid-Atlantic and Midwestern region of the nation; however we do not purport to make comments and recommendations for other regions, especially those located in the western and southeastern sections of the nation.

[1] The Indiana Office of Utility Consumer Counselor, the New Jersey Division of Ratepayer Advocate, and the Missouri Office of the Public Counsel offices participated in the first round of Comments submitted by Mid-Atlantic and Midwestern Consumer Advocates but do not participate in this round because they are still reviewing the specific issues set forth for comment in this round.

I. TRANSMISSION PRICING: PROPOSAL TO ELIMINATE THROUGH-AND-OUT CHARGES (¶ 165-202)[2]

In Paragraph 170, the Commission proposes to eliminate transmission-access charges for power exported from or wheeled-through an ITP's service territory. Under current OATT procedures, exports from one region to another pay the access charges for the region where the transaction originated, for all regions the power is wheeled through, and for the region where the transaction ultimately terminates. Under the Commission proposal, according to Paragraph 180, such transactions would instead pay only the access charge for the terminus region.

Mid-Atlantic and Midwestern Consumer Advocates are concerned with the total elimination of through-and-out charges, absent a showing that the Commission's proposal will not unduly harm consumers. As discussed below, we are concerned that the Commission's presumptions with regard to the economic benefits of its proposal have not been substantiated by a rigorous economic analysis of the impacts of eliminating through-and-out charges. Moreover, the elimination of through-and-out charges may unduly benefit exporters, to the detriment of consumers in both the exporting and importing regions.

The Commission asserts that imposition of through-and-out charges "impedes the ability of distant generators to compete with nearby generators by imposing charges … that are unrelated to actual variable transmission costs." SMD NOPR at ¶ 170. Specifically, the Commission notes that:

> "A customer's choice as to whether to purchase power from a generator located within the same RTO or a neighboring RTO is directly affected by the fact that one generator faces an additional access charge to reach the RTO in which the load is located. This additional access charge may cause the sale to become uneconomic."

[2] MPC joined in the Mid-Atlantic and Midwestern Consumer Advocates' Comments On Notice Of Proposed Rulemaking, filed in this docket on November 15, 2002, but withheld comment on issues discussed in the sections on "Network Access Service" and "Transmission Pricing" in that document. MPC hereby adopts the comments in those sections.

SMD NOPR at ¶ 181. In theory, recovering embedded transmission costs as an incremental charge on exports may lead to economically inefficient outcomes. However, in practice, such inefficiencies may be insubstantial or outweighed by the harm from elimination of export charges. The Commission appears to be proposing to eliminate such export charges without the benefit of a comprehensive analysis of the likely magnitude of such inefficiencies and of the extent to which consumer welfare would be enhanced by eliminating such charges between all regions.[3] There are a number of factors that might cause economic benefits to be less than presumed. For example, export charges may not be a barrier to efficient cross-border trade, either because differences in generation costs between regions in most hours exceeds the export charge or because such export charges are typically discounted below these differentials in regional generation prices.[4] Mid-Atlantic and Midwestern Consumer Advocates therefore submit that the Commission should analyze the economic impact of the proposal to eliminate through-and-out charges before ruling on its merits.

In addition, we are concerned that the elimination of cross-border charges may in fact lead to greater costs to consumers in importing regions. For example, a generator in RTO A may be selling into RTO B, because the market price in RTO B exceeds the sum of the generator's cost and the export charge. In this case, eliminating the export charge would affect neither the economics of the sale nor the market price paid by consumers in RTO B. However, the *total* cost to consumers in RTO B may increase, since under the Commission's proposal the embedded costs previously recovered through the export

[3] The quantitative analyses conducted to-date, such as the analysis of the merger of PJM, NYISO, and ISO-NE, are of limited value in this regard, since such studies do not include the welfare impact of shifting embedded-cost recovery from exporters to importing load as a result of elimination of export charges. In addition, some of these studies do not analyze the impact of eliminating export charges separately from that of establishing a common dispatch market between the regions in question.

[4] Price differentials across seams are more likely to exceed export charges for transfers over frequently congested interties.

charge will instead be recovered from consumers in RTO B.[5] This increase in cost to consumers is a transfer of wealth to exporting generators in the form of higher profits from the transaction.

Mid-Atlantic and Midwestern Consumer Advocates are also concerned that the Commission's proposal may lead to inequitable subsidization of LSEs' bilateral import purchases by other consumers within an RTO. Currently, LSEs importing power from another region directly bear the embedded transmission costs related to these import transactions, in the sense that the bilateral import prices presumably recover the exporting region's through-and-out charges associated with such imports. Under the Commission's proposal, in contrast, the embedded costs related to import transactions will be recovered from all load within the importing RTO, regardless of whether that load benefits from the import transaction.

The Commission's proposal could in fact lead to inefficient outcomes in the case of cross-border transactions that require investment in transmission upgrades. It would be inefficient and inequitable to socialize such incremental upgrade costs across load in the importing region, rather than charging such costs to the export transaction that gives rise to them.

Finally, if the Commission determines, on the basis of a rigorous analysis, that the elimination of export charges is justified on efficiency grounds, it should address the equity implications of its proposal not just in terms of the allocation of export-related embedded costs, but also in terms of the impact on market prices. Specifically, even if it is determined that elimination of export charges between two regions lowers the cost to serve the combined load of the two regions, it is likely that market prices will rise in one

[5] The total cost to consumers in RTO A could also increase, to the extent that less than 100% of the embedded cost previously recovered through the export charge was now recovered from consumers in RTO B.

region and fall (by a greater amount) in the other.[6] If so, the Commission should consider some form of transition mechanism for sharing savings that accrue to one region with regions that incur additional power costs.

II. CONGESTION MANAGEMENT AND LMP (¶ 203-255)

A. Congestion Management

1. General Principles

The Commission states that when SMD is implemented, "the revised tariff would apply to nearly all transmission services on the system. All customers would receive the same quality and quantity of service they currently receive." SMD NOPR at ¶ 370. Mid-Atlantic and Midwestern Consumer Advocates support the Commission's goal of maintaining quality of service for all transmission customers. Additionally, we believe that existing loads should receive the same level and quality of service that they currently enjoy *without any significant increases in transmission costs*. Alternatively, any material near term increases in cost should be accompanied by clearly demonstrated increased quality of service, *e.g.*, lower congestion costs, higher reliability.

2. Locational Marginal Pricing

The Commission proposes to implement a Congestion Management System based on Locational Marginal Pricing (LMP). Based on the experiences of PJM, we believe that a system based on LMP provides signals regarding both the use of the existing generation resources and transmission system, and the development and siting of new generation and transmission or the development of demand side resources.

[6] See, for example, *Impact of the Creation of a Single MISO-PJM-SPP Power Market*, Energy Section Analysis, Inc., July 2002, available at www.miso-pjm-spp.com.

3. Congestion Revenue Rights

Another key feature of the proposed Congestion Management System is the use of Congestion Revenue Rights (CRR), defined as "a property right held by a customer that entitles and/or obligates the holder of the Right to receive/pay specified congestion revenues." Mid-Atlantic and Midwestern Consumer Advocates agree that an LMP-based system should be accompanied by a system of financial transmission rights. We emphasize that such rights must be financial and not represent physical rights to flow power over specific paths. As the NOPR suggests, an entity need not schedule transmission service to collect congestion revenues.[7]

Under the SMD tariff, the Independent Transmission Provider (ITP) would make available receipt point-to-delivery point congestion revenue right *obligations*. Upon request of the market participants, the ITP would also make available receipt point-to-delivery point congestion revenue right *options*. When congestion occurs in the opposite direction from that specified by the CRR, the holder of a CRR obligation is required to pay the negative congestion revenues to the ITP; the holder of a CRR option is not required to pay in that situation.

We believe that an ITP could administer a market for obligation-style CRRs (as NY-ISO and PJM do today), but are concerned that the ITP would be taking on considerable financial risk in administering a market for CRR options. With CRR options, while the ITP would receive payments for the sale of the options these options would only be called where they appear to have value, and not where a liability is likely to be incurred. Thus, there would be no fundamental guarantee of revenue sufficiency. In light of this concern, CRR options may be best left to a secondary market, administered by private interests willing and able to bear the risks of such "congestion derivatives."

[7] The NOPR states, "to the extent the CRR holder opts not to schedule transmission service at those points, it would still receive the congestion revenues." SMD NOPR at ¶ 144, Footnote 90.

In addition to allowing market participants to hedge congestion costs, the Commission proposes that the possession of a CRR provide a scheduling priority. When demand for transmission at any price is greater than Available Transfer Capability (ATC), holders of receipt point-to-delivery point CRRs would receive priority over other market participants. The Commission asks if such a proposal would undermine the benefits of having one tariff.

Mid-Atlantic and Midwestern Consumer Advocates note that the Commission's proposal to provide a scheduling priority to those holding CRRs will transform CRRs from a financial hedging tool into a physical capacity right. We oppose the concept of making CRRs a physical right. We understand that the Commission in the SMD NOPR proposes to eliminate non-firm service and to use CRRs to distinguish between firm and non-firm rights for scheduling priority. In the Comments we submitted on November 15, 2002, we expressed concern over the Commission's proposal to eliminate non-firm service. We believe that non-firm service provides flexibility to transmission customers. In proposing to eliminate non-firm service, the Commission creates a problem regarding scheduling priority that need not exist. The Commission's proposed fix to that problem of converting CRRs into physical rights, however, creates even greater problems and causes confusion. As we noted in the earlier round of Comments, it may not be possible to obtain the CRRs on specific paths, thus exposing customers to not only a loss of the ability to hedge against congestion costs, but also a loss under the Commission's proposal here of scheduling priority when in fact firm service is required. Rather than convert CRRs into physical rights, the Commission should revisit the proposal to eliminate non-firm service.

The NOPR addresses possible methodologies regarding CRR funding. CRRs will be subject to a simultaneous feasibility test, so the ITP would collect sufficient revenues to fund all CRRs under normal operating conditions. However, the Commission notes that given a transmission outage, the ITP could collect less revenue than adequate to fund all CRRs. The Commission suggests the following two methodologies to deal with CRR revenue shortfalls, and requests comments on these methodologies:

- Proportionally reduce revenues paid to all CRR holders based on their target allocation.[8]
- Assign the revenue shortfall to the transmission owner whose facilities are out of service, with an exception for force majeure. Under this methodology, revenue surpluses could also be assigned to transmission owners to encourage them to minimize outages.

Mid-Atlantic and Midwestern Consumer Advocates believe that assigning revenue shortfalls and surpluses to transmission owners would be problematic for several reasons.

- For such a system to be equitable, the ITP would have to establish a direct/cause effect link between a particular transmission outage and CRR revenue shortfall. Given outages of multiple transmission owners, an ITP may find it difficult to establish this direct cause/effect link. Revenue shortfall could also be a result of loop flow[9], for instance, requiring the ITP to ascertain how much of the revenue shortfall is in fact a result of the outage and how much is a result of loop flow.
- Even if a direct causal relationship were established, penalizing or rewarding a transmission owner for outages may skew incentives. For example, a for-profit ITP may be in a position to influence the components and assumptions that determine "normal system operating conditions" in such a manner as to collect and award itself congestion revenue surpluses.

[8] A CRR's target allocation is the amount of revenues the CRR holder would receive if total system CRR revenues were adequate.

[9] Because electricity moves along the path of least resistance and may therefore flow on all available paths from the generator to the points of use, a region's transmission system may become congested due to electricity originating and terminating in another region. This is referred to as loop flow, or parallel path flow. The LMPs of the region that is affected by these flows will reflect this additional congestion, but the region has no mechanism by which to receive congestion payments from the users of these electricity flows. The region may therefore not be revenue adequate to fund all CRRs.

- Finally, making transmission owners liable for congestion revenue shortfalls due to outages introduces an additional operating risk to be borne by transmission owners. In the case of an unplanned outage on the transmission system of a merchant provider, this would effectively be a liability above and beyond any which the provider would contractually incur directly with its customers. The additional risk in such a system would likely result in the provider seeking an increased return on equity and this could increase transmission prices. This system will have impacts on merchant generators that are similar to unplanned outages in that the generators would be held liable for outage-related costs borne by all market participants due to increases in LMPs. We believe that this increased financial risk will discourage project commitments by merchant transmission developers.

Mid-Atlantic and Midwestern Consumer Advocates submit that a more efficient methodology to assign a revenue shortfall would be to proportionately reduce revenues paid to all CRR holders based on their target allocation. In turn, when a revenue surplus arises, funds could be distributed by first making up for past shortfalls based on each entity's target allocation. For example, in PJM, under the current tariff, if additional funds remained at the end of the calendar year, these funds are distributed based on demand for network integration customers and reserved capacity for point to point customers.

4. Auction vs. Allocation

The Commission proposed to allocate CRRs through an auction process. Mid-Atlantic and Midwestern Consumer Advocates are concerned that an auction may not be the best way to allocate CRRs. The Commission's stated reason for an auction is that it allows those who value transmission most to purchase the asset (rights to the revenues associated with congestion). However, the revenues are allocated back to those who pay the access charge; that is, those who use transmission to serve retail customers. If the auction is economically efficient, over the long run, the expected value of the auction revenues must equal the expected value of the congestion costs, thus leaving the buyers of CRRs fully hedged and those who pay the access charge indifferent. However, there will be times when the revenues collected through the auction are not equal to the actual congestion costs incurred. In those instances, the congestion costs incurred will exceed the auction revenues allocated. In contrast, an allocation scheme by design leaves the holders of CRRs fully hedged and those who pay the access charge indifferent to the level of congestion costs. It would appear that, at best, an auction has the same expected value outcome as an allocation scheme, but with a higher variance. This greater variance would most likely manifest itself through higher finance costs.

5. CRRs And The Transition To A Single Transmission Tariff

The Commission requests comments on whether the allocation of CRRs to LSEs should be based on historical usage only or, if instead, the allocation should take into account future load growth. While we believe that future load growth could be taken into account for the allocation of CRRs, it is important to remember that CRRs are financial rights and, as such, overestimating load growth would be advantageous to LSEs. Therefore, we recommend that load growth forecasts should be reviewed or undertaken by the ITP or another third party rather than the LSE or interested party. Then, if the forecasted load growth does not materialize, a mechanism should be in place to true-up any differences in CRR allocations. Alternatively, allocation of CRRs could be based on historical load with frequent true-ups to reflect realized load growth.

CRRs can be transferred to customers through either a direct assignment of CRRs, or a CRR auction with assignment of auction revenues. Although the Commission establishes a preference for an auction after a transition period, it will allow regional flexibility during an initial transition period of 4 years.

We emphasize that the method chosen should preserve the historical rights of Network Integration customers under the OATT. We note that a CRR auction does carry risks not associated with a direct allocation of CRRs, such as:

- Risk of exposing load to congestion costs – An auction would allow existing firm customers the flexibility of either exercising their claim on transmission rights, or in lieu of this, receiving revenues from the sale of these rights. Such a system allows the entity that values the CRR the most to purchase it. There is, however, no intrinsic guarantee that the revenues received from the auction and allocated to those who pay the access charge would be sufficient to cover actual congestion costs.

  While an auction would provide LSEs a share of auction revenues, the LSEs that do not obtain CRRs are potentially exposed to congestion costs.[10]
- Possible barrier to entry to smaller LSEs – In order to submit a bid for a CRR, a LSE must effectively conduct a valuation of that CRR. A valuation involves forecasting congestion costs for a specific receipt point and delivery point pair. The LSE would have to bear the costs to complete such a valuation and submit bids, increasing the cost of doing business. With a direct allocation, such costs would not be incurred.
- Increased financial risk to default service provider – Bidding for CRRs in an auction entails financial risks and potential financial rewards. Regulatory standards might have to be

[10] We envision a situation as follows: A transmission customer exports power from Region A to Region B. The customer decides to request non-firm service, as the magnitude of congestion costs are such that it is willing to bear the risk of congestion. As time passes, many more entities are involved in export transactions from A to B. Congestion costs between receipt and delivery points from A to B increase. The customer now decides that it is indeed worthwhile to purchase CRRs, and bids for such in a CRR auction. Its bid cannot be accepted because the requested path makes an existing CRR infeasible. The LSE does not receive this requested CRR. It may now be exposed to higher than historical congestion costs, but its share of auction revenues may not be adequate to cover these increased congestion costs.

developed to examine the prudence of the default service provider's CRR auction decisions.

Due to these concerns, Mid-Atlantic and Midwestern Consumer Advocates recommend exploring a direct allocation methodology which is flexible enough to facilitate transmission right purchases by new market entrants. For example, PJM's FTR rules state that a participant's total FTR amount to a transmission zone may not exceed that participant's total network load in that zone. An LSE that has lost load to a new entrant may not have to give up CRRs equivalent to the lost load. Under SMD, the Commission proposes that these CRRs could be assigned directly to the new entrant. Mid-Atlantic and Midwestern Consumer Advocates support the concept that CRRs should follow load. Additionally, when load shifting occurs, incumbent market participants may have to alter their receipt point-to-delivery point CRRs to reflect these load shifts. Allowing CRRs to be reconfigured, as the SMD pro forma tariff does, should address this need.

The Commission proposes to allow a four-year transition period in which regions may choose whether to allocate CRRs through a direct allocation or auction process. We note at the outset that we oppose auctioning of CRRs. This issue is addressed in greater detail in subsections 4 and 5 above. However, if the Commission does pursue an auction approach, we believe that a CRR auction should not be implemented immediately in a region that is implementing an LMP regime for the first time. Market participants would be in a much better position to bid for CRRs if they were able to refer to historical LMPs as a guide in valuing those CRRs. Implementing an LMP regime, and shortly thereafter a CRR auction, does not afford market participants sufficient information to accurately value CRRs.

6. CRR Reconfiguration

The Commission suggests a holder of a CRR under SMD could request a "reconfiguration"[11] of the CRR, *i.e.* the holder could turn in its current CRR to the ITP and request a CRR with a new receipt and/or delivery point. Mid-Atlantic and Midwestern Consumer Advocates believe that a market participant should be able to reconfigure an existing CRR outside an auction process. There are two primary reasons for which a market participant would need to do so:

- A change in the generator(s) used to serve load, either contractually or physically, requiring a reconfiguration of the CRR receipt point.
- Load shifting due to retail competition, requiring a reconfiguration of the CRR delivery point.

Furthermore, we believe that requests for reconfiguration due to these reasons should be honored by the ITP, subject to simultaneous feasibility. A market participant who turns in to the ITP a particular CRR in order to reconfigure it may cause another existing CRR, held by another entity, to violate the simultaneous feasibility criteria. Thus, any such reconfiguration would have to be predicated on the condition that it does not adversely affect any existing CRRs held by another entity.

On the other hand, allowing an entity to "trade in" a CRR it currently owns for another existing, unsold CRR may be problematic when such a trade-in is not necessitated by a change in generator or a load shift. If CRRs were to be allocated via an auction, and at the time of the auction the expected value of congestion for a particular source and sink pair is zero, it is likely that the corresponding CRR will remain unsold. However, it is possible that during the term of the CRR, an unexpected occurrence – an unplanned

[11] We refer here to reconfiguration of CRRs outside any auction process. For example, PJM holds an FTR auction in which market participants can offer for sale any CRRs that they currently hold. However, the CRRs purchased by buyers can be different from those that are offered by sellers, subject to simultaneous feasibility. We are not referring to such reconfiguration here, but instead to a stand-alone request by a market participant directly to the ITP for a reconfiguration.

generation or transmission outage, for instance – causes the value of that CRR to rise. Market participants who realize this would then have an incentive to trade in a currently held less valuable CRRs for this un-allocated CRR. This creates a situation in which market participants who are privy to the knowledge of this outage have an unfair opportunity to profit from such knowledge.

Mid-Atlantic and Midwestern Consumer Advocates therefore suggest that an ITP grant reconfiguration only upon verification of either of the two criteria listed above, subject to simultaneous feasibility. We note that participants wanting to reconfigure CRRs for reasons other than those cited above can avail themselves of the secondary market to sell their current CRRs and purchase new ones.

7. Long Term CRRs

The Commission asks for comments on whether multi-year CRRs should be offered when SMD is first implemented. The Commission notes that multi-year CRRs would allow entities with long term power contracts to hedge congestion for the term of contract. However, they are concerned that because congestion patterns change over time, there may be difficulties in market valuation of such a CRR.

Mid-Atlantic and Midwestern Consumer Advocates believe that market valuation issues for long term CRRs at the onset of SMD may be significant. If CRRs are allocated via an auction, changing the value of CRRs after the auction may lead to load being exposed to congestion in future years. If CRRs are directly allocated to market participants, the valuation problem is avoided. At a minimum, multi-year CRRs should not be implemented until congestion patterns appear to be stable.

III. REGIONAL PLANNING PROCESS (¶ 198-200, 335-350)

The Mid-Atlantic and Midwestern Consumer Advocates believe the integration of regional planning requirements in the SMD NOPR is essential. Each ITP should be required to have a planning process that produces, on a regular basis, an analysis of the system that identifies system upgrades that are needed to maintain the reliable operation of the system and upgrades that would bring economic benefits to consumers. SMD NOPR at ¶ 347. The planning process must also evaluate whether or not the needed upgrades, or some other measure, proposed to be undertaken on a merchant basis[12] would obviate the need for the identified upgrade. The ITP would then issue a request for proposal (RFP) to address the reliability and economic needs that were not being addressed on a merchant basis. SMD NOPR at ¶ 348. The RFP process would be open to all market participants and solicit all types of solutions. *Id*. This RFP process would be used by the ITP to direct the implementation of the most cost-effective solution to the identified problem. The ITP would also make a determination of which parts of the region benefit from the proposed solution to the problem and the costs would be collected through regulated transmission rates from the customers in those parts of the region. *Id.*

We agree with the statement in the NOPR that relying on only private investment for expansion of the transmission system may not provide adequate or efficient expansion of the system. For example, private parties may not be eligible to utilize the state process of eminent domain. Additionally, needed and beneficial expansion that does not produce sufficient compensation as a totally private investment may not be pursued. SMD NOPR at ¶ 346. The final rule should be unequivocal that ITPs must do regional planning and that ITPs will have the necessary authority to direct that system enhancements be implemented by transmission owners.

[12] The phrase "merchant basis" refers to the development of a project that will not be paid for by regulated rates.

The manner in which small customers will be receiving service in many restructured states is another reason to implement regional planning by the ITP. Generally, small customers in restructured states have been served by their utilities under capped rates during a transition period. As these transition periods end, the vast majority of small customers will still be served by their utilities under these transition arrangements. It is critical for these customers that the Commission mandate that ITPs implement a planning process that will identify and address economic enhancement of the system. As a result of retail restructuring, no party in the wholesale market has any assurance that it will be the load serving entity for the vast majority of small customers for more than the very near future. As such, there is diminished incentive to make a large investment to relieve congestion faced by those customers unless that investment can be implemented almost immediately and provide enough savings to pay back the investment in a very short period of time. It is impossible to say with certainty that this market structure will produce the necessary system enhancements to provide just and reasonable prices.

A combination of new generation and additional transmission has always been used to serve load growth and new load. For the states that have restructured their electricity market, there is no longer a central planning process that identifies need for new generation, the best type of plant to fill the need, or the best location for that plant. Those functions are now provided by the market. We have seen merchant generation plant development based on the ability of developers to sell the output of their plants at market based rates.

There is, however, little experience with the development of transmission infrastructure through signals provided by market-based rates.[13] There is no clear product that a new integrated transmission

[13] There have been a few direct current (DC) transmission lines undertaken on a merchant basis. Such projects can be beneficial but cannot be expected to entirely satisfy the need for system expansion.

developer can own or sell and, therefore, it is not reasonable to expect that merchant transmission will solve more than a few of the expansion needs of the system.[14]

The interaction of the CRR market and the energy markets is extremely complicated making the prospects for widespread merchant transmission difficult to gauge. Congestion on the system results in high prices for generation owners and transmission remains a monopoly function. It remains true that many of the generation owners are also transmission owners. This adds a further complication to the development of a competitive market in this area. The Commission should approach the development of the merchant transmission market cautiously and demand the demonstration of a rational market system with proven results before abandoning regional planning. Therefore, the Commission was correct in the SMD NOPR to recognize that there continues to be a strong need for system planning to address the economics of the system and to ensure the implementation of solutions that benefit consumers.

We are not opposed to transmission projects and other system upgrades being completed as a private investment, also referred to as a merchant basis. The ITP planning process should have two components: 1) analysis of the impacts of proposed merchant projects and 2) system analysis to identify needed reliability and economic upgrades. Transmission and demand response projects, just like generation projects, should go through the ITP planning process.

[14] Some parties have made proposals where the central form of compensation for merchant transmission projects is the awarding of incremental fixed transmission rights (or congestion revenue rights (CRRs)) that result from adding the new equipment. The economic benefit to consumers from adding new transmission is the relief of congestion or, in other words, less price differential between low cost points on the system and high cost points on the system. CRRs get their value from the price differential between two points on the system. New transmission that relieves congestion results in less price differential and, therefore, the CRRs associated with those upgrades lose value. So, the more congestion that is relieved, the less valuable the developer's compensation. This provides a reverse price signal. More congestion relief should result in more compensation for the developer, not less. Market compensation based on CRRs gives the developer an incentive to stop short of fully relieving the congestion, even if the incremental cost to do so is minimal and, thus, it is economically efficient to do so.

While supportive of the NOPR in this regard, Mid-Atlantic and Midwestern Consumer Advocates offer several suggested clarifications. To date, the experience of RTOs in implementing a full planning process that identifies and directs the implementation of system upgrades for reliability and economic reasons has shown that there is a great deal of opposition to any entity carrying out a planning function. As a result, RTOs have not been fully successful in implementing a process that addresses both economic as well as reliability concerns. Mid-Atlantic and Midwestern Consumer Advocates suggest several clarifications in order to ensure that a full regional planning process that accommodates economic expansion is implemented.

The Commission should reject any attempts to prevent or delay such a process. The Commission called for RTOs to take on the responsibility of system planning and expansion in Order 2000.[15] The Commission directed PJM to establish a planning process that addresses needed system enhancements for economic reasons in its Order of July 12, 2001 in Docket No. RT01-2.[16] PJM has instituted stakeholder discussions on this topic, but PJM has not yet filed any proposal with the Commission that would address this inadequacy in the PJM planning process. The clarifications suggested below are made in order to reduce the effectiveness of attempts to prevent or delay a full regional planning process from being implemented by those who are currently able to take advantage of the economic inefficiency caused by the inadequacies of the transmission system.

A. The ITP Must Have The Explicit Authority To Direct Transmission Expansion For Reliability And Economics

It is crucial that the ITP have the authority to direct the expansion of the transmission system when, after analysis, it determines such expansion is necessary for the reliable operation of the system or would

[15] FERC Regulations Preambles, Para. 31,089 at p. 31,163.

[16] 96 FERC 61,061, *slip op.*, p. 30.

be economically beneficial to consumers and no privately funded project will provide the needed relief. The SMD NOPR gives this authority to ITPs. SMD NOPR at ¶ 348. However, the NOPR contains conflicting language that could be used by those looking to delay or prevent a planning process from being implemented. The Commission should clarify in the final rule that the ITP will have the authority and the obligation to direct that system upgrades be implemented to maintain reliable operation of the system and for the economic benefit of consumers based on an integrated system planning process.

The SMD NOPR proposes a planning process to "identify all expansion needs on the system, including both reliability and economic needs (*e.g.*, to reduce congestion). It is proposed that the planning process leave open the question of how and by whom those needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another." SMD NOPR at ¶ 347. This statement is sufficient to describe the very early stages of the planning process. But, in the absence of a strong and unequivocal statement that the ITP has the authority and obligation to direct an expansion of the transmission system for economic needs, this language could be used to cast doubt on whether the Commission intends for the ITP to have the authority to direct upgrades for reliability and economic reasons.

The ITP must have the backstop responsibility for completing necessary projects if solutions are not forthcoming from the market. The SMD NOPR requires a review of the costs and benefits of the expansion proposals in paragraph 346. If the ITP finds that the upgrade would be in the public interest based on the cost/benefit analysis, then it would have the authority and obligation to direct that such upgrades be implemented.

The Commission must not leave any doubt about its desire that the planning process go to completion. That will require that the ITP direct necessary expansions for both reliability and economics.

Otherwise, parties that may benefit from high congestion prices will have a lever to use to frustrate the process of developing and implementing a regional planning process. Therefore, the Commission should clarify in the final rule that the planning process must be designed to lead to a decision by the ITP on how and by whom an upgrade need will be met and direct that a solution be implemented if the need is not being met by a merchant project.

B. The Planning Process Should Incorporate Merchant Projects But Not Allow Harm To Consumers By Delaying The Process While Seeking A Merchant Solution.

Consumers are suffering ongoing harm from the high prices that result from congestion. Congestion results from inadequacy in the transmission system. This reflects the state of the system when deregulation occurred, but may also be the result of economic decisions by market participants. The regional planning process should move toward a solution to these problems without delay. Any delay in the process would only continue the unreasonable harm to consumers.

The final rule should require that the ITP planning process have a set schedule for establishing the inputs for its analysis, performing the analysis, reviewing the analysis with the public, and rendering decisions based on the analysis. The analysis and review should incorporate all merchant development proposals and decisions would be made accordingly. The process should lead to a final determination and implementation of needed solutions. The process should not create undue delay in order to provide opportunity to merchant development at the expense of consumers.

The SMD NOPR states that the planning process is "intended to supplement … private investment decisions." SMD NOPR at ¶ 346. Mid-Atlantic and Midwestern Consumer Advocates disagree that the planning process is supplemental. The planning process will be potentially incomplete and inefficient unless all projects are integrated under one process. The planning process should ensure that consumers receive benefits, and that improvements in market efficiency are achieved. Delaying or weakening the process only frustrates that purpose.

C. Each ITP Should Have A Regional Planning Process

The SMD NOPR states that a "planning area need not coincide with the geographic area of a Commission-approved RTO or independent transmission provider required by this rule." SMD NOPR at ¶ 340. There needs to be an entity that has the explicit obligation to implement a planning process and the explicit authority to direct expansion of the system. The Commission's statement that a planning area need not coincide with the geographic area of an ITP could result in resistance to an ITP's effort to implement a regional planning process. This could also result in an ITP itself ignoring its obligation to implement such a process. The Commission should encourage information exchange between ITPs beyond a broad area and the coordination of the planning processes of multiple ITPs as appropriate. However, the Commission should be explicit that each ITP has an obligation to institute a planning process of its own.

The SMD NOPR also states that the area covered by PJM, MISO and SPP be a "regional planning area." The implementation of the planning process that addresses expansion for economic needs is complicated and unprecedented. A single process encompassing this large region invites administrative and political difficulties that may unreasonably delay the process. Again, each ITP should have its own regional planning process and produce its own expansion plans. The ITPs should be encouraged to exchange information and coordinate between other regions within their own planning processes. Expansion of this process for super-regional basis should take place only after the anticipated regional process is thoroughly tested.

D. Existing RTOs Should Implement A Planning Process Immediately

The SMD NOPR calls for implementation of a regional planning process that addresses system expansion for both reliability and economic reasons. SMD NOPR at ¶ 345. The NOPR proposes that the process start within 6 months after the effective date of the final rule and that the first regional transmission plan be completed within 12 months after the effective date of the final rule. SMD NOPR at ¶ 345. Mid-Atlantic and Midwestern Consumer Advocates believe that existing RTOs should be ordered to implement this requirement immediately. This is necessary so that existing congestion can be relieved through economic expansion of the transmission system. The existing RTO, and ISOs have planning processes which are being implemented or are at an advanced state of development. Thus, a six month delay is unnecessary and is unfair to consumers. Existing RTOs should immediately submit a planning process to address economic expansion of the system.

E. Merchant Transmission Companies Should Be Paid A Set Amount For Building A Reliability Upgrade

The SMD NOPR states that the planning process should first "identify all expansion needs on the system, including both reliability and economic needs (*e.g.*, to reduce congestion)." SMD NOPR at ¶ 347. The NOPR states that "the planning process should be open to all industry segments." The NOPR goes on to state that "all parties could propose projects." Mid-Atlantic and Midwestern Consumer Advocates support these statements. We urge that the Commission be explicit that reliability upgrades need not be built on a merchant basis. The system long in place in PJM, where transmission owning utilities have the responsibility for reliability upgrades has worked well. Transmission owners that build reliability upgrades should not be additionally compensated by being awarded a collection of financial rights that result from that transmission upgrade. These benefits should only apply to lines which are constructed on a merchant basis.

F. The Planning Process Should Attempt To Identify The Beneficiaries Of An Economic System Expansion And Assign The Costs To Those Beneficiaries

In the transmission pricing section of the NOPR, the Commission proposes a "matching of beneficiaries and cost recovery responsibility…" SMD NOPR at ¶ 197. The Commission states that "our preference is to allow recovery of the cost of expansion through participant funding, i.e., those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion)." SMD NOPR at ¶ 197. The Commission goes on to propose that "participant funding may be an acceptable pricing policy wherein an independent entity determines: (1) the cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with congestion revenue rights); and (3) the assumptions underlying the power flow analysis." SMD NOPR at ¶ 198.

Mid-Atlantic and Midwestern Consumer Advocates support this pricing methodology. The Commission should clarify that in the case of a regional planning process in which the ITP directs that there be a system expansion for economic reasons, the principle of "participant funding" means that the ITP would identify the beneficiaries of that economic expansion and the cost of the expansion will be allocated to those customers through regulated transmission rights. It should be recognized, however, that many, if not most transmission projects, provide benefits to the system as a whole and costs should be allocated accordingly.

G. Cost Allocation Should Be Applied By The ITP On A Case-By-Case Basis

The SMD contains a default cost allocation for new transmission investment. SMD NOPR at ¶ 200. There is a preface to this proposal that it is to be used "[i]n the absence of independence." *Id.* The NOPR contemplates very large planning areas. It is difficult to establish a single rule for cost allocation that works for the myriad of situations that can arise in a single planning area. The final rule should establish the principle that the beneficiaries of the system enhancement should pay the cost for that enhancement and direct the ITP to make a case-by-case determination of the areas that benefit for each new project. Once ITPs are operational, they should not rely on a default pricing principle. Therefore, the Commission should clarify that the default mechanism is only applicable as a temporary measure until the ITP, which is required to be independent, is operational.

IV. LONG TERM RESOURCE ADEQUACY (¶ 457-550)

A. Introduction

The continued reliability of the electric supply must be the bedrock upon which SMD rests. The Mid-Atlantic and Midwestern Consumer Advocates support the Commission's proposal to mandate that each ITP adopt a long term resource adequacy mechanism that will ensure adequate electric supply for its region. The Mid-Atlantic and Midwestern Consumer Advocates commend the Commission for recognizing resource adequacy as an essential component of Standard Market Design. The Mid-Atlantic and Midwestern Consumer Advocates are concerned, however, that the Commission's proposed approach to ensuring long term resource adequacy is inconsistent with the commercial needs of states that allow retail choice, and that it may not best serve the interests of those states that retain fully bundled and regulated retail service.

Mid-Atlantic and Midwestern Consumer Advocates's comments first outline the principles of a well-designed resource adequacy mechanism. We then discuss the elements of the SMD proposal that either satisfy these design requirements or are incompatible with these principles. Finally, we will propose an alternative to the SMD NOPR adequacy requirement, and discuss how the alternative model better meets the design requirements.

The Mid-Atlantic and Midwestern Consumer Advocates emphasize that the following comments reflect an approach to resource adequacy that would function optimally in the regions we represent. To the extent that our counter-proposal is not optimally suited to a specific region's needs, we would encourage the Commission to make appropriate modifications.

We recognize the deficiencies of the existing ICAP mechanisms in PJM, ISO-NE, and NYISO. The Commission should not confuse a capacity market-based approach to long term resource adequacy with the defective ICAP markets currently used in the Northeast. Mid-Atlantic and Midwestern Consumer Advocates submit that a properly designed capacity market can effectively promote long term resource adequacy, protect against the exercise of market power, and produce reasonable prices. The model we propose in these comments is designed to achieve these goals.

B. Principles Of A Well Designed Resource Adequacy Mechanism

A properly designed long term resource adequacy mechanism must recognize and address the prevailing conditions of the market. Given the current sate of electricity markets discussed above, we believe that a long term adequacy mechanism must be founded on the following principles.

1. Provide Reasonable Assurance To Consumers That There Will Be Sufficient Generation Resources To Protect Reliability

Financial forward and options markets for electricity are poorly developed. As a result, energy prices alone provide insufficient information to merchant developers regarding the best options, in technology and sitings, for infrastructure investments. Moreover, in the case of market failure, where a resource need is recognized through the RTO planning process but no merchant solution has emerged, a process must be in place to ensure needed resources are constructed in a timely manner.

The long term adequacy mechanism must provide each market with a measurable degree of assurance against retail customer load shedding. To do this, a proper long term adequacy mechanism must ensure that sufficient capacity is installed and committed to the RTO/ITP.

2. Effectively Mitigate Market Power

At present, most, if not all, of the power markets in the U.S. are characterized by concentrated ownership of generation and limited demand-side participation in energy and capacity markets. For example, according to the PJM Market Monitor's *State of the Market Report 2001*, concentrations in the daily and monthly ICAP markets, as measured by the Herfindahl-Hirschman Index, averaged 2,700 and 3,800 respectively with maximum values of 5,500 to 10,000 respectively. This indicates moderately high concentration to near perfect market power. The degree of supply concentration often leads to a situation where suppliers have fairly complete information regarding the aggregate market demand. Although bilateral contracts can, in theory, help mitigate the impact of that knowledge, suppliers are still able to exercise market power by strategically withholding capacity. In addition, demand side participation in either the energy markets or capacity markets is limited, so supply and demand interactions cannot effectively mitigate market power. The structure of the long term adequacy mechanism must take into account the potential of a highly concentrated supply to exercise its market power and consequently incorporate features that mitigate that market power.[17]

3. Produce Reasonable Prices

The long term adequacy mechanism should produce prices that reflect the value of capacity to a region. When a region requires additional capacity, prices should be a function of the resource's annual fixed carrying charges less revenues from the energy and ancillary services markets. Similarly, existing generation should have the opportunity to earn revenues from the capacity market equal to the going forward fixed costs of the resource less all other net revenues. The long term

[17] Even with the adoption of a design that mitigates market power, there needs to be continued monitoring and mitigation of anticompetitive behavior in capacity markets.

adequacy mechanism should not serve as a source of revenues to subsidize the costs of otherwise uneconomic resources.

4. Not Unnecessarily Limit The Portfolio Choices Of Buyers And Sellers

Buyers and sellers should be free to acquire the mix of contracts, owned resources or spot market purchases that best meets their commercial needs. The structure of the long term adequacy mechanism should not impose obligations or conditions on either supply or demand resources that are not absolutely necessary to ensure that the RTO will have reasonable assurance of adequate capacity.

5. Allow All Resources (Generation, Demand, Transmission) To Participate

Allowing demand side resources to actively participate in the energy and capacity markets is critical to the development of a robust and liquid power market. In addition, demand participation can serve to mitigate seller market power. Just as the Commission has recognized the need for the development of active demand resource participation in energy markets in order to promote truly competitive energy markets, so should the Commission recognize the need for, and actively promote demand resources participation in capacity markets in order to move toward greater competition in capacity markets. Thus, it is critical that the long term resource adequacy mechanism adopted in this proceeding enhance, or at a minimum, not impede, existing levels of demand participation in capacity markets.

6. Accommodate Both Bundled Native Load And Retail Choice Programs.

State regulatory oversight of the sale of electricity to retail consumers is not uniform across the nation. While many states continue to tightly regulate the adequacy of generation in their jurisdiction as well as the price at which electricity is supplied to retail consumers, others such as many of the states in the region encompassed by Mid-Atlantic and Midwestern Consumer Advocates, have allowed some level of competition in the pricing and supply of electricity to retail consumers. There is not even substantial uniformity as to how retail choice programs work among individual states allowing retail choice. Consequently, a well designed long term resource adequacy mechanism must accommodate the varying needs of retail consumers in both bundled native load states and in retail choice states. Such a mechanism should not impose impediments or barriers to Load Serving Entities that raise the cost to comply with resource adequacy requirements so high as to effectively eliminate their ability to continue to actively participate in retail choice programs. `

C. The Commission Should Require A Mechanism To Ensure Resource Adequacy In Standard Market Design

Mid-Atlantic and Midwestern Consumer Advocates commend the Commission for including a resource adequacy requirement in its standard market design initiative. As we stated above, we agree with the Commission that spot market prices do not consistently signal the need for new infrastructure in the electric power industry. SMD NOPR at ¶ 461[18].

Our offices further agree with the Commission where it states: "Resource adequacy today must be assessed at the regional level. Because all customers in an interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region." SMD NOPR at ¶ 458. We agree with the Commission that without a uniform resource adequacy requirement, load-serving entities will plan for varying amounts of reserves. SMD NOPR at ¶ 469-473. Under such a scenario, parties are able to "lean" on the system and obtain a level of adequacy that they

[18] In paragraph 461, the Commission asserts that "spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs." Mid-Atlantic and Midwestern Consumer Advocates note that, while this statement may be true, it is incomplete. Mitigation measures generally allow for revenues that far exceed profitable levels. Moreover, such mitigation measures are designed to provide appropriate levels of energy revenues in a market that also provides capacity revenues. The Commission points to no evidence of mitigation measures stifling expansion of generation and transmission resources. Some regions of the country which are subject to markets that incorporate mitigation measures in their tariffs have actually experienced over-development of generation resources.

did not help create. As stated in the NOPR, "the current physical configuration of the transmission grid often exacerbates [the free ridership] problem because it is often difficult to impose the results of one party's shortfall solely on that party." SMD NOPR at ¶ 472.

Given the state of the industry, the interconnected nature of the grid, and the vital importance of a reliable electric supply, a resource adequacy requirement is essential to the Commission's efforts to standardize markets. We support several principles addressed in the NOPR regarding resource adequacy. However, we have concerns regarding the specific mechanisms proposed in the NOPR.

1. Basic Features Of The Resource Adequacy Requirement (¶ 474-508)

a. The Demand Forecast And Level Of Reserves Should Be Determined By The ITP/RTO (¶ 485-493)

In the NOPR, the Commission seeks to require that the Independent Transmission Provider perform an annual demand forecast for its region. SMD NOPR at ¶ 485. The Mid-Atlantic and Midwestern Consumer Advocates fully support this requirement. PJM and other regional ISO's have performed demand forecasts of this nature in the past and it should be feasible for newly created ITPs to do so as well.

The Commission proposes that the resource adequacy level for a region should be set by the Regional State Advisory Committee. SMD NOPR at ¶ 490. Our offices do not agree that the RSACs should be required to take this responsibility in every region of the country. In PJM, for example, the state commissions have relied on the regional expertise of the ISO to identify the reserve level necessary to achieve reliable and adequate service. Where the responsibility for setting the reserve requirement rests with an ISO/RTO, or where that responsibility is determined to more appropriately be conducted by the ISO/RTO, states should not be required to take back that responsibility.

As noted below in our counter-proposal, we believe that an arbitrary administratively determined 12% capacity reserve margin could result in inadequate reserve margin requirements in some regions. SMD NOPR at ¶ 493. Instead, the Commission should allow the ITP/RTO to set the capacity reserve percentage based on a reliability standard deemed appropriate for the region. In the PJM/MISO region, that percentage should be set in order to achieve the standard of one day in ten years loss of load probability ("LOLP"). One size does not fit all in this situation, and the Commission should not set a percentage figure as a minimum baseline. Instead, each ITP should establish an appropriate reserve level which should be approved by the Commission and/or by any appropriate state authorities.

b. Load-serving Entities (¶ 494-496)

Mid-Atlantic and Midwestern Consumer Advocates agree with the Commission that LSEs must support regional resource adequacy through the acquisition of a combination of resources. SMD NOPR at ¶ 494. The Commission states that for LSEs other than large retail industrial or commercial customers, "their reserves *may* include the ability to reduce their own demand on the grid." SMD NOPR at ¶ 495 (emphasis added). Consumer Advocates are concerned that the use of the word "may" in the SMD NOPR might be interpreted to mean that ITPs, RTO or ISOs can decide whether or not to allow the use of demand resources as a means of meeting resource adequacy requirements. We submit that the Commission should require that all ITPs, RTO and ISOs facilitate the development and the use of demand resources to ensure that LSEs are allowed to include demand reduction potential in their reserve portfolio. Only active facilitation of demand resources will ensure that demand is able to play an active role in ensuring long term resource adequacy.

c. Load-serving Entity's Share Of The Regional Resource Requirement (¶ 497-503)

We agree with the Commission that the regional demand forecast should be forward looking and that an LSE's capacity requirements should be determined based on its most recently documented load ratio share. The method of allocating reserve requirements to meet that regional demand forecast should be based on the best available load data at the time the allocation is made. This method is more accurate and less subject to manipulation than one in which LSE future loads are projected. SMD NOPR at ¶ 499. This is particularly true in regions with retail choice states, such as in the PJM region, where LSEs often do not know from month to month, never mind from year to year, the level of their future load.

The Commission seeks comment on how much time should pass between when the forecast is made and when the LSE must meet its obligation. SMD NOPR at ¶ 502. Under our counter-proposal, the ITP/RTO would forecast the regional requirement for a 6 or 12 month period starting 12 to 18 months after the auction. At the time of the auction, all LSEs would be informed of their expected obligations given their current loads. This notification could be made up to three months in advance of the auction, allowing LSEs time to contract for capacity to satisfy their capacity obligation, if they so choose. Since the purpose of the auction is to secure adequate capacity commitments on a regional basis, individual LSE's obligations will not be determined until the settlement period. See section E below for a complete discussion of our long term adequacy counter-proposal.

d. Resources That Can Satisfy The Resource Needs (¶ 503-508)

The Mid-Atlantic and Midwestern Consumer Advocates support the Commission's assertion that self-supplied generation, distributed generation, and firm contracts that are tied to specific generators and are *recallable*, can be used to satisfy the capacity requirement. SMD NOPR at ¶ 504-505. It is imperative that all resources committed to provide capacity to a region be available to provide energy and count only towards one region's capacity resource requirement. In addition, we support the Commission's requirement that resources committed toward the reserve requirement be deliverable to the load it backs. As the Commission notes in the SMD NOPR, capacity will be of little use if the energy cannot actually be delivered to the load.

We support the Commission's inclusion of demand side response as a way to satisfy the adequacy requirement. However, we do not believe that the 3 to 5 year commitment period envisioned in the NOPR is practical or consistent with the commercial requirements of a demand response program. Demand response programs are just getting started and, given the limited information regarding their operation and performance, customers may be reluctant to participate in programs that require commitments that far in advance. The counter-proposal we describe below relies on a shorter, 18 month ahead commitment period of 6 months duration, thus better accommodating demand response programs. The 18 month planning horizon allows owners and operators of biddable resources greater certainty and thus greater ability to assess what programs they will be willing and able to participate in during future obligation periods. In addition, the counter-proposal we describe does not preclude the participation of demand-side resources.

2. Resource Standards (¶ 509-519)

The technical evaluation of the capabilities of the resources that will be used to meet a region's adequacy needs is critically important. In this regard, we agree with the Commission that the ITP, "must be satisfied that the generation is physically feasible; that is, the generating units are capable of generating the power planned, and enough transmission is available to deliver the power from the generating station to the particular load. The generating units under contract must be real and specific generators." SMD

NOPR at ¶ 511. The responsibility for verifying that generating units can perform as claimed and that their output is deliverable to loads in the region should fall on the *independent* ITP/RTO.

The Mid-Atlantic and Midwestern Consumer Advocates are opposed to the North American Energy Standards Board ("NAESB") being charged "... to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement..." SMD NOPR at ¶ 510. NAESB's stated purpose is to develop business practices. Resource adequacy is not a business practice. The job of verifying generation resources for long term adequacy purposes should rest with the independent ITP/RTO consistent with any relevant technical standards established by the North American Electric Reliability Council ("NERC"). The ITP or RTO is better able to resolve these issues for its region because it has broader regional stakeholder participation and an independent Board that it accountable to this Commission.

We agree that, in the interest of encouraging infrastructure development, resources which are not yet complete should be allowed to participate in the resource adequacy market. SMD NOPR at ¶ 512. Our counter-proposal allows a resource that satisfies ITP/RTO development milestones to participate in the proposed capacity auction. However, we disagree with the Commission's proposal that Commission-approved terms would provide a contract sufficient basis for qualifying generation under development as a capacity resource. SMD NOPR at ¶ 512. Experience in PJM, for example, demonstrates that only a percentage of generation in queues extending multiple years into the future will be built. The ITP/RTO is most familiar with the challenges of building generation in its region and should establish the proper standards for establishing when and under what conditions a facility under development qualifies as a capacity resource. The same should also apply to transmission resources not yet completed. SMD NOPR at ¶ 516.

The Commission requests comment on whether a contract for power from an unspecified source which includes liquidated damages should be included in the resource adequacy plan. SMD NOPR at ¶ 513. The Mid-Atlantic and Midwestern Consumer Advocates oppose such reliance on liquidated damages contracts. Liquidated damages do not provide adequate incentives to maintain reliability. They are a penalty and do not ensure the lights go on when the switch is turned on. Liquidated damages do not address the economic harm to consumers of failure to perform. For purposes of resource adequacy, only capacity from identified resource generation should be included. In addition, safeguards must be established to avoid double counting of claimed capacity resources among regions.

In order for a generation adequacy requirement to work, qualifying generation must be deliverable over the transmission system to the load in question. The Commission seeks comment on whether a load-serving entity should be allowed to meet the deliverability requirement simply by committing to pay congestion costs no matter how high the price. SMD NOPR at ¶ 514. We do not believe that this is appropriate. As the Commission identifies, this scenario could result in a total of commitments that exceeds the available capacity of a bottleneck interface. Under this scenario, the ultimate objective of a resource adequacy mechanism will not be achieved.

Mid-Atlantic and Midwestern Consumer Advocates agree with the Commission that the ITP/RTO must have confidence that demand response resources will be available during times of shortage. SMD NOPR at ¶ 517. Demand response should include biddable demand reduction, interruptible load, and other dependable load management programs, as stated in the NOPR. We agree that, as with generation resources, the ITP/RTO must be able to institute standards to provide assurance that demand response resources are available when needed.

3. Planning Horizon (¶ 520-525)

We agree with the Commission that the planning horizon should be a matter for regional choice. SMD NOPR at ¶ 523. We disagree, however, that the Regional State Advisory Committees should determine the planning horizon for the region. We firmly believe that a well composed, independent ITP/RTO, well versed in energy industry issues, should determine the planning horizon appropriate for its territory. In addition, we submit that the Commission has confused the concept of planning horizon with the concept of commitment period. The two concepts are different and could, and likely should, be different periods.

The Commission in the SMD NOPR proposes a planning horizon and a commitment period of three to five years ahead of the time period in which the resources will be needed. Mid-Atlantic and Midwestern Consumer Advocates do not necessarily oppose a three to five year planning horizon, *i.e.* forecasting demand three to five years ahead and assessing resource adequacy to meet that demand three to five years ahead. However, a commitment period that would require LSEs to have all resources lined up to meet those forecasted demands that far ahead causes substantial concerns. A long term commitment period that allows for the development and construction of baseload or peaking generation is not feasible in a retail access state, nor is it a necessary component of a resource adequacy requirement.

First, such a lengthy lead time may, as the Commission points out in the SMD NOPR, be inconsistent with the needs of competitive suppliers and inconsistent with the uncertainties they face in retail choice states. As the Commission states: "Load-serving entities in retail choice states would benefit from a shorter planning horizon because it would reduce their business risk associated with demand forecast error. Also, they may not want to enter into bilateral contracts for supplies for a time period that is longer than the duration of their contracts with their customers." SMD NOPR at ¶ 523. While the Commission uses the term "planning horizon", it clearly means "commitment period" as well since the NOPR relates LSE obligations to this period. Traditional planning horizons of utilities in the past have often trended out 10 to 20 years in the future. Such a lengthy planning horizon today would greatly outlast most retail contracts. Even the shorter three to five year planning and commitment horizon envisioned in the SMD NOPR suffers the same defect.

Second, lengthy commitment periods are not necessary to accomplish resource adequacy. The combination of price signals from the energy market and regional planning information published by the RTO should provide sufficient information and incentive for developers to build new base-load generation and to develop demand side programs under most circumstances. It is the peaking units that run only a short time during peak hours that may not recover all fixed costs in spot energy markets and that consequently may require the additional incentives provided by a resource adequacy requirement. The capacity market supplements the revenue stream to base load resources and provides primary revenues to resources built principally to ensure the reliability of the power system, that is, peaking resources. Moreover, irrespective of the resource type, the RTO requires a commitment period that is sufficiently long for it to have confidence that resources committed today will be available to the region tomorrow. Also, if inadequate resources are available, it must have sufficient time to secure additional resources on an emergency basis.

The Commission requests comment on the role the Regional State Advisory Committees should play in determining resource adequacy requirements and planning horizons. The Mid-Atlantic and Midwestern Consumer Advocates do not believe the RSACs should determine the reserve requirements or planning horizon for the PJM and Midwestern regions. SMD NOPR at ¶ 524. In the PJM region, this function is currently undertaken by PJM, with state commission input, on a regional basis. We support this method for PJM. Accordingly, we do not offer comment on how to resolve a lack of consensus within the RSAC regarding the appropriate planning horizon, or on whether the Commission should provide maximum and minimum lengths for planning horizons. SMD NOPR at ¶ 524. Each region should address these issues in a manner that best satisfies regional needs.

4. Enforcement (¶ 526-541)

The Commission proposes an enforcement mechanism that has two components. First, LSEs who do not meet their resource adequacy requirement would be required to pay a Commission-set tariff penalty for energy taken off the spot market. SMD NOPR at ¶ 527. Second, the Commission would require that spot market electric service of a load-serving entity that fails to meet its reserve requirement be curtailed first, should the ITP/RTO determine that curtailment is necessary. SMD NOPR at ¶ 527. Neither of these enforcement proposals will work, particularly in states with retail access.

Regarding the first proposal, the Mid-Atlantic and Midwestern Consumer Advocates are concerned that the administratively determined per-megawatt-hour penalty will simply become a cost of doing business if economic conditions warrant paying the penalty rather than acquiring necessary reserves. Adding the risk of substantial penalties exacerbates the risk of uncertainty faced by competitive LSEs in developing markets. These circumstances are avoided in our counter-proposal, as the per-megawatt cost of resource adequacy, in the form of a balancing price, will be known in advance. Those LSEs that do not acquire adequate reserves will simply pay the predetermined balancing price. This concept is similar to the Commission's approach to encourage balancing in the natural gas industry, in which it favors the use of market mechanisms in lieu of penalties to ensuring adequate service.

The Mid-Atlantic and Midwestern Consumer Advocates are also concerned that the penalty system proposed in the NOPR could be easily avoided. In the proposal, penalties are applied to the spot market purchases of an LSE that did not fulfill its resource adequacy obligation. If an LSE that did not fulfill its resource adequacy obligation acquires energy through a bilateral contract with a separate entity that is buying the energy off the spot market, there is no improvement in reliability (no resources were secured in advance for the LSE's load) and there is not possibility of a penalty for any party. This simple strategy would undermine the effectiveness of the resource adequacy proposal in the NOPR.

The Commission's proposal to physically curtail electricity that LSEs take off the spot market during times of shortage may also not be practical throughout the country. As has been stressed repeatedly by many stakeholders throughout this process, the Mid-Atlantic and Midwestern Consumer Advocates believe that the resource adequacy proposal's physical curtailment provisions will not work well in retail access states. Most LSEs, electric utilities and regions lack the technology and meters necessary to curtail service to one set of customers while retaining service for those living next door who are served by a compliant LSE. Additionally, as noted above, it would be very difficult to have a three year generation planning requirement on load serving entities that may not exist three years from now. In Pennsylvania, for example, competitive suppliers were serving over 8,000 megawatts of load (about one third of the total) in April 2000. Today, they are serving only about 2500 megawatts. The remainder have returned to the utility providers of last resort. Many of the LSEs that served load in 2000 have since exited the market. In our counter-proposal, discussed below, the problem of load changing among LSEs is resolved through the balancing mechanism.

5. Summary

The Mid-Atlantic and Midwestern Consumer Advocates agree with the Commission's proposals in the SMD NOPR with respect to the following major issues:

- spot market prices do not consistently signal the need for new infrastructure in the electric power industry;
- resource adequacy must be assessed at a regional level;
- the ITP should perform an annual demand forecast for its area and assess whether the collective resource plans of load-serving entities will adequately meet forecasted demand;
- the ITP should assign each LSE its share of the resource adequacy requirement based on its most recent load data;
- resources used to satisfy resource adequacy requirements should be tied to specific units and the energy from those units should be deliverable to the load backed by the units;
- self-supplied generation, distributed generation, demand side response, and firm contracts that are tied to specific generators and are recallable can be used to satisfy the capacity requirement.

The Mid-Atlantic and Midwestern Consumer Advocates would recommend that the Commission adopt the following modifications on several major issues:

- RSACs should not determine the level of resource adequacy for every region of the country;
- a 12% reserve requirement should not be adopted as a national minimum; instead a reserve requirement standard should be determined based on the needs of a region and should be done on the basis of a reliability criterion such as the one day in ten years LOLP standard;
- verification of generation resources for long term adequacy purposes should rest with the independent ITP consistent with NERC rules;
- the ITP, not the RSAC, should determine the planning horizon for its territory;

- the Commission's enforcement mechanism may prove unworkable, particularly in a retail access state, and should not be adopted.

For these reasons, the Mid-Atlantic and Midwestern Consumer Advocates offer a different proposal in Section E below.

D. A Centralized Procurement Auction Model Is Necessary To Ensure Resource Adequacy

Long term resource adequacy is a public good. The Commission recognizes this in the SMD NOPR where it discusses the "free rider" potential in justifying the need for a long term resource adequacy mechanism. SMD NOPR at ¶ 469 - 473. The Commission notes that without a resource adequacy requirement, in an environment where regional reserves are made available to all, LSEs can reduce their own reserves and rely on the resources of others, leading to systematic under-investment in the resources needed for reliability in the region. Yet, considering the importance of electricity in our economy and indeed in everyday life in our society, shortages and their attendant price hikes and blackouts are politically unacceptable. Furthermore, they threaten the health and safety of consumers and threaten the economic viability of business and industry. This combination of the nature of electricity as an essential product combined with the free rider potential in regional markets leads to the need for greater regulatory intervention in the capacity market. As the Commission itself notes in footnote 218 of the SMD NOPR:

> ". . . public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably."

SMD NOPR at ¶ 472, Footnote 218.

The question remains, however, as to how much regulatory intervention in the provision of capacity is necessary to protect consumers from unreasonably high prices or power shortages. Mid-Atlantic and

Midwestern Consumer Advocates have struggled with this issue, as have many market participants throughout this region and in the Northeast. A concept that has developed in a work group process undertaken by market participants in the PJM, New York ISO and ISO New England regions (referred to herein below as the "Northeast ISOs"), known previously as the Joint Capacity Adequacy Group ("JCAG"), and more recently as the Resource Adequacy Mechanism ("RAM"), is a centralized procurement mechanism for satisfying load obligations for long term reserves. Where the nation has found it necessary to provide for a public good in other contexts, for example the interstate highway system or national military defense, central procurement of the public good has proven a satisfactory means of resolving the free rider problem. The central procurement model for resource adequacy is intended to accomplish a similar result, but to maintain some market elements in the pricing of the public good.

Market participants from the Northeast ISOs, as well as spokespersons for the Northeast ISOs themselves, presented several proposals for Commission consideration at the Commission's November 19, 2002 Technical Conference on Long Term Resource Adequacy, that all share a similar overall construct, *i.e.* the centralized procurement model. The resource adequacy proposal submitted at that Technical Conference by the Pennsylvania Office of Consumer Advocate is one of those centralized procurement models. While all the models recommended by these northeastern market participants and stakeholders share a common centralized procurement auction foundation, the details as to how each of those models is to be implemented differ in significant ways that will have important market impacts for retail consumers and LSEs in terms of the price of long term resource adequacy and the ability of demand resources to actively participate in the centralized procurement auction.

Mid-Atlantic and Midwestern Consumer Advocates support the proposal submitted by the

Pennsylvania Office of Consumer Advocate at that Technical Conference as the model that best satisfies the principles of a well-designed long term resource adequacy mechanism as discussed above in Section B and below in Section E of these comments. That model is presented in greater detail below. This model provides for long term resource adequacy, with active participation by demand resources, while mitigating the potential exercise of market power, producing reasonable prices for capacity and accommodating the unique needs of retail choice states. We believe that the other proposals submitted at that Technical Conference do not satisfy all the concerns laid out above, even though those proposals are also based on a centralized procurement auction model. We will reserve comment on those details, however, until after we review any actual proposals submitted by those other parties in their January 10, 2003 comments on this issue.

E. Consumer Advocate Proposal[19]

1. Overview

Mid-Atlantic and Midwestern Consumer Advocates offer a proposal to the resource adequacy mechanism endorsed in the SMD NOPR. Our proposal was presented by the Pennsylvania Office of Consumer Advocate at the Commission's November 19, 2002 Technical Conference on Resource Adequacy. We believe that it reconciles the reliability needs of the power system with the broader goal of developing truly competitive power markets and is consistent with the above mentioned principles. Stated broadly, the proposal is for an RTO administered capacity auction that combines an administratively

[19] The Mid-Atlantic and Midwestern Consumer Advocates would like to acknowledge the assistance of La Capra Associates in the preparation of this resource adequacy counter-proposal. La Capra Associates is a consulting firm specializing in energy planning and regulatory economics. La Capra Associates has extensive experience in the development of more competitive energy markets and has been involved in electric restructuring matters, including the initial restructuring proceedings, in Pennsylvania. Additionally, La Capra Associates has assisted members of the Mid-Atlantic and Midwestern Consumer Advocates at PJM and in matters at FERC.

determined capacity requirement, market-based pricing with a price ceiling, a daily balancing mechanism, and a backstop mechanism.

Please note that we do not believe that the spot market (either for energy or capacity) is intended to replace proper risk management by sellers and proper investor due-diligence in the power plant development process. Our model does not anticipate that the RTO will become the primary buyer of capacity or that the capacity spot market will or should provide long term revenue certainty to sellers of capacity. We believe that both of these goals – the acquisition of capacity and long term revenue stability -- are best fulfilled through bilateral contractual arrangements between LSEs and capacity sellers.

The capacity market, as we conceive of it, then, is designed to provide a means for the RTO to fulfill its obligation as ultimate guarantor of regional reliability per the SMD NOPR. The model we outline below is intended to provide a reasonable opportunity for capacity resources that commit to PJM to recoup their opportunity costs, to provide some amount of revenue stability to pure peaking resources (those most at risk in the energy market), and to give sufficient warning to the RTO that it needs to invoke its backstop function before a reliability crisis arises.

Our proposal contains five major components:

- An administratively determined regional capacity requirement
- An ITP/RTO administered capacity auction
- Market-based pricing subject to bid limits
- A daily balancing mechanism
- A backstop mechanism.

Taken together, the above components will provide the adequate reserves necessary to achieve a reliable electric grid funded in a fair manner by market participants. Each of these components is discussed below.

2. An Administratively Determined Regional Capacity Requirement

Under our counter-proposal, the ITP/RTO would establish a regional capacity requirement using an agreed upon standard such as the one day in ten years loss of load probability. The ITP/RTO would inform each LSE of its expected allocation of the regional capacity obligation for the next commitment period based on their current loads. Based on this information LSEs might then purchase or sell capacity on the bilateral market prior to the auction. Any deviations between owned or contracted for capacity and obligation during the commitment period is handled through the balancing mechanisms described in detail below.

3. An ITP/RTO Administered Capacity Auction

The ITP/RTO would hold an auction periodically to secure supply (capacity contracts) for a 6 or 12 month capacity commitment period 12 to 18 months hence. Holding regular auctions is intended to allow for fairly easy entrance of capacity resources into the market and to facilitate the regular dissemination of information regarding the regional capacity position. The 12 to 18 month lead time between the auction and the commitment period[20] is intended to coincide with some reasonable estimate of the amount of time the RTO would require to secure capacity on an emergency basis per its backstop role. A capacity resource is obligated the seller to bid all available output into the day-ahead energy market and would grant

[20] In the context of this proposal, commitment period refers to the 6 or 12 month period over which a generator sold in the auction or under bilateral contract with an LSE is claimed as a capacity resource for the region.

the ITP/RTO the right to recall any real-time off-system sales. Each seller will receive its bid price. The weighted average price of capacity sold will be the balancing price for the commitment period.

All capacity installed in the region and not contractually committed to provide capacity to an external region would be required to bid into the capacity auction. Demand resources that meet the appropriate requirements may also bid into the auction, but are not required to do so. Capacity contracts between generators and LSEs in the region with terms covering the settlement period and in place on the day of the auction, would be accounted for during the settlement process. The RTO nets existing contracts from the set of bids during the settlement process. This approach avoids the problems associated with bidding residual supply and demand; the bidders have no information regarding the contractual positions of any of the buyers or other sellers. Because such information is not required for sellers to develop rational bids, the proposed scheme eliminates most of the opportunities from gaming – with the possible exception of explicit collusion – present in the current PJM capacity market, where only the residual is bid.

Generation, demand resources, and transmission projects which have not yet been brought on-line may also participate. Planned resources must be required to enter into agreements with the ITP/RTO that commits them, subject to some ITP/RTO discretion, to meet specific milestones or pay to replace resources not delivered. Likewise, penalties on an existing committed capacity resource which fails to meet its obligations to the region must be in place.

The 12 to 18 month time frame, because it is conceptually tied to the amount of time it would take to get a peaking unit into service on an emergency basis, should be empirically determined and could vary over time. Ultimately, the time frame would depend on institutional readiness. The proposed 12 to 18 month lead time might vary over the years with more experience and better preparation.

4. Market-based Pricing Subject To Bid Limitation

In order to protect consumers from potential seller market power, all offers would be subject to ITP/RTO-imposed bid limits. There would be two types of bid limits. The first limit is a global cap on the bids allowed. The second is a bidder specific bid cap that limits inter-auction bid changes.

Under the first bid cap, no bids would be allowed to exceed a global bid cap. The RTO would establish the bid cap based on its assessment of the annual carrying cost of new peaking capacity less expected energy and ancillary service net revenues. This reflects the fact that revenues in energy markets which clear at the highest price bid accepted in a given hour will be well above actual marginal operating costs for many generators.

Under the second bid cap, a bidder would not be allowed to offer capacity into an auction for a subsequent commitment period for a price that exceeded its most recently accepted bid by more than a predetermined dollar amount or percentage (as established by the RTO).[21] This bidding rule is designed to protect the market in case of shortage. If sufficient capacity were not available to meet the demand (in the auction), suppliers would no doubt be aware, and could try to extract maximum profits by bidding up its offer. However, if the capacity supply were actually tightening up, all infra-marginal generators presumably would earn greater contributions toward fixed costs from the energy market. Thus, there is no compelling argument (based, for example, on some measure of lost opportunity costs) that convinces us that existing capacity should require significantly more revenues from the capacity market during the

[21] For the purposes of applying the second bid cap, incremental capacity from an existing facility (due to capital investments made for that purpose) will be treated as new capacity and is not subject to bidding restrictions that would apply to the balance of the facility.

current auction period than they did during the last. This bidding rule protects LSEs from paying excess prices to existing generation.

5. A Daily Balancing Mechanism

The auction design and settlement rules must not operate as barriers to entry for new retail suppliers, particularly those that, at the outset, may have only limited information as to how many customers they will serve, or what their future loads may be. In addition, since customers may change suppliers relatively often in a dynamic marketplace, with a corresponding change in LSE resource requirements. Thus, the rules must also be flexible in their application and must encourage capacity market liquidity.

We propose a capacity balancing mechanism that would allow an LSE that was short during the settlement period to meet its obligation. The RTO would assign to the LSE a payment obligation equal to the LSE's short position times the balancing price. If an LSE lost load to a competitor, one of two things could happen. If it were purchasing capacity from the RTO market to cover its obligation, it would simply pay less (the reduction in its obligation times the balancing price). If the LSE were covering its obligation with a contract or owned generation, it would now be long on capacity and would be paid the balancing price for its surplus. The balancing mechanism eliminates the price risk associated with losing or gaining load. LSEs that lose load will not have to scramble to sell excess capacity into a relatively illiquid market at an unknown price and LSEs that gain load will know exactly what the capacity balancing price is before they acquire the load. Moreover, because sufficient capacity to meet the region's capacity obligation for the commitment period already would have been secured, there is no risk that an LSE would not be able to acquire capacity or that freed up capacity would be sold out of the market, potentially jeopardizing regional adequacy.

6. Backstop Mechanism

The RTO should provide a backstop mechanism. The backstop mechanism is intended to protect the market from the following two conditions:

a. A committed capacity resource that it is not yet in commercial operation – secured through the auction – fails to meet its milestones and, consequently, the RTO determines that it will not be available to provide capacity during the commitment period and that alternative capacity is not otherwise available in the market.

   In this case, depending upon the circumstances, the RTO (or a Special Purpose Entity (SPE) created for this purpose) could, for example, bring in portable generation to provide the needed capacity on a temporary basis. Under the capacity resource's agreements with the RTO, it could be obligated to pay the greater of the capacity payments it would have received as a capacity resource or the cost of the temporary capacity.

b. Market failure. The RTO determines that without intervention needed capacity will not be added to the region. Such an assessment would likely follow from the RTO's regional market assessments, such as its regional transmission planning work. There could also be a market failure in a particular auction if an inadequate amount of capacity is bid into that auction.

The RTO would evaluate the alternative approaches to the capacity shortfall and would select the option (generation, demand management, transmission, or a combination of options) that would be 'least cost'. Then, the RTO (or as SPE created for this purpose) would hold a competitive solicitation for the implementation of the least cost solution. If construction of new capacity is the least cost solution, upon completion, the RTO (or SPE) would auction the capacity. In the event that the auction is not fully compensatory, the additional costs would be recovered through a reliability charge levied against all load in the region. In this way, the seller of the auctioned capacity would be made whole. The buyer of the resource would operate it subject to any RTO rules (including bid mitigation) that might apply to it and other resources.

On a conceptual level, the resources could be developed by the RTO itself, although we propose that a Special Purpose Entity be created for this purpose or that a regulated, integrated utility implement the RTO plan. Whatever the entity, it is essential that it be able to finance the development of the project. To do so, it will need to be unambiguously entitled to two sources of revenue: the cash from the sale of the resource and payments from the LSEs/customers for the difference between the development costs and the market value of the resource (or what was earlier called the reliability charge). In the case of an SPE, the revenue entitlement will need to be regulated. In the case of a utility, one presumes that there could be reliance upon a state commission order, but a proper statute would clearly be more secure. It might be more straightforward to consider the utilities as they are in place, they have certain expertise, and they will neither own nor operate the resource post-development.

In any event, jurisdictional coordination between the FERC and State Commissions would be required to enable the RTO to efficiently execute its backstop obligations. Much of the regulatory approvals required to site, build and sell power from a project built pursuant to the backstop mechanism will already have to be in place prior to a trigger event for the backstop to be effective. Here, FERC's proposed State Advisory Committee concept seems an appropriate means of coordinating FERC, State Commission and RTO actions and responses to reliability. Through the State Advisory Committee, representatives of the State Commissions would work directly with FERC and the RTO to ensure the ability of the RTO to effectively perform its backstop function, should that be required.

F. The Consumer Advocate Proposal Satisfies The Principles Of A Well Designed Model

The resource adequacy model we present for Commission consideration in these comments satisfies all principles for a well designed resource adequacy mechanism as discussed in subsection B of these comments while providing these benefits at a reasonable cost to consumers.

1. Provide The RTO Reasonable Assurance Of Resource Adequacy

The regular planning and forecasting of regional capacity requirements keeps both the RTO and market participants fully apprised of the region's capacity needs on a forward looking basis. Upon the completion of each auction, the RTO will know that either sufficient capacity resources are committed to the region or that there is insufficient capacity available and that it must act in its backstop capacity. All committed capacity resources are obligated to bid into the day ahead market and the RTO may recall any real time off-system sales. Thus, capacity commitments are obligations to offer energy to the region.

Because the RTO conducts the auction 12 to 18 months prior to the commitment period, should there be a shortfall, the RTO should have sufficient time to assess the magnitude and expected duration of the capacity shortfall and determine the preferred remedy. Should the RTO determine that emergency peaking generation is required, recent experience in New York City and Chicago in siting emergency peaking capacity suggests that this is sufficient lead time to site and build emergency generation.

2. Effectively Mitigate Market Power

The proposal we recommend here mitigates market power in two principal ways. The requirement that all generation must bid into a central auction irrespective of contractual obligations eliminates physical withholding concerns. The bid cap and inter-auction price limits effectively mitigate economic withholding.[22]

3. Produce Reasonable Prices

We realize that there is some debate regarding the use of discriminatory price (pay-as-bid) auctions in energy markets. It is our view that a single market clearing (or uniform) price approach is probably best for energy markets. But we also contend that the nature of the capacity product and its provision are sufficiently different from energy that, in capacity markets, a discriminatory price (pay-as-bid) auction results in a better outcome.

On balance, in competitive (bid-based) *energy markets*, a clearing (or uniform) price method is preferable to a pay-as-bid price for several reasons.

- First, if there were a switch to pay-as-bid (discriminatory) pricing, bidding behavior would change and, in some instances, less efficient power plants would be dispatched ahead of, or instead of, more efficient plants. This is because there would no longer be an incentive for generators to submit bids based upon Short Run Marginal Cost ("SRMC"). As a result, formerly infra-marginal units would have to bid above their SRMC to capture the contributions towards their fixed costs (the infra-marginal dollars) that they would have received in a clearing price market. On any occasion -- and there will be some -- in which a generator has made a successful bid that, in a clearing price market, would not have been successful, the dispatch will be less efficient.

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[22] Even if capacity market design contains market power mitigation measures, continual market monitoring of anticompetitive behavior by the ITP or RTO is required.

- Second, pay-as-bid pricing would result in more complex bidding behavior (as it is not simply SRMC-driven), which would make bidding more information intensive for the generators. The collection and analysis of large amounts of information, could be relatively expensive for small generators and could, in addition, be an anti-competitive barrier to entry. Certainly, it complicates the assessment of potential revenues from the energy market and would, as a result, complicate financing.
- Third, given the foregoing two reasons, it is unlikely that the overall generation costs to consumers will decrease if one adopts a pay-as-bid approach in the energy markets; in fact, they could increase, particularly in the long run, if there are indeed anticompetitive barriers to entry.
- Finally, both pay-as-bid energy markets and clearing price markets could be susceptible to gaming, since the bidding is daily (that is, it happens quite regularly) and collusive behavior can be tacitly learned in such situations. The two pricing methods are probably equivalently problematic in this regard, albeit with one caveat; in a clearing price market, there is a standard against which to measure bidding behavior - SRMC - so there is a more straightforward way to monitor the market so as to prevent or punish collusion. The upshot is that in both the short and long term, there is no clear benefit that would accrue to the pay-as-bid method and, hence, no rationale for its adoption. Indeed, the more likely outcome is that there would be net costs to doing so.

The foregoing reasons to prefer uniform clearing prices in energy markets are not persuasive, however, when considering annual or semi-annual markets for capacity - or calls on energy - 18 months or more in the future. There is no obvious parallel in capacity markets to the energy market's loss of dispatch, and hence resource, efficiencies. Neither is there likely to be a substantial incremental cost to capacity bidding, given that it takes place relatively infrequently. Moreover, while one would not expect bidding strategies to remain invariant to the pricing method, there does not seem to be any compelling reason to believe that a pay-as-bid method can result in greater overall capacity costs to consumers. In order to conclude that pay-as-bid could result in greater capacity costs, there would need to be some evidence - or rationale for believing - that such a pricing methodology, in the capacity market, is more likely to lead to collusive behavior than in a similarly structured market with a uniform clearing price. We do not believe that this is the case. Thus, because different holders of capacity place a different value, depending on the composition of their portfolio, on their perceived opportunities, it seems that a pay-as-bid regime will properly compensate all accepted suppliers without resulting in a needless transfer of wealth from load to generation.

4. Not Unnecessarily Limit The Portfolio Choices Of Buyers And Sellers

The capacity adequacy model we propose does not require bilateral contracting between LSEs and capacity suppliers to function. However, as with any market, buyers that do not wish to be exposed to price uncertainty and sellers that want to lock in a revenue stream will likely find it beneficial to enter into bilateral contracts. The capacity market design requires only that capacity resources commit to the region for the 6 or 12 month commitment period. The capacity market model does not restrict the possible bilateral contractual terms and conditions that market participants might negotiate. Whether offered through the auction, owned or claimed via a bilateral contract, a capacity resource must, by definition, offer its output into the day-ahead energy market with any real-time off-system sales subject to recall and subject to the applicable bid price limits.

5. Allow All Resources To Participate

Our proposal accommodates demand response. The 12 to 18 month forward capacity auction will permit non-utility demand response providers to receive capacity credit for firm commitments. Also, a 12 to 18 month forward commitment will likely be feasible for many customer-based demand programs because that represents a reasonable planning period. Additionally, subject to eligibility rules and milestone conditions, resources under development may also participate in the auction. These resources include base-load and peaking generation and, to the extent feasible, transmission projects.

6. Accommodate Bundled Native Load And Retail Choice Programs

The capacity market design accommodates both the needs of integrated utilities and LSEs serving load under retail choice programs. Load servers, whether integrated utilities or competitive LSEs only purchase (or sell, if surplus) through the auction the difference between their obligation as allocated by the RTO and their owned or contracted for resources. If an integrated utility owns sufficient resources to meet all of its allocated resource obligation, then it purchases no capacity through the auction. A competitive load serving entity is likely to have mismatches during the commitment period between its allocated obligation and its resources, due to the loss or gain of customers. The balancing mechanism assures that the LSE will have access to the capacity to fulfill its obligation at a known price. The function of the auction and the balancing mechanism is the same whether a region includes all bundled native load, competitive LSEs, or a mix of the two. In any case, the auction mechanism provides the RTO reasonable assurance of regional resource adequacy and accommodates the needs of the load servers.

G. Need For Regional Flexibility (¶ 542-550)

At several places throughout the resource adequacy section of the SMD NOPR, the Commission seeks comment on the need for regional variability, including the provisions related to the establishment of a specific minimum reserve requirement and the development of a planning horizon. Mid-Atlantic and Midwestern Consumer Advocates strongly endorse regional flexibility in the development of a resource adequacy mechanism. We have proposed a model for Commission consideration that we believe is proper and that will work well in the regions covered by PJM and the Midwest ISO. We recognize, however, that the configuration of the transmission systems or the dominant types of generating resources (*e.g.*, hydro-power plants) in other regions may require different approaches to long term adequacy. Although we believe that our framework can be modified to accommodate regional variations, should the FERC have concerns that our approach is not workable in other parts of the country, we urge FERC to customize regional solutions rather than reject our proposal on the grounds that it may not work in all regions.

H. Summary Of Resource Adequacy Section

The cost of reliability over and above the level that the market provides is a social cost that should be borne by all those who benefit from a reliable electric system, that is, everyone who uses electricity. In other words, if society concludes that the costs of unreliable service are intolerable – and we agree that they are intolerable – and if the competitive market alone does not produce the level of reliability that society believes is necessary at a price that is reasonable, then we should put our collective thumb down on the scale on the side of reliability and take steps to ensure such reliability at a reasonable societal cost.

Our proposal recognizes that the acquisition of capacity is best fulfilled through a combination of ITP/RTO-administered auctions and bilateral contractual arrangements between Load Serving Entities and capacity sellers. A mandatory semi-annual auction with a ceiling price is intended to mitigate supplier market power that is inherent given the concentration of supply and the inelastic demand. This proposal seeks to resolve the liquidity, price risk, and access problems now faced by Load Serving Entities gaining or losing load on a daily basis. We propose that an ITP/RTO administered capacity auction that combines an administratively determined capacity requirement, market-based pricing subject to bid limitation, a daily balancing mechanism, and a backstop mechanism will ensure long term adequacy.

V. REGIONAL STATE ADVISORY COMMITTEES (¶ 551-555)

In this section of the SMD NOPR, the Commission seeks comment as to whether a formal process should be implemented as part of the Standard Market Design to afford state representatives both an opportunity for direct contact with the governing boards of ITPs, and an opportunity for the state representatives to participate in the ITP's operations. SMD NOPR at ¶ 551-552. The intent is to afford a process that will seek regional solutions to issues that may fall under federal, state or shared jurisdiction. *Id.* at ¶ 553. The Commission proposes this Regional State Advisory Committee ("RSAC") will be flexible as to organization and operation. *Id.* at ¶ 552. The Commission anticipates that an RSAC could address the following types of activities:

- resource adequacy standards, such as reserve requirements and planning horizons;
- transmission planning, expansion, certification and siting;
- rate design and revenue requirements;
- market power and market monitoring
- demand response and load management;
- distributed generation and interconnection policies;

- energy efficiency and environmental issues; and
- RTO management and budget review.

Id. at ¶ 553-554. Comment is sought on whether there should be one committee to further these goals, or several and how state representatives should be selected, *i.e.* whether a gubernatorial selection process or some other selection process should be used. *Id.* at ¶ 553.

Mid-Atlantic and Midwestern Consumer Advocates support full participation by state representatives, including state utility regulatory commissions, state energy offices, state consumer advocate offices and state environmental offices, in regional ITP, RTO or ISO activities. State representatives, within their jurisdiction, have an important role in ensuring both the adequacy of energy infrastructure as well as the reasonableness of energy prices within their jurisdictions. While we understand the overlapping nature of state and federal jurisdiction in these areas, we also understand why some state representative offices, particularly state utility regulatory commissions, may be reluctant to actively participate, join as members, or acquire voting rights in ITPs, RTO or ISOs due to the quasi-judicial nature of their statutory responsibilities.

For example, within PJM, no state utility regulatory commission has sought stakeholder voting rights because of concerns about conflict if an issue raised, addressed and voted upon by the RTO stakeholders later comes before the state commission for decision. Nonetheless, these entities have a long history of experience in regulating this industry and have much of value to add to discussions at the ITP, RTO or ISO level. Often, significant policy decisions are made by stakeholders and ITP, RTO or ISO boards that affect matters under state jurisdiction. Consequently, we support a process that will provide these state representatives the opportunity to have their views and concerns heard by stakeholders and the managing boards of these regional entities.

Mid-Atlantic and Midwestern Consumer Advocates applaud the extension of RSAC responsibilities to coordination of state activities for demand response and distributed generation program development. In practice, neither demand response nor distributed generation will be successfully implemented without the active participation of individual states. Regional solutions should optimize these resource adequacy approaches. We also applaud the extension of RSAC responsibilities into coordination of state activities for market oversight. Since the success of retail competition is inextricably linked to the success of wholesale competition, states have a unique interest in the ITP's, RTO's or ISO's market monitoring activities and reports.

However, Mid-Atlantic and Midwestern Consumer Advocates caution that RSACs must not be implemented in a way that weakens the independence of an ITP, RTO or ISO, or confuses the ITP, RTO or ISO stakeholder process. State utility regulatory commissions and other state representatives should have every opportunity to participate in the ITP, RTO and ISO stakeholder meetings and consensus-building processes. Likewise state representatives should have unobstructed communication with the ITP, RTO or ISO Board. Nevertheless, such access should not amount to a transfer to state representatives of ITP, RTO or ISO responsibilities to make final decisions. Nor should state representatives attain super stakeholder status through the RSAC process.

We have reservations regarding proposed RSAC responsibilities for developing regional approaches to rate design and revenue requirements. We agree that discussions of these issues among state representatives promotes better understanding of issues and clarifies state policies for stakeholders and for the ITP, RTO or ISO. We understand that with the MISO stakeholder process, an effort is underway to better coordinate state policies related to rate design so as to better address regional transmission planning concerns. Such efforts should be encouraged within an RSAC process. However, any RSAC process should stop short of dictating regional solutions in such a way as to subvert statutory requirements for state or federal regulatory approvals.

In some matters, the state or federal statutes may require formal rulemaking or adjudication by the state or federal agencies. Such processes should be conducted independently of the RSAC deliberations. While the RSAC could provide information and comment as would any other party to such proceedings, including proceedings before this Commission, the RSAC process should not become a substitute for such state or federal proceedings.

We are particularly concerned that the SMD NOPR proposal may transfer too much authority from ITPs, RTO and ISOs with respect to resource adequacy matters. SMD NOPR ¶ 490 proposes that the RSAC will set the resource adequacy reserve requirement and SMD NOPR ¶ 524 proposes that RSACs will establish the resource adequacy planning horizon. In PJM, those functions have for some time been undertaken by PJM, both operating as an ISO and even earlier when PJM operated as a tight power pool. The SMD NOPR would propose to transfer that regional authority back to the states. We believe that the PJM states clearly have a very important role in assisting in the development of reserve requirements and planning horizons, but those efforts should be in the nature of advice and input to the ITP, RTO or ISO. Allowing the RSAC to have authority of this nature in PJM would dilute the success PJM has had in promoting resource adequacy across the region and could serve to rebalkanize this region. Instead, we recommend an alternative for the Commission to consider, at least for the Mid-Atlantic and Midwestern regions of the nation.

Mid-Atlantic Consumer Advocates have generally had good experience with the Memorandum of Understanding ("MOU") between PJM and the Mid-Atlantic state regulatory commissions that creates a liaison committee between these agencies and the PJM Board. This MOU ensures that state representatives have their concerns heard within PJM. Many of these state utility regulatory commission staff participate in stakeholder committee proceedings, despite the fact that they have chosen to not vote in these meetings. This process has routinely made PJM stakeholders aware of the states' concerns. The SMD NOPR should provide flexibility for an RSAC process that builds on the PJM MOU process and strengthens the role of the states in the ITP, RTO, ISO process.

Mid-Atlantic and Midwestern Consumer Advocates recommend that each region should decide for itself how active a role the RSAC should play in the ITP, RTO and ISO activities laid out in the NOPR and discussed above. For example, in PJM, where a tight power pool existed prior to development of ISO and RTO structures, state utility regulatory commissions have informally participated in the power pool's development of region-wide reserve requirements, planning horizons and transmission planning and expansion processes. This has not lead to state control of the process or the development of individual state requirements that over-rule regional requirements. This process has worked successfully for many years and should continue. The RSAC process should not limit the successful regional planning that is currently undertaken in PJM. Consequently, the SMD final rule should allow regional flexibility, but should not diminish the role of current levels of regional planning.

Generally, Mid-Atlantic and Midwestern Consumer Advocates recommend that each state independently determine how its RSAC member(s) will be selected. However, we urge the Commission to ensure that at least one of each state's RSAC representatives be a member of the state's utility regulatory commission. As discussed above, state utility regulatory commissions have a unique role. They also have a unique set of skills and experience with these issues. Each state should determine if additional state representatives will participate on its behalf.

In summary, we submit that the Commission should adopt an RSAC process requirement in the SMD final rule. Such a process provides substantial opportunities to resolving potentially conflicting state requirements across an ITP, RTO or ISO region. However, we urge the Commission to ensure that the RSAC process neither serves as an excuse to diminish existing regional cooperation with respect to resource adequacy and regional planning matters, nor as a circumvention of either ITP, RTO or ISO stakeholder processes or state and federal statutory regulatory proceeding requirements. We submit the PJM MOU with the Mid-Atlantic state regulatory commissions as a basis upon which to build a strong, but appropriate RSAC process.

VI. CONCLUSION

Mid-Atlantic and Midwestern Consumer Advocates applaud the Commission's efforts in this proceeding to develop a standard electricity market design. While we support many of the elements laid out in the SMD NOPR, we express concern with respect to the details of several of those proposals. In these Supplemental Comments, we explain why the Commission's proposals with respect to Through and Out Rates, CRR auctions, options and scheduling priorities, regional planning, long term resource adequacy, and RSACs need to be modified in order to accomplish the Commission's goals of promoting competitive wholesale markets while ensuring reliable supply of electricity at reasonable prices. We urge the Commission to adopt the modifications and proposals set forth in these Comments in order to ensure that all consumers, even the smallest consumers on the system, will benefit from competitive markets for electricity.

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Mid-Atlantic and Midwestern Consumer Advocates' Supplemental Comments on Specific Issues were electronically filed today.

Dated at Harrisburg, Pennsylvania this 10th Day of January, 2003.

- Filed Electronically -

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