Comments on New Jersey Solar Successor Program Straw Proposal

Docket No. QO20020184, Solar Successor Program
May 27, 2021
New Jersey Conservation Foundation
National Resource Defense Council

1. Intro.

The solar successor program straw proposal summarizes a vast amount of diligent, thoughtful and extremely hard work by BPU staff, including many hours of dialogue with stakeholders, much careful analysis, and a deep commitment to clean energy. NJCF and NRDC deeply appreciate the effort and the process, as well as this opportunity to offer these comments. While we are deeply concerned with the potential impact of the straw proposal to deeply reduce the amount of renewable energy used by New Jersey electricity customers, we recognize that, in it, staff is attempting to balance many goals and concerns, and we appreciate all their hard work and willingness to engage.

We also recognize, above all, that it is a straw proposal, intended to invite critical discussions and feedback, and to stimulate creative solutions to the critical problems facing New Jersey. As these comments show, our focus is on the existential problem of a rapidly unfolding climate emergency that can only be mitigated by world-wide efforts everywhere, but particularly in countries, regions and states that are, like ours, blessed with strong, modern economies, readily available, low-cost renewable energy, and enlightened political leaders and public servants who are willing to make averting climate catastrophe their highest energy priority.

In that spirit, we respectfully submit these comments on the solar successor straw proposal, with the goal of helping staff and the BPU arrive at a program that achieves both the urgently need growth in overall amounts of clean electricity, and a growing, increasingly competitive solar industry in New Jersey.

2. Summary of comments.

Our analysis of the straw proposal shows that, if it is implemented as proposed, a combination of a number of its key design elements and assumptions are likely to result to dramatically reduce, and may effectively destroy, the renewable portfolio standard requirements established by the legislature in the Clean Energy Act (CEA), and signed into law by Governor Murphy. It would similarly dramatically reduce the already promulgated regulatory RPS requirements of the BPU's 2019 RPS/BGS rule that the state's load-serving entities currently must plan to meet.[1]

The proposal would do this by implementing a solar successor program that would, together with expected SREC prices and the cost of meeting the RPS requirements of existing law, substantially exceed the cost caps of the CEA. It would then reduce those RPS requirements, as needed, to stay within the overall budget, reducing the amount of Class I renewable electricity credits procured by the RPS.[2]

[1] 51 N.J.R. 1471-2.
[2] This substitution of successor program solar spending for REC spending is outlined on p. 7 of the straw proposal.

As stated in the straw proposal,

> One of the key goals for the Successor Program is … to keep ratepayer costs within the statutory cost cap established by the Clean Energy Act, *while meeting New Jersey's long term solar targets* and other societal goals.
>
> Straw Proposal at p. 23. (Emphasis added)

As this passage and others throughout the straw proposal make clear[3], the straw proposals goal's key goals are to meet the state's long term solar targets within in the cost caps, which will be maintained if and as needed by reducing the statutory RPS requirements. Since the successor program's incentives will cost at least 6 times as much as Class I RECs, this approach to ensuring the successor program stays within the overall CEA cost cap will unavoidably result in reducing the total amount of renewable energy purchased by the state's load serving entities and used by New Jersey customers. Specifically, for every successor program MWH increased by this reallocation, six MWH fewer Class I RECs will be purchased by LSEs serving load in New Jersey.

The total reduction to the RPS would, under such an approach, be drastic. Our analysis, using the straw proposal's cost cap tool (CCT), verifies that reduction in the amount of renewable energy purchased caused by the proposal could be, and in all likelihood would be, drastic. For example, our "base case" version of the straw proposal's CCT, which corrects several errors and replaces several highly optimistic assumptions made by straw proposal with more realistic and sustainable ones, the amount of renewable energy LSEs are required to purchase under the BPU's 2019 RPS/BGS rule would be reduced by approximately 50% from 2023 through 2030. See Table I, below. In other words, there is a strong likelihood that the proposal would effectively cancel the higher RPS requirements established by the CEA in 2018, for the rest of this decade.

These reductions in the RPS would have unacceptable environmental impacts. As is well-known, an RPS reduces GHG emissions from existing fossil plants by supporting both existing renewable energy resources, and the development of new renewable energy resources. The generation of both types displaces the MWH of existing fossil plants, and the CO2 produced by burning fossil fuel to generate that MWH. A higher RPS will induce more development of new renewable resources, while ensuring the continued operation of existing resources, and thus result in steeper and deeper GHG emission reductions, compared to a lower RPS.

Since the effect of the straw proposal would very likely be to dramatically reduce the RPS, causing it to fall below the steadily increasing levels the BPU has already promulgated by rule. This will dampen the expected demand for RECs and, in turn, lead to reduced growth in renewable energy development in the region, and lower overall renewable generation, and thus to higher levels of the CO2 emissions that are fueling the rapidly unfolding climate crisis.

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[3] E.g., at p. 7, ("The Successor Program will be designed to better utilize ratepayer funds to incent new solar generation … rather than supporting existing out-of-state generation"), p. 22, (This Straw Proposal seeks to put forward a dynamic approach to setting MW targets that both respects the cost cap .. while meeting EMP goals"), and p. 31, discussing the "any steps necessary" language of the CEA, (which Staff interprets as allowing the Board to reduce the amount of Class I RECs purchased in order to keep the total cost of the cost-cap eligible programs below the cost cap.")

This would be an unacceptable result, especially during this decade. As discussed below, recent climate science makes it imperative that New Jersey, along with the rest of the region and the rest of the world, achieve even greater reductions in the upstream CO_2 emissions due to electricity consumption. As such, any successor solar program must be designed in a way that does not endanger or interfere with the RPS requirements of current law.

Accordingly, in these comments, we seek to (i) identify the elements of the straw proposal that would erode the RPS requirements, (ii) show how they are inconsistent with both existing law and climate policy goals of New Jersey, and (iii) identify alternative approaches to a successor program that would avoid the problems the straw proposal would create, while offering additional suggestions on how to improve the workability and efficiency of the successor program. In the first part of these comments, we address items (i) and (ii). In the second part, we address item (iii), where possible by answering specific staff questions.

Part I will address the following specific issues:

- Review the RPS requirements of existing New Jersey law, and identify the core policy and legal interpretations of straw proposal's proposal that the BPU would need to embrace in adopting the straw proposal, and we show that these interpretations, together with other elements of the straw proposal, would result in significant degradation of existing legal RPS requirements.
- Review recent climate science, which requires even more aggressive – "deeper and steeper" in the words of Governor Murphy's Executive Order 100 – reduction in CO_2 emissions from the power sector in this decade, than those required in the CEA and the RPS/BGS rule of 2019.
- Summarize the means by which a growing RPS materially contributes to achieving these reductions, and by which cuts in the RPS, such as those necessarily built into the straw proposal, would result in more, not less CO_2 emissions.
- Show that roughly one-third of the upstream CO_2 emissions due to the consumption of electricity in New Jersey come from fossil generation located outside of the state, and that therefore -- both for climate responsibility and to achieve the goals required by New Jersey's Global Warming Response Act (GWRA) – New Jersey's RPS must continue to utilize a substantial share of regional Class 1 RECs, which are currently the most cost-effective means to significantly reduce the out-of-state, upstream CO_2 emissions caused by New Jersey's electricity consumption.
- Analyze the straw proposal's interpretation of the cost-cap authority and their proposal for the BPU to reduce the use of Class I RECs as needed in order to be able to develop a somewhat larger, much more expensive successor program, and how that approach would result in far less renewable energy being purchased by LSE's on behalf of New Jersey customers than the levels currently required by law.
- Identify key other assumptions and aspects of the straw proposal that result in it exceeding the CEA's cost caps, and identify potential solutions that do not violate or reduce the renewable energy requirements of existing law.
- Suggest an appropriate focus for any changes in existing law that may be needed to not only achieve the current RPS targets, but that would also ensure the cost-effective attainment of the even deeper GHG emission reductions required from the electric sector in this decade, consistent with recent climate science.

PART 1.

Identifying the key flaw in the straw proposal.

1. Review of existing legal requirements, recent climate science and its implications for a responsible response by New Jersey to global warming.

a. Essential requirements of existing law. Our evaluation of the proposal includes evaluating its compatibility with several critical requirements of New Jersey law. We are concerned that the Proposal is inconsistent with, and could be applied in ways that would impermissibly violate, critical existing legal requirements.

Specifically, the requirements that are or could be impermissibly violated by the Proposal are:

i. The CEA's RPS requirements that 35 percent of all energy sold at retail in New Jersey be renewable energy by 2025 and 50 percent by 2030.

ii. The CEA's express limits on the carrying forward of surpluses under the CEA's RPS cost caps to surpluses from the energy years 2019, 2020 and 2021 to energy years 2022, 2023 and 2024.[4]

iii. N.J.A.C. 14:8-2.3, by which the BPU established and promulgated, in 51 N.J.R. 1471-2, annual RPS requirements comprising the solar carve out, Class I renewables, Class II renewables and the total RPS requirement for the energy years 2020 through 2033, as provided in Table A of the promulgated rule, reproduced here:

Table A

What Percentage of Energy Supplied Must Be Solar, Class I,

or Class II Renewable

Energy Year	Solar	Class I	Class II	Total
June 1, 2018 - May 31, 2019	4.30%	14.175%	2.50%	20.975%
June 1, 2018 - May 31, 2019*	3.29%*	14.175%*	2.50%*	19.965%*
June 1, 2019 - Dec. 31, 2019	4.90%	16.029%	2.50%	18.529%
June 1, 2019 - Dec. 31, 2019*	3.38%*	16.029%*	2.50%*	21.909%*
January 1, 2020 - May 31, 2020	4.90%	21.0%	2.50%	23.50%
January 1, 2020 - May 31, 2020*	3.38%*	21.0%*	2.50%*	26.88%*
June 1, 2020 - May 31, 2021	5.10%	21.0%	2.50%	23.50%
June 1, 2020 - May 31, 2021*	3.47%*	21.0%*	2.50%*	26.97%*
June 1, 2021 - May 31, 2022	5.10%	21.0%	2.50%	23.50%
June 1, 2022 - May 31, 2023	5.10%	22.0%	2.50%	24.50%
June 1, 2023 - May 31, 2024	4.90%	27.0%	2.50%	29.50%
June 1, 2024 - May 31, 2025	4.80%	35.0%	2.50%	37.50%
June 1, 2025 - May 31, 2026	4.50%	38.0%	2.50%	40.50%
June 1, 2026 - May 31, 2027	4.35%	41.0%	2.50%	43.50%
June 1, 2027 - May 31, 2028	3.74%	44.0%	2.50%	46.50%
June 1, 2028 - May 31, 2029	3.07%	47.0%	2.50%	49.50%
June 1, 2030 - May 31, 2031	1.58%	50.0%	2.50%	52.50%
June 1, 2031 - May 31, 2032	1.40%	50.0%	2.50%	52.50%
June 1, 2032 - May 31, 2033	1.10%	50.0%	2.50%	52.50%

[4] As provided in S4275, passed and signed into law on January 21, 2020. P.L.2019, c.448.

(*BGS Providers with existing contracts)

Further, as discussed below, the Proposal, if implemented in the Cost Cap Tool provided with the straw proposal, would unacceptably and dramatically reduce the total RPS requirements in a way that is incompatible with the entire intent and purpose of the CEA.

Any such reduction in the RPS requirements would, in turn, cause dramatically higher levels of upstream CO2 emissions caused by the generation of the electricity consumed in New Jersey, over the course of the coming decade. This would be an unfortunate and surely unintended legacy for the Murphy Administration's BPU to bequeath to the world, in the same decade in which climate science insists on a need for massive, comprehensive decarbonization of the electric supply in every part of the globe – which necessarily must include the entire network of electric generators that produce electricity consumed in New Jersey.

b. Current climate science indicates much deeper reductions in CO2 emissions from generating electricity are necessary by 2030 to avert the rapidly unfolding climate crisis.

The latest reports from the IPCC, supported by a report issued just last week by the IEA, make it clear that global CO2 emissions from electricity must decline by roughly 70% from current levels by 2030.[5] These reductions levels must be achieved in terms of overall emissions worldwide, and therefore, the reductions in highly developed economies with ample access to the lowest cost solar and wind resources must be significantly greater. We recommend New Jersey adopt the goals of 90% clean electricity, from all sources that supply electricity consumed in New Jersey, by 2030, to be consistent with current climate science. But, even without such a change, the Murphy Administration can and must lead to achieve and exceed the maximum amounts of clean electricity, and the associated reductions in upstream CO2 emissions caused by New Jersey's consumption of electricity, required in current law and clearly intended in the CEA.

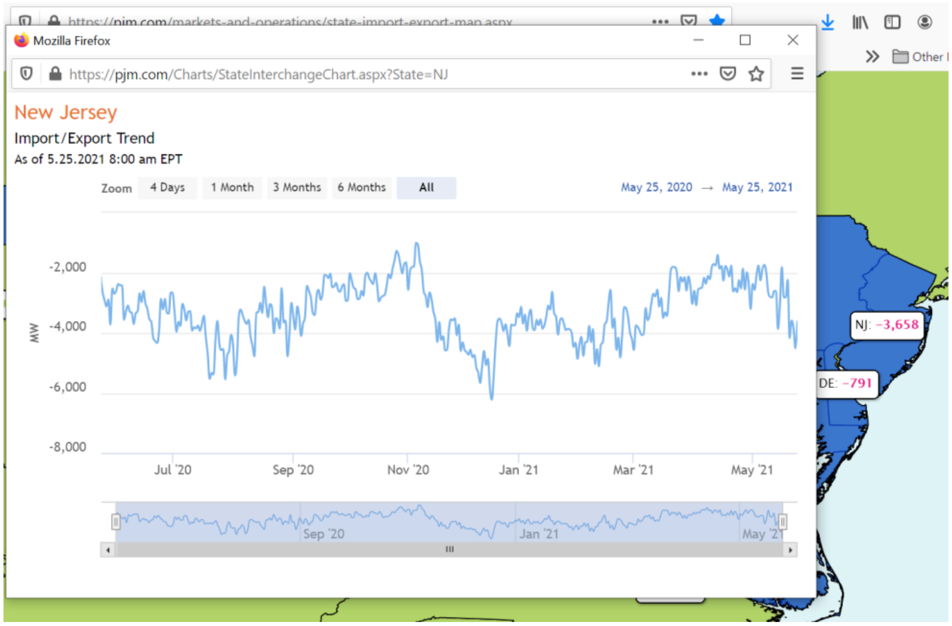
c. New Jersey must support reductions in broader PJM CO2 emissions, both for climate responsibility and because roughly one-third of the upstream CO2 emissions caused by the consumption of electricity in New Jersey *comes from fossil-fired power plants located outside of the state*.

Each MWH of clean electricity generated in the PJM region displaces one MWH of existing resources, and at today's low level of renewable penetration, that displacement is almost entirely of fossil generation. PJM sources matter, because much of the electricity consumed in New Jersey is imported from PJM, as shown in Figure 1.

Figure 1.[6]

[5] SEE IPCC Special Report Global Warming of 1.5°C, available at: https://www.ipcc.ch/sr15/

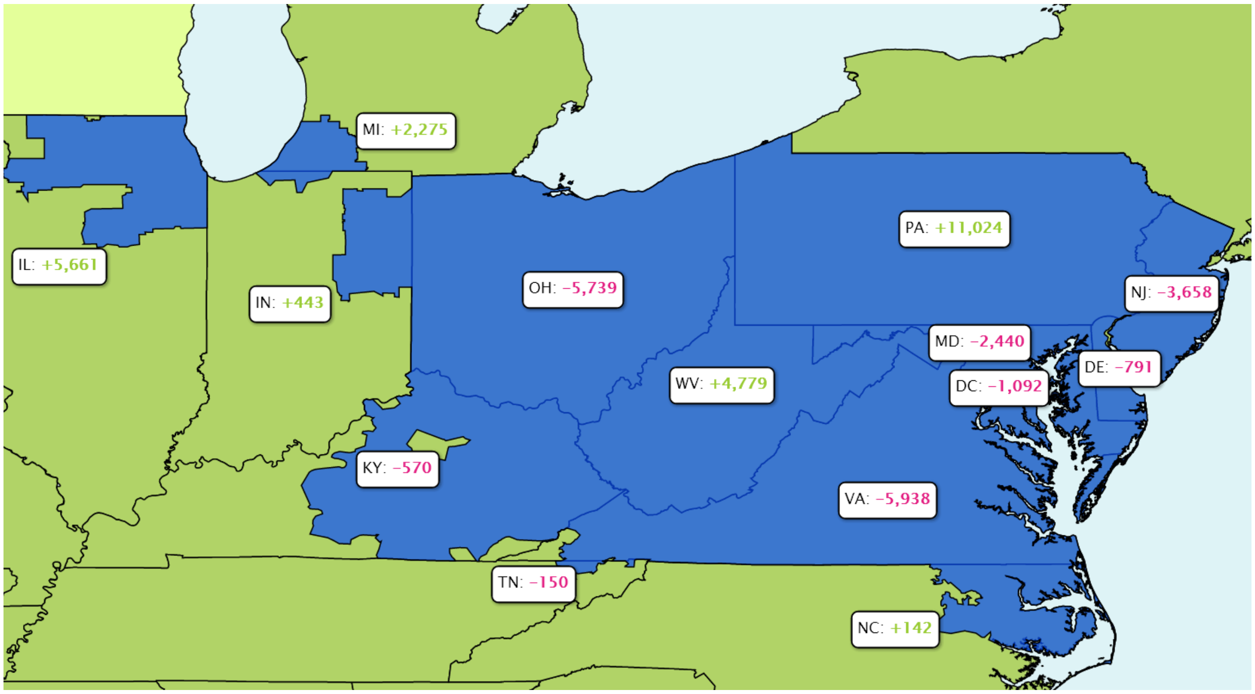
[6] Source: https://pjm.com/markets-and-operations/state-import-export-map.aspx . Accessed May 25, 2021.



As Figure 2 shows, the major exporters of electricity in PJM are West Virginia and Pennsylvania, both with significant amounts of fossil generation. We use simple calculations based on the imported MWH implied by Figure 1 and the average CO2 emission intensity of PJM electric generation to estimate that the consumption of this imported electricity in New Jersey was responsible for upstream CO2 emissions of approximately 10 million metric tons in the last 12 months.[7]

Figure 2

[7] The average hourly imports from Figure 1 are approximately 3340 MWH. This resulted in 29 GWH in the last 12 months being generated elsewhere in PJM, but consumed in New Jersey. Assuming the imports have PJM's reported average CO2 intensity per MWH of 850 lbs., 11 million metric tons of CO2 are emitted by the generation of this electricity. At Pennsylvania's average CO2 intensity of 743 lbs. per MWH, the associated emissions are 9.7 million metric tons. We assume the imports are primarily from PA, and the associated emissions are about 10 million metric tons. New Jersey's reported CO2 emissions from electric generation in state in 2019 were 19.2 million metric tons. Assuming both these levels remain relatively constant year-to-year, total upstream CO2 emissions due to electricity consumption in New Jersey are approximately 29 million metric tons. Of this amount, roughly 33% comes from fossil electricity generated outside of New Jersey but consumed inside the state.



Source: https://pjm.com/markets-and-operations/state-import-export-map.aspx [8]

Both New Jersey's GWRA and any realistic sense of climate responsibility require New Jersey policy makers to make aggressive efforts to reduce these upstream emissions caused by the consumption of electricity in New Jersey.[9] Fortunately, large emission reductions in the region can be made at very low cost, due to the very low costs of larger, competitively developed wind and solar resources in regional locations that have excellent wind and insolation regimes and relatively low development costs. Because of these costs, as recognized in the straw proposal's CCT, Class I RECs from the region cost about $13 per MWH, compared to the current $230 per MWH of instate SRECs, the $132 cost of current TRECs, and the projected average $77 per MWH of the proposed solar incentive.[10]

d. An RPS with a substantial share of compliance credits from Class I RECs is, by far, the most cost-effective way to achieve the large volume of GHG emission reductions needed by 2030.

At current REC and New Jersey solar program costs, every dollar spent on Class I RECs will result in 7 to 32 times as big a reduction in the CO2 emissions caused by New Jersey customers' use of electricity as spending the same dollar on current or new in-state solar electricity. This means that, on the basis of GHG reductions per dollar of ratepayer funds, a large and growing RPS, with a large share of total compliance from Class I RECs, is the fastest way -- i.e., Governor Murphy's "steepest and deepest reductions" --to achieve New Jersey's share of the total GHG emission reductions that must be achieved,

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[88] Accessed May 25, 2021. A chart of each state's continuous import (negative) and export (positive) levels, in MW, such as that of Figure 1, is opened by pointing the cursor at a PJM state on the map and clicking it.
[9] The GWRA finds that New Jersey must, in its efforts to reduce GHG emissions within the state, include complementary programs to reduce GHG emissions from electricity generated elsewhere but consumed in the state.
[10] Some parties in the successor program workshops called for successor incentives to average $116 per MWH.

in this decade, to avert a climate crisis. Further, since it is so much less costly to achieve these emission reductions through renewable energy growth in other parts of PJM, maintaining a substantial share of such reductions through the RPS is the easiest way to meet both the RPS and its cost caps, while conserving additional headroom, under any reasonable budget, for the more focused and competitive successor program incentives called for by the CEA.

Achieving this growth in total clean energy deployment in PJM (which includes all New Jersey generation resources, as well as all other resources that supply electricity consumed in New Jersey), will require a continued growth in total clean MWH generation, at rates even greater than the CEA's targets. This can only happen with continued and growing rapid deployment of clean energy resources, from now until 2030 and beyond, in a cost-effective mix of locations and resource types within both New Jersey and the broader PJM region, that is, through a balanced and cost-effective mix of a growing amount of Class I RECs, and of specific state incentive programs for the most competitive solar projects in New Jersey.

2. The straw proposal's proposed budget-balancing mechanism would dramatically reduce the RPS, decreasing overall clean energy consumption in New Jersey.

a. Straw proposal's budget-balancing tool is based on misconstruing the purpose of the CEA budget caps.

The straw proposal bases its proposed reductions in the size of the RPS, as needed to remain within the cost caps, on a reading of the authority granted to the BPU to "take any steps, including but not limited to changing the renewable energy requirements of this section" to ensure the costs for meeting the RPS requirements do not exceed the CEA's cost caps. In the straw proposal, this means

> .. allowing the Board to reduce the amount of Class I RECs purchased in order to keep the total cost of the cost-cap eligible programs below the cost cap.
>
> Straw Proposal at 31.

The straw proposal also states an intent to respect Governor Murphy's goal of 50% of renewable energy by 2030 (if not that of the CEA), and we interpret this as meaning the straw proposal would allow the BPU to freely cut the RPS before 2030, including to well below the statutory 35 percent in 2025 requirement of the CEA, as well as below the higher and gradually increasing levels promulgated by the BPUs publication of their RPS/BGS rule in the State Register in the fall of 2019.[11]

b. The straw proposal, as modeled in the CCT, could reduce the RPS, and the total amount of clean electricity used in New Jersey, to a fraction of the current legal requirements. To understand the magnitude of the potential reductions to the RPS that would likely result from the straw proposal, we have used the CCT to calculate the reduction in the RPS in each year that would result from the MW targets and incentive values of the proposed successor program. We have used all the assumptions of straw proposal included in the CCT, including their optimistic assumption that SREC prices quickly converge on 75 percent of the SAPC, with the three changes below. As explained in Part II below, such changes are needed for the CCT and the successor program to have any level of realism in terms of the

[11] N.J.A.C. 14:8-2.3, as promulgated in 51 N.J.R 1471. The straw proposal does not mention this rule or how and when the BPU would change it, if the Board adopted the straw proposal.

cost impacts of renewable energy development and to interpret the CEA's cost cap in a legally sustainable manner:

1. *The initial DRIPE estimates decline annually at a rate of 12% per year as the energy and capacity markets together work towards an equilibrium*. We do not, by this, endorse the initial DRIPE estimates or their methodology, but as explained in Part II, any DRIPE effects must decline over time as the PJM markets adjust, in both quantity and price, towards equilibrium. We represent this certain trend with our assumption of a 12% per year decline in the DRIPE.
2. *The private costs incurred to purchase behind the meter equipment are removed from the in the denominator*. We do not believe the inclusion of these costs can be sustained as a matter of law or policy, due to the fact that the denominator must comprise the cost of electricity, not the cost of home or business improvements and capital equipment.
3. *Surplus funds within the RPS cost caps in a given year can only be rolled forward in years 2024 and below*, consistent with the specific new, permissive but limiting language of the CEA as amended by S4275 in January of 2021.

As Table 1 shows, with these conservative assumptions, the straw proposal would dramatically cut the total amount of renewable energy purchased in New Jersey in each year from 2024 to 2030.

Table 1

Energy Year	Headroom under (over) CEA cost caps ($)	RPS % required (existing law)	RPS % after straw cuts	Regional RECs % after straw cuts	Cost cap violations after RPS cuts ($)
2019	$ 301,749,290				
2020	$ 464,087,494				
2021	$ 473,800,187	21%	21.0%	15.3%	
2022	$ 208,814,106	21%	21.0%	14.8%	
2023	$ 54,104,358	22%	22.0%	15.9%	
2024	$ (107,446,841)	27%	13.6%	2.2%	
2025	$ (271,495,644)	35%	12.6%	0.0%	$ (57,126,933)
2026	$ (260,052,600)	38%	14.6%	0.0%	$ (35,391,130)
2027	$ (218,551,159)	41%	18.4%	0.3%	
2028	$ (172,908,062)	44%	26.2%	4.9%	
2029	$ (155,170,978)	47%	31.1%	6.4%	
2030	$ (176,068,144)	50%	32.0%	3.9%	

Table 1 shows that the effective RPS levels, under the straw proposal, would be reduced to as low as 12.6% in 2025, and would never exceed 31% in the entire decade of the 20's. The average reduction in the amount of renewable electricity consumed in New Jersey, across all these years would be approximately 50%. And even so, the straw proposal would violate the cost cap budgets in 2025 and 2026, even after effectively eliminating regional Class I REC eligibility for compliance with the RPS in four of those years.

Not only would the straw proposal, under the assumptions above, reduce renewable electricity consumption in New Jersey, these reductions would be so large as to put a strong damper on regional renewable energy growth throughout the last, most critical ten-year window of opportunity to help avoid climate catastrophe by dramatically increasing the amount of renewable energy consumed in New Jersey, and produced in our entire region.

Clearly, as this and other scenarios included in the Appendix show, to the straw proposal's approach of mining the RPS to create more headroom for the solar successor program can only reduce the total amount of renewable energy used by New Jersey customers, and by amounts that would devastate the RPS, preventing and reversing the reductions in upstream CO2 emissions caused by the consumption of electricity in New Jersey that would otherwise be achieved by the RPS, and resulting in a failure to meet both the state's climate goals and the much more urgent targets needed to avert the unfolding climate crisis. Such a result would be in direct opposition to the CEA's purpose in expanding the RPS requirement.

c. The motivation behind the CEA's RPS expansion was to rapidly reduce CO2 emissions from electricity generation, both in New Jersey and in the broader region where it gets a significant share of its electricity.

The RPS dynamics described above, by which a higher RPS increases total clean electricity generation, which then directly displaces and reduced fossil generation and its CO2 emissions, are well understood by all informed participants in energy and environmental policy making. This dynamic, plus the availability of substantial amounts of clean electricity at low costs throughout much of the PJM interconnected regional grid, were key reasons why NJCF and other environmental groups insisted, in 2017 and 2018, that any legislative subsidies for existing nuclear plants b matched with a 50% RPS requirement by 2030. Indeed, the cost of Class I RECs from the PJM region is roughly equivalent, on a per-MWH basis, to the costs of ZECs allowed in the CEA's companion bill. Together, the two statutes created a commitment to enough of the most competitive, lowest cost, clean energy to provide 80% of New Jersey's total electricity consumption by 2030. This is now less clean energy than needed to avert the climate emergency, but that is even more reason why the solar successor program cannot be designed or implemented in a way that would result in a shortfall relative to the CEA's own targets.

Such an RPS shortfall must be avoided, because the dynamic, described above, by which an increasing RPS leads to reduced CO2 emissions from electric generation works the same way in reverse. A reduction in RPS demand for RECs, over one or several years, will lead to an expectation of lower revenues, reduced profits and thus put a damper on renewable energy deployment in PJM. Since the rate of renewable energy growth in PJM is directly responsible for displacing GHG emissions from existing fossil fuel plants, a reduction in demand for RECs will lead to a relative increase in such GHG emissions. The longer the period that the Successor Program would reduce RPS demand, the greater the associated GHG emissions will be.

d. The CEA's overall Class I RPS targets and cost caps were knowingly and intentionally established to achieve commensurate reductions in CO2 emissions from electricity, with limited and specific exceptions and carve-outs for specific technologies, while keeping electricity affordable.

The legislature, in crafting the CEA, also clearly understood that the generation of renewable MWH directly displaces fossil fuel MWH that would otherwise be generated, along with the CO2 emissions that would result from burning the fossil fuel. Further, the legislation embodies the understanding that, due to such displacement of fossil generation, existing renewable generating resources prevent increases in CO2 from such fossil resources, while adding more renewable generating resources further reduces CO2 from such resources. Accordingly, the legislature surely knew and intended for a larger RPS to increase the demand for the RECs associated with each renewable MWH, and thereby both induce new renewable electricity resources to be built and to generate more renewable MWH, resulting in reduced CO2 emissions, while also ensuring existing renewable energy resources will continue to operate and so prevent offsetting increases in CO2 emissions.

This is why the RPS requirements in the statute do not discriminate between existing and new renewable energy generation, as may occur under the straw proposal. Both are needed to achieve the critically needed net emission reductions. The only discrimination between such sources in the CEA is, in fact, the limited legacy SREC carve-out, which exists to support the early development of a solar industry as a part of the overall specified renewable energy requirements, not as a way to allow the BPU to intentionally reduce the overall requirements, to create their own, new and open-ended successor program carve out, as is proposed.

While the BPU's ability to deliver the even greater amounts of clean electricity and its associated reductions in CO2 emissions under current law may be limited, the Board already has all the authority it needs to avoid either intentionally or accidentally *decreasing* the CEAs total Class I renewable energy requirements. Such a policy would necessarily hasten and deepen the climate crisis, which is the exact opposite of the responsible climate action and leadership Governor Murphy has committed to. Yet this would clearly be the effect of the straw proposal, which was explicitly and intentionally designed to decrease the RPS requirements, prior to 2030, as far below both the statutory levels and those established in the BPU's RPS/BGS rule, as may be needed to support a much smaller amount of much more expensive renewable solar energy.

Such an implementation of the solar successor program would therefore not only vitiate the CEA's renewable portfolio standard requirements, but would necessarily prevent achievement of the concomitant reductions in New Jersey electricity consumers' upstream GHG emissions that would result from RPS compliance. Further, these same emissions reductions – and more, not less -- are desperately needed to help avert the rapidly unfolding climate crisis.

e. The straw proposal's design must reflect the combined purpose of the CEA's new RPS requirements, solar reforms, and cost caps.

The CEA created three linked requirements. First, it expanded the state's renewable energy portfolio standard to 35% renewable energy by 2035 and 50% by 2030. Second, it slightly increased and extended the solar carve out, but at the same time called for the closure of the extremely expensive SREC market used to create incentives for early, higher cost solar, and for any successor solar incentives to be designed to be much more focused on competition and cost reductions. And third, it established an overall cap on the money to be spent on solar and onshore wind energy used to meet the expanded RPS, of 9% of the costs paid by all ratepayers in 2019 – 2021, and 7% of such costs thereafter. While the statute explicitly exempts offshore wind costs from this cap, it does not exempt either SRECs or the successor program incentives. To enforce this cap, it required the Board to "take any steps necessary to prevent the exceedance of the cap on the cost to customers including, but not limited to, adjusting the Class I renewable energy requirements."

Viewing all three of these related statutory requirements as working together without conflict, as must be done in construing the meaning of the statute, means that the proper interpretation is for the BPU to take any and all steps possible to realize all three of them. Accordingly, the "any steps" should, if at all possible, be steps that achieve (i) compliance with the specified RPS targets, (ii) the required modifications to the SREC program, including the design and implementation of a successor program and (iii) the limitation in the cost of the specified Class I renewable resources recovered from customers to the percentage of the electricity costs paid by all customers. Examples of steps that achieve all three of these goals could be setting the incentive levels of the successor program at levels that are reflective of the most competitive solar projects within various types of solar, limiting the size of the MW targets of the successor program to amounts that, at the selected incentive levels, would keep total specified Class I electricity costs within the cost cap levels, and developing means to adjust runaway SREC prices in the closed SREC market at reasonable, fair and affordable levels.

The need to read all of a statute's requirements together in construing its meaning requires the BPU to take all such steps, and exhaust them, before electing to use the more draconian, last-ditch use of the ultimate step authorized by the CEA, namely, of reducing the RPS requirements, despite all their critically important public interest benefits in terms of reducing the electric sector's injurious and destructive CO_2 emissions.

By contrast, the straw proposal interprets this "any steps necessary" authority as allowing the Board to design and implement the successor program with MW targets and incentive levels that would, together with the RPS targets, necessarily exceed the CEA cost cap budgets, and then to simply reduce the RPS requirements by whatever amount is needed, to keep within the CEA cost-cap budget. [12]

The straw proposal suggests this approach would "better utilize ratepayer funds." We respectfully but strenuously disagree, and further are concerned that this approach would require the BPU to exceed its administrative authority by substituting its own judgement regarding the proper size of the RPS for the clear statutory guidance of the key requirements of the CEA, taken all together.

f. The environmental effects of the straw proposal would prevent rather than support, the "steep and immediate reductions in greenhouse gas emissions" recognized and called for in Governor Murphy's Executive Order 100.

The mechanics of the straw proposal, namely to cut the Class I RPS requirement while increasing the amount of money spent on in-state solar projects, will necessarily result in a reduction in the total amount of renewable energy produced. This is unavoidable, because the average incentive cost of in-state successor program solar is, as represented in the CCT, $77 dollars, while the assumed cost of a Class I REC is $13. That means using the same ratepayer funds for successor solar instead of for RECs will only add 1 new solar MWH for every 6 Class I RECs no longer purchased under the RPS. As a result, the straw proposal would cut 6 MWH of renewable electricity consumed in New Jersey for every additional 1 MWH of increased solar electricity produced through the successor program.

Such a dramatic decrease in the amount of renewable energy used in New Jersey cannot be consistent with the "steep and immediate reductions in greenhouse gas emissions" from "traditional methods of energy production that rely on the burning of fossil fuels" and which "in turn contribute to global climate change" that Governor Murphy called for in his Executive Order 100, just 17 months ago.[13] To be consistent with Governor Murphy's Order, any successor program must be designed to support the full RPS requirements of existing law, which are the primary means by which these steeper and deeper emission reductions in GHG emissions will be achieved.

Further, such a reduction in the RPS cannot have been the intent of the legislature in setting the RPS requirements and the caps on the costs of achieving them in the CEA. The legislature demonstrated in the CEA that it knew how to write very detailed guidance and criteria for the successor solar program, and did so, including that the BPU reduce the size of the MW targets of various solar types that cost too much. If they had wanted to instead to tell the BPU to increase the size of MW targets, even if they cost too much, and cut the RPS by the same amount in order to stay within the cost caps, they would have done so clearly and in detail. They did not.

As such, we are concerned that the straw proposal's unilateral cuts to clearly established statutory RPS levels, by an administrative agency that has not exhausted or even explored other steps authorized by

[12] Straw Proposal at p. 31, explains an interpretation of the CEA's 'any steps necessary' language this way: "which Staff interprets as allowing the Board to reduce the amount of Class I RECs purchased in order to keep the total cost of the cost-cap eligible programs below the cost cap."

[13] Executive Order 100, p. 3. Available at https://nj.gov/infobank/eo/056murphy/pdf/EO-100.pdf .

the statute to keep costs within the caps, would be legally impermissible, in addition to being inconsistent with the objectives and principles of Executive Order 100.

Accordingly, we believe it would be legally impermissible of the BPU to use the "any steps necessary, including" language of the CEA to assume full legislative authority and use it to intentionally and substantially downsize the statutory RPS requirements in order to support a much smaller, much more expensive successor solar program.

Instead, we urge the BPU to now aggressively explore the "other steps" it can take under the CEA to attempt to meet the RPS while keeping the other cost-cap drivers under an appropriate level of cost discipline. These steps must be explored and, if possible, taken prior to the last-ditch cost-protection bulwark of reducing the RPS targets. Equally important, if they cannot legitimately be taken, the Legislature needs to be informed of the barriers to effectively addressing the climate emergency, and the most efficient, cost-effective and environmentally responsible ways to remove them.[14]

In sum, dramatic reduction in the RPS that could very likely result from implementation of the straw proposal cannot possibly be what the legislature intended by "any steps necessary" language. Further, such an interpretation would be a 180-degree reversal of the BPU's 2019 RPS/BGS rule. In our view, the cost-cap language should instead be interpreted as requiring the BPU to make every reasonable effort, including the design and implementation of the successor program itself, to keep the cost of reaching the total RPS compliance within the cost cap. Under this interpretation, the BPU would only to reduce the RPS requirement as a last resort, consistent with both the Legislature's and the Board's own affirmation, in statute and rule, of the value of an increasing RPS in achieving critically important GHG emission reductions.

We also urge the BPU and staff to keep in mind, above and beyond any issues of legal interpretation and authority, the impacts their successor program will have, both directly and by example, on New Jersey's contribution to mitigating the unfolding climate crisis. Simply put, a successor program framework that reduces the amount of renewable energy used in New Jersey, and generated in locations that actually emit the upstream CO2 caused by that consumption, would be a tragedy of epic proportions in this, the

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[14] In our view, should the cost cap provisions of the CEA prove to be truly unworkable, any such legislative fix of unworkable provisions of the CEA would need to include the following:

1. An accelerated clean electricity standard, reaching 90% (e.g., 60% renewable plus 30% nuclear) clean electricity by 2030.
2. Replacement of the CEA cost caps with a projected competitive budget developed through a least-cost, best-fit approach comparable to that used in the IEP, for all clean electricity expenditures, needed for the cost-effective and competitive attainment of the CES levels, including limited and temporary carve-outs for promising clean electricity technologies to have the opportunity to quickly become competitive.
3. Clear guidance to the BPU to manage the budget by continually increasing the use of more cost-effective and economical clean energy resources for compliance with the CES, and decreasing the use of less economical ones, to ensure electricity remains affordable to all New Jersey consumers and to spur the rapid, cost-effective electrification of the building, transportation, and manufacturing sectors.

last decade in which humanity must dramatically reduce the electric sector's CO2 emissions, to have any real hope of averting climate crisis. Accordingly, we urge the staff to modify the straw proposal to modify, in accordance with the recommendations in these comments, to be consistent with achieving at least the share of clean electricity required under the CEA, and achieving them in a highly cost-effective manner, while continuing to support the growth of competitive, increasingly lower cost solar in New Jersey.

PART II

Improving the Successor Program

1. The successor program MW targets must be set within an overall budget, not simply imported from the EMP or elsewhere.

The unacceptable erosion of existing RPS requirements addressed in Part I of these comments can only be avoided by first establishing an overall cost-cap budget, then allocating the necessary amounts needed to meet the RPS targets and pay for the legacy SRECs, and then using the remainder to identify feasible successor program MW targets. If that budget is not enough, then several additional steps could be taken to stay within it, without diminishing the RPS targets.

One step would be to explore ways to reduce the cost of the Class I RECs without reducing their volume. Examples include:

- Longer-term contracts for specified numbers of RECs at a fixed price could result in reduced cost. Such contracts are regularly entered into by corporate customers, and could potentially be entered into by BGS suppliers at a discount to the current broker-based REC markets. Contracted REC prices could especially low in the case for specific new projects in highly productive locations.
- A centralized forward procurement market, such as Brattle's FCEM proposal, could likewise reduce REC costs, in part by creating a less volatile price path that would require a lower risk premium from bidders, and in part by attracting a high volume of very competitive bids. An FCEM concept could also establish a clearing price around which even lower cost contracts for differences could be entered into, especially with new projects in highly productive locations.

Another, potentially much more significant source of savings, would come from the ability to acquire SRECs at lower prices than the current, broker-based SREC market. Options to consider in this regard include:

- Offering voluntary fixed price SREC contracts to current SREC holders at a price that is significantly lower than the current spot market price, but substantially higher than the tail-years price that may otherwise be unavoidable for SREC holders as a fundamental oversupply in the SREC market becomes clear.

- Alternatively, impose a lower SAPC level on the now-closed SREC market, either after a finding that the current sustained high price levels are not competitive, or through narrowly focused legislation to extend the SREC eligibility period while lowering the SAPC to a level that allow compliance with the cost caps and the RPS requirements, fair treatment of SREC holders, and continued deployment of the most competitive projects and solar types through the successor program.

Finally, and most importantly, design the solar successor program in line with the criteria in the CEA. This requires a two-stage process.

- First, ensure that the incentive levels of the successor program are at competitive levels, for all solar types, whether the incentives are administratively set, or determined through outright competition. The incentive designers should bear in mind that, with the typical upward sloping supply curve that exists when suppliers have different cost levels, a competitive incentive level will necessarily be too low for some of the suppliers to be able to clear in, or participate in, the market. Prices that allow all suppliers to participate are very likely to be too high to be competitive, and will impair the size of the solar program, its need to reduce costs to grow, and contribute to exceeding the cost cap.
- Second, with competitive incentive levels in hand, identify the MW targets that best fit within the remaining cost cap budget, e.g., after paying for SRECs and buying enough Class I RECs to meet the remaining RPS requirement. We recommend the Board explore the use of a closed descending clock auction to set the initial block prices of descending block tariffs for administrative programs. Such auctions can identify the price and quantity pairs offered at a range of prices, and thus would readily support the co-optimization needed to clear the market while simultaneously determining the quantity of Class I RECs needed. In addition, they could materially help achieve the most competitive results across several types of solar to be considered in the successor program.

Several of our CCT scenarios suggest that a combination of lower SREC prices and dynamically set MW targets would allow substantial growth in the successor program and full compliance with the RPS. See, e.g., Scenarios D3 and D4 in the Appendix.

2. Ensure that any proposed adjustments to the cost cap equation are legally and empirically well founded and robust, to avoid creating false expectations of budget levels and extended periods of administrative uncertainty.

a. Certain DRIPE effects are real, but improperly estimated in terms of methodology and persistence.

We are aware that the Ratepayer Advocate and potentially other parties view any adjustments to the numerator and denominator of the cost cap equation. We urge the BPU to carefully consider those parties legal arguments in light of the very substantial reduction in the total budget available for the RPS, SREC and successor program, with DRIPE adjustments included, that could result from litigation on this issue. Setting a high budget, only to have it struck down because of wishful statutory construction, will only cause delay and chaos in the solar industry and, more broadly, in the state's achievement of its clean energy and climate goals. If there is any significant litigation risk around such construction issues – and we believe there well could be – it may be better to seek a legislative solution than to create false expectations and uncertainty.

However, should the BPU determine that it is well within its legal authority to reduce the numerator of the equation by direct, net ratepayer benefits that result from lower energy and capacity market prices caused by the production of the renewable energy procured through the RPS, we strongly recommend the Board replace the ad-hoc and back-of-the-envelope estimates in the straw proposal with values derived by a professional study, by consultants with ample and demonstrated experience in evaluating price formation over time in PJM's capacity market and its related energy market. Otherwise, DRIPE estimates based on the methodologies used in the straw proposal will, in our view almost certainly, not be withstand litigation, and if they do, will rapidly be proven by future energy and capacity prices to be highly unrealistic.

We see two basic problems with the energy DRIP estimates in the straw proposal. First, energy market price formation has many other determinants than the level of load, so a historical simple regression of price on load is bound to overestimate the contribution of load to prices, and ignore all the other contributions. Further, it will necessarily fail to capture the likely increases in energy prices that many reputable studies anticipate will result, especially during periods of scarcity of wind and insolation during periods of high demand, as regularly occur today in California ISO after sundown. In effect, solar makes energy less expensive when the sun is shining and more expensive after it sets. Using batteries to shift solar production from the day to the evening will tend to raise the price of energy when the sun is shining – by increasing demand to charge the batteries – and increase prices even further in the evening – due to the higher cost and losses of batteries relative to the gas generation that is currently used.

To avoid ignoring these higher price impacts, and only counting the lower cost ones, any energy market DRIPE estimates should be developed using a well-specified production cost model of PJM, with dispatch-interval based, geographically granular data on wind and solar availability, and if batteries are assumed, accurate data on operating parameters, losses and cost.   Any other approach – including using a production cost model with simple capacity-factor based renewable energy production simulation – is likely to overestimate the savings.

The second problem with the energy market DRIPE estimates in the straw proposal is that they are assumed to be independent of the capacity market prices. In reality, bidders into the RPM will raise their bids as they see declining energy and ancillary service prices, so some or all of the energy savings will be charged to customers through higher capacity market prices. For this reason, the straw proposal's energy DRIPE is likely to high, and it should either be eliminated or adjusted through improvements to the capacity DRIPE estimation, discussed next.

Similarly, there are two main problems with the capacity DRIPE estimates. First, capacity prices are determined by the intersection of the supply curve made up of capacity bids and the RPM's "demand curve".   Since most solar in New Jersey does not bid into the capacity market, it cannot shift the supply curve one way or the other.   The demand curves, in turn, are not based on the MW of supply but on the installed reserve requirement (IRM) for PJM as a whole and, in the LDAs, the demand curves are adjusted for addition reliability risks associated with transmission limits. The IRM is determined based on peak load and the amount of UCAP needed to meet it plus maintain needed reserve levels. The amount of solar deployed behind the meter does reduce load, but it may not have a 1:1 impact on the location of the IRM in the demand curve outside of the LDAs, depending on the correlation of solar production with the specific peak periods used in setting the IRM. Further, that impact will decline over time, as the correlation of solar with peak demand generally falls with additional solar deployment and electrification. Inside the LDAs, there is even less of a correlation between the amount of solar and the location of the demand curve. As a result, using PJM's illustrative price impacts of shifting the supply curve is a recipe for dramatically over-estimating the capacity DRIPE.

The second problem with the capacity DRIPE estimates is that the capacity market is designed and observed to equilibrate over time. Low capacity prices, due to the entry of more resources, lead to more retirements of existing resources, which causes capacity prices to increase. For this reason, it is critically important to build a decay function into the DRIPE estimates, rather than assuming they will simply accumulate indefinitely, as the straw proposal's methodology does. This is certain to result in a dramatic over-estimate of customer benefits, which is unlikely to be upheld under legal review, and which in any event will backfire on policy makers and the solar industry alike as reality refuses to conform to the methodology's assumptions.

To correct and avoid all these problems, if the Board elects to include DRIPE adjustments as offsets to the RPS cost, it should hire consultants with ample experience modeling, evaluating and improving the RPM itself to do an independent and professional job of it.[15]

b. We do not see how BTM solar costs can be properly included in the "total paid for electricity".

The straw proposal would add administrative estimates of the cost of behind the meter solar equipment to the "total cost paid for electricity by all customers in the State." On page 24, the straw proposal suggests this language requires consideration of the costs for payments for electricity by customers to both utilities and non-utilities. The proposal then proposes to use EIA – 861A data on utility revenue from end-use (i.e., retail or not-for-resale) customers. However, to that data, the straw proposal would add the installation costs associated with all net-metered, behind-the-meter solar projects that are host owned.

We are concerned that this category of expenses cannot possibly be considered a "cost paid for electricity," for the simple fact that the costs are for equipment, not for electricity. By contrast, all of the categories of data gathered on EIA's Form 861A are "revenues [to the entity selling electricity] from sales of electricity to customers purchasing electricity for their own use." Electricity sales are for either kilowatt-hours of electric energy, or kilo-watts of electric demand. Sales of batteries, generators, solar panels, wiring and inverters are not sales of electricity, they are sales of equipment. As such, we believe adding such costs to the "total cost paid for electricity by all customers in the State" would be improper,

[15] Examples of the kind of expertise needed, and its effective use, are found in the quadrennial reviews of the RPM that PJM hires reputable experts to perform, available at: https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=%7B514988AC-09BD-43DC-8F9E-8997491BE634%7D

and is likely to be seen as simply padding the budget to support more costs being imposed on customers than the legislature actually intended.

This effect is itself another reason why the inclusion of such equipment costs would be improper. The Legislature obviously intended the CEA cost caps to protect customers from excessive and inefficient spending on the various resources it did not exempt from the cost caps. Adding numbers to the numerator that do not really add to the costs paid *for electricity* can only result in increasing the amounts actually charged for electricity to all customers in the state, and thus would directly counter the legislative purpose of the cost caps.

c. The carryover of surplus headroom into years beyond 2024 appears to exceed the specific authority conferred on the BPU by S4275, and should not be relied on in designing the successor program.

The straw proposal identifies carrying over any annual surplus in the cost cap budget to future years as one of several tools it could use to address a deficit. While we argued for this interpretation of the CEA in 2019, our understanding at the time was that the Board did not agree it had that level of discretion under the act. Accordingly, we, together with a number of solar parties, supported the passage of S4275, which allowed such carry-forwards, but only up to and into 2024. We are concerned that, whatever latitude the Board may have had before S4275 was passed to carry savings forward, its current authority is limited to the specific years and amounts now specified in the CEA as a result of the passage and signing of that bill in early 2020. Assuming the carry-forward is available, if it isn't, will only encourage excessively optimistic expectations for the size of the successor program, and disappointment if and when those expectations are not realized.

Part III.

Answers to specific straw proposal questions.

1. Rather than the strict division into competitive solicitation and administratively set incentives, divided at a certain MW size, we encourage the staff to explore, with appropriate experts in competitive procurement and auction design, the use of descending clock auctions for incentive levels within separate categories of solar types. Such auctions could be used, for example, to solve for both MW targets and incentive levels at the same time, for a variety of sizes and types of solar projects. For example, a private descending clock auction for community solar could identify different tranches that would need different incentive levels, allowing the Board to select one or several, depending on their overall cost and impact on the total CEA budget. Such descending clock auctions would make it far easier to co-optimize the overall size and make-up of the successor program, with the overall CEA cap budget. They could also make all the "administrative" incentive programs (which we believe should generally follow the "declining block tariff" approach) much more competitive than purely administrative programs.

They may also allow even categories of solar that are used to pricing their projects after knowing the levels of incentives they would receive to participate in such auctions. For example, developers could negotiate indicative pro-forma contracts with customers, and then use those as the basis for their bids. Winners would complete their projects and deliver the promised customer savings, losers would know that their costs, or their customer discounts, were too high and would need to sharpen their pencils and cost structures to compete in the next auction.

5 and 6. Any kind of “first come, first serve” incentive is going to create problems of crowding. The best approach is to establish the price after every one gets in line, rather than before they do, as proposed in our response to question 1. But, without that, a line that is longer than the MW in the program would be a sure sign that the incentive is too high. By the same token, some degree of undersubscription is likely to be a sign that the incentive is actually appropriately set at a competitive level.

9. Declining block structures should be part of any sequential incentive program. Full or oversubscription of one stage should trigger a significant downward shift in incentive level for the next phase. Only severe undersubscription (e.g., less than 50% of the targets) should trigger an increase. Many developers will take undersubscription as an indication they need to work harder to reduce costs, so the price should not be increased very much in the stage after even a significant undersubscription.

11. See our answer to question 1. Four different cost structures should reveal themselves in private descending clock auction, and potentially much more accurately than any administrative pre-sorting would allow.

13. Competitive procurements with full offtake contracts are almost always conducted on a pay-as-bid basis. Despite widespread impressions to the contrary, pay-as-bid can be as efficient (or more so) in auction theory, depending on the nature of the auction and information assumptions. We recommend pursuing pay-as-bid with up-to-date auction design experts.

15. There is ample empirical literature on procurement bidding fees and bonding levels that are effective. We suggest consulting this literature to set the numbers. The Board should avoid lowering good levels just because bidders don’t like them.

16. We caution against overspending and over-procuring storage in the successor program. Virtually all of the economic value of storage, from a power system perspective, comes from its ability to help manage overproduction of wind and solar at times of more intense wind and sunshine. In this role, storage charges when there is overproduction, and very low wholesale market prices, and discharges when there is underproduction, and much higher wholesale prices. This price arbitrage is typically enough to fully pay for the storage, so no ratepayer incentives are needed. New Jersey is years away from such overproduction, and by the time it starts happening, battery storage will be highly competitive, and able to jump quickly into the arbitrage market with no subsidies needed. In light of this, and especially in light of the need to keep electricity affordable, as well as to keep the successor program within the cost caps, we recommend very limited solar deployment, if any, through the solar successor program budget. Instead, much more focus should be made, outside of the successor program, on storage’s potential for lowering transmission and distribution system costs and for reducing the non-GHG pollutants associated with fossil peaking generation, especially in locations with environmental justice concerns.

17-20. Much of the enthusiasm for agri-voltaics stems from NREL research showing a boost in agricultural productivity in certain locations. Any such deployment of agri-voltaics should need smaller incentives, if any, due to the enhanced agricultural productivity. Accordingly, and due to the uncertain land, water and wildlife impacts of agri-voltaics in New Jersey specific locations, we recommend a very limited pilot program, offering only lower incentives per watt than comparable solar-only projects, and co-developed with the DEP, to better evaluate both the economics and the environmental impacts of agri-voltaics in New Jersey, before establish any significant agri-voltaic component of the successor program.

22-26. Siting Provisions- We appreciate the efforts of staff to include provisions to foster sound siting of solar development including protections for preserved open space and farmland, forests, wetlands, and prime or statewide important soils within Agricultural Development Areas (ADAs). This approach is consistent with the Energy Master Plan goals to encourage solar development on the built environment and marginal lands while avoiding open space, high-value agricultural lands and environmentally sensitive areas.

We understand the intention behind including a waiver process to make exceptions to the siting provisions but would urge the staff and board to be extremely judicious and limited in doing so. We support capping the amount of prime farmland that can be waived but urge you to lower the cap from 5% to 1%. According to statistics from State Agricultural Development Committee (SADC) 5% of prime or statewide important soils within ADAs amounts to over 8,000 acres of prime farmland prioritized for preservation that could be put into large-scale solar development. That is simply too much prime farmland to potentially lose given our lofty farmland preservation goals and isn't necessary given that SADC has identified approximately 100,000 acres of farmland that falls outside of the best soils both inside and outside of the ADAs.

We support a limited pilot project to evaluate the potential costs and benefits of dual-use solar. We simply don't know enough about the feasibility and long-term implications of this approach to adopt it widely. The pilot program should accord with the siting provisions and be located outside of prime or statewide important soils within ADAs. If dual-use proves viable for both solar and agricultural production, dual-use projects should also be subject to the siting provisions and be located outside of prime or statewide important soils within ADAs to avoid conflicting with farmland preservation efforts that don't allow commercial solar on preserved land.

27-29. Please see our comments on establishing MW targets in Part II above. Generally, MW targets should be developed, in light of incentive levels, to ensure the successor program, SREC and achievement of the full RPS targets, all fit within the CEA's cost caps, considering the ongoing costs throughout each successor projects eligibility period.

30. These costs should not be added to the denominator. See discussion in Part II, above.

33. Please see our comments and the changes we urge for the DRIPE calculations and treatment in Part II, above.

Appendix A. Cost Cap Tool Scenario Analysis

This analysis is based on revisions to the CCT. The first set of revisions corrected for errors.

4. EY21 SREC price appears to be based on a projected price for SRECs that did not materialize. EY21 will be finished by June 1, 2021. We changed the projected price to reflect the high SREC prices that have occurred. C12 = $218. Since there is no evidence of declining prices for SRECs to date, we also changed the projected price of SRECs for EY22. C12 = $218.
5. The formula in G15 is incorrect, and we adjusted it.

Additional changes were made in the CCT to reflect policy choices as explained previously in these comments.

6. Changed the RPS targets for 2026-2029 in COL N, Rows 17-20 to match the values of the BPU 2019 RPS/BGS rule.[16] : 38, 41, 44, 47%.
7. Surplus funds within the RPS cost caps in a given year can only be rolled forward in years 2024 and below, consistent with the specific new, permissive but limiting language of the CEA as amended by S4275 in January of 2021. Cells V74-89.
8. The initial estimates decline annually at a rate of 12% per year beginning in 2023, as the energy and capacity markets together work towards an equilibrium. Reduce values in Cells R 42-49, and Cells Q, R 72-79, then zero values in years thereafter.
9. The private costs incurred to purchase behind the meter equipment are removed from the in the denominator. Cells J 38-59.

Scenarios and findings

This analysis is based on revised versions of the original CCT. Version B of the CCT corrects for errors 1 and 2 and is used to create Scenario B1.

Scenario B1 result: There are annual deficits in years 2025, 26 and 27. Scenario B1 violates the cost cap, unless BPU is provided the authority to ignore those cost cap violations and roll over the deficit until surpluses can offset it in later years.

Scenario B1. Annual cost cap violations

Inputs: SREC price 75% of SACP

Successor solar 750 MW/year starting in 2022

	Annual Surplus or Deficit ($)
2025	$ (202,495,183)
2026	$ (131,222,287)
2027	$ (24,740,966)

[16] 51 N.J.R. 1471-2.

Version C of the CCT includes changes 1, 2, 3 and 4 and retains staff's original DRIPE calculations, including numerator and denominator adjustments. The DRIPE benefit and denominator adjustments in Version C provide a larger budget and greater headroom.

<u>Scenario C1 result</u>: Without the ability to roll forward deficits, the results show that the cost cap is exceeded in 2024-2027. To address these violations, the straw proposal recommends substantial reductions in the RPS in 2025, from 35% to 13.8%, as well as reductions in 2026 and 2027. The cost cap is also violated in 2024, as there is not enough headroom from the early years to cover the deficit in 2024.

Scenario C1. RPS Reductions
Inputs: **SREC Price 75%** of SACP
Successor solar 750 MW/year starting in 2022

SREC PRICE 75% of SACP	Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
217	2019	$ 308,481,290				
219	2020	$ 478,253,494				
218	2021	$ 495,049,187	21%	21.0%	15.3%	
218	2022	$ 235,693,906	21%	21.0%	14.8%	
171	2023	$ 102,607,733	22%	22.0%	15.9%	
164	2024	$ (16,082,635)	27%	25.0%	13.6%	
156	2025	$ (202,495,183)	35%	13.8%	1.2%	
149	2026	$ (160,032,894)	38%	21.3%	6.7%	
141	2027	$ (82,650,286)	41%	32.4%	14.4%	
134	2028	$ 3,872,933	44%	44.0%	22.7%	
126	2029	$ 67,507,858	47%	47.0%	22.3%	
119	2030	$ 97,685,755	50%	50.0%	21.9%	

Scenario C2. RPS Reductions

Inputs: **SREC Price 85%** of SACP

Successor solar 750 MW/year starting in 2022

SREC PRICE 85% of SACP	Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
217	2019	$ 308,481,290				
219	2020	$ 478,253,494				
218	2021	$ 495,049,187	21%	21.0%	15.3%	
218	2022	$ 235,693,906	21%	21.0%	14.8%	
194	2023	$ 14,410,379	22%	22.0%	15.9%	
185	2024	$ (183,860,889)	27%	11.4%	0.0%	$ (58,345,498)
177	2025	$ (276,338,282)	35%	12.6%	0.0%	$ (61,969,572)
168	2026	$ (222,678,094)	38%	14.8%	0.2%	
160	2027	$ (131,820,257)	41%	27.3%	9.3%	
151	2028	$ (30,318,108)	44%	40.9%	19.6%	
143	2029	$ 44,203,973	47%	47.0%	22.3%	
134	2030	$ 80,800,611	50%	50.0%	21.9%	

Scenario C2 result: The results from Scenario C2 shows that the impact on RPS is even more severe if SREC prices fall to 85% of SACP, rather than 75% of SACP. Not only is the RPS reduced substantially from 2024 – 2028, the cost cap is still violated in 2024 and 2025 after removing all of the less costly Regional Class I RECs.

Version D of the CCT includes changes 1 – 6, altering the adjustments to the denominator and reducing the DRIPE benefit. The adjustments in Version D provide a larger budget and greater headroom than would be available without adjustments.

Scenario D1. RPS Reductions

Inputs: **SREC Price 75%** of SACP

Successor solar 750 MW/year starting in 2022

Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
2019	$ 301,749,290				
2020	$ 464,087,494				
2021	$ 473,800,187	21%	21.0%	15.3%	
2022	$ 208,814,106	21%	21.0%	14.8%	
2023	$ 54,104,358	22%	22.0%	15.9%	
2024	$ (107,446,841)	27%	13.6%	2.2%	
2025	$ (271,495,644)	35%	12.6%	0.0%	$ (57,126,933)
2026	$ (260,052,600)	38%	14.6%	0.0%	$ (35,391,130)
2027	$ (218,551,159)	41%	18.4%	0.3%	
2028	$ (172,908,062)	44%	26.2%	4.9%	
2029	$ (155,170,978)	47%	31.1%	6.4%	
2030	$ (176,068,144)	50%	32.0%	3.9%	

Scenario D1 shows that substantial annual deficits occur from 2024-2030. If RECs are reduced to address these annual deficits, then the number of Regional RECs are substantially reduced, and the resulting ***RPS is reduced by an average of 47%*** in those years. Even after removing all funds for Regional RECs, the cost cap is still violated in 2024 and 2025. Steps to further reduce the cost cap violation in 2025, 2026 might include reducing the annual MW deployment of successor solar in earlier years, which would further reduce the RPS shown in the table.

Scenario D2 increases the SREC Price to 85% of SACP, and shows a similar, but more extreme pattern described for Scenario D1. The RPS is reduced by an average of 51% from 2024-2030.

Scenario D2. RPS Reductions
Inputs: **SREC Price 75%** of SACP
Successor solar 750 MW/year starting in 2022

Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
2019	$ 301,749,290				
2020	$ 464,087,494				
2021	$ 473,800,187	21%	21.0%	15.3%	
2022	$ 208,814,106	21%	21.0%	14.8%	
2023	$ (34,092,996)	22%	18.4%	11.6%	
2024	$ (275,225,095)	27%	11.4%	0.0%	$ (149,709,704)
2025	$ (345,338,743)	35%	12.6%	0.0%	$ (130,970,033)
2026	$ (322,697,800)	38%	14.6%	0.0%	$ (98,036,330)
2027	$ (267,721,131)	41%	18.1%	0.0%	$ (46,315,629)
2028	$ (207,099,103)	44%	22.6%	1.4%	
2029	$ (178,474,862)	47%	28.7%	4.0%	
2030	$ (192,953,288)	50%	30.3%	2.2%	

Scenario D3. RPS Reductions
Inputs: **SREC Price 33%** of SACP
Successor solar 750 MW/year starting in 2022

SREC PRICE	Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
217	2019	$ 301,749,290				
219	2020	$ 464,087,494				
218	2021	$ 473,800,187	21%	21.0%	15.3%	
218	2022	$ 208,814,106	21%	21.0%	14.8%	
75	2023	$ 424,533,245	22%	22.0%	15.9%	
72	2024	$ 597,221,826	27%	27.0%	15.6%	
69	2025	$ 38,645,373	35%	35.0%	22.4%	
65	2026	$ 3,057,241	38%	38.0%	23.4%	
62	2027	$ (12,037,280)	41%	39.8%	21.7%	
59	2028	$ (29,305,690)	44%	41.0%	19.7%	
55	2029	$ (57,294,661)	47%	41.1%	16.4%	
52	2030	$ (105,150,539)	50%	39.3%	11.1%	

Scenario D3 eliminates any remaining cost cap violations by altering assumptions about SREC prices. The 75% of SACP assumption in the straw proposal creates significant cost cap violations. Scenario D3 solves for the highest SREC price (% of SACP) that eliminates cost cap violations in 2024 – 2026, which is 33% of SACP.

Lower SREC prices preserve most of the RPS, which is reduced by an ***average of 7%*** from 2024-2030.

It is important to note that even this low SREC price does not eliminate further annual deficits, beginning in 2027. The build rate of 750 MW/year is largely responsible for creating those annual deficits.

Scenario D4 eliminates all annual deficits and protects the RPS mandates by reducing the successor program build rate from 750MW/year to 400MW/year from 2022 to 2027, assuming that SREC prices drop to 48% of SACP. This lower rate of new solar development provides an increase over the average build rate of the past six years of 325 MW per year. This lower build rate enables a higher SREC price than in Scenario D3 without creating annual deficits or reducing the RPS.

The combination of SREC price at 48% of SACP and 400 MW/year of solar through 2027 eliminates any cost cap violations in CCT Version D. **Critically, this means that RPS reductions would not be required for costs to remain within the cost cap.**

Scenario D4. RPS Reductions

Inputs: **SREC Price 48%** of SACP

Successor solar 400 MW/year starting in 2022-27, then 750 MW/year

SREC PRICE	Energy Year	Available headroom (no carryover after 2024) ($)	RPS existing law	RPS after straw proposal cuts	Revised regional Class I RECs % of retail sales	Cost cap violations after RPS cuts ($)
217	2019	$ 301,749,290				
219	2020	$ 464,087,494				
218	2021	$ 473,800,187	21%	21.0%	15.3%	
218	2022	$ 208,814,106	21%	21.0%	14.8%	
105	2023	$ 329,084,244	22%	22.0%	16.5%	
100	2024	$ 438,044,789	27%	27.0%	16.9%	
96	2025	$ 5,452,168	35%	35.0%	24.1%	
91	2026	$ 6,473,814	38%	38.0%	25.6%	
86	2027	$ 33,167,595	41%	41.0%	25.7%	
82	2028	$ 61,893,678	44%	44.0%	26.0%	
77	2029	$ 54,746,372	47%	47.0%	25.5%	
73	2030	$ 21,990,496	50%	50.0%	25.1%	

Appendix B

S4275, passed and signed into law on 1/21/20

(2) beginning on January 1, 2020, that 21 percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider be from Class I renewable energy sources. The board shall increase the required percentage for Class I renewable energy sources so that by January 1, 2025, 35 percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider shall be from Class I renewable energy sources, and by January 1, 2030, 50 percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider shall be from Class I renewable energy sources. Notwithstanding the requirements of this subsection, the board shall ensure that the cost to customers of the Class I renewable energy requirement imposed pursuant to this subsection shall not exceed nine percent of the total paid for electricity by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively, and shall not exceed seven percent of the total paid for electricity by all customers in the State in any energy year thereafter <u>; provided that, if in energy years 2019 through 2021 the cost to customers of the Class I renewable energy requirement is less than nine percent of the total paid for electricity by all customers in the State, the board may increase the cost to customers of the Class I renewable energy requirement in energy years 2022 through 2024 to a rate greater than seven percent, as long as the total costs to customers for energy years 2019 through 2024 does not exceed the sum of nine percent of the total paid for electricity by all customers in the State in energy years 2019 through 2021 and seven percent of the total paid for electricity by all customers in the State in energy years 2022 through 2024</u> . In calculating the cost to customers of the Class I renewable energy requirement imposed pursuant to this subsection, the board shall not include the costs of the offshore wind energy certificate program established pursuant to paragraph (4) of this subsection. The board shall take any steps necessary to prevent the exceedance of the cap on the cost to customers including, but not limited to, adjusting the Class I renewable energy requirement.