Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, PA 19403
Phone: 610-271-8050
Fax: 610-271-8057

VIA ELECTRONIC FILING

October 2, 2024

Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
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.

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.

REPORT TO THE NORTH CAROLINA PUBLIC UTILITIES COMMISSION

Congestion in the Dominion Service Territory in North Carolina:

2022/2023 and 2023/2024

The Independent Market Monitor for PJM

October 2, 2024

This page intentionally left blank.

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 2022/2023 and 2023/2024 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 DNCP.

In this report, congestion equals the total congestion charges paid by load at the buses in 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 the load MW and the 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

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 *2023 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.

binding transmission constraints and the distribution factors from the binding constraints to that 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 a metric of the degree to which 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 the generation that serves that load is paid for that energy. Congestion is the difference between what load pays for energy and generation is paid for energy due to transmission constraints. Load pays 100 percent of congestion. 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

5 PJM billing examples can be found in *2023 Annual State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

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 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. That 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. SMP is 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 relative sizes of SMP, CLMP and MLMP.

6 See *2023 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. CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the difference in LMP between the two buses caused by a transmission constraint, or the shadow price of the constraint. 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 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 in both the day ahead and balancing market. 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) show the LMP components for DNCP for the 2012/2013 through 2023/2024 planning periods. Load in the DOM Zone pays the zonal DOM price, regardless of location. The zonal DOM price is the load-weighted (real-time) or load factor-weighted (day-ahead) LMP for the entire DOM Zone. DNCP load pays the same LMP and has the same LMP components as the entire Dominion (DOM) zone. 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 2023/2024 planning periods.[7] Table 1 indicates that, due to transmission constraints and losses, load in DNCP paid real-time load-weighted LMPs that were $4.77 higher than if the load had paid the real-time load-weighted average price for PJM in the 2023/2024 planning period.

Table 1 PJM and DNCP real-time load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2023/2024 planning period

	PJM				DNCP			
	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
2023/2024	$31.70	$31.61	$0.06	$0.02	$36.47	$32.06	$3.99	$0.42

Table 2 shows the day-ahead load-weighted average LMP components for PJM and for DNCP for the 2012/2013 through 2023/2024 planning periods. The CLMPs in Table 2 indicate that, due to transmission constraints, load in DNCP paid day-ahead load-weighted LMPs that were $2.75 higher than if the load had paid the day-ahead load-weighted average price for PJM in the 2023/2024 planning period.

[7] See *2023 Annual State of the Market Report for PJM*, Volume 2: Section 11: Congestion and Marginal Losses.

Table 2 PJM and DNCP day-ahead load-weighted average LMP components (Dollars per MWh): 2012/2013 through 2023/2024 planning periods

	PJM				DNCP			
	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
2023/2024	$32.05	$31.93	$0.10	$0.02	$35.25	$32.41	$2.75	$0.10

Table 3 shows the real-time monthly load-weighted average CLMP components of LMP for PJM and for DNCP for the 2012/2013 through 2023/2024 planning periods.

Table 3 PJM and DNCP real-time monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2023/2024 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
2023/2024	$0.07	$0.06	$0.04	$0.04	$0.08	$0.04	$0.06	$0.06	$0.08	$0.11	$0.05	$0.04	$0.06
	DNCP												
	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
2023/2024	$7.95	$2.03	$1.39	$2.62	$6.89	$2.26	$2.77	$4.92	$3.66	$5.07	$4.99	$2.39	$3.99

Table 4 shows the day-ahead monthly load-weighted average CLMP components of LMP for PJM and for DNCP for the 2012/2013 through 2023/2024 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 2023/2024 planning period.

Table 4 PJM and DNCP day-ahead monthly load-weighted average CLMP component (Dollars per MWh): 2012/2013 through 2023/2024 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
2023/2024	$0.03	($0.00)	$0.01	($0.06)	($0.01)	$0.06	$0.29	$0.33	$0.14	($0.05)	$0.11	$0.27	$0.10
						DNCP							
	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
2023/2024	$4.25	$0.96	$1.12	$1.74	$4.19	$2.82	$2.53	$4.25	$2.07	$1.24	$3.51	$2.94	$2.75

Congestion

Load pays congestion. Congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are 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 standalone 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. With a zero net position (zero MW at the close of the day), virtual bids do not pay congestion, they have net payouts. Net payouts (negative credits) to virtual bids are negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids are 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 the 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

---

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 *2023 Annual State of the Market Report for PJM,* Volume 2: Section 11: Congestion and Marginal Losses.

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 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 DNCP for the 2016/2017 through 2023/2024 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.

Table 5 Total congestion costs (Dollars (Millions)) for DNCP by category: 2016/2017 through 2023/2024 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
2023/2024	$3.9	($2.7)	($0.4)	$6.2

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 2023/2024 planning periods.

Table 6 Total day-ahead and balancing congestion costs (Dollars (Millions)) for DNCP by category: 2016/2017 through 2023/2024 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
2023/2024	$3.9	($3.3)	$0.8	$8.0	$0.0	$0.6	($1.2)	($1.7)	$6.2

Table 7 shows the monthly day-ahead and balancing congestion costs for the 2022/2023 and 2023/2024 planning periods.

Table 7 Monthly congestion costs (Dollars (Millions)) for DNCP: 2022/2023 and 2023/2024 planning periods

	Congestion Costs (Millions)					
	2022/2023			2023/2024		
	Day-ahead	Balancing	Total	Day-ahead	Balancing	Total
Jun	$0.9	($0.2)	$0.7	$0.4	($0.1)	$0.4
Jul	$1.1	($0.2)	$0.9	$0.7	($0.2)	$0.6
Aug	$2.0	($0.3)	$1.7	$0.7	($0.1)	$0.5
Sep	$2.0	($0.2)	$1.9	$0.8	($0.1)	$0.7
Oct	$0.7	($0.1)	$0.7	$0.8	($0.1)	$0.6
Nov	$1.4	($0.2)	$1.2	$0.7	($0.2)	$0.5
Dec	$2.5	($0.4)	$2.1	$0.5	($0.1)	$0.4
Jan	$0.4	($0.1)	$0.4	$1.0	($0.3)	$0.8
Feb	$0.5	($0.1)	$0.4	$0.3	($0.1)	$0.2
Mar	$0.3	($0.1)	$0.2	$0.4	($0.1)	$0.3
Apr	$0.8	($0.2)	$0.6	$0.5	($0.1)	$0.4
May	$0.4	($0.2)	$0.2	$1.1	($0.2)	$0.9
Total	$13.1	($2.3)	$10.8	$8.0	($1.7)	$6.2

Table 8 lists the top 16 constraints affecting congestion costs for DNCP for the 2023/2024 planning period including the type of constraints (Line, Transformer, Flowgate, or Interface), the location of the constraints (external or internal to DNCP), and the constraint specific congestion revenue collected from the load in DNCP in the 2023/2024 planning period. Constraints that are internal to DNCP source and sink within DNCP.

Table 8 Congestion cost (Dollars (Millions)) details for the top 16 constraints affecting the DNCP congestion costs: 2023/2024 planning period

			Congestion Costs (Millions)								
			Day-Ahead			Balancing			Total		
Constraint	Type	Location	Internal	External	Total	Internal	External	Total	Internal	External	Grand Total
Nottingham	Other	PECO	$0.0	$1.2	$1.2	$0.0	($0.0)	($0.0)	$0.0	$1.2	$1.2
Conastone - Northwest	Line	BGE	$0.0	$0.6	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	$0.6
Graceton - Safe Harbor	Line	BGE	$0.0	$0.4	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	$0.4
AP South	Interface	500	$0.0	$0.5	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.4	$0.4
Possum Point	Transformer	DOM	$0.0	$0.3	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	$0.3
Pleasant View - Ashburn	Line	DOM	$0.0	$0.3	$0.3	$0.0	($0.1)	($0.1)	$0.0	$0.2	$0.2
Coolspring - Milford	Line	DPL	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
East Towanda - Hillside	Line	PE	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Lenox - North Meshoppen	Line	PE	$0.0	$0.4	$0.4	$0.0	($0.2)	($0.2)	$0.0	$0.2	$0.2
Collins	Transformer	COMED	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Chaparral - Carson	Line	DOM	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Bedington - Black Oak	Interface	500	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Conastone	Transformer	500	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Stillwell - Dumont	Line	MISO	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Conastone - Peach Bottom	Line	500	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Dickerson - Dickerson Station	Line	PEPCO	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	$0.1
Top 16 Total			$0.0	$4.9	$4.9	$0.0	($0.5)	($0.5)	$0.0	$4.5	$4.5
All Other Constraints			$0.1	$2.9	$3.0	($0.0)	($1.3)	($1.3)	$0.1	$1.7	$1.8
Total			$0.1	$7.8	$8.0	($0.0)	($1.7)	($1.7)	$0.1	$6.1	$6.2

Table 9 lists the top 16 constraints affecting DNCP congestion costs for the 2023/2024 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 16 constraints affecting DNCP congestion costs: 2023/2024 planning period

			Event Hours	
Constraint	Type	Location	Day-Ahead	Real-Time
Nottingham	Other	PECO	5,676	3,407
Conastone - Northwest	Line	BGE	923	553
Graceton - Safe Harbor	Line	BGE	2,821	1,627
AP South	Interface	500	284	110
Possum Point	Transformer	DOM	424	102
Pleasant View - Ashburn	Line	DOM	345	67
Coolspring - Milford	Line	DPL	324	127
East Towanda - Hillside	Line	PE	1,468	1,234
Lenox - North Meshoppen	Line	PE	2,880	3,327
Collins	Transformer	COMED	1,510	-
Chaparral - Carson	Line	DOM	513	-
Bedington - Black Oak	Interface	500	149	-
Conastone	Transformer	500	119	114
Stillwell - Dumont	Line	MISO	626	-
Conastone - Peach Bottom	Line	500	445	255
Dickerson - Dickerson Station	Line	PEPCO	275	164
Top 16 Total			18,782	11,087
All Other Constraints			21,694	15,270
Total			40,476	26,357

Table 10 shows the congestion cost details of the top 16 constraints affecting the part of 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 DNCP in the 2022/2023 planning period.

Table 10 Congestion cost details for the top 16 constraints affecting DNCP: 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	MEC	$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
Bedington - Black Oak	Interface	500	$0.0	$0.2	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	$0.2
Top 16 Total			$0.0	$8.6	$8.6	$0.0	($1.0)	($1.0)	$0.0	$7.5	$7.5
All Other Constraints			$0.0	$4.5	$4.5	($0.0)	($1.3)	($1.3)	$0.0	$3.2	$3.3
Total			$0.0	$13.1	$13.1	($0.0)	($2.3)	($2.3)	$0.0	$10.8	$10.8

Table 11 lists the top 16 constraints affecting DNCP congestion costs for the 2022/2023 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 16 constraints affecting 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	MEC	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	0
Graceton - Safe Harbor	Line	BGE	1,344	435
Bedington - Black Oak	Interface	500	111	1
Top 16 Total			15,007	7,122
All Other Constraints			26,623	14,993
Total			41,630	22,115

ARRs/FTRs as a Congestion Offset in DNCP

Load pays 100 percent of congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on information that is significantly out of date and was never an accurate measure of the source of generation for a zone or subzone. 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 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 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: 2018/2019 through 2023/2024 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	($3.6)	$0.0	$12.6	$15.8	($3.5)	($0.1)	$12.2	103.1%
2022/2023	$2.2	$18.7	($3.7)	$0.4	$17.6	$13.1	($2.3)	($0.9)	$9.9	177.7%
2023/2024	$5.6	$10.4	($1.9)	$0.2	$14.2	$8.0	($1.7)	($0.2)	$6.0	236.0%
Total	$10.8	$50.3	($12.3)	$1.4	$50.3	$49.0	($10.4)	($1.4)	$37.2	135.1%

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 when the prices for FTRs are low relative to actual congestion. The amount of congestion returned to the load varies significantly by planning period. Prior to the 2023/2024 planning period PJM's ARR/FTR design consistently failed to return the congestion revenues to the load in DNCP that paid it. The significant increase in the ARR/FTR offset provided to DNCP load starting in the 2023/2024 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 2023/2024 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.

Table 13 Offset available to load if all ARRs self scheduled

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	($3.6)	$12.2	177.8%
2022/2023	$28.4	($3.7)	$9.9	249.9%
2023/2024	$14.0	($1.9)	$6.0	200.0%
Total	$75.9	($12.1)	$37.2	171.5%

It is not possible for load to directly recover 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 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

[10] See *2023 Annual State of the Market Report for PJM,* Vol. 2, Section 11, Congestion and Marginal Losses for the system wide results.

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 misalignment of congestion payments and congestion revenue rights results in dramatically different congestion offset 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 an additional subsidy to FTR holders at the expense of ARR holders.[11] The order requires PJM to ignore balancing congestion (which is generally negative) when calculating total congestion dollars available to fund

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

FTRs. The result is that congestion dollars paid to FTRs are overstated by the amount of negative balancing congestion. As a result of the FERC order, 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 Table 13 (above) 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. Table 13 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.

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%
2023/2024	0.4%	85.4%	0.1%	5.8%	0.0%	8.4%	0.4%	99.6%	87.8%	12.2%

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 12).

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 2023/2024).

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
2023/2024	3.9	4,757.3

Conclusion

Total congestion decreased from the 2022/2023 planning period to the 2023/2024 planning period.

In the 2022/2023 planning period, DNCP ARR holders received 177.7 percent of the congestion paid by that load (Table 12). If ARR holders in DNCP had self scheduled all their ARRs in the 2022/2023 planning period, they would have been able to offset 249.9 percent of the congestion they paid (Table 13).

In the 2023/2024 planning period, DNCP ARR holders (load) received 236.0 percent of the congestion paid by DNCP ARR holders (Table 12). If ARR holders in DNCP had self scheduled all their ARRs in the 2023/2024 planning period, they would have been able to offset 200.00 percent of the congestion they paid (Table 13).

The 2022/2023 and 2023/2024 results (a return of congestion revenues in excess of congestion payments) was a result of PJM's overallocation of Dominion Stage 1A ARRs relative to how congestion is actually paid. Dominion's overcollection comes at the expense of other load in other zones.

In an LMP market, load pays more than generation receives when there are binding transmission constraints. FTRs/ARRs are the mechanism for returning those excess payments to load. However, the current FTR/ARR mechanism in PJM does not and cannot return excess payments to the load that paid it. 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. While DNCP has recently benefited from the market design (Table 12), the current FTR/ARR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load on a system wide basis.

Table 16 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