Ad Energy's comments on Docket No. QO24020126, "IN THE MATTER OF THE 2024 NEW JERSEY ENERGY MASTER PLAN"

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We appreciate the opportunity to provide these comments on the 2024 Energy Master Plan. We also appreciate the planned process to arrive at a draft and then final 2024 Energy Master Plan. Focused workshops should allow a rich interchange of ideas, ensuring that New Jersey produces the best possible plan to achieve these important goals.

The focus of our comments are on Strategy 2 and Strategy 5 of the 2019 Energy Master Plan.

B. Strategy 2 of the 2019 EMP

1. What mechanisms are needed to ensure clean energy development incentives are aligned to match generation and load?

See Section I on methane and Section II on RPS policy.

2. How can we accelerate the pace at which renewable generation projects are built without making it cost-prohibitive for ratepayers and/or developers?

See Section III on grid modernization. Failure to open the grid for interconnection of DERs is placing upward pressure on SREC values.

Also see Section IV on cost saving opportunities for distributed generation.

C. Strategy 5 of the 2019 EMP

1. How can New Jersey more swiftly advance required electric distribution system upgrades with which DER project developers may be faced in order to bring their project online? Should project developers be required to pay for the full upgrade, or can financial mechanisms be put in place to reduce the upfront burden of grid upgrades, reduce or mitigate any impacts on ratepayers, and achieve cost effective expanded hosting capacity for DER?

See Section III on grid modernization. New Jersey has for years allowed the better to be the enemy of the good, allowing the situation to reach its current crisis proportions. It is time to act, and to act aggressively.

2. How should the state incorporate emerging and existing technologies such as long-duration energy storage, clean hydrogen, and demand response in net-zero emission modelling scenarios that align state emission reductions with the Global Warming Response Act of 2009?

We'll provide further comments in workshop sessions.

I. Methane

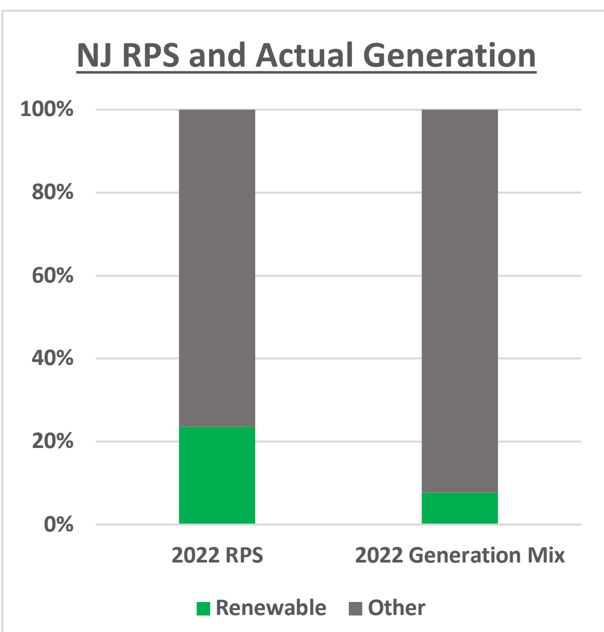
Dealing with methane is not our day job. That said, we are very interested observers of the science of global warming. Methane is a potent greenhouse gas. Recent scientific studies show methane emissions are currently more important than carbon emissions in driving global warming. Other studies indicate that, because of methane leakage and despite advantages in carbon dioxide emissions at point of combustion, the shift from coal electric generation to methane electric generation has not led to reduced warming. To date, New Jersey has done very little to address methane emissions.

Much of the Energy Master Plan is targeted at reducing the end use of methane, both through the cleaning of the electric generation sector and through the electrification of buildings. Leakage from the methane distribution system has received little attention. Studies that compare actual measurements of air concentrations of methane against benchmark concentrations derived from distribution system leakage assumptions consistently show that leakage assumptions are far too low. New Jersey should engage actively in this issue.

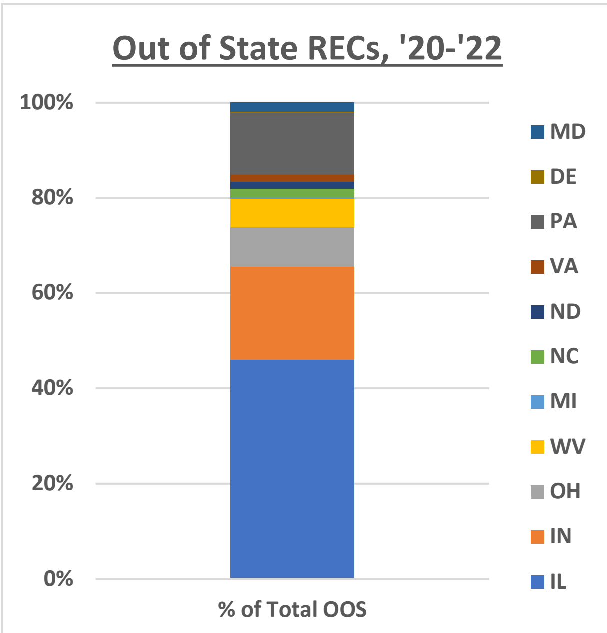
https://rmi.org/reality-check-natural-gas-true-climate-risk/#:~:text=We%20confirm%20past%20studies%20that,risk%20on%20par%20with%20coal.

II. RPS Policy

While New Jersey had a Renewable Portfolio Standard ("RPS") requirement in 2023 of 22%, its actual generation was less than 8% from renewable sources.



The balance of the RPS requirement comes from out of state. Of these out of state RECs, most were from "distant" states such as Illinois, Indiana, and even North Dakota. The average distance from New Jersey to the location of these out of state RECs is 800 miles. Electricity generated in these places does not reach New Jersey.



The RPS requirement is set to increase to 35% in Energy Year 2025. We forecast that in Energy Year 2025 the cost of these out of state, irrelevant to New Jersey RECs will exceed $600m. This money should be invested in a way that advances *New Jersey* clean generation, not Illinois. We also note that at Class I REC prices above the mid $20's these RECs consume cost cap headroom.

<u>We risk recreating a previous PJM issue</u>

That Midwest wind generation is irrelevant to New Jersey can be seen from any of the following three arguments:

1. The cost to build the transmission infrastructure needed to move 35% of our electricity from the Midwest to New Jersey would be *approximately $38 billion*. This is a ridiculous sum.
2. New Jersey ratepayers pay transmission costs of approximately $30 / MWh to move power *within PSEG's footprint*. This implies an absurd transmission cost to move power from the Midwest.
3. Pennsylvania, who sits geographically between New Jersey and the Midwest, *exports power to its east and to its west.*

New Jersey is not alone in its RPS policy structure. Other eastern states have adopted similar policies. Taken together, these policies can have large detrimental regional impact. PJM faced a similar issue a nearly two decades ago. I quote from a PJM white paper in May of 2022 called "**Enhanced 15-Year Long- Term Planning (Master Plan) White Paper**":

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II. Background

In the early 2000s, PJM experienced large west-to-east transfers, and was developing transmission expansion plans to mitigate voltage and thermal ***issues resulting from those transfers***, affecting a number of congested lines in the traditional PJM footprint. In addition, PJM's planning process was responding to steady load growth projections of 2–3% and experienced an all-time peak load of approximately 165 GW in 2006.

The 2008 recession and ***the Marcellus and Utica shale gas boom, which resulted in generation located much closer to the load centers, mitigated many of the reliability issues and the need to build new EHV transmission.*** Although all transmission strengthens the system to some degree, ***had PJM built large amounts of unneeded transmission, consumers may have been burdened with billions of dollars of unnecessary expenditures.*** Moving forward, a robust, scenario-based transmission planning criteria that analyzes an array of future generation expansion scenarios based on a documented record of customer needs and a series of regulatory "check-ins" can prudently establish "guard rails" that help avoid either overbuilding or underbuilding the future transmission system.
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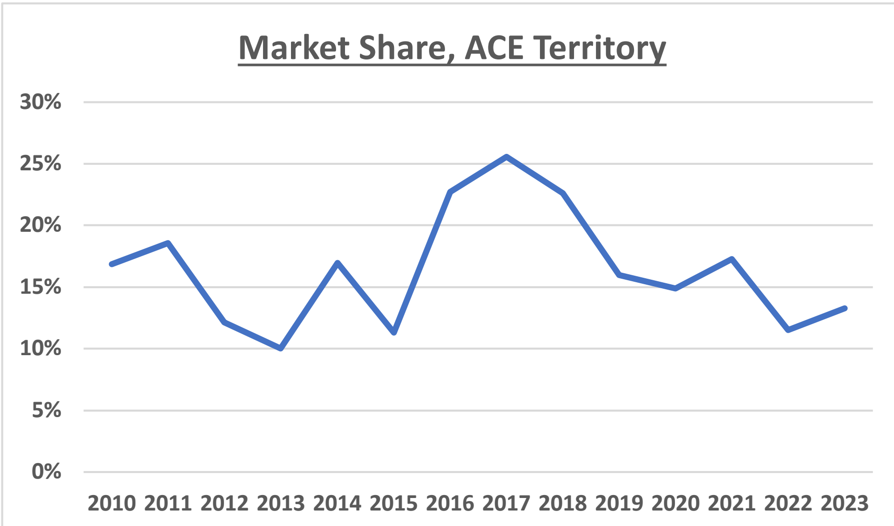
III. Grid Modernization

Grid constraints have become the most important constraint on solar deployment in New Jersey. Many utility customers in New Jersey are not allowed to host solar generation simply because the grid cannot accommodate. For several years the issue has been most acute in Atlantic City Electric. It is now becoming an issue across the state. It is an accelerating problem – more circuits close just as the state attempts to increase solar deployment, crowding more and more remaining open circuits and accelerating their closure. The situation risks derailing near term solar deployment goals if not addressed aggressively.

Grid constraints and incentive cost. Grid constraints put upward pressure on incentive cost. BPU program installation targets determine "demand"; grid constraints, by removing portions of the market from supplying solar installations, reduce the "supply" of solar hosts. This phenomenon places upward pressure on incentive costs. The corollary of this is clear – if we remove grid constraints, we will be able to reduce incentive costs.

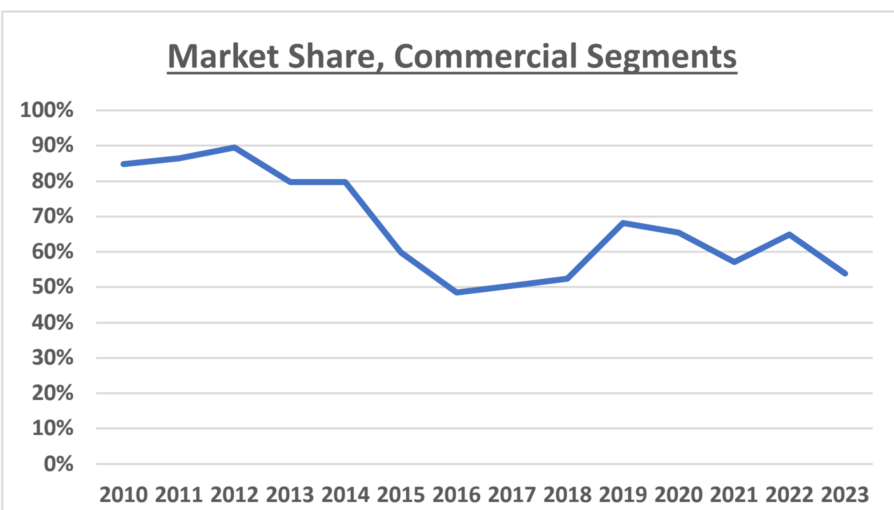
Hints that grid constraints are impacting "supply" show up in market level installation data. Atlantic City Electric has long been by far the most acutely constrained grid in New Jersey. As seen below, from 2019 to now, solar deployments in ACE territory as a percent of total deployments has been declining. It is of course difficult to definitively demonstrate that grid constraints are causing the decline in ACE solar deployments. Nevertheless, our experience conducting business across the state leads us to assess that this is the most important cause.



Note: As we discuss later, we believe there was a "bubble" of activity in the period 2016 to 2018, so we ignore this period in the discussion above.

Grid constraints may also explain another market phenomenon. In 2020, the state transitioned away from the market-priced SREC I program to a fixed priced SREC. Prior to the transition, there was no price difference between a residential and a commercial SREC. After the transition, commercial SRECs have received a higher price than residential SRECs. We would expect this to increase the market share of the commercial segment. This has not happened.

Grid constraints most severely impact large systems. Much of New Jersey's grid remains open to small systems while being closed to large systems. Grid constraints may therefore be restricting "supply" of available commercial installations, placing upward pressure on incentive cost.



Note: Grid Supply is not included, Community Solar is included as Commercial

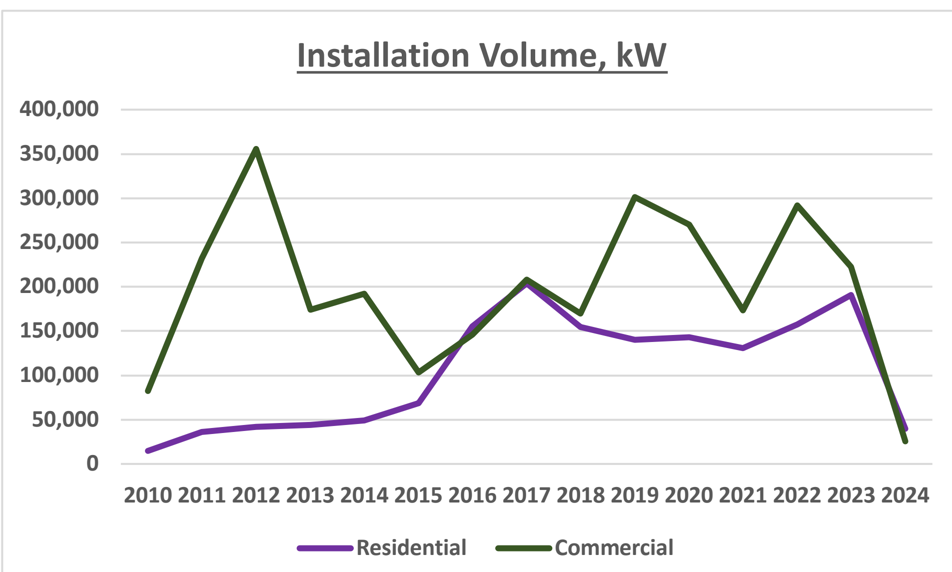
Lessons from Offshore Wind ("OSW"). The State Agreement Approach ("SAA") experience with OSW demonstrated importance of a top down, strategic analysis of grid constraints. The SAA was demonstrated to reduce OSW interconnection costs by 45% relative to a baseline of asking individual projects to pay for interconnection expenses. We currently ask individual solar projects to pay interconnection expenses. Distributed solar is, as its name suggests, highly distributed, and intuition suggests that in this context a top down, strategic approach to grid investment would lead to even more cost reduction.

The time has come for New Jersey to the analogous decision for grid modernization that it took for OSW interconnection. New Jersey is currently operating distributed solar interconnection in a way that our OSW experience has demonstrated to be high cost. It should make this decision quickly, and the decision should include two phases. The first phase, utilities should propose plans to make investments relieve existing severe interconnection bottlenecks. In the second phase, New Jersey should move to adopt performance based regulatory approaches to provide utilities strong incentive to build a modern grid at the lowest possible cost to ratepayers.

IV. Cost reduction

Market history

Before diving into a set of cost reduction proposals, we quickly review New Jersey's distributed solar market history. The chart below depicts installation volumes over time for distributed solar.



Notes on the chart: Grid Supply is not included, Community Solar is included as Commercial

We characterize this market history in a series of periods:

Period 1. 2010 to 2012 – explosion of commercial activity driven by 1603 cash grant program and elevated SREC prices.
Period 2. 2015 to 2018 – rapid expansion of national residential finance companies, followed by their partial retrenchment.
Period 3. Transition to TI and SREC II programs – replacement of floating price SREC to fixed price SREC, together with a transition to higher SREC prices for commercial relative to residential.

Period 1 underlines the importance of liquidity in tax equity. Cash upfront is a much more potent stimulus than a tax credit later.

Period 3 demonstrated, with conviction, that the revenue certainty provided by a fixed price SREC allowed for similar levels of investment to occur at a substantially reduced cost to ratepayers. Generalizing this insight, we can say that the structure of the incentive matters.

Period 3 also raises questions. Most importantly, the transition created a different SREC price for the residential and commercial segments, with the commercial segment receiving a higher SREC price. We would expect this to lead to more rapid growth in the commercial segment relative to the residential segment. This has not happened – in fact, the commercial segment has been losing share to the residential segment.

Lesson learned – incentive structure matters!

The 1603 grant demonstrated this, the shift to fixed-price SRECs showed this, our analysis of the Australian small solar market shows this (more on this below). We have not come close to exhausting opportunities to improve incentive structure to drive down distributed solar costs!

Small scale solar

US is unique in its residential solar cost profile, costing 2 to 3 times as much as much of the rest of the world. The Australian market is a beacon for us: (i) residential solar is installed for less than $1 per watt, and (ii) they installed 3.3 GW of residential solar in 2021. On a per capita basis, that's equivalent to 1.2 GW in New Jersey – from small systems alone!

We derive a set of recommendations to lower the cost of small scale solar from a comparison to the Australian market. These recommendations can be adopted for small commercial projects as well as residential projects.

1. Use estimated production for SREC generation for small systems

This recommendation addresses two existing policy issues. Firstly, we estimate the present value of the cost to comply with GATS reporting from a revenue grade meter to be $1,100 per system. This is a substantial cost for a small system. Taken over 200 MW of systems per year with an average size of 9 kW implies a cost of $24m per year. Secondly, the use of estimated production would remove administrative risk from incentive compliance, allowing for relatively cheap private capital to finance SRECs for small systems, turning 15-year SREC streams into upfront incentives for residential customers. This is how Australia structures its incentive, and it is what US consumers say they want - see page 21 of the AUS Report.

Page 22 of the AUS Report addresses the importance of incentive structure. The leftmost column shows key economic metrics for small scale solar in Australia in 2014. The rightmost column shows that, were we to restructure our incentives to be provided as cash upfront, these key economic metrics, namely contract price per kilowatt and yearly income per kilowatt, would be slightly better than Australia in 2014. Yet Australia in 2014 installed solar on more than 2% of its houses, while in New Jersey we installed on fewer than 0.5% of our houses. Household penetration in Australia in 2014 was higher than New Jersey's current household penetration, and this fact probably does contribute to Australia's relative over performance. It is however unlikely that household penetration alone explains the nearly 5-fold increase in installation activity in Australia. This analogy with Australia suggests that were we to restructure our incentives so that they are provided as cash upfront, we would experience a rapid increase in market activity. This would in turn allow us to lower SREC prices while maintaining target installation volumes.

2. Streamline permitting and interconnection

Australia does not have an application for approval to interconnect small systems. Small system owners simply notify the utility before turning the system on, and utilities are expected to make necessary investments to maintain grid reliability. We see no reason this cannot be achieved in New Jersey. In New Jersey, local permitting offices have proven deeply resistant to change. We estimate that simply using computers to submit permit applications and using cell phones in organizing and administering inspections would save between 10 and 15 cents per watt for small systems.

Commercial solar

Net metering with SRECs is a good subsidy structure for some portions of the commercial market but is not well suited for other portions of the commercial market. Specifically, we propose the creation of an alternative incentive structure that could address the following current market frictions:

1. Landlord-tenant problem. For a substantial portion of the commercial segment, tenants pay utility costs directly, leaving little incentive for landlords to invest in solar.
2. On site load. Limiting system size to on site load limits available economy of scale opportunities.
3. Demand charges. Solar often reduces demand charges, but in an unpredictable way. Therefore, the decision to host solar does not consider impact to demand charges. However, demand charges are often reduced, delivering an unnecessary windfall to the commercial solar host.
4. Credit. When financing is needed, because net metering benefits accrue to the solar host, some prospects will be unable to host solar due to inadequate credit quality.

We therefore propose the addition of an alternative incentive structure for the commercial segment as in the Massachusetts SMART program. The important feature of this program is that it allows for similar project revenue to accrue whether the project is interconnected behind the meter or in front of the meter. This design feature solves all the identified market frictions above.

<u>Green Bank</u>

The Biden administration may be open to amending a proposed IRA regulation regarding tax credit transferability. We encourage New Jersey policy makers to voice support for this amendment. This change would allow a non-profit organization to receive direct pay from the IRS for a tax credit that had been assigned to it. This policy change would allow the NJ Green Bank to provide liquidity to the tax credit market. Specifically, a company installing solar could transfer the tax credit from that installation to the NJ Green Bank for cash, and the NJ Green Bank could then file with the IRS to receive direct pay (ie cash) from the IRS.

Liquidity in tax credit markets has been and remains a key constraint on solar power development in the US. Tax credit transferability between for profit entities has already been successful in improving tax credit liquidity for very large tax credits. The NJ Green Bank could play an essential role in expanding liquidity to smaller tax credits. New Jersey has experienced the stimulus this liquidity can provide during the 1603 grant period, and we are very confident that this would lead to substantial reduction in the cost to develop commercial solar in New Jersey (residential tax credits are unfortunately not eligible for transfer). It would also encourage more direct ownership of solar by NJ companies, keeping NJ incentives inside the NJ economy.

Appendix. Description of transmission cost estimation methodology

- Assume that recent geographic patterns of clean generation development continue
- Assume 35% out of state generation
- The 2019 Energy Master Plan estimates 9 GW of transmission needed to import 20% of NJ electricity
- This implies a total of 15.8 GW of transmission would be needed to import 35% of NJ electricity; current transmission capacity is 7 GW
- MTEP-21 is a $10 bln program of transmission upgrades in MISO; costs are $3.5m per GW-mile
- This implies a cost of $34 bln to build the transmission necessary to import 35% of NJ electricity
- 10% of this electricity is dissipated en route, leading to a total cost of $38 bln
- Not counted here is the cost to build the additional generation needed to replace the 10% losses

	GW	Miles	Cost per GW-mile**	Cost to Build
EMP Exisitng Transmission Capacity*	7.0	400	3,500,000	$ 9,800,000,000
EMP Additional Capacity to Accommodate 20% Imports*	2.0			
Implied Total Capacity for 35% Imports	15.8			
Additional Capacity for 35% Imports	8.8	800	3,500,000	$24,500,000,000
Estimated Transmission Cost				**$34,300,000,000**
Increase due to Line Losses				10%
Total Estimated Transmission Cost				**$37,730,000,000**
* See NJ Energy Master Plan page 55, Section 5; assumes 50% of full cost needed to upgrade transmission from PA to midwest				
**Derived from MISO MTEP-21 program of transmission expansion, a $10bln collection of 18 transmission projects				