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VIA ELECTRONIC FILING

September 15, 2023

Ms. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
420 North Salisbury Street
Raleigh, North Carolina 27603-5918

Re: Docket No. E-22, Sub 418

Dear Ms. Dunston:

Consistent with Article XIV of the Agreement and Stipulation of Settlement filed with the North Carolina Utilities Commission and the Commission's order of December 22, 2016, in Docket No. E-22, Sub 532, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM Interconnection, L.L.C., submits the attached report. The report includes the information specified in Paragraph 6 of the Joint Offer of Settlement between Dominion North Carolina Power and PJM Interconnection, L.L.C., filed in Docket No. E-22, Sub 532, on December 16, 2004.

The Commission has indicated that the Market Monitor should file these reports in Docket No. E-22, Sub 418.

This report shows that the ARR/FTR design does not serve as an efficient mechanism for returning congestion revenues to the load that paid them. The ability of the market design to return all congestion revenues to the load is the most important metric for evaluating whether that design serves the public interest.

Please contact Joseph Bowring if you have any questions about this matter, at 610 271-8051 or at *joseph.bowring@monitoringanalytics.com*.

Yours truly,

Jeffrey Mayes, General Counsel

cc: Andrea R. Kells, Esq.

CERTIFICATE OF SERVICE

I hereby certify that copies of the attached 2023 Report, as filed in Docket No. E-22, Sub 418, was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This 15th day of September, 2023

Jeffrey W. Mayes

CERTIFICATE OF SERVICE
DOCKET NO. E-22, SUB 418

I hereby certify that the foregoing Report on PJM Interconnection LLC was served by first-class mail, postage prepaid, to the following:

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REPORT TO THE NORTH CAROLINA PUBLIC UTILITIES COMMISSION

Congestion in the Dominion Service Territory in North Carolina: 2021/2022 and 2022/2023

The Independent Market Monitor for PJM

September 15, 2023

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Overview of Congestion Calculations

This report provides details of congestion in the part of the Dominion Zone in North Carolina, known as Dominion North Carolina Power (DNCP), for the 2021/2022 and 2022/2023 planning periods. Congestion is defined to be load payments in excess of generation revenues, excluding marginal losses. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

Congestion calculations in this report are for DNCP. The report includes congestion event hours for the constraints that caused the congestion revenue paid by load and the congestion collected from that load for each constraint.[4] Congestion in this report is calculated on a constraint specific basis which reflects the differences between credits and charges caused by binding transmission limits on the power flow from generators, regardless of the location of that generation, to load in the part of DNCP.

In this report, congestion equals the total congestion charges paid by load at the buses in the part of DNCP minus the total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of the location of the generation in PJM.

Congestion charges and credits at specific buses are defined by the congestion component of LMP (CLMP) times load and generation MW. CLMPs are calculated when locational marginal prices (LMP) are calculated in a least cost security constrained dispatch solution. The CLMP at a bus is defined by the shadow prices of binding

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1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.

2 The difference in losses is not part of congestion.

3 PJM billing examples can be found in *2021 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

4 Congestion event hours are hours in which a transmission constraint is binding. In the day-ahead market, an interval equals one hour. In the real-time market, an interval equals five minutes. In order to have a consistent metric for day-ahead and real-time congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any one of its component five-minute intervals is constrained.

transmission constraints and the distribution factors from the binding constraints to each bus, relative to the load-weighted reference bus. The load-weighted reference bus is the theoretical point in a network where the LMP is equal to the load-weighted average price for energy in the least cost security constrained system solution.

The resulting CLMP component of LMP at a bus is not congestion. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[5] CLMPs are merely an indication that the LMP at a bus is higher (in the case of a positive CLMP) or lower (in the case of a negative CLMP) than the average load-weighted LMP of the system (the LMP at the reference bus) due to binding transmission constraints.

The price differences caused by binding transmission constraints cause load to pay more for energy than generation that serves that load is paid for that energy. The amount of congestion collected from load due to a binding transmission constraint is equal to the market flow over the constraint times the price difference between low priced side of the constraint and the high priced side of the constraint. The price difference caused by a constraint is the shadow price of the constraint. Congestion caused by a constraint is therefore equal to the market flow over the binding constraint times the shadow price of the binding constraint.

The congestion calculation reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

In an LMP system, the best way to ensure that load receives congestion revenues is to directly assign the rights to congestion revenues to load. FTRs were the mechanism initially selected in PJM to return the congestion costs that load pays in an LMP market. ARRs were added later.

The ARR/FTR design does not serve as an efficient mechanism for returning all congestion revenues to the load that paid it. The ARR/FTR design was flawed from its introduction and became more flawed as a result of changes to the design since its introduction. The flaws include: the use of generation to load paths to define the rights to congestion; the definition of target allocations based on day-ahead congestion only; the failure to assign all FTR auction revenues to ARR holders; differences between

[5] PJM billing examples can be found in *2020 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

modeled and actual system capability; numerous cross subsidies among participants; the allocation of balancing congestion and M2M payments to load and PJM's repeated subjective interventions in the market.[6]

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design would have been avoided. The design should simply have provided for the return of all congestion revenues to load. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

Locational Marginal Price (LMP)

Components

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The SMP is the same as the load-weighted average LMP resulting from the security constrained dispatch. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints and marginal losses. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution.

6 See *2022 Annual State of the Market Report for PJM,* Vol. 2, Section 13: Financial Transmission and Auction Revenue Rights, for more details on the history of the FTR/ARR design.

CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to provide that energy, after virtual bids have been settled. Congestion equals the sum of day-ahead and balancing congestion.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

The tables (Table 1, Table 2, Table 3, Table 4) provide a break out of LMP components for DNCP for the 2012/2013 through 2022/2023 planning periods. The congestion components of LMP (CLMPs) provided in the following tables are not an indication of the amount of congestion paid by load in DNCP. The CLMPs are an indication of whether the prices in DNCP are higher or lower than the load-weighted average price in the PJM system due to transmission constraints.

Table 1 shows the real-time load-weighted average LMP components for PJM and for DNCP for the 2012/2013 through 2022/2023 planning periods.[7] The CLMPs in Table 1

[7] See *2021 Annual State of the Market Report for PJM*, Volume 2*:* Section 11: Congestion and Marginal Losses.

indicate that, due to transmission constraints, load in DNCP paid real-time load-weighted LMPs that were $5.44 higher than if the load had paid the real-time load-weighted average price for PJM in the 2022/2023 planning period.

Table 1 PJM and DNCP real-time load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2022/2023 planning period

	PJM				NC			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2012/2013	$37.87	$37.82	$0.03	$0.02	$39.21	$37.74	$1.19	$0.28
2013/2014	$54.05	$54.06	($0.03)	$0.02	$61.29	$55.33	$5.72	$0.25
2014/2015	$40.23	$40.18	$0.03	$0.02	$43.57	$40.79	$2.27	$0.51
2015/2016	$28.80	$28.75	$0.04	$0.01	$31.89	$28.95	$2.66	$0.27
2016/2017	$30.57	$30.52	$0.03	$0.01	$31.97	$30.44	$1.24	$0.29
2017/2018	$36.98	$36.93	$0.03	$0.02	$42.92	$38.12	$4.16	$0.64
2018/2019	$31.67	$31.62	$0.03	$0.02	$32.15	$31.29	$0.56	$0.30
2019/2020	$23.72	$23.68	$0.02	$0.02	$24.81	$23.42	$1.17	$0.22
2020/2021	$26.02	$25.98	$0.03	$0.02	$27.29	$25.81	$1.20	$0.27
2021/2022	$52.44	$52.35	$0.06	$0.03	$57.16	$52.37	$4.03	$0.77
2022/2023	$68.07	$67.94	$0.08	$0.05	$78.78	$71.67	$5.44	$1.68

Table 2 shows the day-ahead load-weighted average LMP components for PJM and for DNCP for the 2012/2013 through 2021/2022 planning periods. The CLMPs in Table 2 indicate that, due to transmission constraints, load in DNCP paid day-ahead load-weighted LMPs that were $4.32 higher than if the load had paid the day-ahead load-weighted average price for PJM in the 2022/2023 planning period.

Table 2 PJM and DNCP day-ahead load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2022/2023 planning periods

	PJM				NC			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2012/2013	$37.44	$37.35	$0.10	($0.00)	$38.85	$37.60	$1.07	$0.17
2013/2014	$54.59	$54.36	$0.23	($0.00)	$59.20	$55.51	$4.51	($0.82)
2014/2015	$40.74	$40.49	$0.27	($0.02)	$45.77	$41.33	$3.82	$0.61
2015/2016	$29.15	$29.02	$0.14	($0.01)	$32.69	$29.56	$2.85	$0.28
2016/2017	$30.86	$30.78	$0.10	($0.02)	$32.61	$31.13	$1.39	$0.09
2017/2018	$35.94	$35.86	$0.09	($0.01)	$41.55	$37.32	$3.83	$0.40
2018/2019	$32.37	$32.24	$0.14	($0.01)	$33.86	$32.42	$1.36	$0.08
2019/2020	$23.38	$23.35	$0.04	($0.01)	$24.68	$23.61	$1.17	($0.10)
2020/2021	$25.94	$25.81	$0.11	$0.01	$27.01	$25.97	$1.14	($0.10)
2021/2022	$51.94	$51.62	$0.22	$0.09	$54.84	$51.95	$3.03	($0.14)
2022/2023	$63.72	$63.54	$0.09	$0.08	$70.89	$66.33	$4.32	$0.25

Table 3 shows the real-time monthly load-weighted average CLMP components of LMP for PJM and for DNCP for the 2012/2013 through 2022/2023 planning periods.

Table 3 PJM and DNCP real-time monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2022/2023 planning periods

	PJM												
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$0.03	$0.02	$0.02	$0.01	$0.03	$0.03	$0.04	$0.02	$0.07	$0.06	$0.03	$0.01	$0.03
2013/2014	($0.01)	($0.33)	($0.06)	$0.02	$0.04	$0.03	($0.00)	$0.00	($0.05)	$0.02	$0.00	($0.02)	($0.03)
2014/2015	$0.02	($0.02)	($0.00)	$0.03	$0.13	$0.03	$0.01	$0.01	$0.02	$0.05	$0.05	$0.02	$0.03
2015/2016	$0.03	$0.02	$0.04	$0.07	$0.02	$0.06	$0.02	$0.02	$0.04	$0.06	$0.05	$0.04	$0.04
2016/2017	$0.01	$0.02	$0.03	$0.01	$0.02	$0.02	$0.03	$0.04	$0.07	$0.06	$0.02	$0.02	$0.03
2017/2018	$0.05	$0.01	$0.04	$0.04	$0.09	$0.01	$0.02	$0.01	$0.08	$0.02	$0.01	($0.01)	$0.03
2018/2019	$0.02	$0.01	$0.03	$0.02	$0.02	$0.04	$0.02	$0.02	$0.06	$0.03	$0.03	$0.01	$0.03
2019/2020	$0.01	$0.01	$0.01	$0.01	$0.03	$0.01	$0.02	$0.01	$0.05	$0.05	$0.04	$0.02	$0.02
2020/2021	$0.01	$0.04	$0.04	$0.06	$0.02	$0.03	$0.04	$0.03	$0.02	$0.02	$0.02	$0.02	$0.03
2021/2022	$0.08	$0.05	$0.04	$0.11	$0.21	$0.04	$0.02	$0.03	$0.03	$0.04	$0.10	$0.03	$0.06
2022/2023	$0.02	$0.02	$0.03	$0.10	$0.06	$0.06	$0.07	$0.16	$0.08	$0.08	$0.09	$0.13	$0.08
	NC												
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$2.95	$0.51	$1.65	$0.59	$2.08	($0.08)	$0.89	$2.26	$0.70	$2.49	($0.49)	$0.50	$1.19
2013/2014	$33.08	$1.79	$12.60	$0.40	$3.09	($0.12)	($2.04)	$5.33	$4.29	$0.62	$1.96	$1.60	$5.72
2014/2015	$0.96	$2.29	$6.67	$5.16	$3.68	$1.67	$0.21	$2.06	$2.76	$3.83	($0.69)	$0.19	$2.27
2015/2016	$3.86	$2.27	$1.97	$4.44	$0.00	$5.30	$3.01	$1.68	$0.68	$3.03	$2.53	$2.67	$2.66
2016/2017	$2.14	$0.86	$0.45	$0.87	$1.27	$0.90	$0.25	($0.24)	$2.77	$4.21	$2.05	$0.44	$1.24
2017/2018	$19.01	$0.73	$9.81	$2.16	$4.08	$0.10	$0.84	$0.71	$2.44	$3.37	$1.25	$1.17	$4.16
2018/2019	($0.63)	$0.67	$0.80	$0.61	$1.72	$1.09	$0.02	($0.18)	$1.19	$1.94	$0.53	($0.43)	$0.56
2019/2020	$0.40	$0.26	$0.32	$2.07	$0.55	$0.76	$0.64	$1.12	$3.04	$2.91	$2.13	$0.26	$1.17
2020/2021	$0.52	$2.26	$2.28	$2.71	$3.76	($0.01)	($1.46)	$0.75	$1.42	$2.16	$1.23	$0.83	$1.20
2021/2022	$9.65	$1.99	$2.22	$4.39	$3.91	$1.10	$0.55	$2.57	$2.77	$5.15	$10.16	$3.43	$4.03
2022/2023	$1.64	$1.51	$2.75	$3.19	$5.25	$7.59	$3.05	($0.50)	$12.53	$3.31	$3.03	$19.13	$5.44

Table 4 shows the day-ahead monthly load-weighted average CLMP components of LMP for PJM and for DNCP for the 2012/2013 through 2022/2023 planning periods. The CLMPs in Table 4 indicate that, due to transmission constraints, load in DNCP paid real time load-weighted LMPs that were higher than if the load had paid the real time load-weighted average price for PJM in the 2022/2023 planning period. s.

Table 4 PJM and DNCP day-ahead monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2022/2023 planning periods

						PJM							
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$0.12	$0.04	$0.03	$0.03	$0.10	$0.17	$0.20	$0.10	$0.18	$0.03	$0.09	$0.05	$0.10
2013/2014	$0.76	$0.30	$0.19	$0.02	$0.14	$0.18	$0.29	$0.09	$0.34	$0.06	$0.07	$0.20	$0.23
2014/2015	$0.38	$0.77	$0.29	($0.06)	$0.20	$0.23	$0.23	$0.12	$0.18	$0.27	$0.36	$0.14	$0.27
2015/2016	$0.19	$0.17	$0.07	$0.04	$0.06	$0.30	$0.18	$0.12	$0.23	$0.10	$0.09	$0.09	$0.14
2016/2017	$0.08	$0.01	$0.01	($0.02)	($0.06)	$0.16	$0.26	$0.29	$0.19	$0.06	($0.01)	$0.13	$0.10
2017/2018	$0.56	$0.06	($0.07)	($0.01)	($0.05)	$0.10	$0.13	$0.03	$0.03	$0.02	$0.06	$0.16	$0.09
2018/2019	$0.22	$0.03	$0.06	$0.02	($0.01)	$0.11	$0.05	$0.17	$0.15	$0.27	$0.24	$0.33	$0.14
2019/2020	$0.01	$0.01	($0.06)	($0.08)	($0.03)	$0.02	$0.19	$0.08	$0.06	$0.03	$0.02	$0.15	$0.04
2020/2021	$0.05	$0.35	$0.17	($0.10)	($0.04)	$0.04	$0.28	$0.27	$0.06	($0.00)	($0.05)	$0.17	$0.11
2021/2022	$1.39	$0.39	($0.04)	($0.08)	$0.06	$0.27	$0.22	$0.40	$0.09	($0.11)	($0.30)	$0.03	$0.22
2022/2023	($0.12)	$0.11	($0.03)	($0.04)	($0.06)	$0.28	$0.21	$0.41	$0.05	$0.10	($0.04)	$0.12	$0.09
						NC							
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Annual
2012/2013	$2.60	$1.30	$1.50	$0.59	$1.66	($0.04)	$0.33	$1.53	$0.50	$1.63	$0.40	$0.97	$1.07
2013/2014	$11.39	$2.89	$10.34	$1.72	$3.63	$1.01	$0.56	$4.04	$11.01	$2.86	$2.31	$1.81	$4.51
2014/2015	$2.71	$10.27	$5.60	$4.45	$4.77	$2.61	$2.64	$2.79	$4.06	$3.01	$1.09	$1.17	$3.82
2015/2016	$3.93	$3.05	$2.47	$4.03	$0.90	$4.70	$3.88	$1.92	$1.36	$2.41	$2.07	$2.71	$2.85
2016/2017	$1.73	$0.75	$0.98	$1.14	$1.33	$1.26	($0.16)	$0.62	$2.30	$4.13	$2.18	$1.45	$1.39
2017/2018	$15.01	$1.09	$4.99	$2.11	$7.13	$0.68	$0.98	$1.16	$3.00	$2.60	$1.52	$2.72	$3.83
2018/2019	$2.02	$0.81	$1.26	$0.80	$1.99	$1.93	$0.65	$0.39	$1.70	$3.15	$1.58	$0.28	$1.36
2019/2020	$0.35	$0.38	$0.26	$0.54	$0.53	$1.21	$0.64	$1.19	$3.04	$2.96	$1.99	$0.79	$1.17
2020/2021	$1.02	$0.94	$1.66	$2.13	$1.86	$0.26	($0.22)	$1.10	$1.71	$2.03	$0.94	$1.26	$1.14
2021/2022	$5.70	$3.04	$2.73	$3.69	$2.56	$1.35	$0.77	$0.76	$2.65	$4.15	$7.22	$2.58	$3.03
2022/2023	$2.02	$2.45	$2.06	$2.87	$3.94	$6.48	$3.34	$2.82	$8.24	$4.43	$3.94	$8.19	$4.32

Congestion

Load pays congestion. Congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to transmission constraints but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

In PJM's two settlement system, there is a day-ahead market and a real-time, or balancing, market that make up a market day. Congestion is the sum of all congestion related charges and credits from both the day-ahead and balancing market.

In a two settlement system, all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtuals, physical load and generation have net MW at the close of each market day.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net market flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Congestion is attributed to downstream load buses that pay the congestion caused by the constraint, in proportion to the market flow of the load on that constraint. The congestion collected from each load bus due to a constraint is equal to the share of each load bus of the total downstream load contribution to market flow on that constraint. This calculation is done for both day-ahead congestion and balancing congestion.

The system marginal price (SMP) is uniform for all areas, while the total of the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[8]

Day-ahead CLMP charges and credits are based on MWh and CLMP in the day-ahead energy market. Balancing CLMP charges and credits are based on load or generation deviations between the day-ahead and real-time energy markets and CLMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time CLMP is positive, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time CLMP is negative, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time CLMP is positive, negative balancing congestion costs will result. If there is a negative load deviation at a bus where real-time CLMP is positive, negative balancing congestion costs will result.

In order to provide a more detailed explanation of the congestion calculations from which the total CLMP charges are derived, each category of congestion is defined and a table of the CLMP charges or credits associated with each category is provided at the end of the report.[9] Total CLMP charges are constraint specific CLMPs at each bus times bus specific MW summed across all buses for all constraints. DNCP congestion is equal to the proportional contribution of DNCP load to the total load market flow on all constraints. DNCP congestion is the difference between what DNCP load pays for energy due to binding transmission constraints and what generation, whether inside or outside DNCP, is paid to serve DNCP load.

In addition to congestion calculated for network load, there is explicit congestion. The explicit CLMP charges calculated for DNCP represent the charges associated with point to point transactions that source or sink in DNCP. For example, if a transaction is sourced in Pennsylvania and sinks in DNCP, the charges would be based on the MWh of the transaction multiplied by the difference between the sink CLMP and the source CLMP. The resulting CLMP charges are allocated to the zone and state of the sink

[8] The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load-weighted PJM LMP.

[9] For details of CLMP accounting, see *2021 Annual State of the Market Report for PJM,* Volume 2: Section 11: Congestion and Marginal Losses.

location, in DNCP. The sink location is the buyer's location and reflects the cost to the buyer of the internal purchase or external transaction. The resulting network flow and congestion revenue generated is simply a portion of the total network flow and associated congestion of each binding constraint in a given market period that is paid by load in the sink zone.

Table 5 shows the combined day-ahead and balancing withdrawal charges, injection credits, and explicit CLMP charges for the part of the DNCP for the 2016/2017 through 2021/2022 planning periods. Total congestion is implicit load charges minus implicit generation credits plus explicit load charges minus explicit load credits. Implicit injection credits are negative when the generation MW are multiplied by a negative CLMP. A negative CLMP at generation buses is expected, on average, because the reference bus LMP (SMP) is based on the load-weighted average LMP. In a least cost security constrained dispatch with binding transmission constraints, load always pays more for energy than generation is paid to produce the energy. Average PJM prices at generation source buses are lower than average PJM prices at load buses as a result of transmission constraints.

CLMP values are arbitrary in the sense that they result from the choice of the reference bus. PJM uses a load-weighted reference bus that shifts with the location and the relative size of actual loads across the system. The relative sizes of SMP and CLMP change with the reference bus, but LMP does not. A negative CLMP simply means that the LMP at the bus is less than the SMP, or system marginal price, or the load-weighted average LMP. The calculations in this table are just another way of demonstrating that congestion is equal to payments by load in excess of payments to generation. Total congestion is the same regardless of whether it is calculated using total LMP (net of losses) or CLMP.

Table 5 Total congestion costs (Dollars (Millions)) for the DNCP by category: 2016/2017 through 2022/2023 planning periods

	Congestion Costs (Millions)			
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total
2016/2017	$1.9	($2.5)	($0.1)	$4.3
2017/2018	$3.3	($4.6)	($0.3)	$7.7
2018/2019	$1.0	($2.4)	($0.2)	$3.2
2019/2020	$1.0	($1.8)	($0.3)	$2.6
2020/2021	$2.0	($1.9)	($0.2)	$3.6
2021/2022	$11.1	($1.7)	($0.5)	$12.3
2022/2023	$5.9	($6.4)	($1.5)	$10.8

Table 6 shows the congestion costs categories separated by day-ahead and balancing to show the contributions from both the day-ahead and real-time markets for the 2016/2017 through 2022/2023 planning periods.

Table 6 Total day-ahead and balancing congestion costs (Dollars (Millions)) for the DNCP by category: 2017/2018 through 2022/2023 planning periods

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
2016/2017	$1.9	($2.8)	$0.1	$4.8	($0.0)	$0.3	($0.2)	($0.4)	$4.3
2017/2018	$3.0	($5.3)	($0.4)	$7.8	$0.4	$0.6	$0.1	($0.1)	$7.7
2018/2019	$1.0	($2.7)	$0.1	$3.9	($0.0)	$0.3	($0.4)	($0.7)	$3.2
2019/2020	$1.0	($2.1)	$0.2	$3.3	$0.0	$0.2	($0.5)	($0.7)	$2.6
2020/2021	$2.5	($2.2)	$0.3	$5.0	($0.5)	$0.3	($0.6)	($1.4)	$3.6
2021/2022	$11.9	($3.1)	$0.7	$15.8	($0.8)	$1.4	($1.3)	($3.5)	$12.3
2022/2023	$5.7	($6.6)	$0.8	$13.1	$0.3	$0.3	($2.3)	($2.3)	$10.8

Table 7 shows the monthly day-ahead and balancing congestion costs for the 2021/2022 and 2022/2023 planning periods.

Table 7 Monthly congestion costs (Dollars (Millions)) for the DNCP: 2021/2022 and 2022/2023 planning periods

	Congestion Costs (Millions)					
	2021/2022			2022/2023		
	Day-ahead	Balancing	Total	Day-ahead	Balancing	Total
Jun	$0.4	($0.1)	$0.3	$0.9	($0.2)	$0.7
Jul	$0.4	($0.0)	$0.4	$1.1	($0.2)	$0.9
Aug	$1.0	($0.2)	$0.8	$2.0	($0.3)	$1.7
Sep	$0.8	($0.1)	$0.7	$2.0	($0.2)	$1.9
Oct	$0.7	($0.1)	$0.6	$0.7	($0.1)	$0.7
Nov	$1.1	($0.2)	$0.9	$1.4	($0.2)	$1.2
Dec	$0.7	($0.0)	$0.6	$2.5	($0.4)	$2.1
Jan	$4.8	($1.3)	$3.5	$0.4	($0.1)	$0.4
Feb	$1.6	($0.7)	$0.9	$0.5	($0.1)	$0.4
Mar	$0.6	($0.3)	$0.3	$0.3	($0.1)	$0.2
Apr	$0.7	($0.1)	$0.5	$0.8	($0.2)	$0.6
May	$3.0	($0.3)	$2.7	$0.4	($0.2)	$0.2
Total	$15.8	($3.5)	$12.3	$13.1	($2.3)	$10.8

Table 8 lists the top 15 constraints affecting congestion costs for the part of the DNCP for the 2022/2023 planning period including the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints, and the constraint specific congestion revenue collected from the load in the DNCP in the 2022/2023 planning period.

Table 8 Congestion cost (Dollars (Millions)) details for the top 15 constraints affecting the DNCP congestion costs: 2022/2023 planning period

			Congestion Costs (Millions)								
			Day-Ahead			Balancing			Total		
Constraint	Type	Location	Internal	External	Total	Internal	External	Total	Internal	External	Grand Total
Brambleton - Evergreen Mills	Line	DOM	$0.0	$2.3	$2.3	$0.0	($0.5)	($0.5)	$0.0	$1.8	$1.8
Nottingham	Other	PECO	$0.0	$1.5	$1.5	$0.0	($0.1)	($0.1)	$0.0	$1.5	$1.5
AP South	Interface	500	$0.0	$0.8	$0.8	$0.0	($0.1)	($0.1)	$0.0	$0.8	$0.8
Beaumeade	Other	DOM	$0.0	$0.8	$0.8	$0.0	($0.2)	($0.2)	$0.0	$0.6	$0.6
Conastone - Northwest	Line	BGE	$0.0	$0.5	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	$0.5
Cumberland - Juniata	Line	PPL	$0.0	$0.4	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	$0.4
Bull Run - Clifton	Line	DOM	$0.0	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	$0.3
Boonetown - South Reading	Line	METED	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	$0.3
Pleasant View	Transformer	DOM	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Lauschtown	Transformer	500	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Maroa E - Goose Creek	Flowgate	MISO	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Ashburn - Cochran Mill	Line	DOM	$0.0	$0.2	$0.2	$0.0	($0.1)	($0.1)	$0.0	$0.2	$0.2
Allen - R.P. Mone	Line	AEP	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Dauphin - Juniata	Line	PPL	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Graceton - Safe Harbor	Line	BGE	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Top 15 Total			$0.0	$8.4	$8.4	$0.0	($1.0)	($1.0)	$0.0	$7.4	$7.4
All Other Constraints			$0.0	$4.7	$4.7	($0.0)	($1.3)	($1.3)	$0.0	$3.4	$3.4
Total			$0.0	$13.1	$13.1	($0.0)	($2.3)	($2.3)	$0.0	$10.8	$10.8

Table 9 lists the top 15 constraints affecting DNCP congestion costs for the 2022/2023 planning period. Table 9 provides the type of constraint (Line, Transformer, Flowgate, or Interface), the location of the constraint, the congestion event hours contributed by the constraints for the period analyzed.

Table 9 Top 15 constraints affecting the DNCP congestion costs: 2022/2023 planning period

			Event Hours	
Constraint	Type	Location	Day-Ahead	Real-Time
Brambleton - Evergreen Mills	Line	DOM	638	479
Nottingham	Other	PECO	5,673	3,485
AP South	Interface	500	430	97
Beaumeade	Other	DOM	457	386
Conastone - Northwest	Line	BGE	785	291
Cumberland - Juniata	Line	PPL	495	255
Bull Run - Clifton	Line	DOM	155	50
Boonetown - South Reading	Line	METED	1,631	1,021
Pleasant View	Transformer	DOM	86	65
Lauschtown	Transformer	500	345	107
Maroa E - Goose Creek	Flowgate	MISO	325	181
Ashburn - Cochran Mill	Line	DOM	132	107
Allen - R.P. Mone	Line	AEP	2,109	162
Dauphin - Juniata	Line	PPL	291	-
Graceton - Safe Harbor	Line	BGE	1,344	435
Top 15 Total			14,896	7,121
All Other Constraints			26,734	14,811
Total			41,630	21,932

Table 10 shows the congestion cost details of the top 15 constraints affecting the part of the DNCP for the 2021/2022 planning period, including the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints and the constraint specific congestion revenue collected from the load in the DNCP in the 2021/2022 planning period. shows that 98.4 percent ($12.1 million of the $12.3 million congestion paid) of the congestion paid by DNCP load is due to binding transmission constraints outside of DNCP.

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Table 10 Congestion cost (Dollars (Millions)) details for the top 15 constraints affecting the DNCP: 2021/2022 planning period

			Congestion Costs (Millions)									
			Day-Ahead			Balancing			Total			
Constraint	Type	Location	Internal	External	Total	Internal	External	Total	Internal	External	Grand Total
Greys Point - Harmony Village	Line	DOM	$0.0	$3.0	$3.0	$0.0	($1.2)	($1.2)	$0.0	$1.8	$1.8
Brambleton - Evergreen Mills	Line	DOM	$0.0	$1.6	$1.6	$0.0	($0.1)	($0.1)	$0.0	$1.5	$1.5
Nottingham	Other	PECO	$0.0	$0.9	$0.9	$0.0	($0.1)	($0.1)	$0.0	$0.8	$0.8
Cumberland - Juniata	Line	PPL	$0.0	$0.6	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	$0.6
Rappahanock - White Stone	Line	DOM	$0.0	$0.7	$0.7	$0.0	($0.1)	($0.1)	$0.0	$0.6	$0.6
Idylwood - Clark	Line	DOM	$0.0	$0.5	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	$0.5
Bedington - Black Oak	Interface	500	$0.0	$0.7	$0.7	$0.0	($0.2)	($0.2)	$0.0	$0.5	$0.5
Three Mile Island	Transformer	500	$0.0	$0.5	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	$0.5
AP South	Interface	500	$0.0	$0.5	$0.5	$0.0	($0.2)	($0.2)	$0.0	$0.3	$0.3
Hope Creek - Silver Run	Line	PSEG	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	$0.3
Ashburn - Cochran Mill	Line	DOM	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	$0.3
Prest - Tibb	Flowgate	MISO	$0.0	$0.3	$0.3	$0.0	($0.1)	($0.1)	$0.0	$0.3	$0.3
Conastone - Northwest	Line	BGE	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Juniata	Transformer	500	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Brighton	Other	APS	$0.0	$0.2	$0.2	$0.0	($0.1)	($0.1)	$0.0	$0.2	$0.2
Top 15 Total			$0.0	$10.6	$10.6	$0.0	($2.1)	($2.1)	$0.0	$8.5	$8.5
All Other Constraints			$0.1	$5.0	$5.2	($0.0)	($1.4)	($1.4)	$0.1	$3.6	$3.7
Total			$0.1	$15.6	$15.8	($0.0)	($3.5)	($3.5)	$0.1	$12.1	$12.3

Table 11 lists the top 15 constraints affecting DNCP congestion costs for the 2021/2022 planning period. Table 11 provides the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints and the congestion event hours by the constraints for the period analyzed.

Table 11 Top 15 constraints affecting the DNCP congestion costs: 2021/2022 planning period

			Event Hours	
Constraint	Type	Location	Day-Ahead	Real-Time
Greys Point - Harmony Village	Line	DOM	855	592
Brambleton - Evergreen Mills	Line	DOM	616	194
Nottingham	Other	PECO	3,108	2,044
Cumberland - Juniata	Line	PPL	868	379
Rappahanock - White Stone	Line	DOM	522	149
Idylwood - Clark	Line	DOM	302	133
Bedington - Black Oak	Interface	500	188	226
Three Mile Island	Transformer	500	1,089	481
AP South	Interface	500	301	162
Hope Creek - Silver Run	Line	PSEG	1,137	284
Ashburn - Cochran Mill	Line	DOM	213	106
Prest - Tibb	Flowgate	MISO	2,444	2,133
Conastone - Northwest	Line	BGE	351	141
Juniata	Transformer	500	437	165
Brighton	Other	APS	1,017	1,286
Top 15 Total			13,448	8,475
All Other Constraints			24,208	18,816
Total			37,656	27,291

ARRs/FTRs as a Congestion Offset in the DNCP

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 information. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other Stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays net of payments to the generation that serves the zonal load.

Table 12 shows the congestion offsets paid to load in the part of the DNCP. The congestion offsets include: the allocation of ARR revenue; self scheduled FTR revenue; and the allocation of end of planning period surplus. Table 12 also shows payments by load in the part of the DNCP. Load payments include: day-ahead congestion; balancing congestion; and the allocation of M2M payments.

The offset percentage in Table 12 is the share of the congestion payments that are returned to load in DNCP.

Table 12 DNCP ARR and FTR total congestion offset (in millions) for ARR holders: 2016/2017 through 2022/2023 planning periods

Planning Period	ARR Credits	FTR Credits	Balancing + M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
2018/2019	$0.3	$1.6	($0.7)	$0.3	$1.6	$3.9	($0.7)	($0.1)	$3.0	54.6%
2019/2020	$0.4	$1.2	($0.8)	$0.5	$1.2	$3.3	($0.7)	($0.0)	$2.5	48.9%
2020/2021	$1.0	$3.6	($1.6)	$0.0	$3.0	$5.0	($1.4)	($0.0)	$3.5	84.9%
2021/2022	$1.3	$14.9	($1.0)	$0.0	$15.2	$17.4	($0.5)	($0.1)	$16.9	90.0%
2022/2023	$2.2	$18.7	($3.7)	$0.4	$17.6	$13.1	($2.3)	($0.9)	$9.9	177.7%
Total	$5.3	$39.9	($7.8)	$1.2	$38.6	$42.6	($5.6)	($1.2)	$35.8	107.8%

The results in Table 12 and Table 13 illustrate the fundamental issues with the FTR/ARR design in PJM. If the FTR/ARR design were implemented correctly, the offsets to load would equal congestion payments by load.

Table 12 shows that the offset share for load in DNCP varies by planning period. The offsets are a function of the assignment of ARRs, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices paid for FTRs are high relative to actual congestion, the offset provided by ARRs is higher than in cases where the prices for FTRs are low relative to actual congestion. While the amount of congestion returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load in the part of the DNCP that paid it. The significant increase in the ARR/FTR offset provided to DNCP load in the 2022/2023 planning period was a result of overallocated ARR paths (Stage 1 ARRs) between Dominion generation and load relative to actual system capability (See Table 15).

Table 13 shows the total congestion offset that would be available to DNCP ARR holders if the ARR holders self scheduled all their allocated ARRs as FTRs for the 2018/2019 through 2022/2023 planning periods.[10] The results show that the recovery of congestion varies significantly by planning period, for the same set of rights. Path based congestion rights are not and cannot be made consistent with how load is actually served by the wholesale electricity market based on actual network use.

It is not possible for load to directly recover all of the congestion that they pay under the current ARR/FTR design in which the rights to congestion revenues are assigned based on fictitious contract paths. Path based congestion rights are not and cannot be made

[10] See *2022 Annual State of the Market Report for PJM,* Vol. 2, Section 11, Congestion and Marginal Losses for the system wide results.

consistent with how load is actually served by the wholesale electricity market based on actual network use.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But, system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[11] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again.

The results shown in are not consistent with a rational FTR/ARR design based on the fundamentals of the way that congestion costs are paid. Under a rational design the total offset available to ARR holders if they were to self schedule all of their ARRs as FTRs should equal to the total congestion paid by those ARR holders. If ARRs were assigned correctly, based on actual zonal congestion, and if balancing congestion were appropriately included in total congestion, the zonal offsets to load would equal zonal congestion payments by load. shows hypothetical congestion revenue that would be paid to DNCP ARR holders if all of their ARRs were self scheduled as FTRs (Self Scheduled FTRs or SS FTR). Bal+M2M shows the balancing plus market to market costs that are charged to DNCP load on a load ratio share. Congestion+M2M shows the congestion plus market to market costs paid by DNCP load. The total net offset against congestion charges if DNCP load self scheduled all their ARRs is equal to SS FTR – (Bal + M2M) – (Congestion + M2M). The last column, Offset, shows the percentage of congestion related costs offset by the SS FTR revenue.

11 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 158 FERC ¶ 61,093 (2017).

Table 13 Offset available to load if all ARRs self scheduled (Revised)

Planning Period	SS FTR	Bal+M2M	Congestion +M2M	Offset
2018/2019	$2.1	($0.7)	$3.0	46.0%
2019/2020	$1.3	($0.7)	$2.5	24.9%
2020/2021	$4.9	($1.6)	$3.5	93.6%
2021/2022	$25.3	($1.0)	$16.9	144.1%
2022/2023	$28.4	($2.8)	$10.7	238.3%
Total	$61.9	($6.8)	$36.7	150.5%

Table 14 shows the share of ARR MW, by stage, for ARRs with paths that source inside or outside the Dominion Zone, and congestion that originates inside or outside the Dominion Zone. Table 14 shows that almost all of the congestion paid for by load in Dominion comes from constraints (and generation) outside of Dominion, while almost all of the ARR paths available to Dominion are sourced and sink entirely within the Dominion Zone. This illustrates one of the fundamental issues with the path based approach in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. Table 14 shows the proportion of congestion and the proportion of ARR MW that sink and source entirely within Dominion Zone. Table 14 illustrates one of the fundamental issues with the path based approach which originated (in 1999) in a cost of service design where most load was served by, or assumed to be served by, generation in the same zone as load. In fact, in the PJM market, which operates as an integrated network, a significant proportion of congestion is based on constraints that are not in the same zone as load. The path based approach cannot reflect the actual congestion paid by load. Paths do not reflect the way that load is actually served in a network system like PJM.

Table 14 Share of ARRs and congestion that source in/out of the Dominion Zone

	Stage 1A		Stage 1B		Stage 2		Total		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone	Out of Zone	In Zone
2020/2021	0.4%	64.1%	0.0%	34.2%	0.0%	1.4%	0.4%	99.6%	75.1%	24.9%
2021/2022	0.3%	61.1%	0.0%	37.6%	0.0%	0.9%	0.4%	99.6%	54.7%	45.3%
2022/2023	0.1%	67.4%	0.0%	31.7%	0.0%	0.8%	34.6%	65.4%	75.0%	25.0%

ARR Stage 1A overallocations to LSEs are a significant contributor to the misalignment of congestion rights relative to actual network use. Stage 1A ARRs MW are awarded regardless of whether the physical transmission system can support the theoretical flows from the Stage 1A source and sink points. In the case where Stage 1A ARR MW flows exceed physical transmission limits, PJM modifies the modeled transmission limits in the ARR/FTR market to accommodate the flow. This artificial increase in the transmission limits is then made available in the FTR auctions. FTRs on these paths will have FTR target allocations that exceed the amount of actual congestion. As a result, Stage 1A related overallocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs. The net effect of the Stage 1A overallocations and reductions in ARR allocations made to balance them elsewhere can be positive or negative for a particular ARR holder. In the case of DNCP the net effect has been positive to date. .

Table 15 shows the Stage 1A overallocated ARR MW for the entire Dominion Zone, based on whether the source point is inside or outside of the Dominion Zone, by planning period (2020/2021 through 2022/2023).

Table 15 Stage 1A overallocated ARR MW by source in/out of Dominion Zone

	Out of Zone MW	In Zone MW
2020/2021	0	250.9
2021/2022	0	661.9
2022/2023	0	1,072.0

The Greys Point – Harmony Village Line constraint was the largest contributor to congestion in DNCP in the 2020/2021planning period (Table 8). There was a significant overallocation of ARRs and FTRs on the Greys Point – Harmony Village Line compared to actual network flows in the 2021/2022 planning period. The target allocations of overallocated self scheduled FTRs was a significant source of the unusual increase in the available congestion offset from self scheduling available ARRs as FTRs in the 2021/2022 planning period in the Dominion Zone. Table 16 shows FTR target allocations from the Greys Point - Harmony Village Line constraint compared to actual congestion from the constraint based on actual flows. The dollar amounts in Table 16 are not limited to the FTR target allocations and congestion associated with just the DNCP, but includes the total target allocation and congestion effects of the constraint, although most (99.9 percent of the day-ahead congestion and 98.5 percent of the balancing congestion) effects are Dominion Zone specific. The required payments to FTRs (self-scheduled ARRs and FTRs purchased directly) resulting from this constraint were about twice the level of actual congestion on this constraint. The total target allocations to be paid out were $90,396,866, while the actual congestion available to fund the payments was only $41,452,090. As a result, the offset available to load if all ARRs had been self scheduled would have been significantly higher than actual congestion.

Table 16 FTR target allocations relative to congestion generated by Greys Point – Harmony Village: 2021/2022 planning period

Facility	FTR Target Allocations (No Self Scheduled FTRs)	Self Scheduled FTR Target Allocations	Total FTR Target Allocations (All)	Percent Self Scheduled FTR	Day Ahead Congestion	Balancing Congestion	Total Congestion	Day Ahead Overallocation	Total Overallocation
Greys Point - Harmony Village	$28,154,135	$62,242,731	$90,396,866	68.9%	$63,483,567	-$22,031,477	$41,452,090	$26,913,299	$48,944,776

Conclusion

Total congestion increased from the 2021/2022 planning period to the 2022/2023 planning period.

In the 2021/2022 planning period, DNCP ARR holders received only 90.0 percent of the congestion paid by that load. If ARR holders in the DNCP had self scheduled all their ARRs in the 2021/2022 planning period, they would have been able to offset 144.1 percent of the congestion they paid.

In the 2022/2023 planning period, load in the part of the DNCP ARR holders received 177.7 percent of the congestion paid by that load. If ARR holders in the DNCP had self scheduled all their ARRs in the 2022/2023 planning period, they would have been able to offset 238.3 percent of the congestion they paid.

In an LMP market, load pays more than generation receives. FTRs/ARRs are the mechanism for returning those excess payments to load. But, the current FTR/ARR mechanism in PJM does not and cannot return all the excess payments to load. The FTR/ARR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR/ARR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

Table 17 Congestion definitions

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh