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Gabel Associates' Comments on Docket No. QO20020184 New Jersey 2019/2020 Solar Transition Solar Successor Program: Staff Straw Proposal

Secretary Camacho-Welch:

Thank you for this opportunity to comment on the Solar Successor Program Straw Proposal, *Docket No. QO20020184*. Gabel Associates is a well-established energy consulting firm that provides economic, regulatory, and technical analysis and advice to a wide range of energy clients, including development of hundreds of solar projects in New Jersey, and presentation of expert analysis and testing with respect to cost-benefit analysis of utility ratemaking. Gabel Associates provides consulting support to the New Jersey School Boards Association, the Morris County Improvement Authority, and the Somerset County Improvement Authority, three public entities with a deep interest in solar development. Gabel Associates offers these comments due to our interest in creating a solar incentive program that is fair and balanced and meets the goals of the BPU and New Jersey's Energy Master Plan.

For clarity Gabel Associates has broken down our comments and suggestions by topic:

In the interest of full transparency, extensive and open files are provided as attachments so the BPU and its Staff can have full visibility into the analysis presented, so that there is full and adequate on-the-record support for these recommendations to support adoption by the Board.

1. Incentive levels for Non-Residential Net Metered Projects

1.1. Incentive Levels for Non-Residential Net Metered TPO Projects

The incentive levels for third-part-owned non-residential net metered projects used in the Straw are inconsistent with the Cadmus analysis and will not provide the support for New Jersey to meet its clean energy goals. Although the Straw includes, in Appendix A, calculated incentive levels recently updated by BPU's consultant Cadmus to reflect the extended 26% Federal ITC (Appendix A), the Straw does not present these calculated incentives as its recommended incentive levels. Instead the Straw bases its incentives on the lower values calculated for customer direct owned (DO) projects, and ignores the higher incentives calculated for third-party owned (TPO) projects. **Using these lower values represents a serious flaw in the Straw as it has the effect of eliminating the development of TPO projects, as demonstrated by Cadmus's own analysis.**

TPO projects typically use a Power Purchase Agreement (PPA) model, whereby a vendor develops, finances, owns, and maintains a solar project on the customer's site for a long-term period and recovers its costs through a PPA payment on per kWh basis. TPO is a key element of solar development, allowing customers to focus on their core business while bringing in a third-party solar developer to develop the project and absorb project development, construction cost, operating and market risks, which the Direct Ownership structure does not permit.

It is critical to recognize that public entities rely very heavily on TPO arrangements (85% of municipalities and public schools are TPO). Moreover, public entities cannot take advantage of the federal investment tax credit (ITC) or accelerated depreciation (MACRS) benefits if they own a project. However, by pursuing a PPA with a TPO, the vendor can monetize the tax credits and pass these benefits to customers in the PPA.

School districts, municipalities, and counties are in the business of providing public services and are generally risk adverse; they rely on solar vendors to finance and manage solar projects. By using "the lower of TPO and DO incentive levels approach", the Straw's proposed incentives have the effect of specifically excluding third-party owned solar since, per the Cadmus calculations, this approach will result in proposed incentives that are too low for PPA project development. **By using incentives that are too low for PPAs to move forward, the Straw will have a highly restrictive impact on public and commercial project development and will prevent New Jersey from reaching its EMP goals.**

1.2. TPO Incentive Levels

Based on the above, we recommend that TPO and DO incentives be differentiated and offered at separate levels for each category and that the Cadmus Appendix A TPO values be used for the TPO incentives. This would align the incentives with the Cadmus calculations.

1.3. Direct Ownership Incentive Levels

The Cadmus calculations use a different methodology for DO projects than for TPO projects. There is currently a lack of clarity and respect to the DO calculations particularly with respect to the use of the payback method employed by Cadmus for non-residential DO projects. Additional spreadsheets should be provided by the BPU so that the derivation of these incentives can be tracked and analyzed. We recommend that the DO incentive levels recommended by Cadmus not be adopted at this time and recommend a continued stakeholder process after providing stakeholders with adequate information with respect to Cadmus' derivation of its DO incentives so that they may review and comment. Specifically, the Board should provide the specific and full SAM model which yielded the DO incentives and the support for the use of the payback method.

For Direct Owned (DO) projects, there are other factors which the BPU should consider. These include:

- The analysis is based on a simple payback target rather than an internal rate of return (IRR). While the simple payback may be appropriate for residential investments, businesses generally evaluate their investments on an IRR basis. Whether a company is a solar developer or a widget manufacturer, it will make investment decisions using the same IRR metrics. It is inconsistent to evaluate DO and TPO investments with this "Apples and Oranges" approach.

- The analysis assumes that customers will be able to take advantage of the federal ITC of 26% and MACRS tax benefits. However, many companies do not have the tax appetite to take full advantage of these benefits and, as mentioned above, public sector entities such as school districts, municipalities, and counties cannot take the tax benefits if they own a project since they do not pay federal income taxes. Including the ITC in the DO calculation leads to incentives that are too low for many DO private sector projects and all of the public sector projects.

- The analysis does not consider the opportunity costs of DO vs TPO. A company that has the potential to host a solar installation essentially has two choices: TPO or DO. If the company choses TPO, it will receive benefits (e.g. reduced energy costs and a site lease payment) without requiring any investment or system ownership risk. The DO analysis should include these obligations and risks.

1.4. Incentive Levels Should Be Differentiated by Project Type

The Straw incentives do not recognize the additional costs of carport canopy projects. Although Cadmus calculated significantly different incentive requirements for two project types, roof-top and canopy projects, the Straw Proposal includes an averaged, single proposed incentive level for both types of projects. Because the calculated incentive for canopies is higher than that of rooftop, the effect of averaging and offering only one incentive level will render canopy projects uneconomic, while resulting in "overpayment" to roof projects.

The incentives for rooftop and canopy should be unbundled/differentiated into two separate incentive levels, at the values calculated by Cadmus, so that an adequate incentive for canopy projects can be offered. Canopy projects – which are a highly beneficial technology because they utilize already employed land - are an important application for schools and municipalities which have parking areas.

1.5. Recommended Incentive Levels for Non-Residential Net Metered Projects

Based on the above considerations, a separate incentives category for third party owned (TPO) projects, and for carport canopy and other project types, should be set for non-residential net metered projects based on the Cadmus calculations. The following recommended incentives use the incentives as calculated by Cadmus in the Capstone report as well as updates provided in Straw Appendix A Table 1 and the May 12, 2021 Memo provided during the Straw Stakeholder process[1].

Category	Incentive
Comm_TPO_Carport	$170.00
Comm_TPO_Ground_lg	$95.00
Comm_TPO_Ground_med	$135.00
Comm_TPO_Roof_lg	$100.00
Comm_TPO_Roof_med	$130.00
Comm_TPO_Roof_sm	$150.00

2. Capacity Levels

The annual MW targets proposed in the Straw are insufficient to achieve New Jersey's Energy Master Plan (EMP) goals and are particularly "short" with respect to the commercial net metered category. These should be adjusted, as detailed below.

2.1. The Proposed Total Annual Capacity Addition Falls Short of Achieving EMP Goals

The fixed annual targets used in the Straw proposal do not provide for ongoing solar growth and fall short of the EMP solar goals for 17 GW in 2035 and 32 GW of solar by 2050. Adding the currently installed SREC capacity, the forecasted TREC capacity and the proposed Straw capacity results in 14.7 GW by 2035 and 21.8 GW by 2050. These totals are 14% and 32% below EMP goals for 2035 and 2050 respectively. These shortfalls occur because the Straw proposes no growth in statewide annual solar capacity additions for at least the first three years. This flat growth rate (i.e., a no growth rate in statewide capacity) should be adjusted to provide for annual increases in the amount of capacity so that the EMP goals can be reached. Annual increases of 5% in the total statewide behind-the-meter solar capacity amount would allow New Jersey to meet its EMP goals.

2.2. Capacity for Net Metered Commercial Category Should Be Increased

The Straw contains a substantial increase for grid supply projects, **while providing no growth for non-residential net metered capacity**.

In the pre-COVID years of 2018 and 2019, New Jersey averaged 33 MW/year for Basic Grid and 28 MW/year for Preferred Land Use (Landfills / Brownfields). Yet, the Straw proposes 130 MW/year for each of these categories, a 294% increase for Basic Grid and a 364% increase for Preferred Land Use. Although it is consistent with the EMP to increase the use of Preferred Land for expanding solar capacity, it is unreasonable to nearly quadruple the Basic Grid category, when it is the category of development with significant land use concerns and considerations.

[1] https://njcleanenergy.com/files/file/Solar%20Transition/FY21/NJ%20Solar%20-%20May%202021%20SAM%20runs.pdf

By comparison, the Straw proposes 190 MW of non-residential solar capacity compared to 184 MW/year average for 2018-2019, a negligible 0.6% increase which is essentially a “no growth” scenario for the highly beneficial category of projects at the sites of public and business sites.

Non-residential net metered capacity - historically, a central element of New Jersey’s solar program - should be increased from the level of 190 MW recommended in the Straw Proposal to 280 MW for the first year of the successor program with 5% annual escalation thereafter to reach the same pace as the solar capacity increases set out in the EMP.

This recommendation of 280 MW for non-residential net meter is consistent with the overall increase in solar proposed in the Straw. Total solar is being increased by 357 MW (750 MW compared to the average of 392 MW). The Straw increases solar capacity (net of community solar which is not in the current average rate of 392 MW) by 53%.

Capacity levels for non-residential net metered projects should be increased at a similar rate as the overall solar increase proposed by the Straw and should not be frozen at current levels. Accordingly, the Straw Proposal should be amended to allow 280 MW of non-residential net metered capacity in 2022 (a 52% increase over the 184 MW/year average, consistent with the overall 53% increase), with an annual escalation of 5% thereafter to match the total solar growth required by the EMP.

This capacity amount should be split between Third Party Owned (TPO) and Direct Owned (DO) Projects in proportion to the historic proportion of such project types (60:40); 170 MW per year for TPO projects and 110 MW per year for DO projects. To the extent one sector is undersubscribed the excess capacity should be shifted to the other sector.

Net metered non-residential solar projects have been at the heart of New Jersey’s solar development for more than 15 years. Of the 3,561 MW of solar developed in New Jersey, 1,705 MW have been non-residential net metered (on-site) projects. These projects have important dual benefits: a) because they are located on roofs, in parking lots, and on unused land on customer sites they preserve New Jersey’s scarce open space; and b) they deliver direct customer savings to individual customers, helping customers to reduce their costs, stabilize property taxes (for government entities), and maintain competitiveness (for businesses that go solar). This is an important benefit that New Jersey offers businesses to remain competitive and reduce operating expenses. This approach has been “the New Jersey way” (unlike states with vast open space) and has allowed New Jersey to become a leading solar development state, while respecting scarce open space and helping customers reduce their operating costs.

Given the important benefits these projects bring to New Jersey, the capacity growth of non-residential net metered projects should be central to reaching the EMP solar goals. To do otherwise will put more pressure on New Jersey open space, reducing the environmental benefits of adding solar, and reduce direct customer benefits.

2.3. Grid Capacity Ramp Up

The Straw proposes that basic and preferred use grid projects be subject to a competitive solicitation process. Considering the timing of developing this solicitation process and the time required to then evaluate and award project incentives, it is not reasonable to assume that New Jersey will add this capacity in EY 2022. Further, these projects are often much more complicated and time consuming to develop.

Instead, it is likely that the first few Successor grid projects will come online in 2023 and additional capacity will ramp up in 2024 and 2025. Consistent with this timing, targets for basic grid capacity should be set at 20 MW in EY 2023, and 50 MW per year starting in EY 2024 and every year thereafter. For Preferred Land Use grid projects, capacity targets should be set at 25 MW in EY 2023 and then be set at the Straw proposal level of 130 MW in EY 2024 and every year thereafter.

Importantly this has budget implications as well, as this phase-in of grid capacity will soften (or free up) funding for 2023, 2024 and 2025.

2.4. Successor Program Budget/Rate Impacts

Collectively, the changes proposed herein will have no impact to the Straw budget in the first two years. Specifically, the increases proposed in incentives and capacity levels proposed herein for the non-residential net meter category is offset by reductions to the budget because of the delay in in-service dates for grid projects that will necessarily occur because of the time required to undertake the competitive solicitation of grid capacity.

The Straw proposed program budget has a two-year total of $200.1 million ($66.7 million in 2023 and $133.4 million in 2024). By comparison, the net impact of all the changes recommended above result in a two-year total of $198.5 million ($62.7 million in 2023 and $135.8 million in 2024), or 1% below the proposed budget.

The changes proposed herein provide a capacity breakdown for each category that is more in line with New Jersey's policy goals (use of the built environment and net metered projects) which recognizes the important land use considerations related to grid solar, and the significant benefits provided to customers by on-site net metered projects. The growth path recommended also recognizes the inherent delay in developing and administering the competitive solicitation process which will delay in-service dates for projects subject to the solicitations.

The incentive levels proposed herein will attract the necessary level of capacity expansion envisioned by New Jersey's EMP, while recognizing the budget considerations proposed in the Straw.

3. Cost Cap

New Jersey has a statutory mechanism to assure that the cost of renewables to customers is not excessive. Specifically, the "cost to customers" cannot exceed 7% of "total paid for electricity by all customers" after 2021.

The cost cap is calculated based upon following formula:

$$\frac{Renewable\ Cost\ to\ Customers}{Total\ Paid\ for\ Electricity\ by\ All\ Customers}$$

Accurately accounting for all of the applicable costs to customers in the numerator and the total paid for electricity costs in the denominator allows sufficient cost cap surplus for the BPU to provide adequate incentives to fully pursue the Murphy Administration's renewable energy goals AND realize annual savings below the cost cap.

We have undertaken a detailed review of the cost cap model contained in the Straw and recommend the following adjustments, which use methodologies that are consistent with BPU policy and industry standard approaches.

3.1. Numerator

New Jersey's RPS results in a variety of direct costs (e.g. state incentives) and cost offsets (e.g. Demand Reduction Induced Price Effect or DRIPE, cost savings from on-site solar) that must be properly accounted for to accurately represent the total costs to customers of the RPS compared to total costs to customers if there were no RPS. These are adjustments that reflect actual offsetting benefits to the cost of RECs to ratepayers, which should be accounted for to calculate the cost to ratepayers from meeting New Jersey's renewable requirements.

These numerator elements include:

- Cost of Class I RECs (for total Class I MWh requirements, net of SRECs, TRECs, Successor RECs and ORECs)
- Cost of SRECs
- Cost of TRECs
- Cost of Successor RECs
- DRIPE/Merit Order from solar: this factor reduces wholesale energy prices and provides benefits to all customers. Wholesale market prices are reduced due to reduced demand (behind-the - meter) or injecting low cost (wholesale) projects into the PJM dispatch supply stack, for both energy and capacity
- DRIPE/Merit Order from Class I resources: this is the same dynamic as for solar - injection into wholesale market reduces wholesale power prices
- Direct customer savings from solar: when customers realize reduced electric costs due to using solar energy on their site, the amount they save reduces the total "cost to customers"
- Hedge benefit, the financial risk, and volatility of electric markets is diminished through decreased exposure to floating market prices (i.e., renewable fixed price not tied to fossil fuel prices); valuation of hedge value to customers

The Straw Cost Cap Tool presented in the Straw includes the first five items in the above list (cost of SRECs, TRECs, Successor RECs, Class 1 RECs and DRIPE Merit Order from Solar). The cost cap analysis should be amended to reflect the other three other factors discussed above (DRIPE/ Merit Order from Class 1 RECs, direct customer savings from solar, and Hedge Benefit).

In addition, the following changes should be made to correct the cost cap analysis:

- The SRECs Requirements (D10:D24) are hard coded and do not match the SREC annual percentage requirements. These cells should be updated to calculate SREC requirements based on retail load and annual SREC percentage obligations.

- Class I REC requirements are reduced by the OREC carveout assuming a 35% offshore wind capacity factor. This assumption should be updated to reflect 48.8% per NREL "2019 Cost of Wind Study" (page 26), and BPU OSW Order (page 19 of the BPU Order in DOCKET NO. Q018121289) to more accurately estimate OSW OREC production. Using the lower capacity factor will overstate the costs associated with the balance of Class I obligations.

- Cost of Successor RECs should be updated to reflect appropriate incentive levels recommended hereinabove.

- The energy DRIPE calculations in the cost cap calculator are based on a value which is extremely low ($0.0000095/MWh per MW of installed solar capacity) and which basis has not been provided or explained. It uses a literature review of seven articles from around the world which does not accurately represent the market impacts of New Jersey RPS requirements in New Jersey and the PJM grid. Forecasting energy and capacity DRIPE values is highly dependent on location and time specific data. None of the studies referenced by the Straw were recently conducted in New Jersey or PJM for a forward looking time period. In fact, most of these studies are years old and many reference other parts of the country or world. Therefore, the studies should only be used as a reference point to support the inclusion of DRIPE. In addition, the Straw did not provide any information on how the DRIPE values used in the straw were calculated based upon the studies.

  Instead of the unsupported DRIPE estimate used in the cost cap calculator, DRIPE impacts should be analyzed using AURORA or a similar market simulation model for a variety of reasons:

  - AURORA is a forward-looking model and reflects future load, fuel costs, generation supply mix, environmental constraints, and many other variables that cannot be captured in DRIPE analysis looking at only historical data.

  - AURORA provides results based on PJM fuel prices, regulatory requirements, load shape, transmission expansion, generation mix, and other market variables.

  - New Jersey is not an isolated electric market but exists in a complex electric grid, interacting with transmission, load, and generation throughout the PJM region. In-state renewable capacity additions will have the greatest impact to prices in New Jersey but will also influence prices beyond our borders. Likewise, generation mix changes outside of New Jersey will also impact local prices. As a full market simulation model, AURORA captures the net impact of New Jersey-driven renewable capacity additions both in and out of the state.

  - Because it is forward-looking, AURORA will properly identify the impacts of adding future generation.

  - AURORA is a widely accepted, industry standard model and is used extensively around the country including by the BPU:
    - The BPU uses it in offshore wind matters;
    - The BPU uses it in RGGI analysis;

        - The NJ Department of Treasury (on behalf of BPU) has stated in a procurement document: "AURORA is the most comprehensive and reliable electricity forecasting and analysis tool available".
    - Based on these considerations, Gabel is providing the assumptions and results of its AURORA analysis which supports more rigorously developed DRIPE estimates than those contained in the Straw Cost Calculator. The cost cap calculations should be adjusted to include these impacts. These are included in the Excel File "Aurora Class I and PV DRIPE.xlxs" (Attachment 1).

- Alternatively, DRIPE could be analyzed using a multi-variant regression model using historical PJM data relevant to New Jersey's actual electric market prices. Although regression modeling is not forward looking and cannot anticipate future market impacts, any such modeling should be conducted using actual New Jersey and PJM data, including multiple variables such as load, energy prices, natural gas prices, and emissions prices. It should be noted that BPU staff has in a previous proceeding recommended using regression analysis, however it did not recommend multi-variant analysis, which is needed to separate out the impact of different variables including fuel costs. This multi-variate analysis is provided in "Energy DRIPE - Monthly Regression" (Attachment 3), and can be used as an alternative to AURORA results.

- Direct customer savings for behind-the-meter projects should be included as detailed in the Excel file "Cost Cap Tool_04-07-2021_GA_Adj w Cadmus.xlxs" (Attachment 2).

- The hedge value of reducing New Jersey ratepayers' exposure to volatile fossil fuel prices should be included. Various research papers indicate a conservative avoided risk premium of approximately 10% of costs. The list of hedge research sources is included in Appendix A: Hedge Research Sources.

- We did not include the value of reductions in air emissions or employment and economic development benefits in our TT Cost Cap calculations. These are typically included by BPU in analyses of other clean energy initiatives, are important policy drivers, and should be considered in the BPU's determination in this matter.

3.2. Denominator

The denominator should contain all "paid for electricity" including customer payments to the four utilities (i.e., all base rates and surcharges paid to utilities) and third-party suppliers as well as customer payments to/for other generation resources such as on-site/behind-the-meter solar and on-site/behind-the-meter cogeneration.

The denominator calculations in the cost calculator should be amended to correct certain issues and provide improved accuracy in estimating New Jersey's total cost of electricity. We recommend the following changes to facilitate these improvements:

- Net MWh load and costs: Straw incorrectly assumed that full solar PPA costs and Cogen costs are included the referenced EIA 861M data. However, these load and cost numbers are not contained in the particular EIA data used by the Straw and do not reconcile with BPU's published final retail electric load.

Per the EIA Appendix C Technical Notes, the 861M data is based on data sampling, used "…to estimate for the entire universe of U.S. electric utilities." – March 2021 release, Page 5. In its effort to include the entire U.S., the EIA's 861M data collection and methodology does not fully capture the total electric sales volume and costs paid in New Jersey.

Further, per email with EIA technical staff, solar PPA data, and DG cogen is not included in the 861M data. The email from EIA can be found in Attachment 4; the relevant responses from EIA are as follows:

> Q: Does EIA-861 also contain wind, cogen/CHP, fuel cell, or other technologies? If yes, can you provide a breakout by technology (including revenue, sales, customers)?
>
> A: *No. We only collect or estimate for small scale solar. The other techs are still a small insignificant number on the national level.*
>
> Q: If it does include an estimate of behind the meter solar, can you give some more insight on how this portion is estimated?
>
> For clarification, we are digging into the details of all available data (not estimates based on sampling) to produce the most accurate representation for New Jersey retail electric sales. E.g. New Jersey Board of Public Utilities reports on solar installations indicates that behind the meter solar is around 3,000,000 vs. about 640,000 reported in the 861M data.
>
> A: *We do not collect any PPA data. The TPO data is not in the adjustments, it is included in the data files. We have no idea what the New Jersey number includes so unfortunately we cannot offer any insights as to why they are different.*
>
> *The adjustments to the Sales Revenue and Customers data does not include behind the meter solar generation not reported by TPOs. To complicate things further, some of the solar is behind the meter (such as those in net metering programs), but the ones that are not are not necessarily behind the meter. Some net metered capacity is also utility scale, but we do not estimate the usage for that in our small scale solar estimates. (Large systems are covered under the EIA-923 for generation and EIA-860 for capacity). The methodology we use is in the EPM technical notes.*

The conclusion is that the EIA is targeting data collection on a national scale and does not include all the detailed data for New Jersey. This is clearly illustrated in a comparison of EIA 861M to the BPU's OCE retail sales data. For EY 2020, the EIA 861M data shows 71,856,189 MWh compared to BPU's Final Retail Sales of 71,693,471 MWh. This implies that the total behind-the-meter generation for all solar and cogeneration is 162,718 MWh, a low number that implies an unrealistically low MW of solar and cogen in New Jersey. A more reasonable estimate of behind-the-meter generation in EY 2020 is 5,146,961 MWh, as detailed in the following table. The assumption in the Straw that that EIA included all TPO solar, customer-owned solar, and CHP is incorrect and would assume that all of this behind-the-meter generation totaled just 162,718 MWh for EY 2020. This understates New Jersey's "paid for electricity" by nearly 5 million MWh as shown below. Using too low of a value for electric purchases will overstate the RPS ratepayer cost impact on a percentage basis.

Item	MWh/Year	Note/Source
BPU Reported RPS Retail Metered Load	71,693,471	Final Retail Sales, Page 1 of NJBPU OCE "Energy Year 2020 Compliance Instruction Memo"
Estimated DG Cogen	2,103,840	300 MW @ 80% Capacity Factor
Estimated BTM - PPA Solar	1,886,735	Approximately 49% of EY 2020 SRECs & TRECs
Estimated BTM - Host-Owned Solar	1,156,386	Approximately 30% of EY 2020 SRECs & TRECs
NJ Total Electric Sales Volume	**76,840,432**	**Sum of above listed elements**
EIA 861M Reported NJ Electric Sales Volume	**71,856,189**	**EIA 861M for June 2019 through May 2020**
Difference	**4,984,243**	**EIA Under Reported MWh for EY 2020**
Difference %	6.5%	EIA Under Report Percentage

The cost cap retail sales data assumption should be updated to reflect BPU's own retail sale MWhs and include reasonable estimates for solar PPA and cogen costs, since these are part of "paid for electricity."

- The Straw does not escalate base utility rate and assumes that total electric costs escalate only with load growth. The base value of Projected Total Paid (C38:C59, before incorporating denominator adjustments) should be calculated based on an average retail electric rate times the total retail load and include an annual escalator per EIA Annual Energy Outlook 2021 Reference Case nominal retail escalation.

- The Straw should be updated to include costs of the Successor Program in denominator as "paid for electricity." Excluding this cost understates New Jersey's total electric costs.

- The Straw should be updated to include a more accurate estimate of OREC costs; the Straw used an offshore wind capacity factor of 35%. This assumption should be updated to reflect 48.8% per NREL "2019 Cost of Wind Study" (page 26), and BPU OSW Order (page 19 of the BPU Order in DOCKET NO. Q018121289) to more accurately estimate OSW OREC production. Using the lower capacity factor will understates New Jersey's total electric costs.

- The denominator should include a reasonable reflection of host owned costs. The Straw should be updated to assume $250,000/MW per year for 10 years compared to $100,000/MW per year for 10 years used currently.

3.3. Cost Cap Results Summary

Taking into account all of the changes recommended above, including increased incentive levels, increased non-residential capacity expansion, annual capacity target growth, and appropriately accounting for all cost cap elements results in a substantial annual savings in every year compared to the statutory cost cap.

The recommended cost cap modeling is contained in the attached Excel file: "Cost Cap Tool_04-07-2021_GA_Adj w Cadmus.xlxs" (Attachment 2). This provides full transparency to the model and its results.

New Jersey's solar growth has provided jobs growth, environmental benefits, and ratepayer savings. There is adequate headroom under the cost caps to support higher incentive and capacity levels that will increase on these benefits into the future. The BPU is in a position to provide adequate incentives and solar growth levels to pursue the Murphy Administration's renewable energy goals AND realize savings below the cost cap.

4. Expanding Treatment of Net Meter

The "net metered category" should be clarified to include "campus-based" solar projects.

There is an important category of on-site solar projects that should be specifically recognized in the BPU's decision in this matter. This relates to various configurations of "on-site" (or "behind the meter") projects that are designed and operated to serve on-site load but do not fit squarely into the current BPU definition of "net metered projects".

This category ("campus based solar projects") relates to the development and operation of solar projects that are located on campus settings (either academic, residential, or corporate) where the solar projects are located on the campus and serve the load of various facilities on the campus. These projects yield the same benefits as standard net metered projects – savings to the on-site host and wise use of land resources – and should be formally included in the definition of net metered projects so that these projects can move forward without regulatory uncertainty about whether they can receive net metered incentives.

These campus-based projects do meet a key element of the net metered project definition: their annual production is less than their annual on-site energy consumption. However, due to the physical configuration of these projects and the campus, they do not use the net meter economic convention of crediting their energy use against the retail rate. Instead, the project may have excess energy in an hour that is not credited at the retail rate (as is the case for standard net metered projects) but will have this excess credited (or sold) at the wholesale rate associated with the location. Accordingly, while the annual campus energy use will exceed solar production (as required by the BPU rules for net metered projects), there will be hours where the "credit" is not against the retail rate. This treatment diminishes the economic value of this energy but does not change the nature of the project as one built to serve on-site load.

These campus-based solar projects can also have a) scenarios where mixed generation is present (for example, CHP and solar on the campus); b) scenarios where the solar assets serve loads across the entire campus; c) scenarios where the energy production from other generation resources on the campus leads to injection of energy into the grid, on top of the solar generation; or d) multiple solar projects are on multiple sites on the campus with each one being a separate incentive applications to OCE. These scenarios do not change the essential character of an on-site solar project which is sized to meet the on-campus load. These scenarios should also be qualified for net metered project incentives.

Based on the above, we recommend that the BPU's order in this matter specifically recognize the above considerations and provide that "campus-based" projects as defined above be eligible for net metered incentives. These are important projects for solar development in New Jersey and this finding by the BPU will reduce regulatory uncertainty and allow these types of projects to move forward with net metered incentives.

5. Clarity on Mining Sites as Desired Land Use

The "Desired Land Use" Category should be clarified to explicitly include Mining Sites.
The Straw separates gird projects that will be subject to competitive solicitation into two categories: "basic grid" and "desired land use" Grid Supply. The Straw states that desired land use includes "for example the built environment including rooftops, landfills and brownfields" (Straw page 14) and that "As evidenced by the proposed design of this Successor Program, Staff seeks to uphold the State's policies of expanding New Jersey's commitment to affordable renewable energy while also preserving and protecting open space and farmland. Staff suggests that this is best accomplished by encouraging the development of solar facilities on the built environment and marginal lands and away from open space, flood zones, forested lands, high value agricultural lands and other areas especially vulnerable to climate change" (Straw page 20).

Siting solar projects on mining sites should not be considered "open space" as, whether floating arrays or ground-mounted arrays, these sites are located on unused or underutilized property that is often zoned industrial and so have no impacts on open space. When mining sites are retired the pits are often filled with groundwater or are filled in with unused byproducts from the mining or sand processing operation. As a mining site, the land is not fertile nor suitable for buildings – it is essentially wasted space. Solar can be installed on the sand surface of the mining pits. If the mining pit is filled with water, it can host floating solar. Solar on mining sites can be grid tied projects or they can also serve on-site load. For mining sites that are still active, the portions of a site that are not planned for use or are decommissioned can provide solar energy to the mining operations that take place on site. Considering that "open space" is generally defined as undeveloped land, mining sites should not be under that category.

Furthermore, mining sites should be categorized as "desired land use" because they fulfill multiple BPU "desires": they do not use open space, they offer development opportunities in depressed rural regions of New Jersey and create jobs in the shrinking mining industry. Siting solar on mining sites is in line with the other "desired land use" sites proposed by the Board (rooftops, the built environment, landfills, and contaminated sites), as mining sites also reside on land that had/has another use. Accordingly, mining sites are suited for the "desired land use" category and the Board's definition of "desired land use" should revised to specifically include mining sites.

Appendix A: Hedge Research Sources

- Baatz et al. Estimating the Value of Energy Efficiency to Reduce Wholesale Energy Price Volatility. American Council for an Energy-Efficient Economy; aceee.org/research-report/u1803.

- Stanton et al. Net Metering in Mississippi. Synapse Energy Economics. Appendix A. synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf;

- Hornby et al. Avoided Energy Supply Costs in New England: 2013 Report. Synapse Energy Economics. pp 5-22. publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/AESC%20Report%20-%20With%20Appendices%20Attached.pdf;

- 2013 Integrated Resource Plan. Rocky Mountain Power. pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf and pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf;

- Bolinger et al. Quantifying the Value that Energy Efficiency and Renewable Energy Provide As a Hedge Against Volatile Natural Gas Prices. Lawrence Berkley National Labs. aceee.org/files/proceedings/2002/data/papers/SS02_Panel5_Paper02.pdf;

- Is Fixed Price Energy a Good Deal? Walden Labs. waldenlabs.com/is-fixed-price-energy-a-good-deal;

- EEU Avoided Costs for the 2016-2017 Time Period. P. 17 – number 6. puc.vermont.gov/sites/psbnew/files/doc_library/order-re-eeu-avoided-cost-2016-2017.pdf.