

Background

Delegate Lorig Charkoudian is introducing legislation this session that establishes two solar procurement processes to develop new solar projects in the State to be overseen by the Maryland Public Service Commission (“PSC”). One procurement process is for larger solar projects (utility scale) and is a RFP model. The other procurement process is the provision of administratively determined credits/incentives similar to a model used in New Jersey. Additionally, the proposed legislation closes the existing solar renewable energy credit (“SREC”) market to new projects and obligates the utilities to purchase the SRECs from the grandfathered facilities at the alternative compliance price for SRECs. Finally, the proposed legislation will have ACPs for non-SRECs retained in an escrow account to be used as an offset to the new and old program costs instead of directed to the Strategic Energy Investment Fund (“SEIF”).

The PSC was asked what an estimated cost of the programs may be and the net impact of the offsetting ACPs from non-solar RECs in the draft legislation. The following document contains cost estimates for the draft revised SREC market legislation.

These are rough estimates that can serve as ballparks, and they should not be considered precise projections. Please note that due to the volatile nature of the current solar market (loss of ITC/PTC) and that several assumptions were made, there is a limit to the validity of the cost estimates at this time.

Additionally, the Delegate connected the PSC with an energy company RWE Clean Energy who provided public estimated costs to develop new utility scale solar. This information provided by RWE was used in the analysis though the PSC makes no findings about the appropriateness of the values at this time.

Estimated Cost of the Revised Solar Programs

Administratively determined RECs:

Both New Jersey (NJ) and Delaware (DE) conduct programs to procure RECs from smaller solar systems. The NJ RECs are determined administratively while DE reccs are determined through a bid process. For this process, the NJ REC prices were for 2025 and the DE REC prices were from 2024, though DE did just release its resulting costs for 2025. There was no attempt to modify these values for any future changes that may occur for developer views of the financing or energy markets nor to determine how the final values arrived at in the future through a PSC administrative process may differ from these. These estimates were utilized to represent similar efforts to attract similar positioned smaller solar systems. A detailed survey of other approaches was not completed.

Both NJ and DE provide RECs for different types of small solar installations. For purposes of the cost estimates used in this analysis, the \$110 MWh price from NJ, which was for less than 1 MW DC systems, was selected (Small Net-Metered Non-Residential located on Rooftop, Carport, Canopy and Floating Solar), which represents the highest cost. The prices of the NJ process ranged from \$80 - \$110 MWh depending upon the system type, excluding a \$20 public entities adder.¹ For DE the analysis used the weighted average price of \$43.80 MWh from 2024.² Please note that in Dec 2025, DE posted a weighted average result of \$32.69, which would reduce the cost estimates in this document using DE's values.³ Please note both prices may assume the federal incentives were still in place and an adder may be appropriate for these but none was added at this time due to lack of insight into how that would impact these values.

Utility Scale Solar RFP process

For the utility scale RECs the prices used were provided by RWE as discussed previously. They provided a range of cost estimates from public and private (paid) sources. There was no examination of the validity of these estimates. A cost estimate for the Utility Scale Program used both the cheapest and most expensive cost quoted. Please note that RWE was able to call out specifically the loss of the federal incentive for the higher cost estimate (no similar adjustment was called out for the lower cost estimate).

Grandfathered System Costs

This represents costs of systems installed before the two new programs take effect January 1, 2028. It is fair to consider that some of these costs would be considered “non-incremental” costs since these are systems that have been or may be developed prior to the proposed legislation taking effect and that would have been paid for their RECs at or below the current ACP levels. That said, the proposed legislation ensures these projects shall be paid the ACP value for their SRECs which may or may not have occurred as that is contingent upon at what price current load serving entities (utilities and suppliers) would have been willing to buy SRECs from the market.

To develop the grandfathered cost estimates three subgroups were created: (1) existing solar, (2) projected utility scale, (3) projected net energy metering (NEM)/community solar. For the existing systems it was assumed that all solar in PJM GATs which are located and registered in Maryland would sell their RECs to Maryland. For projected utility scale solar these systems were identified based on solar currently in PJM's queue and have an “in-service date before 2028.” The estimated capacity was reduced using a rule of thumb project

¹ <https://cleanenergy.nj.gov/programs/solar/administratively-determined-incentive-adi-program?section=incentive-values>

² <https://srecdelaware.com/procurements/2024-procurement/>

³ <https://srecdelaware.com/procurements/2025-procurement/>

success rate multiplier based on discussions with colleagues at PJM regarding observations of project queue success rate. For this analysis the older program success rates were used, though under the new process going forward there could be improvements. For projected NEM/community solar it was assumed the remainder of the 3000 MW cap on NEM and community solar projects would be fulfilled by 2028 as conservative cost estimates.⁴ Both the existing solar analysis and the projected NEM/community solar analysis account for projects to receive bonus RECs under the Brighter Tomorrow Act.

Universal Assumptions:

(1) Capacity Factors

- a. Utility Scale – Grandfathered - Projected and Utility Sale Program: 25% (from RWE). This also generally aligns with data found through the EIA.⁵
- b. All Others – We provide two scenarios, one at 15% and another at 20%. The capacity factor for RECs in the GATs system appears to be 13% and it is unclear why this may be. It was bumped up to 15% for purposes of estimates. Lazard’s Levelized Cost of Solar Report contains a range of capacity factors for community and C&I solar which range from 15 – 20%.⁶

(2) There was no attempt to adjust costs for inflation. This would increase costs in later years.

(3) For the ADI and utility scale programs, it was assumed 250 MW of solar was developed per year to 2035 (2000 MW per the program over eight years). The analysis assumes payments begin at 100% in the year for which the projects were procured. This is an aggressive assumption as it is our understanding in the legislation that procurement for 2028 programs would not begin until late 2027. Also, it is not clear even if the procurements were completed in 2027 that the procured capacity would be available at the start of the next year.

⁴ The projected amount of community solar capacity plus existing NEM and Community Solar facilities exceeds the State cap of 3000 MW. 2025 Net Metering Report, Maryland Public Service Commission, Nov. 2025, p. 2. <https://www.psc.state.md.us/wp-content/uploads/2025-Net-Metering-Report-4.pdf>. The PSC makes no finding if the Cap will be reached prior to 2028, this estimate was made to be conservative.

⁵ Table 4.08.B. Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels. Photovoltaics’ had a capacity factor of 25.6% (2014) – 23.2% (2024). Solar Thermal had capacity factors ranging from 18.3% (2014) – 25.0% (2024). https://www.eia.gov/electricity/annual/html/epa_04_08_b.html

⁶ Lazard Levelized Cost of Energy, Jun. 2025, P. 34, <https://www.lazard.com/media/5tlbhyla/lazards-lcoeplus-june-2025-vf.pdf>

(4) The analysis provides a degradation factor of 0% of solar output to be conservative. There appears to be some research from the National Laboratory of the Rockies which indicates panels lose less than 1% output per year.⁷ Any addition of degradation to this analysis would reduce the estimated costs.

⁷ <https://www.nrel.gov/pv/lifetime>

News article: <https://pv-magazine-usa.com/2025/08/04/how-long-do-residential-solar-panels-last-3/>

New Procurement Programs (Incremental Cost)

This section presents estimated costs and gross bill impacts (no adjustment for potentially retained ACP revenues) for the two new solar procurement programs which are incremental cost above current policy based on the assumptions discussed previously.

Estimated Cost of New Procurement Programs (15% Capacity Factor For NEM/Community Solar)

	Total Cost of New Procurements		ADI		Utility Scale	
	DE - Cost, RWE - Lower Estimate	NJ - Cost, RWE - Higher Estimate	DE - Cost	NJ - Cost	RWE - Lower Estimate	RWE - Higher Estimate
2028	\$ 22,055,386	\$ 56,068,661	\$ 12,190,700	\$ 36,135,000	\$ 9,864,686	\$ 19,933,661
2029	\$ 44,110,773	\$ 112,137,323	\$ 24,381,400	\$ 72,270,000	\$ 19,729,373	\$ 39,867,323
2030	\$ 66,166,159	\$ 168,205,984	\$ 36,572,100	\$ 108,405,000	\$ 29,594,059	\$ 59,800,984
2031	\$ 88,221,545	\$ 224,274,645	\$ 48,762,800	\$ 144,540,000	\$ 39,458,745	\$ 79,734,645
2032	\$ 110,276,931	\$ 280,343,306	\$ 60,953,500	\$ 180,675,000	\$ 49,323,431	\$ 99,668,306
2033	\$ 132,332,318	\$ 336,411,968	\$ 73,144,200	\$ 216,810,000	\$ 59,188,118	\$ 119,601,968
2034	\$ 154,387,704	\$ 392,480,629	\$ 85,334,900	\$ 252,945,000	\$ 69,052,804	\$ 139,535,629
2035	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2036	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2037	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2038	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2039	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2040	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2041	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2042	\$ 176,443,090	\$ 448,549,290	\$ 97,525,600	\$ 289,080,000	\$ 78,917,490	\$ 159,469,290
2043	\$ 154,387,704	\$ 392,480,629	\$ 85,334,900	\$ 252,945,000	\$ 69,052,804	\$ 139,535,629
2044	\$ 132,332,318	\$ 336,411,968	\$ 73,144,200	\$ 216,810,000	\$ 59,188,118	\$ 119,601,968
2045	\$ 110,276,931	\$ 280,343,306	\$ 60,953,500	\$ 180,675,000	\$ 49,323,431	\$ 99,668,306
2046	\$ 88,221,545	\$ 224,274,645	\$ 48,762,800	\$ 144,540,000	\$ 39,458,745	\$ 79,734,645
2047	\$ 66,166,159	\$ 168,205,984	\$ 36,572,100	\$ 108,405,000	\$ 29,594,059	\$ 59,800,984
2048	\$ 44,110,773	\$ 112,137,323	\$ 24,381,400	\$ 72,270,000	\$ 19,729,373	\$ 39,867,323
2049	\$ 22,055,386	\$ 56,068,661	\$ 12,190,700	\$ 36,135,000	\$ 9,864,686	\$ 19,933,661

Estimated Cost of New Procurement Programs (20% Capacity Factor For NEM/Community Solar)

	Total Cost of New Procurements		ADI		Utility Scale	
	DE - Cost, RWE - Lower Estimate	NJ - Cost, RWE - Higher Estimate	DE - Cost	NJ - Cost	RWE - Lower Estimate	RWE - Higher Estimate
2028	\$ 26,118,953	\$ 68,113,661	\$ 16,254,267	\$ 48,180,000	\$ 9,864,686	\$ 19,933,661
2029	\$ 52,237,906	\$ 136,227,323	\$ 32,508,533	\$ 96,360,000	\$ 19,729,373	\$ 39,867,323
2030	\$ 78,356,859	\$ 204,340,984	\$ 48,762,800	\$ 144,540,000	\$ 29,594,059	\$ 59,800,984
2031	\$ 104,475,812	\$ 272,454,645	\$ 65,017,067	\$ 192,720,000	\$ 39,458,745	\$ 79,734,645
2032	\$ 130,594,765	\$ 340,568,306	\$ 81,271,333	\$ 240,900,000	\$ 49,323,431	\$ 99,668,306
2033	\$ 156,713,718	\$ 408,681,968	\$ 97,525,600	\$ 289,080,000	\$ 59,188,118	\$ 119,601,968
2034	\$ 182,832,671	\$ 476,795,629	\$ 113,779,867	\$ 337,260,000	\$ 69,052,804	\$ 139,535,629
2035	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2036	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2037	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2038	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2039	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2040	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2041	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2042	\$ 208,951,624	\$ 544,909,290	\$ 130,034,133	\$ 385,440,000	\$ 78,917,490	\$ 159,469,290
2043	\$ 182,832,671	\$ 476,795,629	\$ 113,779,867	\$ 337,260,000	\$ 69,052,804	\$ 139,535,629
2044	\$ 156,713,718	\$ 408,681,968	\$ 97,525,600	\$ 289,080,000	\$ 59,188,118	\$ 119,601,968
2045	\$ 130,594,765	\$ 340,568,306	\$ 81,271,333	\$ 240,900,000	\$ 49,323,431	\$ 99,668,306
2046	\$ 104,475,812	\$ 272,454,645	\$ 65,017,067	\$ 192,720,000	\$ 39,458,745	\$ 79,734,645
2047	\$ 78,356,859	\$ 204,340,984	\$ 48,762,800	\$ 144,540,000	\$ 29,594,059	\$ 59,800,984
2048	\$ 52,237,906	\$ 136,227,323	\$ 32,508,533	\$ 96,360,000	\$ 19,729,373	\$ 39,867,323
2049	\$ 26,118,953	\$ 68,113,661	\$ 16,254,267	\$ 48,180,000	\$ 9,864,686	\$ 19,933,661

Estimated Gross Bill Impact (\$/Month) – New Programs (Residential) (Based on Average Customer usage of 880 kWh)⁸

Gross Bill Impacts - Does not account for ACP Offsets (Assumes 15% Capacity Factor for ADI)						
	Gross Bill Impact - (New Programs)		ADI		Utility Scale	
	DE - Cost, RWE - Lower Estimate	NJ - Cost, RWE - Higher Estimate	Low	High	Low	High
			DE - Cost	NJ - Cost	RWE - Lower Estimate	RWE - Higher Estimate
2028	\$ 0.29	\$ 0.75	\$ 0.16	\$ 0.48	\$ 0.13	\$ 0.27
2029	\$ 0.58	\$ 1.48	\$ 0.32	\$ 0.95	\$ 0.26	\$ 0.53
2030	\$ 0.86	\$ 2.19	\$ 0.48	\$ 1.41	\$ 0.39	\$ 0.78
2031	\$ 1.13	\$ 2.88	\$ 0.63	\$ 1.86	\$ 0.51	\$ 1.02
2032	\$ 1.40	\$ 3.55	\$ 0.77	\$ 2.29	\$ 0.62	\$ 1.26
2033	\$ 1.66	\$ 4.21	\$ 0.92	\$ 2.71	\$ 0.74	\$ 1.50
2034	\$ 1.91	\$ 4.85	\$ 1.05	\$ 3.13	\$ 0.85	\$ 1.72

Gross Bill Impacts - Does not account for ACP Offsets (Assumes 20% Capacity Factor for ADI)						
	Gross Bill Impact - (New Programs)		ADI		Utility Scale	
	DE - Cost, RWE - Lower Estimate	NJ - Cost, RWE - Higher Estimate	Low	High	Low	High
			DE - Cost	NJ - Cost	RWE - Lower Estimate	RWE - Higher Estimate
2028	\$ 0.35	\$ 0.91	\$ 0.22	\$ 0.64	\$ 0.13	\$ 0.27
2029	\$ 0.69	\$ 1.80	\$ 0.43	\$ 1.27	\$ 0.26	\$ 0.53
2030	\$ 1.02	\$ 2.66	\$ 0.63	\$ 1.88	\$ 0.39	\$ 0.78
2031	\$ 1.34	\$ 3.50	\$ 0.84	\$ 2.48	\$ 0.51	\$ 1.02
2032	\$ 1.65	\$ 4.31	\$ 1.03	\$ 3.05	\$ 0.62	\$ 1.26
2033	\$ 1.96	\$ 5.11	\$ 1.22	\$ 3.62	\$ 0.74	\$ 1.50
2034	\$ 2.26	\$ 5.89	\$ 1.41	\$ 4.17	\$ 0.85	\$ 1.72

⁸ Based on 2025 Ten-Year Plan report projected usage and the bill impacts assume all customers pay the same amount on a per kWh basis for the program. Please note that this includes some projected data center usage. If the load forecast is not realized, then bill impacts increase vs if the load forecast increases, then avoided cost increases and bill impacts decrease all else being equal.

Grandfather Program

This section shows costs associated with solar grandfathered which will receive payment at the historic ACP curve level. As previously mentioned, it is fair to assume that some costs associated with this section are likely “non-incremental” since customers would likely have paid for these projects SRECs or the associated ACPs under the old model. Please note that the cost estimates for the PJM Que Solar and NEM/Community Solar are very speculative as these projects have not been developed. If less projects than estimated are built, then grandfathered costs decrease while if more projects are built then project costs could increase.

Estimated Total of Grandfathered Programs (non-incremental to partially incremental costs)

	Grandfathered (15% Capacity Factor For NEW/Community Solar)					Grandfathered (20% Capacity Factor For NEW/Community Solar)			
	Total	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity		Total	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity
2028	\$ 236,707,398	\$ 122,440,146	\$ 43,339,137	\$ 70,928,115	2028	\$ 236,707,398	\$ 163,253,528	\$ 43,339,137	\$ 94,570,820
2029	\$ 182,082,614	\$ 94,184,728	\$ 33,337,798	\$ 54,560,089	2029	\$ 182,082,614	\$ 125,579,637	\$ 33,337,798	\$ 72,746,785
2030	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2030	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2031	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2031	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2032	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2032	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2033	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2033	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2034	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2034	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2035	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2035	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2036	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2036	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2037	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2037	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2038	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2038	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2039	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2039	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2040	\$ 163,874,353	\$ 84,766,255	\$ 30,004,018	\$ 49,104,080	2040	\$ 163,874,353	\$ 113,021,673	\$ 30,004,018	\$ 65,472,106
2041	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2041	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2042	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2042	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2043	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2043	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2044	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2044	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2045	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2045	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2046	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2046	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2047	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2047	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2048	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2048	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106
2049	\$ 161,304,725	\$ 82,196,627	\$ 30,004,018	\$ 49,104,080	2049	\$ 161,304,725	\$ 109,595,503	\$ 30,004,018	\$ 65,472,106

Estimated Gross Bill Impact (\$/Month) – Grandfathered Program (Residential)(Based on Average Customer usage of 880 kWh)⁹

Gross Bill Impact of Grandfathered Assumes 15% Capacity Factor for NEM/Community Solar				
	Total	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity
2028	\$ 3.15	\$ 1.63	\$ 0.58	\$ 0.95
2029	\$ 2.41	\$ 1.24	\$ 0.44	\$ 0.72
2030	\$ 2.13	\$ 1.10	\$ 0.39	\$ 0.64
2031	\$ 2.10	\$ 1.09	\$ 0.39	\$ 0.63
2032	\$ 2.07	\$ 1.07	\$ 0.38	\$ 0.62
2033	\$ 2.05	\$ 1.06	\$ 0.38	\$ 0.61
2034	\$ 2.03	\$ 1.05	\$ 0.37	\$ 0.61

Gross Bill Impact of Grandfathered Assumes 20% Capacity Factor for ADI				
	Total	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity
2028	\$ 4.01	\$ 2.18	\$ 0.58	\$ 1.26
2029	\$ 3.06	\$ 1.66	\$ 0.44	\$ 0.96
2030	\$ 2.71	\$ 1.47	\$ 0.39	\$ 0.85
2031	\$ 2.68	\$ 1.45	\$ 0.39	\$ 0.84
2032	\$ 2.64	\$ 1.43	\$ 0.38	\$ 0.83
2033	\$ 2.61	\$ 1.41	\$ 0.38	\$ 0.82
2034	\$ 2.58	\$ 1.40	\$ 0.37	\$ 0.81

⁹ Based on 2025 Ten-Year Plan report projected usage and the bill impacts assume all customers pay the same amount on a per kWh basis for the program. Please note that this includes some projected data center usage. If the load forecast is not realized, then bill impacts increase vs if the load forecast increases, then avoided cost increases and bill impacts decrease all else being equal. Also note that some of the grandfathered costs would be paid by customers regardless of the proposed legislation being implemented.

Additional Impacts to Grandfathered Program

As noted, if there are no changes to the current SREC procurement structure then customers would pay for some or all the grandfathered SRECs. The previous gross bill impact for grandfathered programs does not account for the interplay between grandfathered SREC payments and the fact customers would have (1) potentially paid these in their current supply rates if no legislative change occurs, and (2) there is potentially avoided cost of not making future SREC payments above current levels under the old method. The following table captures what could potentially be a “net/anticipated” bill impact for the grandfathered SREC program. This assumes that customers for grandfathered SREC systems today and going forward pay the ACP for solar in rates (e.g. if there is a solar REC deficiency then utilities/suppliers pay the market ACP values for their RECs).

Please note that the following is very dependent upon the load forecasts used to estimate the SREC need in the future. If the load forecast is not realized, then bill impacts increase vs if the load forecast increases then avoided cost increases and bill impacts decrease. The load forecast is based on the 2025 Ten-Year Plan. The forecast is also very dependent upon as to how much of the projected solar in PJM’s queue and remaining 3000 MW NEM/Community Solar cap is reached prior to 2028, neither of which is certain.

Estimating Net/Anticipated Impact of Grandfather SRECs Based on NEM + Community Solar with 15% Capacity Factor								
	SREC need based on 2025 10-yr plan	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity	Total Grandfathered SRECs	(Avoided) vs In Excess	Monetary Impact	Bill Impact - Avg Residential
2028	6,895,133	3,653,183	1,333,512	1,922,119	6,908,815	13,682	\$ 444,667	\$ 0.01
2029	7,887,363	3,653,183	1,333,512	1,922,119	6,908,815	(978,548)	\$ (24,463,699)	\$ (0.32)
2030	9,269,997	3,653,183	1,333,512	1,922,119	6,908,815	(2,361,182)	\$ (53,126,594)	\$ (0.69)
2031	9,394,835	3,653,183	1,333,512	1,922,119	6,908,815	(2,486,020)	\$ (55,935,449)	\$ (0.72)
2032	9,535,174	3,653,183	1,333,512	1,922,119	6,908,815	(2,626,359)	\$ (59,093,076)	\$ (0.75)
2033	9,649,523	3,653,183	1,333,512	1,922,119	6,908,815	(2,740,708)	\$ (61,665,929)	\$ (0.77)
2034	10,324,145	3,653,183	1,333,512	1,922,119	6,908,815	(3,415,330)	\$ (76,844,935)	\$ (0.95)

Estimating Net/Anticipated Impact of Grandfather SRECs Based on NEM + Community Solar with 20% Capacity Factor								
	SREC need based on 2025 10-yr plan	Existing Solar	Project PJM Queue Solar	Remaining NEM/CS Capacity	Total Grandfathered SRECs	(Avoided) vs In Excess	Monetary Impact	Bill Impact - Avg Residential
2028	6,895,133	4,870,911	1,333,512	2,562,826	8,767,249	1,872,116	\$ 60,843,779	\$ 0.81
2029	7,887,363	4,870,911	1,333,512	2,562,826	8,767,249	879,886	\$ 21,997,157	\$ 0.29
2030	9,269,997	4,870,911	1,333,512	2,562,826	8,767,249	(502,748)	\$ (11,311,824)	\$ (0.15)
2031	9,394,835	4,870,911	1,333,512	2,562,826	8,767,249	(627,586)	\$ (14,120,679)	\$ (0.18)
2032	9,535,174	4,870,911	1,333,512	2,562,826	8,767,249	(767,925)	\$ (17,278,306)	\$ (0.22)
2033	9,649,523	4,870,911	1,333,512	2,562,826	8,767,249	(882,274)	\$ (19,851,159)	\$ (0.25)
2034	10,324,145	4,870,911	1,333,512	2,562,826	8,767,249	(1,556,896)	\$ (35,030,165)	\$ (0.43)

Potential Offsets

The previous bill impacts did not account for offsets from retained ACP revenues that the legislation envisions,

ACP Offsets

The legislation requires ACPs be diverted to an escrow account starting in October 2026 to be used to offset costs of the program which would not start until 2028. This means the ACP revenues would net against the cost of the program. As discussed below, it is not known if the currently high amount of ACP payments will continue (over \$300 million for Tier 1 ACP was paid last year), but there is a decent likelihood of high ACP continuing into the near future. The following table provides the estimated bill reduction assuming the retention of certain amounts of ACP to help cover program expenses. These values netted against the previous bill impacts (primarily the “new programs”) provide estimated net/anticipated bill impacts for the proposed legislation.

	Monthly Bill Reduction of Applying ACP to Program (Average Residential Usage of 880 kWh/month)				
Potentially Applied ACP by Year	\$ 100,000,000	\$ 200,000,000	\$ 300,000,000	\$ 400,000,000	\$ 500,000,000
2028	\$ (1.33)	\$ (2.67)	\$ (4.00)	\$ (5.33)	\$ (6.66)
2029	\$ (1.32)	\$ (2.64)	\$ (3.96)	\$ (5.28)	\$ (6.60)
2030	\$ (1.30)	\$ (2.60)	\$ (3.90)	\$ (5.21)	\$ (6.51)
2031	\$ (1.28)	\$ (2.57)	\$ (3.85)	\$ (5.14)	\$ (6.42)
2032	\$ (1.27)	\$ (2.53)	\$ (3.80)	\$ (5.06)	\$ (6.33)
2033	\$ (1.25)	\$ (2.50)	\$ (3.75)	\$ (5.00)	\$ (6.26)
2034	\$ (1.24)	\$ (2.47)	\$ (3.71)	\$ (4.94)	\$ (6.18)

Offsetting Estimated Costs of the Revised Solar Programs

The legislation revising the RPS program for solar anticipates utilizing ACPs to offset the costs outlined above. For many reasons, forecasting ACP revenue is very difficult. At this time, we do not attempt to forecast revenue amounts, however we have reason to express some confidence that Maryland will realize significant ACP revenue for the foreseeable future. This opinion is based on recent trends affecting ACPs in the state. However, there are many unknowns that could affect the supply of RECs in PJM, which means that this analysis could change quickly and meaningfully in the future.

Recent Trends for Maryland RPS Compliance

- Beginning in 2021, Solar REC retirement began to lag RPS requirements significantly, resulting in ACPs:
 - 2021: \$76.9 million
 - 2022: \$85.9 million
 - 2023: \$55.9 million
 - 2024: \$37.1 million
- Solar REC retirement is beginning to rise closer to RPS requirements, and at this time we believe Solar ACPs will continue to fall as solar installation in Maryland continues to rise closer to the RPS.
- Beginning in 2023, Tier 1 REC retirement began to lag RPS requirements significantly, resulting in ACPs:
 - 2023: \$262.3 million
 - 2024: \$319.3 million
- As outlined below, we believe Tier 1 REC retirement to continue to lag the RPS requirements, leading to continued significant ACP payments to Maryland. However, this analysis could change quickly and meaningfully in the future, depending on the supply of Tier 1 RECs that could become available, new load in the region, and any policy changes in states with which we compete for Tier 1 RECs.

Trends Affecting Tier 1 RPS Compliance in Maryland

- For most Tier 1 RECs, and certainly for the major types of Tier 1 RECs utilized for compliance with Maryland's RPS, we compete with several other states in the region. Our leading competitors are New Jersey, Pennsylvania, and Virginia.
- Reports of Average Costs of Tier 1 RECs for 2024:
 - Maryland: \$27.09
 - New Jersey: \$31.76

- Pennsylvania: \$31.01
- Virginia: not available
- Maryland's Tier 1 RPS (without carve-outs) is set at 27.05% for 2024, with future requirements fluctuating until being set at 21.48% in 2030 and future years.
 - MD's ACP for Tier 1 compliance is \$27.50 for 2024, and decreases gradually over time until being set at \$22.35 for 2030 and beyond.
 - 2024 average Tier 1 REC prices are only slightly lower than MD's ACPs. Given an apparent shortfall of Tier 1 RECs available for compliance in competing PJM states, it appears to be attractive for LSEs to pay the ACP instead of retiring RECs in Maryland. This trend likely will continue, especially as MD's ACPs fall over time, while ACPs in competing states are static going forward. Furthermore, NJ's and VA's Tier 1 requirements will rise significantly in future years.
- New Jersey's Tier 1 RPS is currently set at 35%, and is scheduled to rise to 50% by 2030.
 - New Jersey's ACP for Tier 1 compliance is \$50, continuing into the future.
 - Current Tier 1 REC prices fall well below NJ's ACP, making it attractive for LSEs to retire RECs instead of paying ACPs.
 - Note that in May 2025, New Jersey relaxed its Tier 1 requirement, from 38% to 35%, in order to bring down prices. A market analysis reports this action caused prices to come down by approximately 25%.
- Pennsylvania's Tier 1 RPS is 7.5% and will stay at that percentage into the future, under current law.
 - Legislation in PA to raise the Tier 1 RPS has been introduced in the last two years, but did not pass previously. Prospects for passage in the near future are unclear.
 - PA's ACP for Tier 1 compliance is \$45, continuing into the future.
 - Current Tier 1 REC prices fall well below PA's ACP, making it attractive for LSEs to retire RECs instead of paying ACPs.
- Virginia's Tier 1 RPS is currently set at 17.48% in 2025, increasing to approximately 30% in 2030, and then increasing to 100% by 2050.
 - VA's ACP for in-state compliance is \$75, continuing into the future
 - VA has a requirement for 75% of Tier 1 RECs to be generated in-state.
 - VA's ACP for out-of-state compliance is \$45, continuing into the future
 - Current Tier 1 REC prices fall well below VA's ACPs, making it attractive for LSEs to retire RECs instead of paying ACPs.

Potential Tier 1 REC Price Drivers and Possible Effects on Maryland ACPs

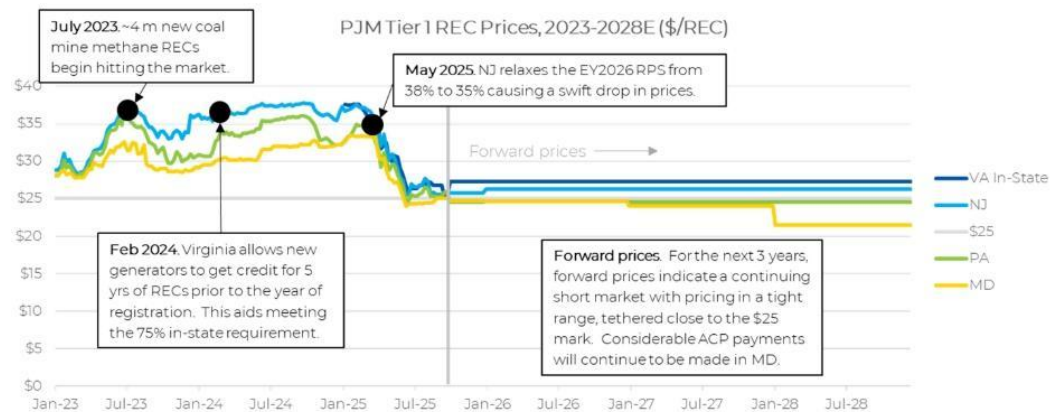
An [analysis by Power Advisory](#) offers some insights into drivers that could put upward or downward pressure on Tier 1 REC prices.

- Downward Price Driver: New Jersey RPS Change. The May 2025 action by New Jersey to freeze its RPS put downward pressure on REC prices. It is possible New Jersey could do this again, which would continue to put downward pressure on REC prices.
- Secondary Downward Price Drivers:
 - PJM's interconnection queue is improving.
 - In the last two years, 4 million new RECs derived from coal mine methane have come into the market. These RECs can only be used for compliance in Pennsylvania, but their availability puts some downward pressure on other Tier 1 RECs.
 - Facilities owned by International Paper, located in Virginia, have started to generate RECs from waste heat, which will help to meet VA's 75% in-state Tier 1 requirement.
- Longer-term Potential Price Driver: Offshore Wind. Excess RECs could be sold for compliance in PA and VA, putting downward pressure on Tier 1 prices.

Power Advisory's analysis forecasts:

Pricing

Over the past 3 years, PJM Tier 1 REC prices have been in the high \$20s to high \$30s. NJ and VA prices have been higher than PA which have been higher than MD, due to ACP and supply/demand dynamics. Prices have recently declined to the \$25 mark following the NJ decision, and very much reaggregated in a tight range. Forward prices indicated that pricing will continue in this range for the foreseeable future. That's because there will still be an undersupply condition, and a considerable amount of MD ACPs will be paid.



Aside from Power Advisory's analysis and forecast, a major future driver of REC prices will be load growth in Maryland compared to competing states. Currently, Tier 1 requirements are based on a percentage of sales. One particular unknown is the growth of large-load customers like data centers, where they likely will be located, and whether their contributions to increased electricity sales will increase the number of Tier 1 RECs required for compliance. Another unknown is the extent to which new renewable energy RECs will be used for voluntary purchases versus RPS compliance (currently, approximately 40% of RECs are purchased nationwide for voluntary purposes.) We note a clear future data point, which is Maryland's Tier 1 ACP falling, while competing states' ACPs remain

steady. Finally, a significant unknown is what, if any, policy changes our competing states may make to their RPS requirements in the near future and what impact that could have on Tier 1 prices.