Mid-Atlantic Solar & Storage Industries Association
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March 1, 2019

Ms. Aida Camacho-Welch
Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, New Jersey 08625

Re: New Jersey Solar Transition Staff Straw Proposal ("Straw Proposal")

Dear Ms. Camacho-Welch:

On behalf of the Mid-Atlantic Solar & Storage Industries Association (MSSIA), formerly known as the Mid-Atlantic Solar Energy Industries Association (MSEIA), please accept these comments related to the above-referenced matter.

MSSIA is a trade organization that (as MSEIA) has represented solar energy companies in New Jersey, Pennsylvania, and Delaware since 1997. During that 21-year-plus period, the organization has spearheaded efforts in the Mid-Atlantic region to make solar energy a major contributor to the region's energy future.

During these years, MSSIA has adopted and followed three fundamental policy principles, which in short can be stated as: (1) Grow solar energy in our states as quickly as practicable; (2) do so at the lowest possible cost to ratepayers, while delivering the greatest possible benefit as a public good; and (3) preserve diversity in the market, including opportunity for Jersey companies to grow sustainably and create local jobs (see MSSIA's fundamental policy principles at https://mseia.net/fundamental-principles/).

Staff Proposal for SREC market closure

In addition to 13 numbered questions, staff set forth a proposal for discussion and consideration in the section, "Request for Comments" consisting of four bullet points at the bottom of page 4, describing the process for closure of the SREC market.

The clear implication of that proposal is that projects which currently have received SRP approval may have that approval rescinded retroactively. Our analysis indicates that without making a change in the process (discussed below), this will happen to a large number of projects, likely totaling 100 MW to 200 MW. We believe and hope that this was not an intended outcome of the Straw Proposal.

Projects that are especially vulnerable to being harmed by the process outlined in the Straw Proposal include municipal and school projects, landfill and brownfield projects, and other projects of special social value.

One consequence of the resulting situation is that most projects will race to beat other projects in order to avoid having their approval rescinded. Costs of development and construction will balloon, and quality and safety will suffer. Of course, no matter how desperately projects accelerate development, permitting, and construction, many projects will still have their approvals rescinded – even though their construction may already be complete. We believe that the costs of this forced acceleration alone will total tens of millions of dollars of loss, in addition to the economic loss to those who lose the unexpected race to finish.

MSSIA joined with other solar industry leaders who constitute the Committee of New Jersey Solar Developers (CNJSD) to submit suggested solutions for an orderly transition, including:
1. Establish a date as soon as possible (SREC Transition Date), after which all approvals will likely be for a transition program. Once a transition program is established, all approvals with that notice will receive a further notice detailing the transition program in which they will participate.

2. The MSSIA/CNJSD proposed transition program is one in which projects will receive a 0.8 factor for SREC generation; that is, projects in the transition program will receive 0.8 SRECs per megawatt-hour instead of 1.0 SRECs per megawatt-hour.

The transition program will feature a separate, transitional RPS to cover one year of continued solar development, but transitional SRECs and legacy SRECs could still trade in common in the SREC market.

The proposed one-year, transitional RPS is proposed to be 0.58% (about 450 MW). The program size is designed to accommodate continuation of the solar industry with allowance for the community solar and subsection r programs, and to help fulfill the 50% by 2030 requirements in the Act.

3. SRP approvals before the SREC Transition Date will be grandfathered, so that even if they reach COD after attainment of 5.1% and fall into the transition program, they will still earn 1.0 SRECs per MWH.

More detail is contained in the MSSIA/CNJSD proposal, which is attached as Appendix 1.

MSSIA has the following answers to the numbered questions posed in the Straw Proposal:

1) In your direct experience, how has the current SREC program functioned over the past 5 years?

In our direct experience, the SREC program over the past 5 years, and for the years before that, gets mixed grades.

A solar incentive program needs to accomplish five basic things, and they are analogous to MSSIA's three fundamental policy principles mentioned above. They are also mirrored in the BPU's long-held policy principles. A solar incentive program should:

1. Drive solar development sufficiently to fulfill the state's goals for renewable energy and solar energy in particular.
2. Do so at the least possible cost to ratepayers, and deliver value regarding other policy priorities (use of landfills & brownfields, community resiliency, relief of congestion, etc.).
3. Grow solar in a steady, sustainable fashion, in order to create economic growth and New Jersey jobs.
4. Provide a path to lower incentives when the price of solar power drops.
5. Enable policy makers to make adjustments by vintage year.

MSSIA view the performance of the SREC program over the past five years, and before, can be expressed with the following grades:

1. Driving solar development: B

The SREC program has driven enough solar development to make New Jersey, at times, a national leader in driving solar development. Over the last five years, however, Jersey has fallen behind other states. Also, if lower costs had been achieved, the state could have developed much more solar for the same cost, creating more growth for solar businesses and more jobs, and bringing us much further in combatting global warming.

2. Cost: F

New Jersey's incentives are the highest in the nation. Jersey ratepayers have paid several times more for each unit of solar energy compared to surrounding states. Currently, for instance, the estimate total present value of SREC incentives paid to a large commercial project built in New Jersey is roughly 7 times more than the present value of the NY SUN incentive for a similar project built in New York. For small commercial the multiple is about 4, and for residential the multiple is about 5 (see Appendix 2). The New Jersey estimated net present value is about 2.7 times higher than the Delaware SREC procurement program (see Appendix 2). Several factors contribute to these multiples, so they are not necessarily representative of the results that can be achieved by switching to a more secure incentive in New Jersey. Nevertheless, surrounding states consistently achieve results with far lower incentives than New Jersey, and MSEIA believes that program design is the most important factor influencing this difference.

3. Steady, sustainable growth: F

The SREC market has caused multiple boom-and-bust cycles as severe oversupply threatened the SREC market, giving rise to repeated crises that necessitated "rescue" legislation. The number of Jersey jobs in the solar industry has actually declined in some years as a result.

4. Path to lower incentives as the price of solar power drops: F

Since 2012 the price of SRECs has generally been rising, all while the price of production of solar power has been steadily falling. This is because the SREC market does not respond to the cost of solar power, it responds to supply vs. demand. Only legislative intervention has reduced the cost of SRECs. The SREC incentive is not competitive; there is no direct competition among solar projects for incentives.

5. Enable policy makers to make adjustments by vintage year: D

In general for the past five years as well as previous years, policy makers have been impeded from making price adjustments for new projects or particular vintage years without severely harming older projects, since the SREC market produces only one SREC price, which must apply to all projects, future as well as past.

2) How should any proposed SREC Successor Program be organized in conformance with the Clean Energy Act and Staff's SREC Transition Principles? Please provide detailed quantitative and qualitative responses as to the perceived pros and cons of each of the following options:

a. a fixed price SREC;

b. a market-determined SREC; and

c. any other option(s).

First, it is important to note that the term "market-determined" in option "b." can mean several different things. For instance, New Jersey made its SREC a tradable commodity, in which the price is set by trading. In Connecticut and Delaware, on the other hand, the price of SRECs is based on direct competition in the form of an auction (head-to-head bidding) for long-term contracts. Both are market mechanisms.

Similarly, the term "fixed" in option "a." above might refer to an administratively determined price, or it could mean a market determined price (such as through competitive bidding as in Delaware and Connecticut) that is then fixed for a certain term.

We will assume for the purpose of our answers that option "a." means an administratively-determined price, and option "b" includes both tradable commodity SREC programs and competitively-bid SREC programs.

There are two fundamental things investors must be able to do in order to invest in solar projects with the lowest possible incentive payment:
1. They must be able to utilize the incentive rates *at face value* when evaluating projects in pro-forma modeling – that is, not to have to discount the value of the incentives in their analysis.
2. They must be able to utilize low-cost capital – equity sources with a low hurdle rate, and low-cost debt. Those sources are available when the degree of risk is low.

MSSIA's response regarding the options presented above are as follows:
a. a fixed price SREC
As stated above, for the purpose of its answer MSSIA is assuming that this means an administratively determined price.
There is considerable evidence that administratively-fixed SREC (attribute) payments achieve lower costs than market-based programs. This can be seen in the Northeast, where the lowest cost program of any major market in the region is the New York SUN program (see above). Its net present value cost for a commercial project outside NY City is 4 to 7 times lower than New Jersey's incentive program, depending on which market segment is being considered. Several national and international studies have reached similar conclusions (see Stern Review, NREL Feed-in-Tariff Policy Report, and the European Renewable Energies Federation in Appendix 3).

The Ernst & Young Renewable Energy Country Attractiveness Indices Report no. 28 states the matter succinctly:
"One of the benefits of FIT mechanisms is that, as illustrated in previous issues of the CAI, they tend to provide less costly renewable energy per kWh generated, due to their lower risk profile and greater certainty. They are easier to understand by both investors and finance providers and tend to attract a greater plurality of market participation (from local communities and businesses as well specialist developers, investment funds and utilities) than more complex market-based mechanisms (such as green certificates - GC). As a consequence, well-designed FITs have usually led to greater capacity growth, subject to planning and grid availability, and a more conducive environment – where there are appropriate skills to encourage local manufacture.

In contrast, market-based mechanisms, due to their higher risk, and higher cost of capital, have on the whole been less effective in terms of capacity build and much more expensive to the consumer/tax payer per kWh produced – although not in terms of cost per head of population, due to much lower levels of capacity deployment".

An administratively-fixed price is very controllable. At any time, the administrative body can lower the price, or raise it, to suit policy objectives (as was done recently in the NY SUN program).

MSSIA details a proposed Successor Program design below and in the Appendices that suggests a market-based hybrid approach, but we believe that an administratively-determined price could be a viable alternative that satisfies staff's SREC Transition Principles.

b. a market-determined SREC
As stated above, for the purpose of its answer MSSIA is assuming that this can mean a tradable market commodity (like New Jersey) or competitive bidding for long-term SREC contracts (like Delaware and Connecticut).

Tradable Market Commodity

A tradable market commodity for SRECs, like New Jersey's current incentive system, suffers from several fundamental problems, as follows. Several of the problems listed below are interrelated.

1. Risk

Making the incentive program a tradable market commodity artificially injects risk into the revenue stream for a solar system investor/owner. As in any investment, the revenue stream must be higher when risk is high. This can be called a risk premium, and as long as the risk is there it is unavoidable.

New Jersey's program carries very high risk. SRECs may go to a very high percentage of SACP at the highest – perhaps as high as 95%. On the other hand, if a severe oversupply situation occurs and there is no legislative "rescue", the SREC price can fall to just above zero, as has happened in other states. After the first three years of SRECs, which can be put under contract, investors routinely discount the SACP by 50% or more. Some require a high rate of return, and some take both measures to overcome the risk.

2. Unrestrained development (boom-and-bust)

As stated before, progress toward long-term goals, as well as economic growth and job growth, require sustained, steady growth. During times when tradable SRECs are high, the solar industry delivers very high growth, and its momentum is hard to stop. The result is that the market is quickly and repeatedly oversupplied, resulting in market crashes, unless the market is propped up by legislative rescues. These boom-and-bust cycles are inherent in the current market structure.

3. Inelastic market ("vertical demand curve")

A study of the SREC market and its problems was conducted for the BPU in April 2012 by the Rutgers Bloustein School entitled *"The Implications of a Vertical Demand Curve in Solar Renewable Portfolio Standards".* Describing what it called "inelasticity" and a "vertical demand curve", the report in its abstract stated, "As a result, SREC prices are unnecessarily volatile, result in uncompetitive market outcomes, increases in the cost of solar financing and therefore the cost of SRECs, and make it more difficult to evaluate solar policy. The resulting "boom-bust" cycles are very problematic for policymakers." The study, attached as Appendix 4, illustrated the issue with the following diagram:

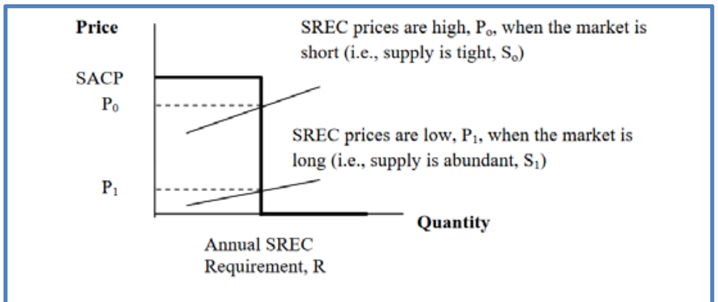

Fig. 1. The Vertical Demand Curve for NJ SRECs Results in Volatile Prices

This is one of the primary reasons why SREC prices will go a very high percentage of the SACP when the market is balanced or short, and very low (near zero) when the market is long (over-supplied).

3. Price unresponsive to the cost of solar power

With a tradable commodity SREC, the price responds only to the balance of supply and demand. While theoretically it has an indirect tie to cost, this has not materialized in the market. Since 2012, the cost of producing solar power has gone steadily and significantly down (see Lawrence Berkeley Laboratories' "Tracking the Sun" reports at https://emp.lbl.gov/tracking-the-sun), while at the same time the SREC prices generally have been rising.

5. Policy makers impeded from make adjustments by vintage year
If policy makers wish to administratively push down SREC incentive prices – due to the inability of the market to respond to the dropping cost of solar, or due to budget constraints – they are impeded from making such price adjustments for new projects or particular vintage years without severely harming older projects. This is due to the fact that the SREC market produces only one SREC price, which must apply to all projects, no matter the vintage year.

To some degree, it is possible to partially mitigate these problems with program changes, including:

- Manage the pace of construction. Limit approvals each year to that year's solar requirement. Breaking up a year into half year allocations or quarterly allocations may improve business continuity. This will decrease uncertainty, enabling a reduction in SACP values for a new program.
- Establish vintage-specific SACP values. This will create a large amount of administrative burden, but will allow incentive price to be adjusted to market conditions.
- Establish a floor price for SRECs. Providing this level of security will allow the SACP values to be reduced substantially. Of course, the provision of a minimally acceptable floor price begs the question, "why not just make the floor price the price; why establish trading any higher than that?"
- Differentiate the incentives for different sizes and types of projects, so project types that require less incentive revenue receive less.

Although these measures can reduce the high-cost drivers plaguing tradable SREC programs, the problems, especially the cost premium due to risk, cannot be eliminated without virtually eliminating the tradable character of the program. Therefore, it is not possible for a tradable SREC to achieve the lowest possible cost to ratepayers.

Competitive bidding - procurement
Delaware and Connecticut hold periodic competitive procurements for long-term SREC contracts. They are small solar markets, unlike the major markets in New Jersey, New York, and Massachusetts. Nevertheless, their results can be instructive. We will use as an example. The SRECDelaware Program holds a yearly procurement for 20-year contracts. The SRECDelaware Program produced an overall weighted average of $21.26 per SREC in the 2017 procurement and $28.50 in the 2018 procurement. Comparing Delaware with New Jersey, the net present value of New Jersey incentives is about 2.7 times higher than the net present value of SRECDelaware-procured incentives.

One problem with competitive procurement programs is that they are well-suited for a few small projects, but not as much for large numbers of small projects. First, the administrative burden in conducting competitive procurements for tens of thousands of projects per year, both on the program administrative side and on the developer side, would be high. Second, smaller projects have short development times. A procurement one or two times per year would make it very challenging for New Jersey business to keep their doors open, let alone grow and hire, in between procurements.

3) Based on your response to question 2 above, provide precise quantitative and qualitative recommendations as to how your preferred SREC Successor Program model would be implemented, keeping in mind the necessity of satisfying the "SREC Transition Principles" set forth above.

MSSIA suggests a hybrid approach addressing the two major parts of an incentive system. The two major parts are:
1. The incentive program
Typical issues include such questions as:
a. What type of incentive is it?

b. How is the price determined (tradable commodity? competitive bidding? administrative? legislative?)
c. Is the incentive decoupled from the energy payment or bundled with the energy payment?
d. What is the term of payment (3 years? 10 years? 20 years?)
e. Is the payment for a specific project designed to be levelized over the term of payment, or declining over the term?
f. How does the incentive price decline over time for different vintage years?
g. Is there differentiation in price between different sizes/types of projects?
h. Is there an annual goal for solar growth built into the program?

2. The funding mechanism

Typical issues include such questions as:

a. Who pays the generator? Utility companies? A state authority? The suppliers?
b. What is the ultimate source of funds – ratepayers or taxpayers?
c. Assuming the ratepayer is the source of funds, what is the transaction path from the ratepayer to the generator?
d. Are long-term contracts involved? Another form of certainty?

The funding mechanism is a tricky subject. The goal, as stated before, is to provide a low-risk incentive revenue source for generators, so that they can invest at the lowest possible cost. But many mechanisms to provide low-risk revenue income involve having an entity to stand behind the revenue in the form of a contract. Utilities may resist playing a role involving long-term contracts, and that route could become expensive. Another possible solution is a governmental or quasi-governmental entity (such as an authority, as in Delaware). That path can be difficult and time-consuming to enact, and can add significant cost. Finding a simple, low-cost solution to the question of how to provide a feasible, low-risk, low-cost revenue source within a limited time frame is an essential element in fulfilling staff's SREC Transition Principles. The same challenge faced the offshore wind industry, and some important work has already been done to solve the problem for offshore wind.

MSSIA offers a detailed suggestion regarding program design, detailed below and in Appendices, which includes a powerpoint presentation regarding the funding mechanism. The essential features of the proposed program are expressed below.

Generally, the proposed *incentive program* includes many features of the Massachusetts SMART program. MSSIA suggests consideration of three variations of a *funding mechanism*, including many features of New Jersey's OREC funding mechanism.

MSSIA Suggested Incentive Program

1. Yearly solar capacity goals are set for each year through 2030, to support compliance with the renewable energy requirements of the Clean Energy Act (50% by 2030). A suggested year-by-year schedule is presented below.
2. The incentive program is a per-KWH payment based on a 20-year levelized price per KW for the sum of incentive + energy (bundled price). A defined energy value is subtracted from the total price to determine the incentive payment.
3. The price is set by a statewide, annual auction of 10% of the year's solar capacity goal. The auction is for large projects, and is held in order to provide a market-based price. Bidders in the auction receive the price they bid. The mean bid price resulting from the auction sets a base price for the rest of the year's program. A secret price cap is set for each year's auction by the BPU.
4. The base price (energy + incentive) applies to either net-metered or grid-supply projects. Any project can choose to connect behind the meter or directly to the grid. Interconnection reviews for all projects

under 10 MW are performed by EDCs, using a common review procedure and costs whether connected behind the meter or directly to the grid.
5. Factors are added to the base price for different project size segments. Factors are also added to the base price for types of projects that fulfill special policy goals identified by the BPU (e.g., landfills and brownfields, congested areas, public projects).
6. The BPU and project manager can adjust the base price and factors if program goals are not being met, or if dramatic market changes happen mid-year (such as new or changed federal incentives, tariffs, etc.) with appropriate stakeholder input.
7. The incentive program is available statewide.

MSSIA Suggested Funding Mechanisms
MSSIA suggests consideration of three variations on a funding mechanism. The variations are further described in Appendix 5, MSSIA Successor Program Funding Mechanism Alternatives Matrix (spreadsheet), and Appendix 6, MSSIA Successor Program Funding Mechanism (powerpoint slides).

Following are common features of all three:
1. The incentive payment prices are determined by monthly board orders, ordering the payment agent to pay specific 20-year levelized prices to approved projects expressed on a list in the order. The approved project list, and the prices, are prepared by board staff and/or the program administrator.
2. The board order states that once set for an approved project, the price will not be reduced in the future. If possible, language to that effect will also be included in a law, as was done in the Offshore Wind Development Act.

The <u>first</u> of three variations on the funding mechanism is described below. It most closely resembles the OREC funding mechanism.
1. The EDCs are the payment agents.
2. The EDCs make the incentive + energy payments to the generators. The total compensation is determined according to the board order referred to in the previous section. In exchange for the incentive payment, the generators transfer the SRECs to the EDCs.
3. The EDCs allocate the SRECs to energy suppliers and transfer the SRECs to them (as the solar RPS obligors), at no cost.
4. The EDCs obtain the funds to pay the generators from ratepayers, through a non-bypassable wires charge.
5. The generator reimburses the EDC for the energy payments the generator receives. The EDC returns these energy reimbursements to ratepayers, so that the net cost to ratepayers is only the incentive cost.

The <u>second</u> of three variations on the funding mechanism is described below. It still resembles the OREC funding mechanism, but is modified in a way that bears a resemblance to the Massachusetts SMART program. The modification, described in item no. 2 below, makes the mechanism simpler by eliminating unnecessary transactions.
1. The EDCs are the payment agents.
2. The EDCs make only the incentive payments to the generators. The total compensation is determined according to the board order referred to above. The incentive payment is determined by taking a project's total compensation (energy + incentive) rate and subtracting the energy value. The energy value will be either 1) the actual energy payments to the generator if connected to the grid, or 2) a defined energy amount representing the value of behind-the-meter energy delivered. In exchange for the incentive payment, the generators transfer the SRECs to the EDCs.
3. The EDCs allocate the SRECs to energy suppliers and transfer the SRECs to them (as the solar RPS obligors), at no cost.

4. The EDCs obtain the funds to pay the generators from ratepayers, through a non-bypassable wires charge.
5. (eliminated)

The third of three variations on the funding mechanism is described below. This alternative makes the mechanism still simpler, by taking EDCs out of the payment path.
1. The energy suppliers are the payment agents.
2. The EDCs make only the incentive payments to the generators. The total compensation is determined according to the board order referred to above. The incentive payment is determined by taking a project's total compensation (energy + incentive) rate and subtracting the energy value. The energy value will be either 1) the actual energy payments to the generator if connected to the grid, or 2) a defined energy amount representing the value of behind-the-meter energy delivered. In exchange for the incentive payment, the generators transfer the SRECs to the suppliers.
3. (eliminated)
4. The energy suppliers obtain the funds to pay the generators through their energy rates.
5. (eliminated)

Estimated Incentive Rates

MSSIA has performed preliminary modeling of incentive rates for the recommended 20-year fixed program, as well as comparative incentive rates for a 15-year fixed program and a 10-year tradable commodity program.

An investor model was used to identify the incentive rates that would produce a target unlevered internal rate of return (IRR). For the tradable commodity alternative, the target IRR was slightly higher than for the fixed programs, to partially account for the higher risk. In addition, a discount off the SACP was applied for each year, with higher discounts in later years. In our experience, this is how most solar industry investor evaluate projects.

The models used for MSSIA's analysis, in operable form, are provided along with these comments as Appendix 7 (20-year fixed incentive), Appendix 8 (15-year fixed incentive, and Appendix 9 (10-year tradable commodity). The model used is proprietary and the intellectual property of an MSSIA member. **Accordingly, MSSIA requests that the models provided with these comments be kept confidential** in accordance with the confidentiality procedures set forth in N.J.A.C. 14:1-12.3, as expressed in staff's request for comments. The models to be kept confidential are marked "CONFIDENTIAL" and bear a copyright mark.

The modeling was done for project sizes typical of four market segments: Residential (7 KW), Small Commercial (250 KW), Large Commercial (1 MW), and grid-supply (10 MW). Based on an assumed market share for each segment, a weighted average incentive rate was calculated.

A summary of the modeled prices and the resulting net present value (NPV) costs over the life of the incentive program alternatives is attached as Appendix 10. The net present value costs are the time-discounted costs of incentives for new solar capacity built under the successor program through 2030, according to the year-by-year solar goals shown below.

The modeled, weighted average incentive rates for the alternative incentive programs are:
20-year fixed SREC - $84
15-year fixed SREC - $95
10-year tradable commodity SACP - $202

For the tradable commodity SREC program alternative, the actual SREC prices were assumed to average 88% of SACP.

Yearly Goals for Solar

As stated before, MSSIA suggests yearly goals for solar power that will set the size of the incentive program for each year. The yearly goals are crafted to provide about 6.3 gigawatts (GW) of new solar capacity by 2030 – enough to contribute substantially to the Clean Energy Act's 50% by 2030 requirement and sustain economic growth in the solar industry.

The recommended yearly goals are:
2020 – 450 MW
2021 – 475 MW
2022 – 500 MW
2023 – 525 MW
2024 – 550 MW
2025 – 575 MW
2026 – 600 MW
2027 – 625 MW
2028 – 650 MW
2029 – 675 MW
2030 – 700 MW
Total – 6,325 MW

Other Issues

MSSIA offers a few other issues that its members believe are worthy of discussion:

1. Capacity set-aside for the residential market segment
Residential developers and installers are concerned that large projects in the C&I and grid-supply sectors could overwhelm the program, leaving no room for the residential sector of the industry. We believe that since the residential sector is an intensive creator of in-state jobs and is particularly valuable in creating benefits for the distribution system, that there should be discussion of protecting the residential segment. The establishment of a capacity set-aside or "carve-out" for residential should be considered.

2. Limitation on grid-scale projects
MSSIA members feel that there should be discussion about providing a cap on grid-scale projects to prevent them from overrunning the rest of the market segments.

3. Limits to concentration of participants
In certain cases in New Jersey's solar incentive programs, limits have been placed on how great a percentage of a particular market segment could be devoted to a single entity. We believe that discussion of such limitations would be appropriate in the design of the successor program.

4) How should Legacy SRECs be valued? Should these Legacy SRECs be valued under the SREC Successor Program or valued separately?

MSSIA understands that the cost of legacy projects is an important issue for compliance with the cost caps in the Clean Energy Act. MSSIA is willing to engage in conversations about ways of dealing with legacy SREC program costs, while being fair to prior investments and ensuring that they retain value, per staff's SREC Transition Principle no. 3.

Valuing legacy SRECs under the successor program, or some other separate program, would essentially extinguish the current SREC program. Investors in projects built under the legacy SREC program invested with the justifiable expectation that they qualified for the current (legacy SREC) program. Switching legacy projects to any new program would require great care to ensure that SREC Transition principle no. 3 is honored.

5) How should Pipeline SRECs be valued? Should these Pipeline SRECs be valued under the SREC Successor Program or valued separately?
a. Should the Board continue the current SREC program as a separate program? If so, how?
b. Should the Board include the current SREC program within the SREC Successor Program? If so, how?

See above recommendations for grandfathering projects that already have SRP approvals, and for a transition program.

6) For any solar transition, should the Board set a megawatt ("MW") target for annual new solar construction? If so, should those targets be defined as percentage of retail sales or a set MW cap? Under what circumstances and/or assumptions is this target achievable?

A MW target is preferable and simpler, so long as it is feasible to do so.

7) In any SREC Successor Program, should the Board seek to set annual MW capacity caps for new solar construction or percentages of retail sales? Why or why not? If yes, what should be the value through 2030 and why? If yes, should the Board seek to set differentiated capacity caps under the solar RPS based on project type?

As explained before, MSSIA believes that yearly capacity targets should also be capacity caps for program approval. To approve unlimited construction in a given year would simply be impractical given the cost caps. MSSIA also believes that capacity set-asides and limitations for specific market segments should be considered, as explained in the answer to question no. 3.

8) In the SREC Successor Program, should the Board provide differentiated SREC or solar value incentives to different types of projects? Should such differentiated SREC compensation be created through SREC multipliers, through an add-on valuation, or through some other method? Based on what factor(s) should any SREC compensation be differentiated?

Yes, MSSIA believes there should be differentiation of incentive rates for different project sizes, and for projects advanced specific policy goals, as stated in the answer to question no. 3.

9) How should the cost cap be measured? Should any "head space" under the cost cap in the first years be "banked"? Why or why not?

Yes, any "head space" under the cost caps in the first years should be "banked".

Complying with the 50% by 2030 without exceeding the cost caps will be extremely challenging, particularly if the state wishes to minimize sending incentive dollars out of state without realizing the benefits. The averaging accomplished by banking any head space – both in early years and in later years – will be an important tool in overcoming these challenges.

10) Can and should the cost cap be determined based on net costs that include some type of valuation of associated benefits? If so, what should those qualitative and quantitative benefits be and how should they be assigned a value? If the Board can and should consider a net benefits test, should other cost impacts be included? Which ones? Why? If other cost impacts should not be included, why not?

MSSIA believes that the cost cap calculations should be based on net costs. Net costs should be comprehensive, including a full range of costs and benefits. Benefits should include:
1. Avoided costs related to the distribution system – "non-wires alternatives"
2. Wholesale electric market price reductions, especially peak price reductions (see NREL study of savings to NYISO and three other RTOs)
3. Price suppression in regional fossil fuel prices through suppression of demand for them.
4. Avoided costs of greenhouse gas pollution
5. Avoided costs of regional criteria pollutants – including health & medical costs and lost productivity costs.
6. Economic benefits due to job growth, local business growth, investment in the state, and federal contributions to investment.

The cost impacts of infrastructure improvements that are necessary to accommodate renewable energy on the grid should also be included.

The calculation of these benefits and costs should be undertaken by expert consultants with a proven track record of success in similar studies.

MSSIA believes that in order to optimize the benefits and costs associated with the state's renewable energy programs, it is necessary to map all of the choices and potential measures involved in getting to the goals. Comprehensive study, with comparison of many options, is necessary in order to provide the path with the least societal costs and greatest benefits. The relative importance and amounts of a number of methods of achieving high renewable penetration need to be considered together, including:

- The optimum generation mix of solar, offshore wind, onshore wind, biomass, and natural gas, if any.
- Curtailment of renewable resources during their peaks
- Inter-regional, long-distance transmission
- Stationary storage
- The use of electric vehicle batteries for storage, using bi-directional charging (vehicle-to-grid)
- Heavy demand-side management
- Load shaping through consumer-level real-time pricing
- Targeted distribution system upgrades
- New grid control and monitoring, including sophisticated prediction of renewable resources
- New energy transaction methods, and new utility business models
- Review of the valuation and monetization of distributed renewable resources

We believe that an effort of a breadth and scale similar to the Minnesota Solar Pathways Study, Solar Potential Analysis Report, is needed. The report is a large file attached separately as Appendix 11, but can also be downloaded at http://mnsolarpathways.org/spa/

11) What steps should the Board take to implement the cost cap? In particular, please discuss the pros and cons of decreasing the Class I REC Renewable Portfolio Standards. Should any measures implemented differentiate among the different type of Class I renewable energy technologies? Should these measures differentiate among the different market sectors (e.g. utility-scale grid supply versus small residential systems)? Should these measures be technology neutral? Why or why not?

MSSIA has not yet formed a policy position on this issue, but will be ready to discuss it in stakeholder processes.

12) Should the solar industry transition into a true, incentive-free market as the costs of solar begin to approach "grid parity be a goal, or even a consideration, of the SREC Successor Program? If so, how can a SREC Successor Program assist that transition? Should a transition also encompass changes to the net metering program (cf. ongoing FERC/PJM review of DER aggregation)?

MSSIA advocates for building solar energy at the least possible cost to ratepayers, and that includes transitioning to an incentive-free environment as soon as possible. We believe that MSSIA's suggestion for setting the price in the successor program – by a competitive auction each year – will be effective in bringing about that transition as soon as possible.

We thank you for considering these comments, and look forward to exploring these matters further.

Best regards,

Lyle Rawlings

Lyle Rawlings, President