UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	)))))	Docket No. RM21-17-000

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] and the Advanced Notice of Proposed Rulemaking issued in the proceeding on July 15, 2021 ("ANOPR"),[2] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[3] submits these comments.

I. COMMENTS

The Market Monitor supports the purpose of the ANOPR, which is to review transmission related regulations and determine whether additional reforms to the regional transmission planning and cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of

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1 18 CFR § 385.211 (2021).

2 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 ("ANOPR").

3 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be included in all aspects of the NOPR.

A. Regional Transmission Planning

1. Planning for the Transmission Needs of Anticipated Future Generation

The Commission asks whether the existing regional transmission planning and cost allocation processes appropriately consider the transmission needs of anticipated future generation, or instead rely on less comprehensive information, such as existing interconnection requests with completed facilities studies, and whether such current planning criteria are appropriate or should be revised.

Uncertainty is a central feature of transmission planning. PJM's transmission planning addresses that uncertainty in defined ways. The planning process uses the available information. The planning process is not failing to use more comprehensive information. The issue is not whether the information is comprehensive, but it is about the quality of that information, i.e. is the information likely to be correct. The term information seems to imply that the information is correct, or at least has a high probability of being correct. But the ANOPR's use of the term information includes actions with a much lower probability of occurrence. The transmission planning process reasonably relies on information with a high probability of being correct. Transmission planning results in decisions that have very substantial financial and physical results. Transmission facilities must obtain a certificate of public convenience and necessity (CPCN), with all the complexity and impacts on people and property that entails, particularly for greenfield sites, and transmission facilities must be paid for by customers.

The uncertainties faced by transmission planners include the entry of new generation, the retirement of old generation, changing patterns of congestion, load growth, fuel costs, fuel availability, power usage, the phasing out of old generation and transmission technologies and the introduction of new technologies, including technologies that may not yet be commercial or even exist, as well as new policies and programs that can affect transmission planning inputs. These changes can also affect transmission already in development. For example, the Potomac Appalachian Transmission Highline (PATH) and Mid-Atlantic Power Pathway (MAPP) projects were both large transmission projects that were based on and included in the RTEP models and that began construction. Even after over one billion dollars were spent on the development and construction of these projects, they were later deemed to be unnecessary when the reliability needs that led to the projects changed significantly. Changes in load growth, participation in demand response programs, and additional generation commitments were cited as reasons for the termination of the projects.[4] The characteristics of new technologies are a function of advances in science and engineering and also of the incentives incorporated in the market design and in the rules for interconnection queues. The reality of the transmission and generation and load elements of the grid is path dependent.

Requiring transmission planners to account for anticipated new generation, in ways that incorporate new generation with a lower probability of completion than under the current rules, would impose even more uncertainty on the planning process and would be likely to result in significant wasted time and resources.

The total amount of generation at all stages of development in the PJM interconnection queues is not a source of reliable information about what is likely to actually be built. This is a result in significant part of the incentives incorporated in the design of the queue process which result in developers holding places in the queues as

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4 See PJM. Letter to PJM Transmission Expansion Advisory Committee (August 12, 2012). <https://www.pjm.com/~/media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx>.

options rather than as intentions to build every project. As a result of experience with projects that were in the queue, were included in transmission planning, but were not put in service, PJM changed the threshold for including new generation in the transmission planning process. The goal was to improve the quality of information about new generation in the transmission planning process. Prior to 2020, PJM included generation and merchant transmission projects that had proceeded at least through the execution of the Facility Study Agreement (FSA) stage of the interconnection process in the model along with any associated network upgrades.[5] Changes were made in 2020 to include only those projects that had proceeded beyond the FSA stage of the interconnection process including those with an executed Interconnection Service Agreement (ISA), Construction Service Agreement (CSA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). The ISA defines the cost responsibility of the generation or transmission developer for required system upgrades, identifies interconnection rights regarding operational restrictions, transmission injection and withdrawal rights and additional construction responsibility items. A CSA is issued to generation or transmission interconnection customers when their projects require facilities to be built to interconnect to the transmission system. The CSA provides the terms and conditions under which the construction will be performed. A UCSA is issued to a developer making an upgrade to an existing transmission facility. A WMPA is issued to developers interconnecting to non FERC jurisdictional facilities who intend to participate in the PJM wholesale market and is similar to an ISA without the interconnection provisions. TSAs are issued to customers seeking new transmission service. PJM will include projects with an executed Facilities Study Agreement (FSA) only if those projects are needed to meet the new load requirements resulting from normal forecasted load growth.[6] Requiring

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5 *See* PJM Manual 14B: PJM Region Transmission Planning Process, Rev. 43 (January 24, 2019).

6 *See* PJM Manual 14B: PJM Region Transmission Planning Process, Rev. 49 (June 23, 2021).

projects that have proceeded to a point further in the queue process than the FSA helps ensure that only projects with a higher certainty of completion are included in transmission planning.

While the probability of a project going into service increases as each step of the planning process is completed, there is still a risk associated with including planned generation in the RTEP planning assumptions, even when those projects have completed steps beyond the FSA. On June 30, 2021, 217,381.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the system impact study (SIS), facility study agreement (FSA) or have completed a step beyond the FSA, and the completion rates for all projects that have not reached the SIS milestone), only 39,081.6 MW (17.9 percent) of new generation in the queue are expected to go into service. Completion rates for new generation projects with a completed Facilities Study Agreement (FSA) average 48.7 percent across all unit types and those which have completed a step beyond the FSA have an average completion rate of 55.0 percent across all unit types.[7]

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by both thermal resources and renewables. Of the 22,808.6 MW of combined cycle projects in the queue on June 30, 2021, 14,211.6 MW (62.3 percent) are expected to go in service based on historical completion rates. Of the 160,392.1 MW of renewable projects in the queue, only 19,384.5 MW (12.2 percent) are expected to go in service based on historical completion

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[7] *See* Monitoring Analytics, LLC, *2021 Quarterly State of the Market Report for PJM: January through June* (August 12, 2021), Section 12: Generation and Transmission Planning, at 635 "Completion Rates," Table 12-22.

rates. Of the 160,392.1 MW of renewable projects in the queue, only 7,714.3 MW (4.8 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue. Completion rates will also be a function of any new incentives that may be built into the revised interconnection process.

Nonetheless, requiring transmission planners to include some or all of new projects which do not have an executed ISA, CSA, UCSA, WMPA or TSA requires planners to make judgments based on incomplete information that will have significant consequences. The shape of the future grid and the most efficient shape of the future grid in 10, 20 or 30 years is unclear at best. The decisions made about the transmission grid must incorporate accurate information but be flexible and be able to incorporate new information as it evolves. The decisions made by transmission planners should be incremental, recognizing that the future is uncertain and that selecting very large transmission projects based on very specific assumptions about the future that are in turn based on incomplete information are likely to be wrong.

To illustrate the distinction, the offshore wind projects in New Jersey have a high probability of completion and it would be reasonable to incorporate these projects in transmission planning, as PJM is already doing. But there are a variety of renewable projects in the queue with a very low probability of completion. PJM has no way to sort those individual projects by probability of completion. It would not be reasonable to incorporate these projects in transmission planning until the projects' probabilities of completion are known with more certainty.

2. Coordinating Between the Regional Transmission Planning and Cost Allocation and Generator Interconnection Processes

The ANOPR asks whether the regional transmission planning and cost allocation processes' consideration of transmission needs driven by reliability, economic considerations, and Public Policy Requirements are inappropriately siloed from one another, and, if so, whether this influences the consideration of potential benefits of a regional transmission facility (and the associated beneficiaries for purposes of allocating the costs of such a facility).

PJM's Regional Transmission Expansion Plan (RTEP) process includes a broad range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure. It is appropriate to account for all elements that drive the need for transmission. These elements of the RTEP are not siloed in PJM.

However, permitting Transmission Owners to redefine supplemental projects and end of life projects as outside the RTEP does create inappropriate siloing of the planning process and interferes with the regional planning process that the Commission supports.

In addition, when the transmission owner is a vertically integrated company that also owns generation or may build generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor to the transmission owner.

3. Competition

The ANOPR requests comments regarding whether the current approach to oversight of transmission investment adequately protects customers, particularly given the potentially significant and very costly investments proposed to meet the transmission needs driven by a changing resource mix, and, if customers are not adequately protected from excessive costs, which potential reforms may be required and are legally permissible to ensure just and reasonable rates.

The Commission has effectively used competition as a substitute for direct cost of service regulation as a means to ensure just and reasonable rates in the energy market. While that approach cannot be adopted in exactly the same form in the provision of transmission services, the goal of wholesale power market design should be to enhance competition and to ensure that competition is the driver for all the key elements of markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.[8]

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined within the RTEP process and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

4. Economic Considerations, Market Efficiency and Cost/Benefit Analysis

In PJM, the stated purpose of the market efficiency analysis is to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modifications to existing RTEP reliability based enhancements that when modified would relieve one or more constraints.

In PJM, the market efficiency criterion is misnamed. The RTEP market efficiency criterion and the associated cost/benefit analysis incorrectly define the benefits of transmission projects and therefore result in uneconomic transmission upgrades. Market

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[8] The Market Monitor has longstanding concerns that not enough has been done to alleviate anticompetitive incumbent advantages and barriers to entry based on exclusive incumbent ownership of unused property rights that were obtained for the benefit of ratepayers, and exclusive incumbent ownership of facilities for interconnection, such as substations. *See, e.g., Primary Power, LLC v. PJM,* Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, Docket No. EL12-69-000 (June 22, 2012). The requirement for incumbents to permit colocation of network facilities in the telecommunications industry is a better model for competition in the electric transmission industry. *See* 47 CFR § 51.323 (Standards for physical colocation and virtual colocation).

efficiency explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete as a potential alternative.

The PJM market efficiency process uses speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of fuel costs and congestion, and eliminates the potential for new generation to respond to market signals. The market efficiency process allows transmission assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives or whether there are complementary alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. The Market Monitor recommends that the existing market efficiency criterion for transmission upgrades be eliminated.

If the RTEP market efficiency criterion is retained, there are significant issues with cost/benefit analysis that should be addressed in PJM's existing market rules, and in the Commission's guidance for cost/benefit analysis more generally. In PJM's specific case, the current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased energy costs in upstream zones that results from an RTEP project when calculating the energy market benefits. All benefits and costs should be included from all zones and LDAs whether the zone or LDA is benefiting or being harmed by the proposed project. The cost/benefit analysis should account for the fact that in the cost of service model, transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost/benefit analysis is effectively meaningless and low estimated costs may result in incorrectly favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost/benefit analysis.

Creating a mechanism to permit competition between transmission and generation should be an explicit goal.

The ANOPR (at PP 15 and 94) discusses congestion reduction and building transmission to allow lower cost power to flow to customers as an economic benefit to be considered in an RTEP process. Caution must be applied when considering congestion reduction or localized LMP reductions as an economic benefit to a potential transmission project. Assuming that congestion is a cost to load without accurately accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs (or their equivalents) causes an overstatement of the potential economic benefits of a transmission project. The benefit of a transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load, including the accurately calculated impact of ARRs and FTRs. Failing to accurately account for the return of congestion may substantially overstate the potential benefits of upgrades, and ignore the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

The issue with PJM's cost/benefit analysis also affects the Interregional Market Efficiency Process (IMEP) between PJM and MISO. While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. The allocation of costs to each RTO for IMEPs is in proportion to the estimated benefits to be received. MISO measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

5. Cost Allocation

The allocation of transmission costs is a complex issue including both analytical and policy considerations. Cost allocation questions must be addressed in a comprehensive manner. Cost allocation should be reviewed from the ground up and attempt to separate the analytical elements from the policy choices. The Commission should determine the best venue for such review, but the process should start with a careful review of all elements that affect the current allocation of transmission costs, a definition of analytical alternatives and the policy options.

Instituting a new rulemaking proceeding would be a reasonable approach to permit an efficient and timely resolution of the cost allocation issues. Comprehensively addressing allocation issues in a rulemaking proceeding would avoid the barriers to communication imposed by ex parte rules, and would allow the Commission to determine rules for cost allocation that best serve the public interest and incorporate the policy goals of the states.

6. Line Ratings[9] [10]

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Over defining line ratings results in less reliability than planned for. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a

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9 *See* Monitoring Analytics, LLC, *2021 Quarterly State of the Market Report for PJM: January through June* (August 12, 2021).

10 *See Managing Transmission Line Ratings*, Speaker Comments of Joseph Bowring, Independent Market Monitor for PJM, Docket No. AD19-15-000 (September 17, 2019); Post Technical Conference Comments of the Independent Market Monitor for PJM, AD19-15-000 (November 4, 2019).

wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real-time conditions and to help ensure that real-time prices are based on actual current line ratings. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

B. Identification of Cost and Responsibility for Regional Transmission Facilities and Interconnection Related Network Upgrades

1. Queue Management

Managing the generation queues is a highly complex process. That process has morphed as the traditional interconnection process for large thermal generators has been significantly affected by the large number of relatively small renewable projects. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created and that the interconnection requirements of renewable projects are addressed. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, improvements in queue management to ensure that projects are removed from the queue without delay if they are not viable, and a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one, they also affect all the projects that follow them in the queue whenever one of the projects is withdrawn. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The incentives for such behavior, and potential disincentives, should also be addressed.

In 2020, PJM conducted interconnection process workshops designed to review current processes, receive input and recommendations from stakeholders and to develop improvements to the process, including ways to resolve the current interconnection study backlog. The workshops resulted in the creation of the Interconnection Process Reform Task Force (IPRTF), with the goal of improving the overall queue management. The current proposals being discussed in the IPRTF include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue and incentives to remove projects that are not expected to reach commercial operation from the queue that are contributing to the substantial queue backlog in PJM.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

Any consideration of modifying participant funding should include an evaluation of the impact on the queue process. The strong incentives in the participant funding model result in developers choosing sites that maximize benefits and minimize costs. While there continues to be speculative entry, even speculative entry is disciplined by the participant funding incentives. In the absence of that market discipline, it is likely that speculative queue entry would increase, potentially very significantly, and that developers would propose locations with high interconnection costs, and a wider range of interconnection points, that would require more analysis and result in higher interconnection costs. The result would likely be to exacerbate existing queue issues and to increase transmission costs to customers.

2. Participant Funding

The Commission (at P 71) seeks comment on whether the current participant funding approach to the generator interconnection process results in only a subset of beneficiaries paying for transmission infrastructure that, in practice, may benefit many.

The immediate issue of multiple projects jointly benefitting from transmission upgrades has been partially addressed in PJM's interconnection process and is being further refined through PJM's cluster analysis. This is a legitimate issue and failure to fully address the issue could continue to encourage queue gaming and other inefficient behavior. All interconnections in a cluster should share the costs of jointly beneficial upgrades rather than penalizing the first mover through the assignment of a disproportionate share of costs.

The current participant funding approach for generation interconnection-related transmission upgrades is consistent with efficient investment incentives and a competitive market for power. The current participant funding approach allocates the costs to the direct beneficiary of the interconnection, the resource investor. The participant funding approach also provides a direct incentive for the prospective investor to find the location that will maximize their expected benefit, net of their expected costs, including the costs of interconnection.

The ANOPR asks (at P 71) whether the participant funding approach may fail to account for the benefits that these interconnection-related network upgrades may provide to other anticipated future generators seeking to interconnect and/or existing or future transmission customers. The immediate issue can be addressed through the clustering approach. The broader question is not an issue in a market. While a planning, or cost of service, approach must make decisions about how to allocate all the transmission and generation costs associated with meeting load, that is not true in a market. When new generation is interconnected, the result may be to increase energy costs or to decrease energy costs. The actual impact may change over time. There is no permanently correct answer to which is a benefit and which is a cost. The interconnection process is one significant intersection between the arena of markets and the arena of transmission planning. In order to maintain a competitive energy market and a competitive capacity market, it is essential not to extend the planning/cost of service paradigm into the markets. Of course new generation and associated transmission upgrades create benefits for the markets. But there is no reason to allocate any part of the generation investment, including the interconnections costs, to anyone. The question of cost allocation is not relevant in a market. Those costs are appropriately part of a private decision about whether and where to build generation. Markets obviate the need for nonmarket discussions of allocations based on beneficiaries. New interconnecting generators are beneficiaries of prior transmission upgrades, whether funded as part of an interconnection requirement, or paid for by load through the transmission planning process, but it would be equally inappropriate to allocate costs of existing transmission to new generators. Interconnected generators will also benefit from future upgrades to the transmission system. The temptation to change the fundamentals of the investment decisions by competitive market entrants should be resisted. There are likely to be significant and in some cases unanticipated unintended consequences of such changes. Nothing significant about the relationship between markets and transmission has changed that warrants such a change.

C. Establishment of an Independent Transmission Monitor

The ANOPR seeks comment (at P 163) on "whether, to improve oversight of transmission facility costs, it would be appropriate for the Commission to require that transmission providers in each RTO/ISO, or more broadly, in non-RTO/ISO transmission planning regions, establish an independent entity to monitor the planning and cost of transmission facilities in the region." Within that broader framework, the ANOPR seeks comments on a wide range of specific potential responsibilities of independent transmission monitors.

The Market Monitor supports the Commission's concept of an independent transmission monitor for both RTO/ISO markets and non-RTO/ISO areas. At a high level, the purpose of an independent transmission monitor would be to provide an expert, informed, and independent source of information about the transmission component of the organized markets, and the transmission component of the areas without organized markets. That information is essential for the Commission, for state public utility commissions, for all market participants, for all customers and for PJM. Focus on each of the specific potential areas identified would provide such essential information. PJM needs an independent transmission monitor for the same reasons it needs an independent market monitor.[11] As is the case for the Monitoring Plan in PJM, the independent transmission monitors should have the responsibility to monitor, to report the results of analysis and monitoring, and to recommend market rule changes.

The creation of such an independent transmission monitor falls within the scope of the Commission's authority to regulate the terms and conditions of transmission service.[12]

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11 *See, e.g.*, *Wholesale Competition in Regions with Organized Markets*, Order No. 719, 125 FERC ¶ 61,071 at PP 353–354 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009). The ANOPR seeks comment (at P 174) on whether the RTO could perform an independent transmission monitoring function.

12 *See, e.g.*, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 532 (2011) ("Section 201(b)(1) of the FPA gives the Commission jurisdiction over "the transmission of electric energy in interstate commerce." The Commission's jurisdiction therefore extends to the rates, terms and conditions of transmission service, rather than merely transactions for such transmission service specified in individual agreements. Moreover, section 201(b)(1) gives the Commission jurisdiction over "all facilities" for the transmission of electric energy, and this jurisdiction is not limited to the use of those transmission facilities within a certain class of transactions. As a result, the Commission has

The Market Monitor recommends that the geographic/market area responsibilities of independent transmission monitors align with the current geographic/market area responsibilities of market monitors. As the markets and transmission network are closely integrated, there is a natural match between the markets and the transmission grid in the same geographic/market areas. But the independent transmission monitors should be explicitly assigned the role of coordinating with the neighboring independent transmission monitors in both RTO/ISOs and in areas without organized markets to monitor and focus attention on interregional coordination and projects or the lack thereof. Monitoring and reporting on interregional coordination and interregional transmission projects should be included as a core responsibility of the independent transmission monitors.

Both the independent market monitoring function and a new independent transmission monitoring function should extend to non RTO/ISO regions. Like RTO/ISO regions, non RTO/ISO regions have endemic structural market power, but non RTO/ISO regions lack transparency, structurally separate market rules and market administration, and organized wholesale markets.

As the ANOPR recognizes, an independent transmission monitor can only function with a clear definition of the roles and responsibilities and with a clear definition of access to the data and information required to fulfill those roles and responsibilities. The roles and responsibilities should include regular preparation of public reports and protection of confidential information. The required access includes relevant data and information held

jurisdiction over the use of these transmission facilities in the provision of transmission service, which includes consideration of the benefits that any beneficiaries derive from those transmission facilities in electric service regardless of the specific contractual relationship that the beneficiaries may have with the owner or operator of these transmission facilities."), *order on reh'g*, *order on reh'g*, Order No. 1000-A, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

by the RTO/ISOs; balancing authorities; transmission companies; NERC; and Reliability Councils.[13]

The Market Monitor supports the creation of an independent transmission monitoring function, and recommends that the existing independent market monitoring function be clarified and enhanced to explicitly include the independent transmission monitoring role. In PJM, the Market Monitor's roles and responsibilities are clearly defined in the Market Monitoring Plan in Attachment M and Attachment M–Appendix to the OATT. The Plan includes and defines key functions that would also apply to the independent transmission monitor function. The Plan could be expanded to incorporate the independent transmission monitoring function. For example, the PJM Market Monitoring Plan provides for independence and a structurally separate organization with clear conflict of interest provisions.[14] Strong, clear conflict of interest provisions are critical in order to ensure the independence of the monitoring functions.

There are synergies between the two monitoring functions that would make the combination more effective and less costly than separate organizations. RTO/ISO market monitors know and understand the market rules, governance rules, and the stakeholder process. The energy market and the transmission system operate as a single integrated system. The market monitors' knowledge of the energy, capacity and ancillary services markets will be essential to monitoring transmission effectively. Monitoring transmission will also benefit the market monitoring function as additional knowledge about some aspects of transmission planning is incorporated.

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13 The Market Monitoring Plan authorizes access to information about transmission operation. *See* OATT Attachment M § V.A.

14 *See* OATT Attachment M § IX; Market Monitoring Services Agreement § 18.1; 18 CFR § 35.28(g)(3)(vi).

Market monitors have existing structures and staff that will enable economies of scale if independent market monitoring and independent transmission monitoring were combined. The Market Monitor has an independent and standalone IT infrastructure and capability that will not need to be replicated. The Market Monitor has administrative overhead that will not need to be duplicated. Nonetheless, the Market Monitor would need to hire additional staff with some additional areas of expertise and purchase additional software to perform the independent transmission monitoring function as described in the ANOPR.

The Market Monitor is already actively engaged in many of the areas described for an independent transmission monitor. For example, the Market Monitor reviews transmission projects under the cost/benefit driver and reviews the design of the cost/benefit driver.[15] The Market Monitor makes recommendations about the role of transmission in PJM competitive markets and the role of competition in developing least cost transmission.[16] The Market Monitor has filed comments and actively participated in proceedings concerning competition in the transmission sector.[17] The Market Monitor presents data on the potential for conflicts of interest between transmission owners performing interconnection studies at PJM's request for market participants who compete with the transmission owners and for market participants who are affiliated with the transmission owner.[18] The Market Monitor analyzes transmission related congestion in

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15 *See* Monitoring Analytics, LLC, *2020 State of the Market Report for PJM*, Vol II. Section 12: Generation and Transmission Planning, at 569–632 (March 11, 2021).

16 *See id.* at 571–573.

17 *PJM Interconnection, L.L.C.*, Order on [Order No. 1000] Compliance Filings, 142 FERC ¶ 61,214 at PP 167–168 (March 22, 2013); *TranSource, LLC v. PJM*, Opinion No. 566 168 FERC ¶ 61,119 at PP 12–13 (2019).

18 *See* Monitoring Analytics, LLC, *2020 State of the Market Report for PJM*, Vol II. Section 12: Generation and Transmission Planning (March 11, 2021) at 601–603.

detail and its implications for the costs and benefits of building transmission.[19] The Market Monitor includes the effect of line ratings, transmission outages, and voltage stability issues on the energy market in its monitoring and reporting.[20] The Market Monitor participated in Commission workshops on line ratings, dynamic line ratings and Grid Enhancing Technologies.[21] The Market Monitor makes recommendations regarding CIRs and their role in competition in the capacity market and their impact on interconnection queues.[22] The Market Monitor includes analysis of the impacts of CETL on the capacity market and the bases for CETL in the transmission system in reports on capacity market auctions.[23] The Market Monitor has filed comments with the Commission on the role of storage as a transmission asset (SATA).[24] The Market Monitor actively reviews and makes recommendations on interregional coordination with all the neighboring balancing authorities and the nature of the agreements with those balancing authorities, including the role of HVDC lines and associated transmission rights.[25] The Market Monitor took a lead

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19 *See id*. at 608–613.

20 *See* Monitoring Analytics, LLC, *2020 State of the Market Report for PJM*, Vol II. Section 3: Energy Market, at 109–232 () and Section 12: Generation and Transmission Planning at 619-632

21 *See, e.g.*, *Grid Enhancing Technologies*, Comments of the Independent Market Monitor for PJM, Docket No. AD19-19-000 (November 6, 2021); *Managing Transmission Line Ratings*, Post-Technical Conference Comments of the Independent Market Monitor for PJM, AD19-15-000 (November 4, 2019).

22 *See, e.g.*, 2020 State of the Market Report for PJM, Volume II Section 5: Capacity Market. (March 11, 2021).

23 *See* "Analysis of the 2021/2022 RPM Base Residual Auction-Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018), as well as the *2020 State of the Market Report for PJM*, Volume II, Section 5: Capacity Market, Table 5-2.

24 See, e.g., Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Comments of the Independent Market Monitor for PJM, Docket No. ER16-23-000 et al. (February 21, 2017).

25 *See 2020 State of the Market Report for PJM*, Volume II Section 9: Interchange Transactions.

role in drafting modified manual language to address IARRs. The Market Monitor is involved in other areas directly related to system requirements based on the capability of the transmission system, including the review of the costs of reliability must run service,[26] black start service,[27] and reactive capability.[28]

The Market Monitor also has responsibilities related to the costs of competing transmission projects. The Market Monitor's experience in creating financial models used in the analysis of the costs of new capacity resources is directly applicable to the financial models required to analyze the long term costs of transmission projects.[29] The PJM Markets and Reliability Committee (MRC) approved language requiring that the "PJM Office of Interconnection, after seeking the advice and recommendation of the PJM Independent Market Monitor, shall develop an initial Comparative Framework to evaluate the quality and effectiveness of binding cost containment proposals (related to construction cost caps) vs. cost estimate proposals."[30]

The Comparative Framework evaluation, including the market monitor's role in the process, is documented in PJM's Manual 14F: Competitive Planning Process. The

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26 *See, e.g.*, OATT Attachment M–Appendix § IV.2; RC *Cape May Holdings, LLC*, 162 FERC ¶ 61,194 (2018) (Order Approving Settlement on RMR Rates with Market Monitor et al.); *Exelon Generation Company, LLC*, Comments and Motion for Technical Conference of the Independent Market Monitor for PJM, Docket No. ER10-1418-000 (July 15, 2010).

27 *See, e.g.*, OATT Attachment M–Appendix § III; *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080 at P 33 (2021).

28 See, e.g., Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Comments of the Independent Market Monitor for PJM, AD16-17 (July 29, 2016); Panda Stonewall, LLC, 160 FERC ¶ 62,096 (July 27, 2017).

29 See Monitoring Analytics, LLC, CONE Template, <*https://www.monitoringanalytics.com/tools/docs/IMM_MOPR_Gross_CONE_Template_v1.xlsx*>.

30 See PJM, "Highlights of LS Power / DC Office of People's Counsel May 2018 MRC Alternative Motion with Friendly Amendment," (May 24, 2018), which can be accessed at: <*https://www.pjm.com/-/media/committees-groups/committees/mrc/20180524/20180524-item-03c-cost-containment-ls-power-highlights-of-may-alt-motion.ashx*>.

comparative cost framework states that "In accordance with the Open Access Transmission tariff, Attachment M, the MMU has access to all data submitted to PJM through PJM's competitive proposal window process," and that "the MMU may, at its discretion, perform an independent financial analysis of projects submitted to PJM through PJM's competitive proposal window process."[31]

The 2020 RTEP Window 1 was the first open window that received transmission proposals subject to cost caps to be evaluated under the comparative cost framework. The analysis performed by PJM under the new process was insufficient and did not follow the process defined in the PJM manual. The existing proposal templates do not provide enough information to adequately perform a financial analysis. The Market Monitor recommended that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. The data related issues that arose in this process, including access to confidential data, is additional evidence that the roles and responsibilities and the access to data and information need to clearly defined by the Commission in the PJM Market Monitoring plan and its analogs for other market monitors.

The Commission has raised important issues at the intersection between transmission planning and markets, and between transmission planning and nonmarket approaches to generation. The Market Monitor supports the Commission's concept of an independent transmission monitor for both RTO/ISO markets and non-RTO/ISO areas that would provide an expert, informed, and independent source of information about transmission planning, competition and costs to the Commission, state public utility commissions, all market participants, all customers, and PJM.

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31 *See* PJM, PJM Manual 14F: Competitive Planning Process, Rev. 7 (July 1, 2021).

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it resolves the issues raised in this proceeding.

Respectfully submitted,

Jeffrey W. Mayes

Joseph E. Bowring
Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8051
joseph.bowring@monitoringanalytics.com

Jeffrey W. Mayes

General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

Howard J. Haas
Chief Economist
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8054
howard.haas@monitoringanalytics.com

John Dadourian
Senior Analyst
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8050
john.dadourian@monitoringanalytics.com

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