Monitoring Analytics

Potential Impacts of the Creation of Maryland FRRs

The Independent Market Monitor for PJM

April 16, 2020

This page intentionally left blank.

Summary

The Independent Market Monitor for PJM (IMM or MMU) analyzed the impacts of the creation of Fixed Resource Requirement (FRR) entities in Maryland. FRR entities elect to not participate in the PJM Capacity Market and to use the FRR option to satisfy their capacity obligations. Under the FRR option, Load Serving Entities (LSEs) in Maryland would need to meet their FRR capacity obligations through owned generation, if any, and bilateral contracts with the owners of capacity, primarily within the Maryland portions of BGE, Pepco, DPL and APS Zones but also including resources from outside Maryland. The IMM analyzed six scenarios. Separate Locational Deliverability Areas (LDAs) for APS and DPL were not analyzed because most of the APS and DPL capacity is outside Maryland.

The Maryland analysis is complicated by the fact that Maryland includes some or all of four LDAs and includes other unique features. Of the four LDAs in Maryland, the BGE LDA is entirely within Maryland but Pepco, DPL and APS LDAs are only partly within Maryland. The BGE Zone in Maryland includes the BGE LDA and the BGE portion of the Rest of SWMAAC LDA, both of which are part of the SWMAAC parent LDA. The Pepco Zone in Maryland includes the Maryland portion of the Pepco LDA and the Pepco portion of the Rest of SWMAAC LDA, both of which are part of SWMAAC parent LDA. The DPL Zone in Maryland includes the Maryland portion of the DPL South LDA and the Maryland portion of the Rest of EMAAC LDA, both of which are part of EMAAC parent LDA. The APS Zone in Maryland is part of the APS LDA which includes three geographically separated subzones.

In Scenario 1, the IMM assumes that an FRR is established that includes all of Maryland and that the FRR procures the entire Maryland capacity obligation at a rate equal to the weighted average net Cost of New Entry (CONE) times B offer caps applicable to the LDAs in Maryland ($198.53 per MW-day) for the 2021/2022 PJM Reliability Pricing Model (RPM) Base Residual Auction (BRA). The IMM concludes that under Scenario 1 net load charges for Maryland under the FRR alternative would increase by $206.6 million or 23.4 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 2, the IMM assumes that an FRR is established that includes all of Maryland and that the FRR procures the entire Maryland capacity obligation at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Maryland ($170.67 per MW-day). The IMM concludes that under Scenario 2 the net load charges for Maryland under the FRR alternative would increase by $53.9 million or 6.1 percent compared to the results of the 2021/2022 RPM BRA.

For both Scenarios 1 and 2, the IMM also analyzed the impacts on the RTO, excluding the Maryland portion. In both scenarios, the Rest of RTO clearing price would decrease by $5.77 per MW-day to $134.23 per MW-day, or 4.1 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $31.50 per MW-day to $134.23 per MW-day, or 19.0 percent. Net load charges for the

RTO excluding Maryland would be lower by $460.2 million or 5.4 percent compared to the 2021/2022 RPM BRA net load charges.

In Scenario 3, the IMM assumes that an FRR is established for the BGE LDA (BGE FRR) and that the FRR procures the entire BGE capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for BGE ($180.50 per MW-day). The rest of Maryland remains in the PJM Capacity Market. The IMM concludes that under Scenario 3 net load charges for BGE under the FRR alternative would increase by $26.7 million or 6.1 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 4, the IMM assumes that an FRR is established for the BGE LDA and that the FRR procures the entire BGE capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($200.30 per MW-day).[1] The IMM concludes that under Scenario 4 the net load charges for BGE under the FRR alternative would increase by $77.8 million or 17.7 percent compared the results of the 2021/2022 RPM BRA.

For both Scenarios 3 and 4, the IMM also analyzed the impacts on the RTO, excluding the BGE FRR. In both scenarios, the Rest of RTO clearing price would decrease by $5.39 per MW-day to $134.61 per MW-day, or 3.8 percent compared to the results of the 2021/2022 RPM BRA. In both scenarios, the EMAAC clearing price would decrease by $29.68 per MW-day to $136.05 per MW-day, or 17.9 percent. The clearing prices in all Maryland LDAs other than BGE would decrease. Net load charges for the RTO excluding the BGE FRR would be lower by $462.2 million or 5.2 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 3 and 4, the IMM also analyzed the impact on Maryland. In both Scenarios 3 and 4, the net load charges for Maryland, excluding the BGE FRR, would decrease by $27.1 million or 6.1 percent compared to the results of the 2021/2022 RPM BRA. The net load charges for all Maryland, including the BGE FRR, under Scenario 3 would decrease by $0.4 million or 0.04 percent compared to the results of the 2021/2022 RPM BRA. The net load charges for all Maryland, including the BGE FRR, under Scenario 4 would increase by $50.7 million or 5.7 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 5, the IMM assumes that an FRR is established for the Maryland portion of the Pepco LDA (Pepco/MD FRR) and that the Pepco/MD FRR procures the entire Pepco/MD FRR capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for Pepco ($210.86 per MW-day). The rest of Maryland and the DC portion of the Pepco LDA remain in the PJM Capacity Market. The IMM concludes that under Scenario 5 net load charges for the Pepco/MD FRR under the FRR alternative would

[1] The clearing price of the BGE LDA in the 2021/2022 RPM BRA ($200.30 per MW-day) was higher than the net CONE times B offer cap for the BGE LDA ($180.50 per MW-day).

increase by $107.4 million or 42.5 percent compared to the results of the 2021/2022 RPM BRA.

In Scenario 6, the IMM assumes that an FRR is established for the Maryland portion of the Pepco LDA and that the Pepco/MD FRR procures the entire Pepco/MD capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). The IMM concludes that under Scenario 6 the net load charges for the Pepco/MD FRR under the FRR alternative would decrease by $13.6 million or 5.4 percent compared the results of the 2021/2022 RPM BRA.

For both Scenarios 5 and 6, the IMM also analyzed the impacts on the RTO, excluding the Pepco/MD FRR. In both scenarios, the Rest of RTO clearing price would decrease by $2.75 per MW-day to $137.25 per MW-day, or 2.0 percent compared to the results of the 2021/2022 RPM BRA. The clearing price in the Maryland portion of the APS Zone would decrease. The clearing price in the BGE LDA and the Maryland portion of the DPL South LDA would remain the same. Net load charges for the RTO excluding the Maryland portion of the Pepco LDA would be lower by $89.8 million or 1.0 percent compared to the 2021/2022 RPM BRA net load charges.

For both Scenarios 5 and 6, the IMM also analyzed the impact on Maryland. In both Scenarios 5 and 6, the net load charges for Maryland, excluding the Pepco/MD FRR, would decrease by $8.8 million or 1.4 percent compared to the results of the 2021/2022 RPM BRA. The net load charges for all Maryland, including the Pepco/MD FRR, under Scenario 5 would increase by $98.6 million or 11.2 percent compared to the results of the 2021/2022 RPM BRA. The net load charges for all Maryland, including the Pepco/MD FRR, under Scenario 6 would decrease by $22.4 million or 2.5 percent compared to the results of the 2021/2022 RPM BRA.

Table 1 presents a summary of the results for all six scenarios including the impact on net load charges: for the defined FRRs; for Maryland excluding the defined FRRs; for all of the Maryland including the defined FRRs and the non FRR portions of Maryland; and for the rest of the PJM market, where the rest of the PJM market includes the non FRR portions of Maryland when relevant.

Table 1 Scenario summary

	FRR		Rest of Maryland		Maryland		Rest of PJM Market	
Scenario	Change	Percent	Change	Percent	Change	Percent	Change	Percent
1	$206,615,122	23.4%	NA	NA	$206,615,122	23.4%	($460,191,255)	(5.4%)
2	$53,905,803	6.1%	NA	NA	$53,905,803	6.1%	($460,191,255)	(5.4%)
3	$26,736,029	6.1%	($27,106,589)	(6.1%)	($370,560)	(0.0%)	($462,199,033)	(5.2%)
4	$77,780,764	17.7%	($27,106,589)	(6.1%)	$50,674,175	5.7%	($462,199,033)	(5.2%)
5	$107,356,584	42.5%	($8,775,716)	(1.4%)	$98,580,868	11.2%	($89,781,373)	(1.0%)
6	($13,604,117)	(5.4%)	($8,775,716)	(1.4%)	($22,379,833)	(2.5%)	($89,781,373)	(1.0%)

Based on the analysis, the creation of a Maryland FRR, a BGE FRR or a Pepco/MD FRR, is likely to increase payments for capacity by customers in Maryland. It is assumed that the actual price for capacity in Maryland would be the result of a negotiation between the owners of the required capacity, and the State of Maryland.[2] The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Creation of an FRR creates market power for the small number of local generation owners from whom generation must be purchased in order to meet the reliability requirements of the FRR entities. There is at least one single pivotal supplier in each of the Maryland, BGE, and Pepco FRRs which means that there is at least one generation owner, and in some cases more, that has monopoly power in each case. All participants in the Maryland, BGE, and Pepco FRRs fail the three pivotal supplier test which follows from the one pivotal supplier results and reinforces the conclusion that there is structural market power in each case. In the FRR approach, there is no PJM market monitoring of offer behavior by generation owners, there are no market rules governing offers, and there are no market rules requiring competitive behavior. In the absence of a competitive market that includes the FRR area(s), there is no competitive market reference point to define what a competitive offer would be from the FRR generation owners in a bilateral negotiation or what the competitive market price would be. Prior market results do not define a competitive outcome in subsequent periods because market dynamics and market outcomes may change significantly. As a result, even the higher estimates of the cost impact to the customers of Maryland from the creation of an FRR are likely to be conservatively low. If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Introduction

In this report, the IMM analyzes the rules governing the FRR alternative to direct participation in the PJM Capacity Market and a range of potential impacts of creating a Maryland FRR service area both on payments by customers in Maryland and by customers in the balance of the RTO, based on explicitly stated assumptions.[3] The IMM previously published a report on the impacts of a ComEd FRR but the public discussion of potential FRRs in other LDAs has not been supported by analysis to date.[4] The IMM will provide analyses of the outcomes under different assumptions and of other potential FRRs, upon request. The IMM previously provided comparable analysis of FERC's resource specific FRR approach and of PJM's extended resource carve out

---

2 This could also include the owners of capacity that could be imported, limited by the CETL.

3 See Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"), Article 1 and Schedule 8.1.

4 "Potential Impacts of the Creation of a ComEd FRR," Monitoring Analytics, LLC, <http://www.monitoringanalytics.com/reports/Reports/2019.shtml> (December 18, 2019).

proposal or repricing approach.[5] The IMM also provided an analysis of the impact of the MOPR order on prices in the upcoming BRA.[6]

The American Electric Power Company, Inc. (AEP) created the first FRR service area based on the original RPM tariff rules implemented in 2007.[7] AEP was a vertically integrated utility (transmission, generation and distribution assets) which participated in all the other PJM markets, but which, rather than participating in the PJM Capacity Market, received payment for generation capacity well in excess of capacity market prices, based on a cost of service model, under a regulatory arrangement with Ohio.

In order to create a new FRR service area, a utility (investor owned, electric cooperative or public power entity) must elect the FRR option consistent with the PJM Market Rules. The utility can make a voluntary FRR election or be required to make the FRR election by the state in which the FRR exists.

There are four transmission zones in Maryland: Allegheny Power Company (APS), Baltimore Gas and Electric Company (BGE), Delmarva Power and Light (DPL), and Potomac Electric Power Company (Pepco). Maryland could require that all LSEs located in the state elect FRR status or that all LSEs in specific zones elect FRR status.[8] Regardless of the existence of retail choice, the FRR entity must include all load in the FRR service area and must provide adequate capacity to meet that load. In the AEP case, AEP owned enough generation assets to meet its PJM defined UCAP obligation. In Maryland, there are not enough capacity resources to meet the PJM defined FRR UCAP obligation. In order to create a viable Maryland FRR, LSEs in Maryland would need to contract with other capacity resource owners in Maryland, and capacity resource owners external to Maryland, limited by CETL, to meet the FRR UCAP obligation for the load in Maryland. There are shortfalls in internal capacity for a BGE FRR, while a Pepco FRR would be a net exporter.

---

5 See Monitoring Analytics, LLC "MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf> (September 26, 2018).

6 See Monitoring Analytics, LLC "Potential Impacts of the MOPR Order," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf> (March 20, 2020).

7 See RAA Schedule 8.1; 117 FERC ¶ 61,331 (2006) at PP 36, 113.

8 An FRR entity is required to meet the capacity obligations of all alternative retail LSEs in the FRR service area. The alternative retail LSEs are required to compensate the FRR entity based on a state mandated compensation mechanism or based on the Rest of RTO capacity price, in the absence of a state compensation mechanism. For any delivery year subsequent to those addressed in the FRR entity's current FRR capacity plan, the alternative retail LSE may satisfy the load payment to the FRR entity with capacity resources.

The analysis in this report is based on the actual auction inputs and results for the PJM Reliability Pricing Model (RPM) BRA (BRA) for the 2021/2022 Delivery Year, the last BRA run.[9]

The IMM evaluated the results of creating a Maryland FRR service area for load in Maryland, and for the rest of the capacity market, under six scenarios:

- Scenario 1: An FRR is established that includes all of Maryland and the FRR procures the entire Maryland capacity obligation at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Maryland ($198.53 per MW-day).
- Scenario 2: An FRR is established that includes all of Maryland and the FRR procures the entire Maryland capacity obligation at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to LDAs in Maryland ($170.67 per MW-day).
- Scenario 3: An FRR is established for the BGE LDA and the FRR procures the entire BGE capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for BGE ($180.50 per MW-day).
- Scenario 4: An FRR is established for the BGE LDA and the FRR procures the entire BGE capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($200.30 per MW-day).
- Scenario 5: An FRR is established for the Maryland portion of the Pepco LDA and the FRR procures the entire Pepco/MD capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap ($210.86 per MW-day).
- Scenario 6: An FRR is established for the Maryland portion of the Pepco LDA and the FRR procures the entire Pepco/MD capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day).

Assumptions

1. In Scenarios 1 and 2, the PJM Capacity Market would not include Maryland. In Scenarios 3 and 4, the PJM Capacity Market would not include the BGE LDA. In Scenarios 5 and 6, the PJM Capacity Market would not include the Maryland portion of the Pepco LDA.

[9] Participant behavior and market performance were evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

2. In Scenarios 1 and 2, the FRR service area would include all of Maryland. In Scenarios 3 and 4, the FRR service area would include the BGE LDA. In Scenarios 5 and 6, the FRR service area would include the Maryland portion of the Pepco LDA.
3. There would be capacity imports into Maryland FRRs only from capacity resources needed to cover any shortfall in meeting the FRR obligation. The price of imports to Maryland from capacity resources outside Maryland is assumed to be the same as the price paid to the capacity resources in Maryland meeting the FRR obligation.
4. All capacity resources would be eligible to meet FRR reliability requirements.[10] This includes matched seasonal resources with an annual equivalent offer price less than or equal to the rate paid to all annual capacity resources in the FRR service area.
5. Unmatched seasonal resources would offer their capacity in the PJM Capacity Market. These resources would be mapped to the relevant parent LDA. In the 2021/2022 BRA, 28.1 annual equivalent ICAP MW or 0.2 percent of the Maryland FRR obligation, were offered as seasonal capacity.
6. All resources that do not enter a contract with a Maryland FRR would offer their capacity resources in the PJM Capacity Market.
7. The MW capacity of energy efficiency resources that are part of the FRR plan would be added back to the FRR obligation.[11]

Market Structure

Table 2 shows the Maryland generation capacity resources in terms of installed capacity (ICAP).

Table 2 Generation capacity resources by transmission zone in Maryland

Zone	ICAP (MW)
APS	198.2
BGE	4,880.5
DPL	1,893.8
Pepco	6,966.6
Total	13,939.1

10 Since the precise locations of demand resources are not disclosed, the offered capacity MW of annual demand resources in the APS, BGE, DPL and Pepco Zones were prorated based on Maryland's share of nominated MW in the zone. All submissions for Price Responsive Demand (PRD) were mapped to Maryland. The energy efficiency resources with at least one registration in Maryland were mapped to Maryland.

11 The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast accounts for the contribution of energy efficiency resources to reducing demand. To avoid double counting, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation.

Table 3 shows the installed capacity by fuel source for the capacity resources located in Maryland.[12]

Table 3 Installed capacity by fuel source[13]

		Installed Capacity (MW)										
LDA	Zone	Coal	Gas	Nuclear	Oil	Solar	Solid Waste	Wind	DR	EE	PRD	Total
BGE	BGE	1,963.0	474.8	0.0	677.9	0.0	57.0	0.0	199.0	95.1	240.0	3,706.8
DPL South	DPL	0.0	0.0	0.0	246.3	36.5	0.0	0.0	22.5	15.3	75.0	395.6
Pepco	Pepco	2,433.0	3,412.6	0.0	308.0	0.0	52.0	0.0	185.0	61.9	195.0	6,647.5
Rest of EMAAC	DPL	0.0	1,611.0	0.0	0.0	0.0	0.0	0.0	43.6	0.0	0.0	1,654.6
Rest of SWMAAC	BGE, Pepco	0.0	761.0	1,707.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,468.8
Rest of RTO	APS	180.0	0.0	0.0	0.0	10.1	0.0	8.1	167.7	0.0	0.0	365.9
Total Maryland		4,576.0	6,259.4	1,707.8	1,232.2	46.6	109.0	8.1	617.8	172.3	510.0	15,239.2

Maryland's renewable portfolio standard (RPS) has a target of 50 percent renewable energy by 2030.[14] The 2030 target includes additional requirements that 14.5 percent of energy consumption be sourced from solar generators and 1.94 percent sourced from offshore wind generators.[15] [16] The standards for 2020 require 28.0 percent renewable with 6.0 percent sourced from solar. The Maryland FRR capacity for this study includes 172.7 MW of tier 1 renewable resources.

The most recent data from Maryland shows that renewable energy production from Maryland resources was 1,119.3 GWh in 2019, or 3.1 percent of Maryland energy production in 2019. In 2018, renewable energy production from Maryland resources was 1,132.4 GWh, or 2.8 percent of Maryland energy production. Maryland also imports significant levels of renewable energy in order to meet RPS targets. In 2018, Maryland imported 80.4 percent of the total RECs that met tier 1 RPS standards; 67.8 percent of the imported tier 1 RECs were from renewable energy resources.

12 The ICAP MW values reflect administrative reductions applied by PJM to the capabilities of wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity.

13 Two hydroelectric power plants that are physically located in Maryland but electrically located in zones outside Maryland are not included in Table 3.

14 Maryland's RPS definition is not zero carbon. Maryland's RPS definition of tier 1 renewable resources includes wind, solar, waste to energy, and landfill gas technologies. Both waste to energy and landfill gas energy production result in carbon emissions.

15 See Maryland State Legislature, Senate Bill 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.

16 Order No. 88192 – Case No. 941 – Offshore Wind, Maryland Public Service Commission, May 11, 2017, <https://www.psc.state.md.us/order-no-88192-case-no-9431-offshore-wind/>.

Market share is calculated by dividing the output of a supplier by total supply in a market. Concentration ratios are a summary measure of market share. The Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market.

FERC's Merger Policy Statement states that a market can be broadly characterized as: unconcentrated if the market HHI is below 1000, equivalent to 10 firms with equal market shares; moderately concentrated if the market HHI is between 1000 and 1800; and highly concentrated if the market HHI is greater than 1800, equivalent to between five and six firms with equal market shares.[17]

Table 4 shows the HHI results for the FRRs analyzed. The HHI results show that the BGE and Pepco/MD FRRs are highly concentrated and the Maryland FRR is at the high end of moderately concentrated.

Table 4 HHI results

Market	HHI
BGE	4,917
Pepco	5,457
Maryland	1,680

The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the capacity market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in a market even when the HHI level is not in the highly concentrated range. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the ownership structure of supply available to meet it.

A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the pivotal supplier test are measured by the residual supply index (RSI_X). The RSI_X is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_X is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices.

---

17 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement, 77* FERC ¶ 61,263 *mimeo* at 80 (1996).

Table 5 shows the results of the pivotal supplier test for the FRRs analyzed. There is at least one single pivotal supplier in the Maryland, BGE, and Pepco FRRs. All participants in the Maryland, BGE, and Pepco FRRs fail the three pivotal supplier test (RSI_3 is less than 1.0).[18]

Table 5 Pivotal supplier results

Market	RSI_1	RSI_3	Total Participants	Failed RSI_3 Participants
BGE	0.14	0.01	5	5
Pepco	0.34	0.08	6	6
Maryland	0.61	0.32	21	21

Table 6 shows: Maryland peak load as a share of the peak load of each zone; the, zonal UCAP obligation for the 2021/2022 Delivery Year; and Maryland's share of the zonal UCAP obligation for each zone in Maryland. This is the capacity obligation assigned to Maryland and each Maryland zone in the PJM Capacity Market. For example, the zonal UCAP obligation for the entire APS Zone is 10,317.8 MW. Maryland's share of the APS Zone zonal UCAP obligation is 2,057.4 MW. The total Maryland zonal UCAP obligation for 2021/2022 Delivery Year is 15,848.4 MW.[19]

Table 6 Maryland share of the zonal UCAP obligation by transmission zone

Zone	Share of the Peak Load (Percent)	Zonal UCAP Obligation (MW)	Maryland Share of Zonal UCAP Obligation (MW)
APS	19.9%	10,317.8	2,057.4
BGE	100.0%	7,435.0	7,435.0
DPL	32.7%	4,373.0	1,431.7
Pepco	69.2%	7,116.0	4,924.3
Total		29,241.9	15,848.4

Table 7 shows: Maryland peak load as a share of the peak load of each zone; Maryland's peak load forecast MW by zone; and Maryland's FRR UCAP MW obligation by zone.

18 The one pivotal supplier test and the three pivotal supplier test here include all market supply and all market demand for each FRR.

19 The reliability requirement for an LDA is the projected internal capacity in the LDA plus the capacity emergency transfer objective (CETO) for the delivery year. The CETO is calculated to meet 1 day in 25 year loss of load expectation for an LDA. See "PJM Manual 18: PJM Capacity Market," § 2.4.2 Reliability Requirement in Locational Deliverability Areas, Rev. 43 (Dec. 3, 2019). The FPR is calculated to meet 1 day in 10 year loss of load expectation for an LDA. See "PJM Manual 20: PJM Capacity Market," § 1.7 Compliance with ReliabilityFirst (RF), Rev. 10 (March 21, 2019).

This is the capacity obligation that would be assigned to Maryland and each Maryland zone if each were an FRR. The FRR obligation includes the EE add back. The FRR obligation is based on the PJM peak load forecast for the delivery year. The PJM peak load forecast is assumed to account for the contribution of energy efficiency resources because load is assumed to be reduced by the energy efficiency resources.[20] Consistent with the approach PJM uses to run capacity auctions, to avoid the double counting that would result from including EE as a supply side resource when it also reduces demand, the amount of energy efficiency capacity included in the FRR plan is added back to the FRR obligation. For example, the FRR UCAP obligation for BGE is defined as the BGE zonal forecast peak load (6,386.0 MW) times the forecast pool requirement (1.0898), or 6,959.5 MW plus the EE add back (103.6 MW) or 7,063.1. The total Maryland FRR obligation including the EE add back for the 2021/2022 Delivery Year is 15,022.5 MW.

Table 7 Maryland share of the peak load, peak load forecast and FRR obligation by transmission zone[21]

Zone	Share of the Peak Load (Percent)	Share of Zonal Peak Load Forecast (MW)	FRR UCAP Obligation (MW) plus EE add back
APS	19.9%	1,767.1	1,925.8
BGE	100.0%	6,386.0	7,063.1
DPL	32.7%	1,229.7	1,356.8
Pepco	69.2%	4,229.5	4,676.8
Total		13,612.3	15,022.5

Comparing Table 6 with Table 7 shows the zonal FRR UCAP obligations are lower than the UCAP obligations in the capacity market. The reduced obligations are a result of the fact that the RPM auction clearing uses sloped demand curves (Variable Resource Requirement or VRR curves) while the FRR Entities use vertical demand curves based on a fixed MW requirement. Under the current rules for every LDA, the calculated reliability requirement reflects the more stringent 1 day in 25 years loss of load expectation. The calculated RTO wide reliability requirement reflects the less stringent 1 day in 10 years loss of load expectation. The difference in reliability standards for an individual LDA and the RTO is intended to capture the diversity benefit. However, if a Maryland FRR service area were created, the FRR UCAP obligation reflects only the 1 day in 10 years loss of load expectation, which is a less stringent reliability standard than

20 There are significant issues with the measurement and verification of EE. See the 2019 State of the Market Report for PJM, Section 6: Net Revenue pg. 314.

21 The contribution percentages are the five year historical average of the Maryland portion of each zone’s load during the yearly maximum load hour.

the 1 day in 25 years that would apply if Maryland remained in the PJM Capacity Market.[22]

Table 8 shows that the total capacity in Maryland offered in the 2021/2022 RPM BRA is not enough to meet the Maryland FRR obligation. LSEs in Maryland would need to secure capacity both from resource owners in Maryland and capacity resources outside Maryland to meet the FRR UCAP obligation for the Maryland FRR service area.

Table 8 shows unforced capacity offered, FRR UCAP obligation plus the EE add back and shortfall in the Maryland portion of each LDA. In the 2021/2022 BRA, 3,571.5 MW UCAP were offered in the BGE LDA. The BGE FRR obligation for the 2021/2022 Delivery Year is 7,063.1 MW. The BGE LDA needs to import 3,491.6 MW UCAP or 49.4 percent of the FRR UCAP obligation from capacity resources located outside the BGE LDA. The entire BGE LDA is located within the BGE Zone. The BGE Zone also includes a portion of the Rest of SWMAAC LDA. The BGE obligation can be met in significant part by imports from the portion of the Rest of SWMAAC inside the BGE Zone.

Table 8 Capacity, FRR obligation and shortfall for Maryland by LDA[23]

LDA	Zone	Capacity (UCAP MW)	FRR Obligation (UCAP MW) plus EE add back	Shortfall (UCAP MW)	Shortfall (Percent)
BGE	BGE	3,571.5	7,063.1	(3,491.6)	(49.4%)
DPL South	DPL	379.5	1,356.8	(977.3)	(72.0%)
Pepco	Pepco	6,143.6	4,676.8	1,466.8	31.4%
Rest of EMAAC	DPL	1,648.7	-	1,648.7	NA
Rest of SWMAAC	BGE, Pepco	2,415.4	-	2,415.4	NA
Rest of RTO	APS	373.9	1,925.8	(1,551.9)	(80.6%)
Total Maryland		14,532.6	15,022.5	(489.9)	(3.3%)

The Maryland analysis is complicated by the fact that Maryland includes some or all of four LDAs and includes other unique features. Table 9 shows the LDA, modeled LDA and parent LDA for each zone in Maryland. All transmission zones are LDAs, but there are also additional LDAs, including parts of zones in some cases and multiple zones in other cases. Not all LDAs are modeled separately in the PJM capacity market auctions. Of the four LDAs in Maryland, the BGE LDA is entirely within Maryland but Pepco, DPL and APS LDAs are only partly within Maryland. The BGE Zone in Maryland includes the BGE LDA and the BGE portion of the Rest of SWMAAC LDA, both of

22 This result, which has been part of the RPM design from its inception, should be reviewed to ensure its consistency with the design of FRRs and the capacity market. In the future, this rule could be changed to ensure consistency.

23 The capacity includes the annual equivalent of matched seasonal resources. Since the 2020/2021 Delivery Year, RPM rules allow seasonal resources to offer in the capacity market. Complementary seasonal capacity resources are matched within the auction clearing process.

which are part of the SWMAAC parent LDA. The Pepco Zone in Maryland includes the Maryland portion of the Pepco LDA and the Pepco portion of the Rest of SWMAAC LDA, both of which are part of SWMAAC parent LDA. The DPL Zone in Maryland includes the Maryland portion of the DPL South LDA and the Maryland portion of the Rest of EMAAC LDA, both of which are part of EMAAC parent LDA. The APS Zone in Maryland is part of the APS LDA which includes three geographically separated subzones.

Table 9 LDA and parent LDA of zones located in Maryland

Zone	LDA	Modeled LDAs	Parent LDA
BGE	BGE	BGE, Rest of SWMAAC	SWMAAC
Pepco	Pepco	Pepco, Rest of SWMAAC	SWMAAC
DPL	DPL	DPL South, Rest of EMAAC	EMAAC
APS	APS	Rest of RTO	RTO

The BGE Zone, excluding the BGE portion of the Rest of SWMAAC, is a modeled LDA. The Rest of SWMAAC is a modeled LDA. The Pepco Zone, excluding the Pepco portion of the Rest of SWMAAC, is a modeled LDA. The DPL Zone is not a modeled LDA. The DPL Zone in Maryland includes the Maryland portion of the DPL South LDA and the Maryland portion of the Rest of EMAAC LDA, both of which are part of EMAAC parent LDA. DPL South, Rest of EMAAC and EMAAC are modeled LDAs. The APS LDA is not a modeled LDA. The APS Zone is a part of the Rest of RTO LDA, which is a part of the RTO parent LDA. The Rest of RTO is not a modeled LDA. The analysis of Maryland is limited to the portions of LDAs within Maryland. The Rest of SWMAAC LDA is unique in PJM. The Rest of SWMAAC LDA is not associated with any load or geographical region. It includes two generators both geographically located in Maryland, one in the BGE Zone and one in the Pepco Zone. These generators are connected to the high voltage transmission system.[24]

---

[24] PJM defines SWMAAC as a Global LDA and BGE and Pepco as Zonal LDAs. The PJM definition of the parent SWMAAC LDA includes all generation and load connected to the 500 kV and lower transmission system in the BGE and Pepco Zones. The PJM definition of the BGE and Pepco LDAs includes only generation and load connected to the 230 kV and lower transmission system. See "PJM Manual 14 B: PJM Region Transmission Planning Process," § C2.2 Current Locational Deliverability Area Definitions, Rev. 46 (August 28, 2019).

Table 10 shows the weighted average net CONE times B offer caps applicable to LDAs in Maryland and weighted average clearing prices in the 2021/2022 BRA.[25] [26]

Table 10 Net CONE times B offer cap for each Zone in Maryland and weighted average clearing price for Maryland

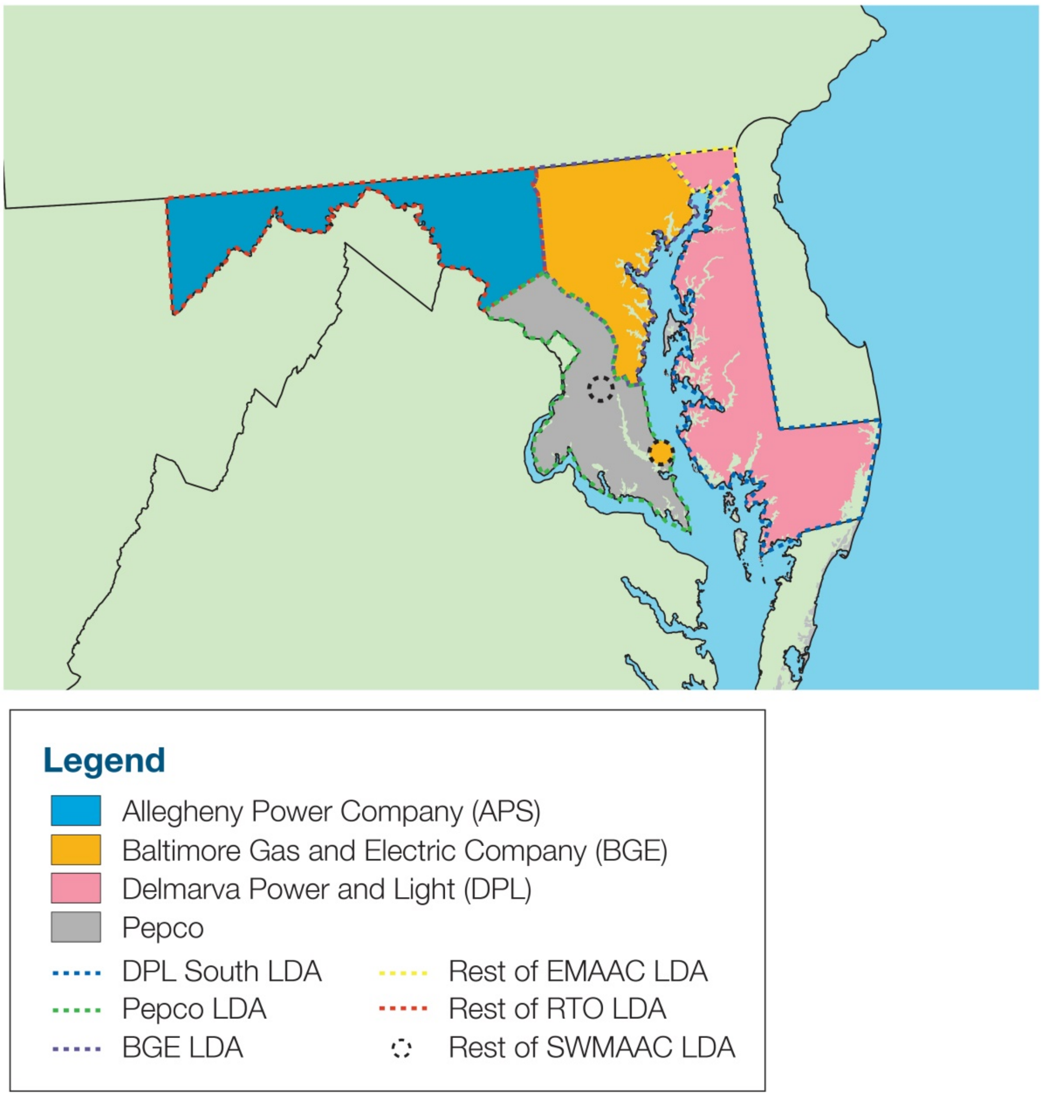
Zone	FRR UCAP Obligation (MW) plus EE add back	Offer Cap ($ per MW-day)	2021/2022 BRA Clearing Price ($ per MW-day)
APS	1,925.8	$218.31	$140.00
BGE	7,063.1	$180.50	$200.30
DPL	1,356.8	$221.76	$165.73
Pepco	4,676.8	$210.86	$140.00
Maryland (Weighted Average)		$198.53	$170.67

Figure 1 is a map of the zones and modeled LDAs in Maryland.

25 Weights are the zonal FRR UCAP obligations. These weights are used throughout the report when weighted average offer caps are calculated.

26 The net CONE times B offer caps are calculated by zone. The gross CONE values are very close across zones but net revenues vary. BGE had relatively high net revenues. See Table 5 in "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

Figure 1 Maryland zones and modeled locational deliverability areas



Existing FRR Design

The existing FRR approach remains an option for utilities with or without retail choice, including both investor owned and publicly owned utilities.[27] [28] Such utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. There is no reason for any special exemptions for such utilities. Such utilities

27 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.

28 The current FRR rules address areas with retail choice. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.D.8.

have the option to use the existing FRR option if they plan to continue to be cost of service based or wish to become cost of service based.

The RAA provides that states may require LSEs to become FRR entities.[29]

The Reliability Assurance Agreement (RAA) defines the purpose of the FRR alternative.[30]

> The Fixed Resource Requirement ("FRR") Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

The Reliability Assurance Agreement also defines the eligibility criteria for the FRR election.[31]

> A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.
>
> A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately

29 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.I.

30 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.A.

31 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.B.

> allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

An IOU is defined in the PJM RAA as "an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution."

An entity must request to elect the existing FRR option no later than four months prior to the BRA for the first delivery year of the election. An entity must under the existing FRR option submit its FRR capacity plan no later than one month prior to the BRA for the effective delivery year. The minimum term for election of the existing FRR option is five consecutive delivery years. Under the existing FRR option, an entity may terminate its FRR election following the minimum term by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year. In the event of a State Regulatory Structural Change, an entity may elect or terminate its FRR election by providing written notice to PJM no later than two months prior to the BRA for the effective delivery year.[32]

Public power entities and electric cooperatives could use the existing FRR option if they plan to continue to be cost of service based. To request the existing FRR option, public power entities or electric cooperatives need to demonstrate that the identified service area meets the definition of an FRR Service Area as defined in the RAA. The definition of FRR Service Area provides that "In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above."

---

32 State Regulatory Structural Change is defined as "to any Party, as a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable." See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

Under the current rules, an FRR entity can sell excess capacity in RPM auctions for a delivery year subject to a cap equal to the lesser of (a) 25 percent of the unforced capacity equivalent of the installed reserve margin for such delivery year multiplied by the preliminary forecast peak load for which such FRR entity is responsible under its FRR capacity plan(s) for such delivery year, or (b) 1,300 MW.[33] For Maryland and BGE, this cap would equal 1,300.0 MW. For Pepco, this cap would equal 1,152.3 MW. In order to sell excess capacity in RPM auctions for a delivery year, an FRR entity must commit additional capacity resources above its defined FRR UCAP obligation in an amount equal to the lesser of three percent of the FRR UCAP obligation or 450 MW.[34] For Maryland, this additional threshold quantity would equal 445.0 MW. For BGE, this additional threshold quantity would equal 208.8 MW. For Pepco, this additional threshold quantity would equal 138.3 MW.

Results

Scenario 1

In Scenario 1, an FRR is established that includes all of Maryland and the FRR procures the entire Maryland FRR UCAP obligation of 15,022.5 MW at a rate equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Maryland ($198.53 per MW-day).[35] Maryland has 489.9 MW UCAP or 3.3 percent fewer MW than needed to meet its FRR obligation. The Maryland FRR would need to contract with capacity resources outside Maryland to cover the deficit. If a Maryland FRR service area were created, the Maryland FRR would be required to procure 15,022.5 MW UCAP, 825.9 MW (5.2 percent) less than if Maryland remained in the PJM Capacity Market. In Scenario 1, summer capacity resources in Maryland are matched with winter capacity resources in Maryland such that the total annual equivalent price is less than or equal to the weighted average of the 2021/2022 net CONE times B offer caps applicable to the LDAs in Maryland rate ($198.53 per MW-day). The unmatched seasonal resources

---

33 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.E.2.

34 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1 and Schedule 8.1.E.

35 The FRR UCAP obligation is defined as the [(obligation peak load * final zonal FRR scaling factor) – nominal PRD value committed by the FRR entity] * [forecast pool requirement + EE add back]. The final zonal FRR scaling factor equals the final zonal peak load forecast for the delivery year / zonal weather normalized peak load for the summer concluding prior to the start of the delivery year. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 8.1.F. The EE add back MW are determined by PJM in the BRA. See "PJM Manual 18B: Energy Efficiency Measurement & Verification," Rev. 04 (Aug. 22, 2019).

are mapped to the parent LDA. For example, a seasonal resource in the BGE LDA would be mapped to the SWMAAC LDA and a seasonal resource in the DPL South LDA would be mapped to the EMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources in the Maryland FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is assumed that the actual price for capacity in the Maryland FRR would be the result of a negotiation between the owners of the required capacity, and the State of Maryland.[36] The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 11 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 1. All binding constraints would remain the same except the EMAAC constraint. The Rest of RTO LDA clearing price would decrease by $5.77 per MW-day from $140.00 per MW-day to $134.23 per MW-day, or 4.1 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $31.50 per MW-day from $165.73 per MW-day to $134.23 per MW-day, or 19.0 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA.

Table 12 shows the gross and net load charges to Maryland for the 2021/2022 BRA and for Scenario 1. The net load charges when Maryland is included in the PJM Capacity Market are net of Capacity Transfer Rights (CTRs) payments to load.[37] CTRs are analogous to FTRs in the energy market and return capacity market congestion revenues to load. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The difference exists because load pays for all capacity at the single LDA clearing price despite the fact that the capacity imported into the LDA receives a lower price. Credits for CTRs do not exist with an FRR because the CTR credits are based on the operation of an integrated capacity market with locational pricing.

Table 12 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for Maryland were $996,442,575. In the 2021/2022 RPM BRA, only 1,937.7 MW UCAP of

---

36 This could also include the owners of capacity that could be imported, limited by the CETL.

37 The MW of CTRs available for allocation to LSEs in an LDA is equal to the unforced capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). The price of the CTR credits is the locational adder for the LDA.

BGE capacity resources cleared. The BGE LDA needed 5,125.6 MW UCAP to meet the BGE zonal UCAP obligation. The CTR credits received by the BGE LDA are based only on the UCAP MW needed to meet the BGE UCAP obligation. The BGE LDA imported 6,005.0 MW of capacity from the rest of the SWMAAC LDA. The clearing price for the BGE LDA was $60.30 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $112,812,971. The load in the DPL Zone received CTR credits of $5,156,858, of which Maryland's share was $1,688,355, based on the estimated peak load contribution. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Maryland were $881,941,248.

If a Maryland FRR were created and the capacity price for Maryland were equal to the weighted average net CONE times B offer caps applicable to the LDAs in Maryland, net CONE times B ($198.53 per MW-day), the load charges for Maryland would have been $1,088,556,370, an increase of $206,615,122, or 23.4 percent higher than in the 2021/2022 BRA. (Table 12)

The higher load charges in Scenario 1 compared to the results of the 2021/2022 BRA are the result of higher prices and the elimination of CTRs, which more than offset the lower FRR UCAP obligation for the load in Maryland.

Table 13 shows the net load charges for the RTO excluding the load in the Maryland FRR for Scenario 1. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Maryland FRR, were $8,718,528,597. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding Maryland were $8,504,903,427.

Under Scenario 1, the gross load charges for the 2021/2022 RPM BRA for the RTO excluding Maryland would have been $8,279,983,407. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding Maryland, would be $8,044,712,172, a reduction of $460,191,255 or 5.4 percent.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 11 Clearing prices in Scenario 1 and Scenario 2 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 1 and Scenario 2	Change	Percent
Rest of RTO	$140.00	$134.23	($5.77)	(4.1%)
Rest of MAAC	$140.00	$134.23	($5.77)	(4.1%)
Rest of EMAAC	$165.73	$134.23	($31.50)	(19.0%)
Rest of SWMAAC	$140.00	$134.23	($5.77)	(4.1%)
Rest of PSEG	$204.29	$204.38	$0.09	0.0%
PSEG North	$204.29	$204.38	$0.09	0.0%
DPL South	$165.73	$134.23	($31.50)	(19.0%)
Pepco	$140.00	$134.23	($5.77)	(4.1%)
Rest of ATSI	$171.33	$163.08	($8.25)	(4.8%)
ATSI Cleveland	$171.33	$163.08	($8.25)	(4.8%)
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	NA	NA	NA
PPL	$140.00	$134.23	($5.77)	(4.1%)
DAY	$140.00	$134.23	($5.77)	(4.1%)
DEOK	$140.00	$134.23	($5.77)	(4.1%)

Table 12 Net load charges for Maryland (Scenario 1)[38]

Maryland FRR	BRA	Scenario 1	Change	Percent
Zonal UCAP Obligation (MW UCAP)	15,848.4	15,022.5	(825.9)	(5.2%)
Zonal Capacity Price ($/MW-day)	$172.26	$198.53	$26.27	15.3%
Gross Load Charges	$996,442,575	$1,088,556,370	$92,113,796	9.2%
Value of CTRs	$114,501,326	$0	($114,501,326)	(100.0%)
Net Load Charges	$881,941,248	$1,088,556,370	$206,615,122	23.4%

Table 13 Net load charges for RTO excluding Maryland (Scenario 1)

RTO (Excluding Maryland)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	147,778.9	148,648.1	869.2	0.6%
Gross Load Charges	$8,718,528,597	$8,279,983,407	($438,545,190)	(5.0%)
Value of CTRs	$213,625,171	$235,271,235	$21,646,064	10.1%
Net Load Charges	$8,504,903,427	$8,044,712,172	($460,191,255)	(5.4%)

38 The net load charges for the BRA include make whole payments. The gross load charges for the delivery year are calculated using the unrounded zonal capacity price.

Scenario 2

In Scenario 2, an FRR is established that includes all of Maryland and the FRR procures the entire Maryland FRR UCAP obligation of 15,022.5 MW at a rate equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Maryland ($170.67 per MW-day). Maryland has 489.9 MW UCAP or 3.3 percent fewer MW than needed to meet its FRR obligation. LSEs in Maryland would need to contract with capacity resources outside Maryland to cover the deficit. If a Maryland FRR service area were created, Maryland would be required to procure 15,022.5 MW UCAP, 825.9 MW (5.2 percent) less than if Maryland remained in the PJM Capacity Market. In Scenario 2, summer capacity resources in Maryland are matched with winter capacity resources in Maryland such that the total annual equivalent price is less than or equal to the weighted average clearing prices in the 2021/2022 RPM BRA applicable to the LDAs in Maryland ($170.67 per MW-day). The unmatched seasonal resources are mapped to the parent LDA. For example, a seasonal resource in the BGE LDA would be mapped to the SWMAAC LDA and a seasonal resource in the DPL South LDA would be mapped to the EMAAC LDA.

Table 11 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 1. All binding constraints would remain the same except the EMAAC constraint. The Rest of RTO LDA clearing price would decrease by $5.77 per MW-day from $140.00 per MW-day to $134.23 per MW-day, or 4.1 percent, from the Rest of the RTO clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $31.50 per MW-day from $165.73 per MW-day to $134.23 per MW-day, or 19.0 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA.

Table 14 shows the gross and net load charges to Maryland for the 2021/2022 BRA and for Scenario 2. The net load charges when Maryland is included in the PJM Capacity Market are net of CTRs.

Table 14 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for Maryland were $996,442,575. In the 2021/2022 RPM BRA, only 1,937.7 MW UCAP of BGE capacity resources cleared. The BGE LDA needed 5,125.6 MW UCAP to meet the BGE zonal UCAP obligation. The CTR credits received by the BGE LDA are based only on the UCAP MW needed to meet the BGE UCAP obligation. The BGE LDA imported 6,005.0 MW of capacity from the rest of the SWMAAC LDA, consistent with the CETL value for BGE LDA. The clearing price for the BGE LDA was $60.30 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $112,812,971. The load in the DPL Zone received CTR credits of $5,156,858, of which Maryland’s share was $1,688,355, based on the estimated peak load contribution. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Maryland were $881,941,248.

If a Maryland FRR were created and the capacity price for Maryland were equal to the weighted average of the Maryland LDAs' clearing prices in the BRA ($170.67 per MW-day), the load charges for Maryland would have been $935,847,051, an increase of $53,905,803, or 6.1 percent higher than in the 2021/2022 BRA.[39]

The higher load charges in Scenario 2 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the elimination of CTRs, which more than offsets the lower FRR UCAP obligation for the load in Maryland.

In the 2021/2022 RPM BRA, the load in Maryland was charged for 15,848.4 MW UCAP, Maryland's share of the zonal unforced capacity obligation. If a Maryland FRR service area were created, the load in Maryland would need to procure 15,022.5 MW UCAP, the FRR UCAP obligation for Maryland.

Table 15 shows the net load charges for the RTO excluding the load in Maryland for Scenario 2. The net load charges for the RTO excluding Maryland are the same as Scenario 1.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 14 Net load charges for Maryland (Scenario 2)

Maryland FRR	BRA	Scenario 2	Change	Percent
Zonal UCAP Obligation	15,848.4	15,022.5	(825.9)	(5.2%)
Zonal Capacity Price ($/MW-day)	$172.26	$170.67	($1.58)	(0.9%)
Gross Load Charges	$996,442,575	$935,847,051	($60,595,523)	(6.1%)
Value of CTRs	$114,501,326	$0	($114,501,326)	(100.0%)
Net Load Charges	$881,941,248	$935,847,051	$53,905,803	6.1%

Table 15 Net load charges for RTO excluding Maryland (Scenario 2)

RTO (Excluding Maryland)	BRA	Scenario 1 and Scenario 2	Change	Percent
Zonal UCAP Obligation	147,778.9	148,648.1	869.2	0.6%
Gross Load Charges	$8,718,528,597	$8,279,983,407	($438,545,190)	(5.0%)
Value of CTRs	$213,625,171	$235,271,235	$21,646,064	10.1%
Net Load Charges	$8,504,903,427	$8,044,712,172	($460,191,255)	(5.4%)

39 The $172.26 per MW-day is the Zonal UCAP Obligation weighted average net load price for Maryland, the capacity price charged to the load in the Zones within Maryland. In the 2021/2022 BRA, the FRR Obligation adjusted for EE add back, weighted resource clearing price for Maryland was $170.67 per MW-day. The difference of $1.58 per MW-day was due to ComEd's Maryland's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Scenario 3

In Scenario 3, an FRR is established for the BGE LDA and the FRR procures the entire BGE capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap for BGE ($180.50 per MW-day). The BGE FRR has 3,491.6 MW UCAP or 49.4 percent fewer MW than needed to meet its FRR obligation. The BGE FRR would need to contract with the owners of capacity resources outside the BGE FRR to cover the deficit. If a BGE FRR service area were created, the BGE FRR would be required to procure 7,063.1 MW UCAP, 372 MW (5.0 percent) less than if the BGE LDA remained in the PJM capacity market. In Scenario 3, summer capacity resources in the BGE LDA are matched with winter capacity resources in the BGE LDA such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap for BGE ($180.50 per MW-day). The unmatched seasonal resources are mapped to the rest of SWMAAC LDA.

This is a sensitivity analysis based on the assumption that the owners of capacity resources needed to meet the reliability requirements in the BGE FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is assumed that the actual price for capacity in the BGE FRR would be the result of a negotiation between the owners of the required capacity, and the State of Maryland. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 16 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 3. All binding constraints would remain the same. The Rest of RTO LDA clearing price would decrease by $5.39 per MW-day from $140.00 per MW-day to $134.61 per MW-day, or 3.8 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $29.68 per MW-day from $165.73 per MW-day to $136.05 per MW-day, or 17.9 percent, from the EMAAC clearing price in the 2021/2022 RPM BRA. The ATSI LDA clearing price would decrease by $7.52 per MW-day from $171.33 per MW-day to $163.81 per MW-day, or 4.4 percent, from the ATSI LDA clearing price in the 2021/2022 RPM BRA.

The Maryland portion of the APS Zone clearing price would decrease by $5.39 per MW-day from $140.00 per MW-day to $134.61 per MW-day or 3.8 percent from the Maryland portion of the APS Zone clearing price in the 2021/2022 RPM BRA. The Maryland portion of the Pepco LDA clearing price would decrease by $5.39 per MW-day from $140.00 per MW-day to $134.61 per MW-day or 3.8 percent from the Maryland portion of the Pepco LDA clearing price in the 2021/2022 RPM BRA. The Maryland portion of the DPL South LDA clearing price would decrease by $29.68 per MW-day from $165.73 per MW-day to $136.05 per MW-day or 17.9 percent from the Maryland portion of the DPL South LDA clearing price in the 2021/2022 RPM BRA.

Table 17 shows the gross and net load charges to the BGE FRR for the 2021/2022 BRA and for Scenario 3. The net load charges when the BGE LDA is included in the PJM Capacity Market are net of CTR payments to load.

Table 17 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for BGE LDA were $551,408,992. In the 2021/2022 RPM BRA, only 1,937.7 MW UCAP of BGE capacity resources cleared. The BGE LDA needed 5,125.6 MW UCAP to meet the BGE zonal UCAP obligation. The CTR credits received by the BGE LDA are based only on the UCAP MW needed to meet the BGE UCAP obligation. The BGE LDA imported 6,005.0 MW of capacity from the rest of SWMAAC LDA. The clearing price for the BGE LDA was $60.30 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $112,812,971. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the BGE LDA were $438,596,021.

If a BGE FRR were created and the capacity price for the BGE Zone were the net CONE times B offer cap ($180.50 per MW-day), the load charges for the BGE Zone would have been $465,332,050, an increase of $26,736,029, or 6.1 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 3 compared to the results of the 2021/2022 BRA are the result of higher prices and the elimination of CTRs, which more than offset the lower FRR UCAP obligation for the load in BGE.

Table 18 shows the net load charges for the RTO excluding the load in the BGE FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the BGE FRR were $9,163,562,179. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the BGE FRR were $8,948,248,654.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the BGE FRR would have been $8,719,022,577. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for the RTO excluding the BGE FRR would be $8,486,049,621, a reduction of $462,199,033 or 5.2 percent.

Table 19 shows the net load charges for Maryland excluding the load in the BGE FRR for Scenario 3. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for Maryland excluding the BGE FRR were $445,033,582. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Maryland excluding the BGE FRR were $443,345,227.

Under Scenario 3, the gross load charges for the 2021/2022 RPM BRA, for Maryland excluding the BGE FRR would have been $416,366,569. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for Maryland excluding the BGE FRR would be $416,238,638, a reduction of $27,106,589 or 6.1 percent.

Table 20 shows the change in the net load charges for BGE, the rest of Maryland and Maryland. Under Scenario 3, the net load charges for BGE would increase by 6.1 percent. The net load charges for Maryland excluding the BGE FRR would decrease by 6.1 percent. The net load charges for Maryland would decrease by 0.04 percent. The reduction in load charges for the rest of Maryland due to the decrease in clearing prices in APS, the Maryland portion of Pepco and the Maryland portion of DPL South offsets almost exactly the increase in the net load charges for the BGE LDA.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 16 Clearing prices in Scenario 3 and Scenario 4 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Rest of RTO	$140.00	$134.61	($5.39)	(3.8%)
Rest of MAAC	$140.00	$134.61	($5.39)	(3.8%)
Rest of EMAAC	$165.73	$136.05	($29.68)	(17.9%)
Rest of SWMAAC	$140.00	$134.61	($5.39)	(3.8%)
Rest of PSEG	$204.29	$204.38	$0.09	0.0%
PSEG North	$204.29	$204.38	$0.09	0.0%
DPL South	$165.73	$136.05	($29.68)	(17.9%)
Pepco	$140.00	$134.61	($5.39)	(3.8%)
Rest of ATSI	$171.33	$163.81	($7.52)	(4.4%)
ATSI Cleveland	$171.33	$163.81	($7.52)	(4.4%)
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	NA	NA	NA
PPL	$140.00	$134.61	($5.39)	(3.8%)
DAY	$140.00	$134.61	($5.39)	(3.8%)
DEOK	$140.00	$134.61	($5.39)	(3.8%)

Table 17 Net load charges for BGE LDA (Scenario 3)

BGE FRR	2021/2022 BRA	Scenario 3	Change	Percent
Zonal UCAP Obligation (MW UCAP)	7,435.0	7,063.1	(372.0)	(5.0%)
Zonal Capacity Price ($/MW-day)	$203.19	$180.50	($22.69)	(11.2%)
Gross Load Charges	$551,408,992	$465,332,050	($86,076,942)	(15.6%)
Value of CTRs	$112,812,971	$0	($112,812,971)	(100.0%)
Net Load Charges	$438,596,021	$465,332,050	$26,736,029	6.1%

Table 18 Net load charges for RTO excluding BGE LDA (Scenario 3)

RTO (Excluding BGE)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	156,192.3	156,693.8	501.5	0.3%
Gross Load Charges	$9,163,562,179	$8,719,022,577	($444,539,602)	(4.9%)
Value of CTRs	$215,313,526	$232,972,956	$17,659,430	8.2%
Net Load Charges	$8,948,248,654	$8,486,049,621	($462,199,033)	(5.2%)

Table 19 Net load charges for the rest of Maryland excluding BGE (Scenario 3)

Maryland (Excluding BGE)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	8,413.4	8,440.4	27.0	0.3%
Gross Load Charges	$445,033,582	$416,366,569	($28,667,013)	(6.4%)
Value of CTRs	$1,688,355	$127,931	($1,560,424)	(92.4%)
Net Load Charges	$443,345,227	$416,238,638	($27,106,589)	(6.1%)

Table 20 Change in load charges for BGE, rest of Maryland and Maryland (Scenario 3)

	BGE		Rest of Maryland		Maryland	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(372.0)	(5.0%)	27.0	0.3%	(345.0)	(2.2%)
Gross Load Charges	($86,076,942)	(15.6%)	($28,667,013)	(6.4%)	($114,743,955)	(11.5%)
Value of CTRs	($112,812,971)	(100.0%)	($1,560,424)	(92.4%)	($114,373,395)	(99.9%)
Net Load Charges	$26,736,029	6.1%	($27,106,589)	(6.1%)	($370,560)	(0.0%)

Scenario 4

In Scenario 4, an FRR is established for the BGE LDA and the FRR procures the entire BGE capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($200.30 per MW-day). [40] The BGE FRR has 3,491.6 MW UCAP or 49.4 percent fewer MW than needed to meet its FRR obligation. The BGE FRR would need to contract with the owners of capacity resources outside the BGE FRR to cover the deficit. If a BGE FRR service area were created, the BGE FRR would be required to procure 7063.1 MW UCAP, 372 MW (5.0 percent) less than if the BGE LDA remained in the PJM Capacity Market. In Scenario 4, summer capacity resources in the BGE LDA are matched with winter capacity resources in the BGE LDA such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($200.30 per MW-day). The unmatched seasonal resources are mapped to the Rest of SWMAAC LDA.

Table 16 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 4. All binding constraints would remain the same. The Rest of RTO LDA clearing price would decrease by $5.39 per MW-day

[40] The clearing price of the BGE LDA in the 2021/2022 RPM BRA ($200.30 per MW-day) was higher than the net CONE times B offer cap for the BGE LDA ($180.50 per MW-day).

from $140.00 per MW-day to $134.61 per MW-day, or 3.8 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The EMAAC LDA clearing price would decrease by $29.68 per MW-day from $165.73 per MW-day to $136.05 per MW-day, or 17.9 percent, from the EMAAC LDA clearing price in the 2021/2022 RPM BRA. The ATSI LDA clearing price would decrease by $7.52 per MW-day from $171.33 per MW-day to $163.81 per MW-day, or 4.4 percent, from the ATSI LDA clearing price in the 2021/2022 RPM BRA.

The Maryland portion of the APS Zone clearing price would decrease by $5.39 per MW-day from $140.00 per MW-day to $134.61 per MW-day or 3.8 percent from the Maryland portion of the APS Zone clearing price in the 2021/2022 RPM BRA. The Maryland portion of the Pepco LDA clearing price would decrease by $5.39 per MW-day from $140.00 per MW-day to $134.61 per MW-day or 3.8 percent from the Maryland portion of the Pepco LDA clearing price in the 2021/2022 RPM BRA. The Maryland portion of the DPL South LDA clearing price would decrease by $29.68 per MW-day from $165.73 per MW-day to $136.05 per MW-day or 17.9 percent from the Maryland portion of the DPL South LDA clearing price in the 2021/2022 RPM BRA.

Table 21 shows the gross and net load charges to the BGE FRR for the 2021/2022 BRA and for Scenario 4. The net load charges when the BGE LDA is included in the PJM Capacity Market are net of CTR payments.

Table 21 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the BGE LDA were $551,408,992. In the 2021/2022 RPM BRA, only 1,937.7 MW UCAP of BGE capacity resources cleared. The BGE LDA needed 5,125.6 MW UCAP to meet the BGE zonal UCAP obligation. The CTR credits received by the BGE LDA are based only on the UCAP MW needed to meet the BGE UCAP obligation. The BGE LDA imported 6,005.0 MW of capacity from the rest of the SWMAAC LDA. The clearing price for the BGE LDA was $60.30 per MW-day higher than the clearing price of the rest of the SWMAAC LDA. The load in the BGE Zone received CTR credits of $112,812,971. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for the BGE LDA were $438,596,021.

If a BGE FRR were created and the capacity price for the BGE FRR were the clearing price in the BRA ($200.30 per MW-day), the load charges for the BGE FRR would have been $516,376,785, an increase of $77,780,764, or 17.7 percent higher than in the 2021/2022 BRA.[41]

[41] The $203.19 per MW-day is the zone net load price, the capacity price charged to the load in the BGE Zone. In the 2021/2022 BRA, the resource clearing price for the BGE LDA was $200.30 per MW-day. The difference of $2.89 per MW-day was due to BGE's portion of

The higher load charges in Scenario 4 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the elimination of CTRs, which more than offsets the lower FRR UCAP obligation for the load in Maryland. In the 2021/2022 RPM BRA, the load in the BGE LDA received CTR credits of $112,812,971. Credits for CTRs do not exist with an FRR. CTR credits are based on the operation of an integrated capacity market with locational pricing.

In the 2021/2022 RPM BRA, the load in the BGE Zone was charged for 7,435.0 MW UCAP, BGE's share of the zonal unforced capacity obligation. If a BGE FRR service area were created, the load in the BGE Zone would need to procure 7,063.1 MW UCAP, the FRR UCAP obligation for the BGE Zone.

Table 22 shows the net load charges, for the RTO excluding the BGE LDA, for Scenario 4. The net load charges for the RTO excluding the BGE FRR, are the same as Scenario 3.

Table 23 shows the net load charges, for Maryland excluding the BGE LDA, for Scenario 4. The net load charges for Maryland excluding the BGE FRR, are the same as Scenario 3.

Table 24 shows the change in the net load charges for BGE, the rest of Maryland and Maryland. Under Scenario 4, the net load charges for BGE would increase by 17.7 percent. The net load charges for Maryland excluding the BGE FRR would decrease by 6.1 percent. The net load charges for all of Maryland would increase by 5.7 percent. The reduction in load charges for the rest of Maryland due to the decrease in clearing prices in APS, the Maryland portion of Pepco and the Maryland portion of DPL South partly offset the increase in the net load charges for the BGE LDA.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 21 Net load charges for BGE LDA (Scenario 4)

BGE FRR	2021/2022 BRA	Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	7,435.0	7,063.1	(372.0)	(5.0%)
Zonal Capacity Price ($/MW-day)	$203.19	$200.30	($2.89)	(1.4%)
Gross Load Charges	$551,408,992	$516,376,785	($35,032,207)	(6.4%)
Value of CTRs	$112,812,971	$0	($112,812,971)	(100.0%)
Net Load Charges	$438,596,021	$516,376,785	$77,780,764	17.7%

funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 22 Net load charges for RTO excluding BGE LDA (Scenario 4)

RTO (Excluding BGE)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	156,192.3	156,693.8	501.5	0.3%
Gross Load Charges	$9,163,562,179	$8,719,022,577	($444,539,602)	(4.9%)
Value of CTRs	$215,313,526	$232,972,956	$17,659,430	8.2%
Net Load Charges	$8,948,248,654	$8,486,049,621	($462,199,033)	(5.2%)

Table 23 Net load charges for the rest of Maryland (Scenario 4)

Maryland (Excluding BGE)	2021/2022 BRA	Scenario 3 and Scenario 4	Change	Percent
Zonal UCAP Obligation (MW UCAP)	8,413.4	8,440.4	27.0	0.3%
Gross Load Charges	$445,033,582	$416,366,569	($28,667,013)	(6.4%)
Value of CTRs	$1,688,355	$127,931	($1,560,424)	(92.4%)
Net Load Charges	$443,345,227	$416,238,638	($27,106,589)	(6.1%)

Table 24 Change in load charges for BGE, rest of Maryland and Maryland (Scenario 4)

	BGE		Rest of Maryland		Maryland	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation (MW UCAP)	(372.0)	(5.0%)	27.0	0.3%	(345.0)	(2.2%)
Gross Load Charges	($35,032,207)	(6.4%)	($28,667,013)	(6.4%)	($63,699,220)	(6.4%)
Value of CTRs	($112,812,971)	(100.0%)	($1,560,424)	(92.4%)	($114,373,395)	(99.9%)
Net Load Charges	$77,780,764	17.7%	($27,106,589)	(6.1%)	$50,674,175	5.7%

Scenario 5

In Scenario 5, an FRR is established for the Maryland portion of the Pepco LDA (Pepco/MD FRR) and the FRR procures the entire Pepco/MD capacity obligation at a rate equal to the 2021/2022 net CONE times B offer cap ($210.86 per MW-day). The Maryland portion of the Pepco LDA has 1,466.8 MW UCAP or 31.4 percent more capacity than needed to meet its FRR UCAP Obligation. If a Pepco/MD FRR service area were created, the load in the service area would be required to procure 4,676.8 MW UCAP, 247.5 MW (5.0 percent) less than if the Maryland portion of the Pepco LDA remained in the PJM Capacity Market. All the remaining annual resources in the Pepco/MD FRR would be assigned to the rest of the Pepco LDA, which would remain in the PJM Capacity Market.[42] In Scenario 5, summer capacity resources in Pepco/MD LDA are matched with winter capacity resources in Pepco/MD LDA such that the total annual equivalent price is less than or equal to the 2021/2022 net CONE times B offer cap ($210.86 per MW-day). The unmatched seasonal resources are mapped to the parent LDA.

42 Under PJM's implementation, the resources mapped to an LDA are deliverable to the load in every part of the LDA. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.

This is a sensitivity analysis based on the assumption that the owners of capacity resources in the Pepco/MD FRR would request payment at the existing offer cap and that all capacity resources would be paid the same price. It is assumed that the actual price for capacity in the Pepco/MD FRR would be the result of a negotiation between the owners of the required capacity, and the State of Maryland. The price for capacity resources could substantially exceed the capacity market clearing price and the capacity market offer cap.

Table 25 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 5. All binding constraints would remain binding. The Rest of RTO LDA clearing price would decrease by $2.75 per MW-day from $140.00 per MW-day to $137.25 per MW-day, or 2.0 percent, from the Rest of RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price for the remaining portion of the Pepco LDA in the PJM Capacity Market would be $137.25 per MW-day.

The Maryland portion of the APS Zone clearing price would decrease by $2.75 per MW-day from $140.00 per MW-day to $137.25 per MW-day or 2.0 percent from the Maryland portion of the APS Zone clearing price in the 2021/2022 RPM BRA. The BGE LDA clearing price and the Maryland portion of the DPL South LDA clearing price would remain the same.

Table 26 shows the gross and net load charges for the Pepco/MD FRR for the 2021/2022 BRA and for Scenario 5. The net load charges when the Maryland portion of the Pepco LDA is included in the PJM Capacity Market are net of CTR payments to load.

Table 26 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Maryland portion of the Pepco LDA were $252,589,415. In the 2021/2022 RPM BRA, the import limit to the Pepco LDA was not constrained. The load in the Pepco Zone did not receive CTRs. The net load charges for the 2021/2022 RPM BRA for the Maryland portion of the Pepco LDA were $252,589,415.

If a Pepco/MD FRR were created and the capacity price for the Maryland portion of the Pepco LDA were the net CONE times B offer cap ($210.86 per MW-day), the load charges for the Maryland portion of the Pepco LDA would have been $359,945,999, an increase of $107,356,584, or 42.5 percent higher than in the 2021/2022 BRA.

The higher load charges in Scenario 5 compared to the results of the 2021/2022 BRA are the result of higher prices which more than offset the lower FRR UCAP obligation for the load in BGE. There were no CTRs in Pepco in the 2021/2022 BRA.

Table 27 shows the net load charges for the RTO excluding the Maryland portion of the Pepco LDA for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Maryland portion of the Pepco LDA, were $9,462,381,757. After accounting for payments due to CTRs valued at $328,126,497, the net load charges for the 2021/2022 RPM BRA for the RTO excluding the Maryland portion of the Pepco LDA were $9,134,255,260.

If a Pepco/MD FRR were created, the gross load charges for the 2021/2022 RPM BRA, for the RTO excluding the Maryland portion of the Pepco LDA would have been $9,392,850,657. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for RTO excluding the Pepco/MD FRR would be $9,044,473,887, a decrease of $89,781,373 or 1.0 percent.

Table 28 shows the net load charges for Maryland excluding the load in the Pepco/MD FRR for Scenario 5. Based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, the gross load charges for the 2021/2022 RPM BRA, for Maryland excluding the Pepco/MD FRR were $743,853,160. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA for Maryland excluding the Pepco/MD FRR were $629,351,834.

Under Scenario 5, the gross load charges for the 2021/2022 RPM BRA, for Maryland excluding the Pepco/MD FRR would have been $740,772,499. After accounting for CTRs, the net load charges for the 2021/2022 RPM BRA, for Maryland excluding the Pepco/MD FRR would be $620,576,118, a reduction of $8,775,716 or 1.4 percent.

Table 29 shows the change in the net load charges for Pepco/MD, the rest of Maryland and Maryland. Under Scenario 5, the net load charges for Pepco/MD would increase by 42.5 percent. The net load charges for Maryland excluding the Pepco/MD FRR would decrease by 1.4 percent. The net load charges for Maryland would increase by 11.2 percent. The reduction in load charges for the rest of Maryland due to the decrease in clearing prices in APS partly offset the increase in the net load charges for the Maryland portion of the Pepco LDA.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

Table 25 Clearing prices in Scenario 5 and Scenario 6 compared to the actual BRA results

LDA	2021/2022 BRA	Scenario 5 and Scenario 6	Change	Percent
Rest of RTO	$140.00	$137.25	($2.75)	(2.0%)
Rest of MAAC	$140.00	$137.25	($2.75)	(2.0%)
Rest of EMAAC	$165.73	$165.73	$0.00	0.0%
Rest of SWMAAC	$140.00	$137.25	($2.75)	(2.0%)
Rest of PSEG	$204.29	$204.29	$0.00	0.0%
PSEG North	$204.29	$204.29	$0.00	0.0%
DPL South	$165.73	$165.73	$0.00	0.0%
Pepco (Excluding Pepco/MD)	$140.00	$137.25	($2.75)	(2.0%)
Rest of ATSI	$171.33	$171.33	$0.00	0.0%
ATSI Cleveland	$171.33	$171.33	$0.00	0.0%
ComEd	$195.55	$195.55	$0.00	0.0%
BGE	$200.30	$200.30	$0.00	0.0%
PPL	$140.00	$137.25	($2.75)	(2.0%)
DAY	$140.00	$137.25	($2.75)	(2.0%)
DEOK	$140.00	$137.25	($2.75)	(2.0%)

Table 26 Net load charges for Maryland portion of the Pepco LDA (Scenario 5)

Pepco/Maryland FRR	BRA	Scenario 5	Change	Percent
Zonal UCAP Obligation	4,924.3	4,676.8	(247.5)	(5.0%)
Zonal Capacity Price ($/MW-day)	$140.53	$210.86	$70.33	50.0%
Gross Load Charges	$252,589,415	$359,945,999	$107,356,584	42.5%
Value of CTRs	$0	$0	$0	0.0%
Net Load Charges	$252,589,415	$359,945,999	$107,356,584	42.5%

Table 27 Net load charges for RTO excluding Maryland portion of the Pepco LDA (Scenario 5)

RTO (Excluding Pepco/Maryland)	BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation	158,703.0	159,018.5	315.5	0.2%
Gross Load Charges	$9,462,381,757	$9,392,850,657	($69,531,100)	(0.7%)
Value of CTRs	$328,126,497	$348,376,770	$20,250,273	6.2%
Net Load Charges	$9,134,255,260	$9,044,473,887	($89,781,373)	(1.0%)

Table 28 Net load charges for the rest of Maryland (Scenario 5)

Maryland (Excluding Pepco/MD)	BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation	10,924.1	10,945.9	21.8	0.2%
Gross Load Charges	$743,853,160	$740,772,499	($3,080,661)	(0.4%)
Value of CTRs	$114,501,326	$120,196,381	$5,695,055	5.0%
Net Load Charges	$629,351,834	$620,576,118	($8,775,716)	(1.4%)

Table 29 Change in load charges for Pepco/MD LDA, rest of Maryland and Maryland (Scenario 5)

	Pepco/Maryland		Rest of Maryland		Maryland	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation	(247.5)	(5.0%)	21.8	0.2%	(225.7)	(1.4%)
Gross Load Charges	$107,356,584	42.5%	($3,080,661)	(0.4%)	$104,275,923	10.5%
Value of CTRs	$0	0.0%	$5,695,055	5.0%	$5,695,055	5.0%
Net Load Charges	$107,356,584	42.5%	($8,775,716)	(1.4%)	$98,580,868	11.2%

Scenario 6

In Scenario 6, an FRR is established for the Maryland portion of the Pepco LDA (Pepco/MD FRR) and the FRR procures the entire Pepco/MD capacity obligation at a rate equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). The Maryland portion of the Pepco LDA has 1,466.8 MW UCAP or 31.4 percent more capacity than needed to meet its FRR UCAP Obligation. If a Pepco/MD FRR service area were created, the load in the service area would be required to procure 4,676.8 MW UCAP, 247.5 MW (5.0 percent) less than if the Maryland portion of the Pepco LDA remained in the PJM Capacity Market. All the remaining annual resources in the Pepco/MD FRR would be assigned to the rest of the Pepco LDA, which would remain in the PJM capacity market. In Scenario 6, summer capacity resources in the Pepco/MD LDA are matched with winter capacity resources in Pepco/MD LDA such that the total annual equivalent price is less than or equal to the clearing price in the 2021/2022 RPM BRA ($140.00 per MW-day). The unmatched seasonal resources are mapped to the parent LDA.

Table 25 compares the clearing prices for the rest of the PJM Capacity Market by LDA for the 2021/2022 RPM BRA and for Scenario 6. All binding constraints would have remained binding. The Rest of the RTO LDA clearing price would decrease by $2.75 per MW-day from $140.00 per MW-day to $137.25 per MW-day, or 2.0 percent, from the rest of the RTO LDA clearing price in the 2021/2022 RPM BRA. The clearing price for the remaining portion of the Pepco LDA in the PJM Capacity Market would be $137.25 per MW-day.

The Maryland portion of the APS Zone clearing price would decrease by $2.75 per MW-day from $140.00 per MW-day to $137.25 per MW-day or 2.0 percent from the Maryland portion of the APS Zone clearing price in the 2021/2022 RPM BRA. The BGE LDA clearing price and the Maryland portion of the DPL South LDA clearing price would remain the same. Table 30 shows the gross and net load charges for the Maryland portion of the Pepco LDA for the 2021/2022 BRA and Scenario 6. The net load charges when the Maryland portion of the Pepco LDA is included in the PJM Capacity Market are net of CTRs.

Table 30 shows that, based on actual auction clearing prices and quantities, make whole MW and RPM zonal UCAP obligation, gross load charges for the 2021/2022 RPM BRA for the Maryland portion of the Pepco LDA were $252,589,415. In the 2021/2022 RPM BRA, the import limit to the Pepco LDA was not constrained. The load in the Pepco Zone did not receive CTRs. The net load charges for the 2021/2022 RPM BRA for the Maryland portion of the Pepco LDA were $252,589,415.

If a Pepco/MD FRR were created and the capacity price for Maryland portion of the Pepco LDA were the clearing price in the BRA ($140.00 per MW-day), the load charges for the Maryland portion of the Pepco LDA would have been $238,985,298, a decrease of $13,604,117, or 5.4 percent lower than in the 2021/2022 BRA.[43]

The lower load charges in Scenario 6 compared to the results of the 2021/2022 BRA are the result of the same clearing prices and the lower FRR UCAP obligation for the load in Maryland. There were no CTRs in Pepco in the 2021/2022 BRA.

Table 31 shows the net load charges for the RTO excluding the Pepco/MD FRR for Scenario 6. The net load charges for RTO excluding the Pepco/MD FRR are the same as Scenario 5.

Table 32 shows the net load charges, for Maryland excluding the Pepco/MD FRR, for Scenario 6. The net load charges for Maryland excluding the Pepco/MD FRR are the same as Scenario 5.

Table 33 shows the change in the net load charges for the Pepco/MD FRR, the rest of Maryland and Maryland. Under Scenario 6, the net load charges for the Pepco/MD FRR would decrease by 5.4 percent. The net load charges for Maryland excluding the Maryland portion of the Pepco LDA would decrease by 1.4 percent. The net load charges for Maryland would decrease by 2.5 percent.

If Maryland were to subsidize any generating units, the subsidy costs would be in addition to the direct FRR costs.

---

43 The $140.53 per MW-day is the zone net load price, the capacity price charged to the load in the Maryland region in the PEPCO LDA. In the 2021/2022 BRA, the resource clearing price for the PEPCO LDA was $140.00 per MW-day. The difference of $0.53 per MW-day was due to PEPCO's portion of funding for cleared Price Responsive Demand (PRD) credits and make whole payments to the seasonal resources.

Table 30 Net load charges for Maryland portion of the Pepco LDA (Scenario 6)

Pepco/Maryland FRR	BRA	Scenario 6	Change	Percent
Zonal UCAP Obligation	4,924.3	4,676.8	(247.5)	(5.0%)
Zonal Capacity Price ($/MW-day)	$140.53	$140.00	($0.53)	(0.4%)
Gross Load Charges	$252,589,415	$238,985,298	($13,604,117)	(5.4%)
Value of CTRs	$0	$0	$0	0.0%
Net Load Charges	$252,589,415	$238,985,298	($13,604,117)	(5.4%)

Table 31 Net load charges for RTO excluding Maryland portion of the Pepco LDA (Scenario 6)

RTO (Excluding Pepco/Maryland)	BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation	158,703.0	159,018.5	315.5	0.2%
Gross Load Charges	$9,462,381,757	$9,392,850,657	($69,531,100)	(0.7%)
Value of CTRs	$328,126,497	$348,376,770	$20,250,273	6.2%
Net Load Charges	$9,134,255,260	$9,044,473,887	($89,781,373)	(1.0%)

Table 32 Net load charges for the rest of Maryland (Scenario 6)

Maryland (Excluding Pepco/MD)	BRA	Scenario 5 and Scenario 6	Change	Percent
Zonal UCAP Obligation	10,924.1	10,945.9	21.8	0.2%
Gross Load Charges	$743,853,160	$740,772,499	($3,080,661)	(0.4%)
Value of CTRs	$114,501,326	$120,196,381	$5,695,055	5.0%
Net Load Charges	$629,351,834	$620,576,118	($8,775,716)	(1.4%)

Table 33 Change in load charges for BGE, rest of Maryland and Maryland (Scenario 6)

	Pepco/Maryland		Rest of Maryland		Maryland	
	Change	Percent	Change	Percent	Change	Percent
Zonal UCAP Obligation	(247.5)	(5.0%)	21.8	0.2%	(225.7)	(1.4%)
Gross Load Charges	($13,604,117)	(5.4%)	($3,080,661)	(0.4%)	($16,684,778)	(1.7%)
Value of CTRs	$0	0.0%	$5,695,055	5.0%	$5,695,055	5.0%
Net Load Charges	($13,604,117)	(5.4%)	($8,775,716)	(1.4%)	($22,379,833)	(2.5%)