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March 22, 2016

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., EL16-6-001 & ER16-121

Dear Ms. Bose:

On March 15, 2016, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submitted comments in this proceeding. On March 16, 2016, the Market Monitor submitted an errata filing identifying two formatting errors in the filing. The Market Monitor has discovered an error in the March 16 filing. On page 3, line 6, the reported percent should be 59.8 rather than 30.7. The modified sentence reads: "Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period." The calculated percent offset does not include end of year shortfall or excess, which will have a small impact on the self scheduled FTR revenue and therefore on the percent offset.

Please find a corrected pleading attached.

If you have any questions regarding this filing, please contact the undersigned at (610) 271-8053.

Sincerely,

Jeffrey W. Mayes, General Counsel

Attachment

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket Nos. EL16-6-001 &
	)	ER16-121-000
	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to the Notice Inviting Post-Technical Conference Comments issued February 23, 2016, in the above proceeding, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[1] ("Market Monitor"), submits these comments, including responses to the specific questions included in the Notice.

I. INTRODUCTION

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

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1 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").

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced to permit the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[2] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated congestion revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market.[3] Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load. Congestion revenues are defined to be equal to the sum of day-ahead and balancing congestion. FTRs are one way to do that.

Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs).[4] The load still owns the rights to congestion collected under this system, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights in the FTR auction in exchange for a revenue stream based on the price of FTRs in the Annual FTR Auction.

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2 *See* 81 FERC ¶ 61,257, at 62,241 (1997).

3 *See Id*. at 62, 259–62,260 & n. 123.

4 *PJM*, 102 FERC ¶ 61,276 (2003).

Under the ARR construct, all of the FTR auction revenue should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. One of the reasons for this inefficiency is the link, established by PJM member companies in their initial FTR filings, between congestion revenues and specific generation to load transmission paths. The original filings, made before PJM members had any experience with LMP markets, retained the view of congestion rooted in physical transmission rights. In an effort to protect themselves, the PJM utilities linked the payment of FTRs to specific, physical contract paths from specific generating units to specific load zones. That linkage was inconsistent with the appropriate functioning of FTRs in an LMP system. The ARR allocation in 2015 continued to be based on those original physical generation to load paths, an illustration of the inadequacy of that contract path approach and a major source of the issues with the FTR model in 2015.

If the original PJM FTR design had simply been designed to return congestion revenues to load, many of the subsequent issues with the FTR design would have been avoided. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

II. REGARDING PJM'S FILING AND PROPOSED CHANGES.

A. Whether PJM's conservative modeling of outages that limited the allocation of Stage 1B ARRs have resulted in an inequitable cost shift, and please explain why.

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.

While PJM's approach to outages in the Annual FTR Auction reduces revenue inadequacy, which was caused in part by Stage 1A ARR overallocations, it does not address the Stage 1A ARR overallocation issue directly, and has resulted in decreased Stage 1B ARR allocations through proration, decreased Stage 2 ARR allocations through proration and decreased FTR capability.

For the 2015 to 2016 planning period, Stage 1A of the Annual ARR Allocation was infeasible. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the PJM OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances.

Table 1 shows the ARR allocations for the 2011 to 2012 through 2015 to 2016 planning periods. Stage 1A allocations cannot be prorated and have been slowly increasing. Stage 1B and Stage 2 allocations can be prorated. Stage 1B and Stage 2 allocations were steadily declining over the 2011 to 2012 through 2013 to 2014 planning periods, but were very significantly reduced in the 2014 to 2015 planning period as a result of PJM's arbitrary increase in modeled outages designed to increase revenue adequacy. There was a small increase in Stage 1B and Stage 2 ARR volume from the 2014 to 2015 planning period to the 2015 to 2016 planning period.

There was an 84.9 percent decrease in Stage 1B ARRs allocated and an 88.1 percent decrease in total Stage 2 ARR allocations from the 2013 to 2014 planning period to the 2014 to 2015 planning period. Total Stage 1B and Stage 2 ARR allocations increased in the 2015 to 2016 planning year over the 2014-2015 planning year allocations, from 4,605.6 MW to 6,996.1 MW. But the ARR allocations for the 2015-2016 planning year were still 79.7 percent below 2013 to 2014 planning year volumes of 34,444.0 MW.

Table 1 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2015 to 2016 planning periods

Stage	2011/2012 ARR	2012/2013 ARR	2013/2014 ARR	2014/2015 ARR	2015/2016 ARR
Stage 1A	64,159.9	67,299.6	67,861.4	68,837.7	71,874.0
Stage 1B	22,208.3	18,431.7	15,782.0	2,389.6	3,643.1
Stage 2-1	3,072.5	2,700.6	3,519.2	360.9	643.8
Stage 2-2	6,652.6	3,334.3	3,200.0	455.9	511.2
Stage 2-3	6,382.6	6,218.7	2,611.8	291.2	521.5
Total Stage 2	16,107.7	12,253.6	9,331.0	1,108.0	1,676.5

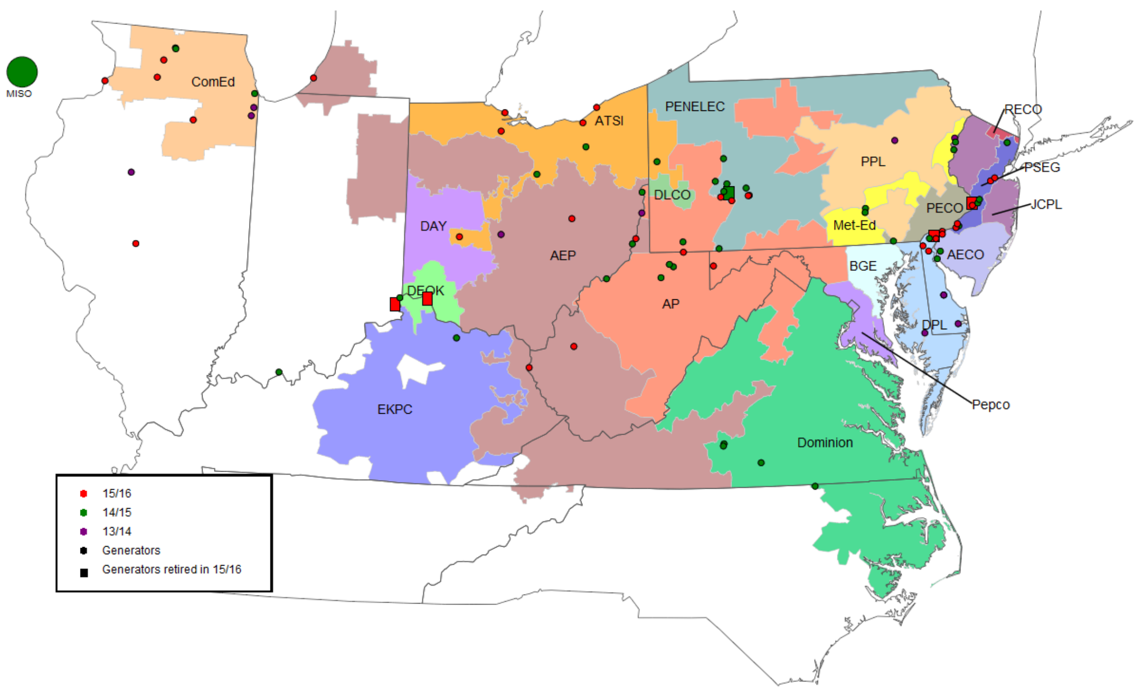
Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.[5]

[5] PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p22.

In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM was required to raise the modeled capacity limits on 84 facilities, 24 of which were internal to PJM, a total of 6,271 MW.[6]

Figure 1 shows a map of over allocated ARR source points in Stage 1A, regardless of reason, for the 2013 to 2014 through 2015 to 2016 planning period. The year indicated for each source point is the latest year that source was announced as over allocated in the Stage 1A process. Generators retired as of the 2015 to 2016 planning period are indicated by a square marker to show Stage 1A source points that are no longer in service for the most recent Stage 1A allocation period.

Figure 1 Overallocated Stage 1A ARR source points



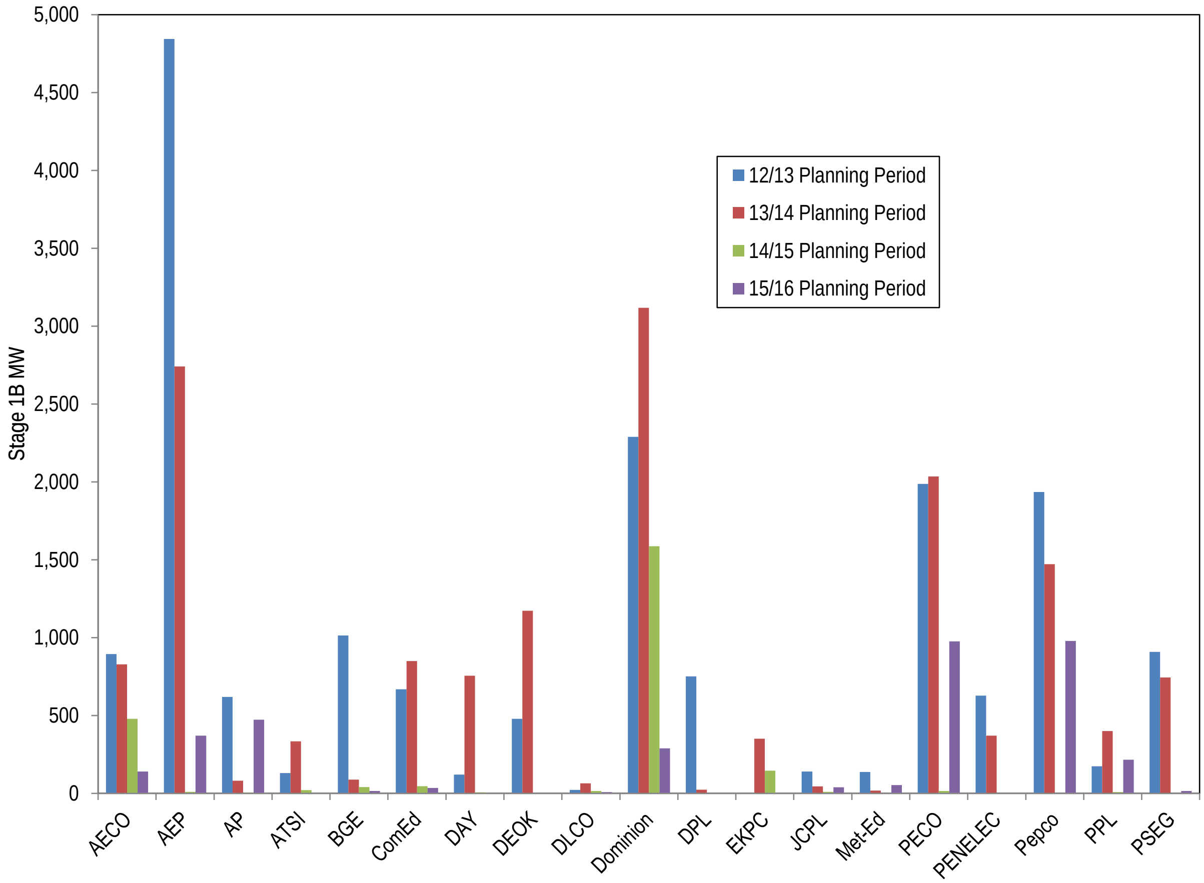
PJM began using a much more conservative approach to modeling the transmission capability for the 2014 to 2015 planning period. PJM simply assumed higher outage levels

6 *PJM 2015/2016 Stage 1A Over allocation notice*, PJM FTRs, <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2015-2016/2015-2016-stage-1a-over-allocation-notice.ashx> (March 5, 2015).

and included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

It is not clear what the distributive effects PJM's conservative modeling of outages had among ARR holders. Figure 2 shows the volume of cleared Stage 1B ARRs that source within the given zone from the 2012 to 2013 through 2015 to 2016 planning periods. The sharp decrease in the 2014 to 2015 planning period can be attributed to PJM's efforts to conservatively model outages in response to revenue adequacy concerns. The slight rebound in the 2015 to 2016 planning period is representative of PJM loosening their conservative outages slightly in response to over correction the planning period before. In the 2013 to 2014 planning period, Pepco was allocated 1,471.9 MW of ARRs to sink in the zone. In the 2014 to 2015 planning period, with PJM's conservative outage assumptions, that decreased to 0.2 MW with an increase to 978.5 MW in the 2015 to 2016 planning period, after PJM relaxed their outage assumptions slightly in response to the excess revenue at the end of the previous planning period. PPL experienced a similar reduction, and then an increase in allocated Stage 1B MW, going from 399.3 MW in the 2013 to 2014 planning period down to 7.7 MW in the 2014 to 2015 planning period, and then up to 216 MW in the 2015 to 2016 planning period.

Figure 2 Cleared Stage 1B ARR volume: Planning periods 2012 to 2013 through 2015 to 2016



B. PJM proposes to eliminate portfolio netting.

a. Comment on the current practice of netting positively valued FTRs against negatively valued FTRs within an FTR holder's portfolio: Unequal Treatment of FTRs

Under the current portfolio netting rules, negative target allocations are first netted against positive, and then the payout ratio is applied. This results in two significant problems. First, a participant can shield itself from both monthly revenue inadequacy and the end of planning period uplift charge by shrinking the size of their net positive target allocations. This is advantageous because the participant can still be profiting from their negative target allocations if they are paid to take counter flow positions and pay back less than they received. Additionally, portfolio netting results in positive target allocations receiving different payout ratios depending on the composition of the portfolio they are in. All positive target allocation FTR should be treated equally, regardless of the portfolio they are in, and this can only be accomplished by eliminating portfolio netting. Not treating all FTRs equally results in participants with more negative target allocations receiving a subsidy by reducing the effective payout ratio to participants with fewer negative target allocations. The reduced payouts to participants with fewer negative target allocations subsidize increased payout ratios to participants with larger negative target allocations, and is an unbalanced distribution of available congestion revenue collected.

Table 2 demonstrates the impact on the payout ratio to positive target allocation FTRs with and without portfolio netting. In the example, the total congestion collected is $4,750 and the total net target allocation is $9,500, resulting in a reported payout ratio of 50.0 percent. With portfolio netting, the net target allocation is simply multiplied by the payout ratio to calculate the congestion revenue a participant receives. For Participant 1, this is $250 multiplied by 0.5 for a total revenue received of $125. The revenue to positive TA column is an indication of how much revenue the positive target allocations, which are the only part of a portfolio receiving available revenue, of a participant need to be paid in order to reach the congestion revenue received. For participant 1, they are effectively being paid $875 of their $1,000 so that the congestion revenue received can be $125. The result of this is that Participant 1's positive target allocations are effectively granted a payout ratio of 87.5 percent simply because they hold negative target allocations, while Participant 3, who holds no negative target allocations, is only paid at a 50.0 percent payout ratio.

Without portfolio netting all participants are paid at the same effective payout ratio for their positive target allocations. Counting negative target allocations as a source of revenue raises the payout ratio to 54.5 percent. Without portfolio netting, the payout ratio is first applied to positive target allocations, then the participant's negative target allocations are added. The result of this calculation is that each participant is paid an equal 54.5 percent regardless of their portfolio's negative target allocations. In this example, Participant 1 pays $204.55 into the available revenue, in net, while Participant 3 is paid 54.5 percent of the positive target allocations, resulting in a payment of $4,745.45. Eliminating portfolio netting is the only way to treat positive target allocations equally across all portfolios, and eliminates the subsidy positive target allocations holders are paying to negative target allocation holders.

Table 2 Change in positive target allocation payout ratio given portfolio construction

Congestion = $4,750 Net TA = $9,500					With Netting			Without Netting		
Participant	Positive Target Allocations	Negative Target Allocations	Net Target Allocations	Reported Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio
1	$1,000.00	($750.00)	$250.00	50.0%	$125.00	$875.00	87.5%	($204.55)	$545.45	54.5%
2	$750.00	($200.00)	$550.00	50.0%	$275.00	$475.00	63.3%	$209.09	$409.09	54.5%
3	$8,700.00	$0.00	$8,700.00	50.0%	$4,350.00	$4,350.00	50.0%	$4,745.45	$4,745.45	54.5%
Total	$10,450.00	($950.00)	$9,500.00	-	$4,750.00	$5,700.00	-	$4,750.00	$5,700.00	-

Another way to examine the unequal treatment of FTRs based on the portfolio they are in is to examine the actual payments counter flow FTRs make with and without portfolio netting. Table 3 shows a single participant's portfolio, and their payments from counter flow FTRs, with and without portfolio netting in an isolated system. In this example, the congestion revenue collected is $10.50 both with and without portfolio netting. The payout ratio with portfolio netting is 70.0 percent, and without portfolio netting increases to 77.5 percent due to the negative target allocations being accounted for as a source of revenue. With and without portfolio netting, the total payout received must equal the congestion collected of $10.50. However, under the logical assumption that only positive target allocations receive congestion revenue, the expected payment to positive target allocation holders changes due to the different payout ratios. With portfolio netting the expected payout is $14.00 ($20*0.7) and without portfolio netting the expected payout to positive target allocations if $15.50 ($20*0.775). The subsidy amount is the total payout minus the sum of the expected payment for positive target allocations and the negative target allocations. This provides the difference in what is calculated with portfolio netting and what should be calculated to pay positive target allocations at a given payout ratio. The negative payout ratio is one plus the subsidy amount divided by negative target allocations. The total subsidy amount, divided by negative target allocations, is the percent subsidy provided to negative target allocations as a result of portfolio netting. One plus the subsidy provides a number more familiar to FTR holders. This percentage can be multiplied by the negative target allocation to calculate a participant's actual payment.

The effect of portfolio netting can be interpreted in two ways. One is that, under the same portfolio construction, positive target allocation FTR holders experience a smaller amount of available revenue simply because negative target allocations are not properly accounted for. In this example, with portfolio netting, positive target allocation holders are essentially only receiving $9 in congestion rather than the actual $10.50 with the remaining $1.50 going to negative target allocation holders. The second interpretation is that negative target allocation FTRs are being subsidized by positive target allocation FTRs and only paying their target allocation multiplied by the payout ratio, instead of the largely assumed and claimed 100 percent. Negative target allocation holders paying less than 100 percent is another way to reduce the revenue that should be available to pay positive target allocations and is a flawed result of settlement rules. Under either interpretation, it is evident that positive target allocation holders are not receiving their share of available revenue simply because of portfolio netting.

Table 3 Counter flow payments with and without portfolio netting

PR Net = 70.0%; PR No Net = 77.5%	With Netting	Without Netting
Congestion Revenue	$10.50	$10.50
Positive TA	$20.00	$20.00
Negative TA	($5.00)	($5.00)
Net TA	$15.00	$15.00
Total Payout	$10.50	$10.50
Expected Payment for Positive TA	$14.00	$15.50
Subsidy Amount	$1.50	$0.00
Negative Payout Ratio	70.0%	100.0%

b. Comment on the current practice of netting positively valued FTRs against negatively valued FTRs within an FTR holder's portfolio: Netting and the Mathematical Equivalence of FTRs

A single FTR can be broken into multiple FTRs. The newly formed set of multiple FTRs can have the same net target allocation as long as the start and end points of the constituent FTRs are, in net, the same as the original.[7] Opponents of the elimination of FTR netting have claimed that without netting this would no longer be true. However, this assertion does not account for revenues from negative target allocation FTR paths in the mathematically equivalent set of FTRs. Appropriately including these revenues results in mathematical equivalence between the single FTR and that same FTR broken into a constituent set of FTRs with the same start and end point.

Table 5 shows the effects on a participant with and without portfolio netting under three distinct scenarios. Table 4 provides the day-ahead CLMP values for each node used in the example. In this example, a participant can either buy an FTR position directly from A to B or can break it into individual pieces with the net effect of an FTR from A to B and a net target allocation of $5. In this example, there was $3.60 in congestion collected due to a payout ratio of 72.0 percent and a total payout in each of the three scenarios of $3.60. This payout amount is simply the payout ratio of 72.0 percent multiplied by the net target allocations of $5 in each scenario.

With the elimination of netting, if the additional revenue created by considering positive and negative target allocations separately is disregarded, it appears as if the payout for the same net FTR is drastically different depending on the composition of the FTR. The results of this mistake are payouts of $3.60, -$0.60 and -$25.80 for the same net FTR in each distinct scenario. However, if the negative target allocations are properly accounted for as a source of revenue when considering congestion collected, the total revenue available increases, thereby increasing the payout ratio for each scenario's positive target allocations. The total revenue available is the $3.60 in congestion collected plus the negative target allocations, resulting in revenue available to pay positive target allocations of $3.60, $18.60 and $108.60 with payout ratios to positive target allocations of 72.0 percent (unchanged due to no negative target allocations), 93.0 percent and 98.7 percent. Multiplying these correct

[7] DC Energy Dr. Stevens affidavit at 13, Table 4.

payout ratios by the scenario's positive target allocations, and then adding the scenario's negative target allocations results in a net payout of $3.60 for each scenario.

The results of this example demonstrate the mathematical fact that no matter how an FTR path is constructed, as a single FTR or a mathematically equivalent set of FTRs, the total payment the FTR path will be the same. Attempts to disprove this fact ignore the revenues from the constituent FTR counter flow positions and the resulting change in payout ratio that is experienced by positive target allocations. A net FTR may be constructed in any manner and the resultant total payout will be equivalent with and without portfolio netting.

Table 4 Nodal day-ahead CLMPs

Node	DA CLMP
A	$20
B	$25
C	$40
D	$100
E	$10

Table 5 Mathematically equivalent FTR payments with and without portfolio netting

FTR Path(s)	Positive TA	Negative TA	Net TA	Available Revenue Netting	Netting Revenue Received	No Netting Revenue Received (Incorrect)	Available Revenue No Netting	Payout Ratio No Netting	Correct No Netting Revenue Received
A-B	$5.00	$0.00	$5.00	$3.60	$3.60	$3.60	$3.60	72.0%	$3.60
A-C, C-B	$20.00	-$15.00	$5.00	$3.60	$3.60	-$0.60	$18.60	93.0%	$3.60
A-C, C-E, E-D, D-B	$110.00	-$105.00	$5.00	$3.60	$3.60	-$25.80	$108.60	98.7%	$3.60

c. Do the current tariff provisions on netting work to protect the markets against the potential exercise of manipulation, and if so, how?

The answer is no.

The beneficiaries of the subsidies created by the current netting provisions assert that eliminating their subsidy would create a new opportunity for market manipulation. There is no basis for this assertion. If there were any potential for market manipulation, it should be addressed directly rather than maintaining an inefficient system of subsidies that requires holders of positive FTRs to subsidize those with negative FTRs in their portfolios in proportion to the level of their negative FTRs. The assertion that an inefficient market design and special subsidies are required in order to prevent market manipulation is a creative effort to defend subsidies but is ultimately a demonstration of the weakness of the position.

Supporters of the current tariff provisions state that without portfolio netting it would be possible to increase a participant's proportion of positive target allocations to receive a larger share of any end of planning period excess. The proposed manipulation would be the simultaneous purchase of offsetting prevailing flow and counter flow FTRs. While this would also work with netting, the profitability would increase without netting because there is no offset from the counter flow positions. Supporters of portfolio netting argue that, based on this potential manipulation the proposal to eliminate portfolio netting should be dismissed.

Under the current netting rules, a participant can reduce its net positive allocation of any end of planning period uplift charge by purchasing additional counter flow FTRs, and shift the burden to other FTR market participants. Without the current portfolio netting rules this is not possible, since the shortfall allocation would not be based on their net positive, but rather their gross positive, target allocations.

Supporters of the current tariff provisions also state that they use the existing netting provisions to construct their portfolios to avoid losses from the payout ratio adjustments and end of planning period uplift charges, at the expense of those that do not.[8] As Elliott Bay states:

> "Accordingly, with netting, buying a counter flow FTR (being paid in the FTR auction to assume the congestion obligations) would reduce a market participant's target allocation, and hence its share of underfunding but there is nothing unjust about being paid $3.50 for a counterflow FTR that will result in $3.50 reduction in market participant's share of congestion revenues."[9]

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8 *See* Elliott Bay at 18, DC Energy Dr. Stevens affidavit at 13

9 "Motion for leave to answer and answer of Elliott Bay Energy Trading," Docket Nos. EL16-6-000 and ER16-121-000 (December 4, 2015), at 18.

Elliot Bay misunderstands the problem created by netting. The problem is the subsidy that the participant will receive should they hold positive target allocations when there is revenue inadequacy. For purposes of revenue inadequacy, the participant has reduced their net positive target allocation by $3.50, meaning they will receive less of the revenue inadequacy penalty because they hold negative target allocations. The difference in losses comes from participants with fewer negative target allocations, who will be required to pay more of the revenue inadequacy penalty simply because of their portfolio structure. Eliminating portfolio netting would eliminate this subsidy, and pay each participant the actual value of their positive target allocation FTRs.

Supporters fail to explain why the existing practice of purchasing counter flow FTRs to reduce their share of the revenue inadequacy is not manipulation when there is a revenue shortfall and why the proposed practice is manipulation when there is a revenue excess.

Existing market rules restrict the ability to manipulate the market in this manner currently, and those rules will remain effective at limiting the ability of participants to manipulate the market without portfolio netting. Rules on wash trades for example, could be used to address any such behavior. Credit and bid limits impose some restrictions. A simple prohibition on the behavior would also work. Whether the rules remain the same or are modified, the manipulation rules should be reviewed.

d. *If netting is eliminated and causes the potential for the exercise of manipulation, what measures would need to be put into place to prevent potential market manipulation?*

The potential for manipulation exists under the netting rules and would continue with the elimination of the netting rules. There are currently no specific rules in place to mitigate market manipulation of the end of planning period uplift/surplus.

Rules on wash trades for example could be used to address any such behavior. A simple prohibition on the behavior would also work.

A more direct approach would be to eliminate counter flow FTRs. Both the identified schemes, with and without netting, depend on the existence of counter flow

FTRs. The elimination of counter flow FTRs would solve a number of issues including the identified potential manipulation issues, all of which depend on the use of counter flow FTRs. Counter flow FTRs are inconsistent with the efficient operation of the FTR Market. Counter flow FTRs reduce FTR prices, reduce ARR funding, create cross subsidies among portfolios, facilitate gaming the rules and facilitate PJM's inappropriate use of ARR surplus revenues to purchase counter flow FTRs.

As noted by several commenters, counter flow FTRs (defined here as FTRs having a negative auction price) reduce FTR prices.[10] The commenters have suggested this price suppressive effect is a benefit of counter flow FTRs. But when counter flow FTRs suppress the price of FTRs, they correspondingly suppress the value of ARRs to the detriment of ARR holders and the benefit of FTR holders.

e. Would allocating surplus funds to load rather than to FTR holders, or carrying surplus funds forward to fund any future revenue inadequacy be ways of addressing potential manipulation?

The IMM does not believe that either allocating surplus funds to load or carrying surplus funds forward are appropriate market design changes. Both would affect a fundamental part of the ARR/FTR design while not addressing the underlying issues with the design.

There are direct and effective ways to address any incentives to manipulate the markets which do not require such changes.

Ensuring that all congestion revenues are returned to load would address the fundamental ARR/FTR design issues and also solve the potential issue of incentives for manipulation. In a design in which load traded their rights to congestion revenues for a payment, the rights to congestion revenue no longer belong to them.

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[10] *See* Appian Way at 5, DC Energy et al at 8, Elliott Bay at 16

Under the existing design, all FTR auction revenue should go to ARR holders in return for selling their rights to congestion revenues to FTR holders. Currently, any excess auction revenue is used to pay for counter flow FTRs, or given to FTR holders at the end of the planning period. Both methods constitute a misallocation of FTR auction revenues, and a subsidy from ARR holders to FTR holders.

C. The appropriateness of using the 1.5 percent adder for all zones, regardless of the actual zonal load growth rate and negative load growth projections for some areas; and the appropriateness of conducting the 10-year study with different growth rates as a sensitivity study, as is done for other RTEP studies. Is the cost of building transmission as a result of the 1.5 percent adder justified by the benefit of being able to accommodate the current allocations in Stage 1A?

The 1.5 percent adder for all zones will not materially affect or resolve the Stage 1A over allocation issue. Stage 1A allocations are based on generation to load paths from 1998 or from the date that new areas were integrated into PJM markets. There have been many changes in the status of the generation resources and the transmission network during this period. Generators may have retired and load may have shifted so that the historic generation to load path is no longer meaningful. The fact that PJM has not built additional transmission to support the Stage 1A allocations is consistent with this view. If the RTEP process had identified a need to build transmission, it would have been built. But this has not happened. The reason that PJM does not build transmission to solve the Stage 1A overallocation issue is that, in reality, the relevant lines are not overloaded. This is evidence that the historical generation to load paths that underlie the Stage 1A allocation are fictitious, as are many other outdated generation to load paths.

The Stage 1A ARR allocation issue is complex and any solution to the related issues must be part of a broader solution to the current flawed design of the ARR/FTR markets. Resolution of the Stage 1A allocation issue should not be done in a vacuum with the result that holders of Stage 1A rights are denied access to congestion revenues they should receive. The implementation of the IMM's recommendation to return all congestion revenues to load would resolve this issue as well as the broader FTR/ARR design issues.

III. QUESTIONS REGARDING PJM'S PROPOSED SOLUTIONS IN THE CONTEXT OF ITS CURRENT TARIFF.

A. If infeasible Stage 1A ARRs should continue to be awarded and treated as they are today.

PJM rules currently provide that in the first stage of the allocation of ARRs, network transmission service customers can obtain ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[11] While transmission upgrades are being implemented, Stage 1A ARRs, and therefore FTRs, are overallocated which can lead to revenue inadequacy. But transmission upgrades are not, in general, undertaken because the source of the infeasibility is not, in general, actual overloads on transmission lines.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy.

But any solution to the Stage 1A ARR allocation issue must be part of a broader solution to the current flawed design of the ARR/FTR markets. A simple removal of the requirement would not be appropriate.

The origin and basis for the requirement to assign Stage 1A ARRs is complex. The issues associated with over allocation appear to be based on interpretations of the Federal

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[11] *See* PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), at 22.

Power Act, of Order No. 681, on the related use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the Stage 1A requirements. More fundamentally, the issues are one more manifestation of the failure of the existing ARR/FTR design to effectively allocate all congestion revenue to load.

The current rules governing Stage 1A ARR allocations are not required by the Federal Power Act or by Order No. 681. The origin of the perceived obligation to allocate a defined level of Stage 1A ARRs is in Section 217(b)(4) of the Federal Power Act and Order No. 681.[12] Section 217(b)(4) does not provide for a defined level of allocation, but, rather, provides:

> The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

The reasonable needs of LSEs standard in Section 217(b)(4) is not a defined level and the long-term basis for existing or planned power supply arrangements is not linked irrevocably to specific historic generation to load paths. Section 217(b)(4) appears to leave substantial flexibility in meeting the defined requirements.

In Order No. 681, the rule implementing Section 217, the Commission provided guidelines for compliance with Section 217, including guideline 5, which pertains to LSEs' reasonable needs:

> Load serving entities must have priority over non-load serving entities in the allocation of long-term firm transmission rights that are supported by existing transmission capacity. The transmission

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[12] 16 U.S.C. § 824q; Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 116 FERC ¶ 61,077 at PP 79–80 (2006) (Order No. 681), order on reh'g, Order No. 681-A, 117 F.E.R.C. ¶ 61,201 (2006).

> organization may propose reasonable limits on the amount of existing transmission capacity used to support long-term firm transmission rights.[13]

Guideline 5 expressly provides that LSEs should have priority in allocations of FTRs supported by existing transmission capacity, but does not require any defined level and does not require the construction of new transmission. Guideline 5 also expressly recognizes that an RTO may "propose reasonable limits on the amount of existing transmission capacity used to support long term transmission rights."

The Commission found that PJM's existing tariff did not comply with Guideline 5 because the proration of ARRs at a constrained facility (where the simultaneous feasibility test (SFT) failed) applied more heavily to ARRs held by LSEs located nearer to a constraint.[14] Such LSEs were deemed more likely to have historically relied upon the constrained facility to serve load.[15] The Commission instituted settlement judge proceedings to resolve the issue.[16]

The resolution that PJM chose was a settlement removing the simultaneous feasibility test from stage 1A allocations.[17] By allocating all ARR requests without regard to

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13 Order No. 681 at P 325; codified at 18 CFR § 42.1(d)(5).

14 *See* 18 PJM, 117 FERC ¶ 61,220 at PP 80, 87 (2006) ("[W]hen PJM determines that all requested ARRs are not simultaneously feasible, PJM's existing pro-rationing methodology limits the amount of congestion hedges that can be allocated to certain transmission customers, due primarily to the proximity of their loads to the constrained facilities. This may result in certain LSEs in close proximity to a constrained facility being pro-rated more severely than more distant loads that produce flow on the constraint."); *order on settlement, etc.*, 119 FERC ¶ 61,144 (1 (2007).

15 *Id.*

16 *Id*. at P 80.

17 *See* 119 FERC ¶ 61,144 at P 91 ("PJM and the settling parties agreed to permit LTTRs in stage 1A of the allocation process that would otherwise have been infeasible so that the affected LSEs could obtain LTTRs up to their Zonal Base Loads. This is consistent with the intent of section 217 of the FPA and of Order No. 681: to ensure that LSEs can secure a reasonably sufficient amount of LTTRs to meet their load obligations.").

the SFT, PJM avoided further consideration of the proration rules. The Commission approved the settlement, explaining in part its reliance on PJM statements that it did not anticipate allocating many ARRs that would have failed the SFT.[18] The Commission explicitly raised the possibility that it may investigate the approach to Stage 1A ARRs allocations in the future.[19]

Part of the Stage 1A ARR allocation issue has the same roots as the broader issues of the ARR/FTR market design. Stage 1A allocations are based on generation to load paths from 1998 or from the date that new areas were integrated into PJM markets. There have been many changes in the status of the generation resources and the transmission network during this period. Generators may have retired and load may have shifted so that the historic generation to load path is no longer meaningful. The fact that PJM has not built additional transmission to support the Stage 1A allocations is consistent with this view. If the RTEP process had identified a need to build transmission, it would have been built. But this has not happened. The reason that PJM does not build transmission to solve the Stage 1A overallocation issue is that, in reality, the relevant lines are not overloaded. This is evidence that the historical generation to load paths that underlie the Stage 1A allocation no longer reflect reality as is the case for many other outdated generation to load paths.

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[18] *Id*. at P 92 ("DC Energy admits that it relies on PJM's representation that "[a]bsent unanticipated reductions in system capability, at this time PJM does not expect that it will need to implement these Settlement terms in order to allocate otherwise infeasible ARRs in stage 1A of the allocation process." The Commission concurs with this observation. Further, according to PJM, in 2008, a static var compensator should be installed at Bedington-Black Oak interface increasing the transfer capability of this interface by 250 MW. In fact, PJM predicts that, after this upgrade is installed, the stage 1A and 1B ARR requests should not experience pro-rationing due to the Bedington-Black Oak interface through 2015.[footnote omitted] PJM will include this transmission upgrade in its planning process to allow requested ARRs to be feasible. As a result, absent reductions in system capability, PJM does not expect that it will need to allocate otherwise infeasible ARRs in stage 1A of the allocation process.").

[19] *Id*. at P 94.

While Stage 1A overallocations result, in a mechanical sense, in a reduction in congestion payments per MW of FTRs, the Stage 1A obligation is not the source of the problem.

The IMM recommends that the basis for the Stage 1A allocations be reviewed and made explicit, that the role of all out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. PJM's obligation to provide Stage 1A ARRs must be met, but it must be met in a rational way.

Resolution of the Stage 1A allocation issue should not be done in a vacuum with the result that holders of Stage 1A rights are denied access to congestion revenues they should receive.

The implementation of the IMM's recommendation to return all congestion revenues to load would resolve the Stage 1A allocation issue as well as the broader FTR/ARR design issues by ensuring that all ARR holders receive the congestion revenues they pay. This would provide a complete offset to congestion costs, which is sometimes erroneously referred to as a hedge. This approach would, in general, provide congestion revenues to Stage 1A ARR holders greater than or equal to those that result from the current process.

B. The options and implications for, and potential benefits or drawbacks of, ARR allocation based on more frequent updates of the Simultaneous Feasibility Test model, which could, for example, allow for seasonal variations of line ratings, as well as more timely recognition and modeling of transmission outages and upgrades placed into service.

The goal of the ARR/FTR model should be to return all congestion revenues to load. If the model is redesigned so that ARRs are designed to return all congestion revenues to load and the model provides a mechanism for the congestion revenue rights of ARRs to be auctioned in return for FTR auction revenue, then seasonal modeling would be an improvement. For example, monthly or seasonal modeling more accurately reflects information about the expectation and duration of outages.

Under the current ARR/FTR model, using a seasonal allocation of ARRs would further reduce the payment of congestion revenues to load. Under the current model, the redefinition of the ARR product and the associated more frequent modeling should be implemented only if it does not interfere with the goal to return all congestion revenues to load.

C. The options to update PJM's Simultaneous Feasibility Test model, including source points and sink points, to reflect current system usage and topology; concerns about updating the model; the potential benefits or drawbacks for updating the model; and processes for allowing more frequent updates. If the Simultaneous Feasibility Test model were to be updated more frequently, would infeasible ARRs continue to exist?

The use of outdated generation to load paths is an issue. But updating the model to reflect more current generation to load paths does not resolve the fundamental ARR/FTR model issues. The simple incorporation of updates generation to load paths would perpetuate the archaic contract path model of ARR allocation. The contract path model is not an efficient or effective way to ensure that all congestion revenues are returned to load. It could perpetuate the history of substantial underpayments of congestion to load by assuming that only congestion on specific paths should be returned to load and that the balance is available for distribution to other participants. That is not correct. Load pays for the transmission system and load pays all congestion charges.

D. Whether the incentives for Transmission Owners to schedule outages and conduct timely work align with ARR/FTR construct, and whether there are any proposals that can improve this alignment; and the effectiveness of the current reporting requirements for Transmission Owners to share information with PJM.

There are clear rules defined for assigning on time or late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[20] However, the on time or late

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[20] OATT Attachment K Appendix § 1.9.2 (Outage Scheduling).

status only affects the priority that PJM assigns for processing the outage request. Many (72.8 percent) non-emergency, expected to cause congestion, late transmission outages were approved and completed. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

A transmission outage ticket with a duration exceeding five days with an on time status can retain its on time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[21] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

PJM rules define a transmission outage request as on time or late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

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21 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 64.

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this since the rule has no direct connection to the annual FTR auction opening date. The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR Auction bidding opening date.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

E. Whether continuing to include balancing congestion in the definition of FTRs is appropriate (and why), or whether FTRs should be defined and settled only including day-ahead congestion. Are there any aspect(s) of balancing congestion that should be included in the definition of FTRs, and, if so, what are they and why they should be included?

The purpose of the ARR/FTR design is to return congestion revenue to load. As an accounting fact, balancing congestion, either positive or negative, is a component of congestion revenue as defined by PJM.[22] Ignoring losses, congestion is the difference between what load pays for energy and what generation is paid.

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22 The Total Transmission Congestion Charges are the sum of the Day-ahead and Balancing Congestion Charges for all PJM Members, adjusted for the value of day-ahead and balancing congestion revenues due to inadvertent interchange, losses, and the MISO and NYISO joint operating agreement coordination, minus the negatively valued FTR Target

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads, which pay for the transmission system, to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system, which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices, which result in load payments in excess of generation revenues, which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues, which equals total congestion revenues.

As long as the congestion revenues were allocated to loads, the loads received the appropriate congestion offset, regardless of the actual level of congestion. Loads were never paid uplift to make up the difference between expected and realized congestion. By receiving the actual congestion incurred, loads were made whole for actual congestion incurred. That is all that was necessary. That is all that is necessary.

With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

Allocations. PJM. "Manual 28: Operating Agreement Accounting," (Revision 72), P 56. Effective Date: 12/17/2015

With the creation of ARRs, participants who paid for the transmission system have the ability to sell the rights to the congestion in the form of FTRs. FTRs have a right to the congestion collected, no more, no less. For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[23] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day-ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders.

The arguments for a subsidy depend on the assertion that if actual congestion is less than day-ahead congestion, FTRs are underfunded. This is equivalent to arguing that FTR holders have a property right to day-ahead congestion, calculated as target allocations based on day-ahead LMPs. This property right does not exist. This property right should not exist, based on the logic of the ARR/FTR design, or based on the explicit language of the tariff. Therefore there is no such thing as underfunding.

The appropriate term to indicate that total congestion revenue is less than the day-ahead target allocations is revenue inadequate.

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23 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

It has been asserted that a majority of PJM stakeholders view FTRs as a hedge against day ahead congestion. This assertion is sometimes based on a stakeholder poll taken at the FTR Senior Task Force ("FTRSTF") in which 73.4 percent of 127 respondents agreed that the FTR product is a hedge against day-ahead congestion. Holding aside questions about survey design and whether the responses were unambiguous and the outcome of the corresponding sector weighted vote, the assertion that a majority of PJM stakeholders support the view that FTR should be subsidized by load so that FTRs are guaranteed to cover day-ahead congestion is demonstrably false.

The effort to redefine the FTR product from a right to an allocation of congestion revenues to a right to recover day-ahead congestion has been raised and rejected repeatedly in the PJM stakeholder process. The FTR review process has lasted years. One consistent outcome is that the stakeholders have repeatedly and unambiguously rejected PJM's proposal and the proposal of the financial traders to require load to subsidize FTRs by eliminating balancing congestion from the calculation of total congestion. This is evidence that the stakeholder process has been successful. Those who do not like the outcome assert that the process is the problem. The process is not the problem. The subsidy proposal is the problem.

IV. 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,

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Dated: March 15, 2016

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 15th day of March, 2016.

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