



December 5, 2016

Via Electronic Filing

TO:

Kathleen H. Burgess, Secretary
New York State Public Service Commission
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FROM:

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RE: In the Matter of the Value of Distributed Energy Resources (Case 15-E-0751)

Dear Secretary Burgess,

Please find comments of the Solar Energy Industries Association and Vote Solar (the Solar Parties) in response to the *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*.

Sincerely,

/s/ Richard Umoff
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I. INTRODUCTION

On October 27, 2016, the Department of Public Service (“DPS”) Staff filed a report that included a proposed mechanism for compensating some distributed energy resource (“DER”) customers based on the value of distributed energy resources rather than the retail electric rate.¹

Subsequently, comments were solicited from parties by December 5, 2016. The Solar Energy Industries Association and Vote Solar (the “Solar Parties”) offer comments below in response to the Staff report and recommendations.²

The Solar Parties represent hundreds of businesses, customers and stakeholders involved with and supportive of the development of New York’s clean energy economy. The Solar Parties wish to provide a clear voice in support of a strong distributed renewable energy market. We believe that the Staff report and recommendations represent a framework that can create a strong market, but key improvements will need to be made to realize this.

For many years New York has supported the growth and development of distributed energy resources through various policies, programs and regulations, the majority of which have been developed and implemented by the Public Service Commission (“Commission”) and NYSEERDA. As a result, New York’s solar and renewable energy market is a leader in the Northeast and the country in deployment driven by innovative policy.³ However, as the Commission and others have recognized, much more can and should be done to ensure that New York’s distributed energy resources market continues to accelerate growth and that all customers can participate.

The policy of net energy metering (“NEM”) continues to be a cornerstone for giving electric consumers the ability to economically offset their energy demands with customer-sited

¹ Case 15-E-0751

² Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, October 27, 2016 (Case 15-E-0751); The comments herein represent the views of the Solar Parties and not any individual solar company.

³ In 2015, New York had the 9th most new solar capacity installed in the country. The Empire State has cumulatively installed 638 megawatts (MW) of solar, enough to power 108,000 homes. In 2015, New York has the 4th most solar jobs in the country, with 8,250 people employed as a result of solar. SEIA, Top 10 Solar States, accessed from: <http://www.seia.org/research-resources/top-10-solar-states>

generation. The simplicity and understandability of net metering has made it one of the most successful policies for clean energy across the country.

The Commission recently chose to expand this growing market so that all customers can participate, whether they can site a distributed energy resource on their property or not, through the establishment of community distributed generation (“CDG”). As part of this major expansion of the distributed energy resources market, the Commission began a process to consider a new mechanism for valuing and compensating distributed energy resources (also referred to herein as “DERs”).⁴

On April 18, 2016 the Solar Parties filed our first comments and highlighted five core principles for this docket:

- 1. **Process for Developing DER Rider:** The process for developing the DER Rider should be transparent and ensure that parties have an opportunity to provide meaningful stakeholder input. Underlying data, assumptions and methodologies should be accessible and subject to stakeholder review (consistent with appropriate confidentiality concerns). Parties should be given sufficient notice throughout the process to enable stakeholder engagement. Parties should have the opportunity to provide expert opinion on key issues and develop an administrative record as needed. Development of the DER Rider should be done in close coordination with related regulatory proceedings and clean energy programs.*
- 2. **Right to Self-Consumption:** All customers should have a right to self-consumption and control over their energy usage. This means that all customers have the right to determine the amount of energy they purchase from the grid, the amount of energy they self-produce and consume, and the amount of energy they save through efficiency or energy conservation measures. Customers have the right to reduce their demand for energy purchased from the grid through onsite generation.⁵ In addition, the choice to*

⁴ Case 15-E-0751

⁵ See definition of “net metering” under the Public Utility Regulatory Policies Act 16 USC 1621(d)(11)

employ DER, including distributed solar, should not limit the rate schedule options available to customers.

- 3. Proper Valuation and Compensation:** *DER offers many benefits to the electric utility system and by extension to non-DER customers. The value of DER should thus be properly quantified and DER customers should be adequately compensated for the value their DER provides to all customers when exported to the grid. This includes accounting for the long term value of DER to the system consistent with the deferral and depreciation of long-lived utility assets.*
- 4. Simplicity, Gradualism, and Predictability:** *Customers and businesses must be able to make educated investment choices with knowledge of the economic factors that will affect their investment, and with sufficient certainty to secure loans or other financing to deploy DER. A significant part of this certainty is to maintain simplicity in the structure and mechanics of DER compensation, as much as possible, such as has been the case with net metering. In addition, changes to tariffs or changes to the assumptions used for credit value calculations should only apply to projects not yet operating and should not impact existing customers who have already made investments in DER (see Grandfathering). Additionally, any such changes should be made publicly available for at least six months before implementation to accommodate business and sales cycles.*
- 5. Grandfathering:** *The Commission should preserve project economics and protect customer and investor expectations for financial commitments already made.⁶ While the Solar Parties recognize that the rates within the tariff structures are subject to change, the Commission's grandfathering policy should, at the very least, preserve the rate classes and tariff structures of DER customers as regulatory reforms are implemented to avoid making existing projects uneconomic and chilling the market for new deployments resulting from concern over regulatory risk. Customers should be grandfathered for the useful life of their system.*

⁶ The Commission has recognized the importance of grandfathering through REV thus far, and the Solar Parties encourage the Commission to continue implementing a strong grandfathering policy.

Looking back on the process that has led to this point and at the Staff report and recommendations, we believe that Staff has largely respected these principles and delivered a framework that, if improved upon through the final comment process, will set the foundation for a strong market that the Commission can build upon going forward. Over the past year, Staff and a diverse set of parties and stakeholders have worked in a transparent and collaborative manner to consider the matters at play in this docket. During many meetings, opinions have been articulated, research has been provided and questioned, and we have all learned a significant amount.

The Staff report and recommendations outline a proposed compensation mechanism for distributed energy resources that respects customers' right to self-consumption. We are glad to see that Staff has followed this principle by allowing customers to offset their own demand behind the meter with their distributed generation and leaving self-consumed energy out of utility net revenue impacts.

The Staff report and recommendations also attempt to fairly value and compensate customers for their distributed energy resources, while admitting that current valuation mechanisms are imperfect and incomplete. We agree that fair and full valuation of distributed energy resources is a challenge and are glad to see a Market Transition Credit mechanism used to aid in this pursuit. However, the Staff report and recommendations still falls short of fairly compensating customers for the benefits they are bringing to the state.

As a result of this imperfect value of distributed energy resources, the mechanism as a whole as currently proposed does not create a smooth path from the current retail rate net metering system to the value of distributed energy resources. The speed of the transition and the significant added complexity and unpredictable variability of the new mechanism risk hindering the growth of the distributed energy resources market and undermining progress toward achieving the Commission's policy objectives.

On the project revenue side, there are a number of aspects of Staff's proposal that, when taken together, combine to create an interim crediting mechanism that undervalues solar and imperils New York's emerging solar market. We do not believe this is Staff's intent, but rather the product of tackling some very difficult issues while also attempting to balance the varying interests of diverse stakeholders. However, the fact remains that a number of Staff's recommendations have the effect of undervaluing solar and potentially undermining the market before it can scale. Some of these issues, such as Staff's proposal to apply just 80% of MTC to generation, clearly undervalue solar and steeply reduce project revenues for CDG projects from the get go. Meanwhile, other aspects of the tariff that may be acceptable on their own, such as the 20-year tariff term or the increased volatility in the rate, will have the cumulative effect of significantly undervaluing solar, increasing financing costs, and making project development much more challenging in New York if not addressed.

From the customer side, which stems directly from project economics, the complexity and unpredictable variability can increase the customers' perceived and actual financial risk tied to adopting distributed energy resources, and reduce the savings that can be offered to the customer. While New York is one of the fastest growing solar markets in the country, it is still a fairly young solar market with residential and non-residential customers still beginning their education on how solar and other distributed energy resources can benefit them. The NY-Sun program was created in 2012, and the incentive budget was not set until 2014. California, by comparison, launched its California Solar Initiative in 2002. New Jersey's solar carve-out and Solar Renewable Energy Credit (SREC) program launched in 2005. Unlike more mature markets, New York consumers are still being introduced to and educated about solar. If the on-bill credit mechanism changes too much from the current net metering construct, customer education and adoption will become more difficult. And, if savings cannot be offered to customers, New York will not see the customer uptake needed to develop its market.

In these comments, the Solar Parties address the details of the Staff report and recommend a number of changes needed to create an environment for a rational, vibrant solar market in New York. These changes will ultimately allow New York to advance its DER deployment goals while also making progress on other REV objectives and maintaining safe, reliable, and

affordable service for all ratepayers. We hope that the Commission will adopt these changes and work to provide as detailed and transparent a Value of Distributed Energy Resources (VDER) Tariff as is practicable at this stage in or shortly after the Order is released so that the market may continue to grow.. Below is a summary of the Solar Parties' recommendations, and specific changes discussed in these comments are enumerated in Appendix A.

1. Expand the program to allow more customers to participate in community

distributed generation. The Staff report and recommendations seem to set two different allowable utility net revenue impact limits, one at 2% over the entire mechanism and one at 2% annually for the next two years. The allowable utility net revenue impact should be set to the 2% annual, or 4% in total, that is stated in the report but not represented in the illustrative tranche sizes. This increase will lead to more valuable distributed energy resources being developed in the state and more customers having the opportunity to participate in the energy transition those resources are delivering for our electric grid.

2. Allow more customers to reap significant economic benefits from their participation

in community distributed generation. The Staff report and recommendations will lead to a steep drop in value from retail rate net metering to the new value of distributed energy resources. This drop in value will limit project development and reduce customer savings from the projects that do get built, thereby putting customers who cannot put solar on their own roof at a disadvantage as compared to those that can. Even those customers who can benefit from projects may not adopt distributed energy resources if they do not understand how the Phase One tariff would benefit them.

3. Fully compensate commercial and industrial and remote net metered customers for

their valuable distributed energy resources. The Staff report and recommendations admit that some values brought to the state by distributed energy resources are hard or impossible to quantify at this time. To address this, Staff proposes a Market Transition Credit ("MTC") to accommodate unquantified values and continue market growth. Specifically, the Market Transition Credit represents the value of distributed energy resources to the delivery of energy through the electric distribution and transition grids. However, for commercial and industrial ("C&I") and remote net metered customers

(“RNM”) a highly variable and incomplete delivery value is used as compensation and no Market Transition Credit is provided. This delivery value and the related locational value should be made significantly more stable for C&I/RNM customers that do not subscribe to CDG projects, and a 100% Market Transition Credit should be provided to CDG project subscribers to recognize the comparable value delivered by C&I/RNM customers as CDG subscribers.

I. DISCUSSION

Our comments below follow the Staff report and recommendations. For each issue, we state a position of support, support with recommended modifications, or opposition. We include rationale for our positions where pertinent.

- **Section 2.1 - Project and Customer Classification⁷**

The Solar Parties support Staff’s recommended classification of project types and customers.

- **Section 2.2 - DER Technologies Under Consideration⁸**

- a. Applicability of Phase 1 Tariff

Staff recommends applying the Phase 1 tariff to net metering (NEM) eligible technologies. The Solar Parties support this position.

- b. Recommendations Regarding Storage

Staff makes a number of recommendations regarding storage in this section. The Solar Parties support all recommendations, but also note that the economics of storage are still challenging in many applications. For this reason, the Solar Parties strongly support the proposed “solar plus storage” incentive program to be developed by NYSERDA in 2017. The Solar Parties encourage further discussion of storage in Phase 2.

- c. Application of VDER Tariff to Projects Greater than 2 MW

⁷ Staff Report at 19

⁸ Staff Report at 20

The Solar Parties support Staff's recommendation to consider the application of a Phase Two Tariff to projects larger than 2 MW. The Solar Parties believe there is a meaningful opportunity to develop projects above 2 MW on the VDER tariff and look forward to discussing this in Phase 2.

- **Section 2.3 - General Recommendations⁹**

- a. Legacy Projects

The Solar Parties support Staff's recommendation to keep projects in service at time of Phase One Order on NEM. This is necessary to protect current contracts, and to establish a stable and dependable policy environment in New York. We cannot over-state the importance of honoring investment and contractual expectations as the policy landscape evolves. Knowing that the then-current structure will continue to apply to a given project is critical for investors and customers to be willing to invest. Further, we urge the Commission to implement reasonable 'glide paths' and notice periods before structural changes are implemented to avoid abrupt changes that would render early development efforts worthless. The Solar Parties discuss term length in greater detail in the *20 Year Term* section of these comments.

- b. Opt-In

The Solar Parties support Staff's recommendation to allow opt in, but suggests that customers be allowed to opt out one time to encourage customer experimentation with the new tariff. The Solar Parties are concerned that by not allowing customers one opportunity to opt out, early adopters will be penalized if they try the new tariff and find it is not workable, a risk that may deter many customers from even considering the new tariff. Additionally, the Solar Parties are concerned that some consumers may not fully understand the implications of the new tariff, and may wish to move back to NEM once they realize they have moved to a more complex tariff that does not suit them. These customers should have the opportunity to do so.

- c. Cost Allocation

The Solar Parties support Staff's proposed cost allocation principles and recommendations. However, it is important to note that some benefits will cross customer classes, such as loss

⁹ Staff Report at 23

reduction, T&D deferral, and environmental value that benefit all customers to some extent. Therefore, while we support Staff's principles of linking the beneficiary to the cost recovery, this should not preclude recognition that some benefits are enjoyed by all or many customer classes, which should be reflected in cost allocation.

d. Limited Net Revenue Impact

The Solar Parties acknowledge that the Phase One Tariff may result in a shift in cost-recovery from participating to non-participating ratepayers. However, it is equally important to acknowledge that participation in DER will provide offsetting direct monetary and externality benefits to both participants and non-participants alike. The Solar Parties provide more specific feedback on Staff's revenue impact analysis in the *Evaluation of Phase One Impacts and Tranche Design* section of these comments.

e. 2% Upper Limit on Revenue Shift

The Solar Parties do not support the 2% net annual revenue impact metric as an upper bound for the program.

The Solar Parties recommend a 4% upper limit on net revenue impact. Staff's proposal is very conservative and will unnecessarily restrain market growth at a critical time in market development. A 4% upper limit is a more reasonable upper bound for the following reasons. First, a 4% upper limit, when combined with proper cost allocation and recognition of the benefits delivered by solar systems, is a reasonable revenue impact for a program such as this. Over a two-year Phase One period, the 4% limit represents less than a 2% annual bill impact for non-participants. The impact on non-participants' bills may be even less if DER implementation reduces wholesale energy and capacity costs to non-participants.

Second, a 4% upper bound will allow the market to scale at an early stage in development. Currently, the CDG market is facing significant soft costs, such as customer acquisition, land use and permitting issues, and program management, that will most quickly be overcome by scaling the market. Reducing soft costs early will allow for more cost effective solar deployment over the long run, expanding the opportunity for more customers to go solar. Additionally, the CDG market is facing very high interconnection costs at this early stage.

Third, a 4% revenue impact upper limit will ensure that residential customers who cannot participate in the onsite mass market have an opportunity to participate in the CDG market. Staff has indicated that CDG customers should be on the same or similar footing as onsite mass market customers.¹⁰ However, as the program stands now, mass market growth will be counted towards the overall upper limit on revenue impact. This means that mass market customers, who will remain on retail rate net metering, will take market capacity from CDG customers who are moving onto a new paradigm that steps down in value from retail rate over time. A more reasonable upper bound would relieve this constraint, ensuring that all residential customers across utility service territories have an opportunity to participate in New York's solar market, which is a key objective of both the CDG program and REV. Additionally, a broader based CDG market will ensure that development is evenly distributed across utility service territories, relieving the administrative burden on any one utility that may occur if the market is focused in one or two service territories only.

Additionally, there is significant reason to believe that the value stack is underestimating the value of solar, and thus a 4% revenue impact is not likely to actually be 4%. Specifically, the undervalued parts of the stack are the D value proposed, some fraction of the ancillary services left out of the energy value, and the full environmental benefits. Also, the current capacity factors for solar system production used by Staff overestimate each MW's contribution to the revenue impact. The currently used capacity factors are too high because they do not properly account for snow and other derates.

Fourth, a larger program is needed to meet the Governor's solar objectives under NY-Sun and to make meaningful progress towards the state's clean energy goals. The 2% revenue limit, especially when combined with Staff's latest approach to cost allocation,¹¹ will lead to a rather small program that is insufficient to make significant progress towards the Governor's 3 GW goal and the state's overall 50% CES goal.

¹⁰ See *Staff White Paper on Ratemaking and Utility Business Models*, July 28, 2015 (Case 14-M-0101) at 94

¹¹ Staff's proposal to allocate 100% MTC to the residential class results in smaller tranches than allocating 80% MTC to the residential class as proposed by the Solar Parties.

The Solar Parties urge the Commission to seize this opportunity to establish New York as a true national solar leader and implement as robust a program as possible.

f. 20 Year Term

The Solar Parties agree with Staff's recommendation that the VDER tariff should apply to projects on a vintage basis.¹² Currently, Staff recommends a 20-year term. Staff reasons that the 20-year term is consistent with 20-year REC contracts, is consistent with other jurisdictions, and is sufficient for financing. The Solar Parties strongly urge Staff to reconsider this proposal, as it has a significant impact on the ability to finance projects, and ultimately extend solar access to ratepayers throughout New York.

The discussion of the tenor of the tariff compensation treatment in this proceeding thus far has significantly missed the practical reality of project economics in New York. Other than monetary remote net-metering which was subject to a 25-year term, net metering in New York never came with an end date. Accordingly, project developers have always looked at projects in New York as 35-year investments – consistent with the estimated useful life of the equipment – with the assumption that following the initial agreement term with the original customers, the project could sell power under net metering for as long as the system could operate. Whether covered under the original customer agreement or not, the reality is that the market was already baking in life expectancies and economics on the order of 35 years into their investment decisions.

The impact of limiting the term under the Phase I Tariff to 20 years will be not only to increase prices to customers relative to what could have been offered under a net metering regime, but it may cause projects to become non-viable. In evaluating this sensitivity on projects currently under development, developers must now assume that projects will receive only wholesale price compensation after year 20, rather than a retail rate under net metering. This adjustment significantly impacts the back-end economics, and may lead developers to model project decommissioning after year 20 instead of continued operation. This significantly erodes the

¹² Staff Report at 25

projects' NPV, and also creates doubt about the longevity of projects that will be instrumental in achieving the state's greenhouse gas emission goals.

Therefore, the Solar Parties strongly disagree with the 20-year term. The Solar Parties recommend that New York maintain its current policy and allow projects to maintain net metering, or the subsequent VDER tariff as applicable, for the life of the project. In the alternative, a 25-year term at the very least should be adopted. Although 25 years would be a significant reduction in certainty and ultimately impact the value proposition of solar to customers, it would be much more tolerable than 20 years for project economics. While an additional five years may seem insignificant, modeling by companies represented by the Solar Parties has shown that an additional five years will make a significant difference for financing, especially in those utility service territories where financing is difficult. This would increase access to the solar market from ratepayers who may not otherwise be able to participate in the market, and spread the market out across multiple service territories more evenly. Increased customer participation will allow the market to scale more quickly throughout the state, helping to drive down costs and reduce barriers to deployment. Further, a 25-year term would not be outside the norm. Currently Massachusetts and Minnesota offer 25-year terms for their community solar projects. New York should provide at least the same level of certainty in its market as well.

Finally, although five years longer than current REC contracts, the additional five years would likely save ratepayers over the long run by fixing an additional 5 years of avoided environmental and regulatory costs at today's prices while twenty years from now these costs will likely be higher, not lower.

Should the Commission decide to implement a Phase One Tariff with a term less than the useful life of the project, we urge the Commission to include a clear statement in its Order regarding what form of compensation should apply to a CDG project after the Phase One Tariff term. In particular, it seems consistent with REV principles that after the Phase One Tariff term, these projects will move to a new tariff or market-based compensation system that continues to fully compensate them for energy, capacity, distribution, and environmental values. While by no

means a replacement for a longer Phase One Tariff term in terms of financeability, a clear statement that projects would move to a compensation structure other than simply defaulting to the wholesale energy markets that exist today would help support project financing.

g. Crediting

The Solar Parties support Staff's recommendation to use monetary crediting. The Solar Parties agree with Staff that monetary crediting is a more accurate valuation aligned with REV goals because generation is valued based on where and when it occurs.

h. Metering Requirements

The Solar Parties support Staff's recommended hourly metering requirement.

i. Carryover Credits

The Solar Parties support Staff's recommendation for carry over credits on a monthly basis. This is consistent with industry best practices and maintains an easy customer experience that enables customer adoption.

j. Transfer of Ownership

The Solar Parties support Staff's recommendation to keep projects on their current rate in the case of project transfer or subscriber turnover. This is key to financing and market stability, and follows industry best practice. This policy should apply regardless of whether the project has been interconnected. Namely, transfer of project ownership should not affect the project's tranche or tariff eligibility.

k. DER Incentives

The Solar Parties support Staff's recommendation that projects on NEM or the Phase 1 Tariff remain eligible for NYSERDA incentives. The Solar Parties agree that the underlying policy objective of the NYSERDA tariff remains intact as projects are moved onto evolving tariffs. Further, this is consistent with a stated REV and CES principle of incentivizing market development where necessary even as tariffs are unbundled.

l. Future Rate Changes

The Solar Parties support Staff's approach to changes in underlying rates for DER customers.

m. Subsequent DER Tariffs/Opt-In

The Solar Parties support Staff's recommendation to allow projects/customers to move to subsequent tariffs, but recommends that customers have an option to move back once at the customer's discretion. This will encourage experimentation without penalizing early adopters.

- **Section 2.4 - Continuation of Net Metering¹³**

The Solar Parties strongly support Staff's proposal for continuation of net metering (or grandfathering) as stated in the report. The grandfathering proposal is critical to respecting previous investments made by market participants, and establishing a stable market environment by reinforcing to developers, customers and financiers that New York will not undermine energy investments by imposing new tariffs on existing projects. The Solar Parties strongly oppose a stricter continuation policy than proposed, as such a policy would undermine market confidence. Further, a stricter policy is not necessary, as the proposed policy limits project development by design because it is based on a high investment threshold (25%) and a limited window (90 days). Finally, the upper limit on revenue shift will protect against any unexpected development that would have an impact on utility revenues or customer bills.

The Commission should provide greater clarification for the eligibility for and allocation of Tranche 0 capacity to both pre-SIR and post-SIR projects to ensure fair allocation of capacity to projects. The Solar Parties may provide more detail on this issue in reply comments.

In addition, the Solar Parties think it is important to note that this type of capacity-limited grandfathering is not an appropriate precedent for future policy transitions, and that such a limitation is justified only because of the unique circumstances affecting the distributed solar market at present.

¹³ Staff Report at 29

However, the Solar Parties recommend that the Commission establish increased transparency regarding project eligibility. The Solar Parties are concerned that because payment of the 25% interconnection payment is known only to a single developer and the utility, the rest of the market will not know the tranche eligibility of a given project. Utilities should be directed to make public the number of interconnection payments they have accepted for each Tranche within 30 days of the Commission Order, and to update this information no less frequently than every week with the number of MW for which they have received payment. We anticipate that during the first 90 days after the Commission's order, many developers will seek to secure placement in Tranche Zero, and it would be unfair to require the market to make large interconnection payment without knowledge of the tranche into which their project would fall. Going forward, we recommend that the utilities be directed to develop a user-friendly interface similar to that used for the MW Block program to track progress toward the completion of each Tranche. The user-friendly component can be delayed until the tariff is fully implemented.

- **Section 2.5 - Value Stack¹⁴**

The Solar Parties support Staff's thoughtful approach to developing the value stack and Staff's express recognition of the importance of gradualism. Despite this acknowledgement by Staff, the fact remains that the value stack is a stark departure from traditional net metering that is not gradual. The novelty and uncertainty resulting from the value stack will lead to more difficult financing, which will ultimately erode the value proposition for the customer and make it more difficult to scale the market at a time when scale is essential to driving down costs and advancing the state's REV goals. The Solar Parties urge the Commission to keep this in mind as it considers the design of the value stack and market transition credit.

- a. Distribution System Implementation Plans/Benefit Cost Analysis Handbooks

The Solar Parties support Staff's approach to using these resources as instructive but not determinative.

- b. Behind the Meter

¹⁴ Staff Report at 31

The Solar Parties support Staff's recommendation to treat behind the meter generation as load reduction, and to apply the Phase One Tariff to net injections only. This is the defining feature of the net metering construct and is key to customer adoption. This has been a central issue for the Solar Parties from the start of this proceeding, as the net metering mechanism that allows customers to offset their net energy consumption from the grid has proven to be an effective and intuitive way to enable customers to adopt DERs and take control of their own energy use. Similarly, the Solar Parties support application of the Phase One Tariff to net injections only.

c. Phase 1 Value Stack

i. **Energy Value**

The Solar Parties accept Staff's recommended approach to use the actual day-ahead NYISO hourly LBMP energy price for the energy value, with the clarification that this should include all of the components of zonal LBMP (energy, congestion and losses). The Solar Parties recognize that this approach helps to achieve the goal of establishing an accurate representation of value within the rate. However, this approach also creates more uncertainty and complexity for solar project development, which ultimately makes financing more difficult and erodes the value proposition for solar customers. If an hourly-variable energy rate is adopted, this value could well decline over time as more zero-marginal cost renewables are added to the mix. Therefore, at this stage it is very important that this component of the stack be complemented by fixing the other components of the rate, in order to maintain project financeability and customer understanding. As each feature of the rate becomes more complex, there will be a compounding effect on the financeability and value proposition to the customer, which will ultimately impact New York's ability to develop or maintain a robust solar market. By introducing the varying energy component, the monetary credit would fluctuate like a time-of-use rate and is not influenced by the customer's own volumetric rate components. Therefore, the Solar Parties urge the Commission to balance the goal of developing more accurate valuation in each component (or a more precise price signal overall) against New York's goal of developing a strong solar market that can be accessed by all ratepayers.

ii. Installed Capacity Value

The Solar Parties appreciate and supports Staff's recognition of the distinct characteristics of dispatchable and non-dispatchable resources. It is clear that separate treatment is appropriate for technologies in each of these categories to reflect and optimize their unique characteristics.

The Solar Parties support Staff's first recommended approach to valuing capacity. Under this approach, the capacity value would be determined using a per kWh compensation based on the capacity portion of the utility's full service market supply charges, using the service class with a load profile most similar to a solar generation profile for each kWh of generation all year. The Solar Parties' understanding is that the service class used in this approach would be the SC1 or SC2 rate. The Solar Parties recommend that Staff identify a rate class to be used as soon as possible, and we recommend SC1 be used. The Solar Parties oppose using an undefined rate class to be determined at a later date.

Additionally, although the Solar Parties support using the supply credit for installed capacity value, it should be noted that this approach further increases the complexity of the tariff, resulting in more difficult financing and ultimately less value for customers. For this approach to be successful, more transparency is needed around the manner in which this value will be set. The Commission should direct the utilities to publish the information necessary to determine this value so that solar developers can adopt it in their project modeling as soon as possible.

While the Solar Parties believe the approach discussed above should be the default for non-dispatchable resources, the Solar Parties support allowing non-dispatchable resources to opt into Staff's alternative option based on 460 peak hours in the previous year. Even though this alternative option results in a much less predictable revenue stream because of weather fluctuations, and as a result in some areas projects would not be viable with this approach, keeping this as an option would allow systems the opportunity to design for afternoon peaks rather than maximizing year-round generation. The Solar Parties believe there is value in allowing the development of both west-facing/tracking systems and south-facing systems as they serve somewhat different system needs. However, this latter approach should remain opt-in only in areas that are not suitable or appropriate for optimizing around afternoon peaks and/or would not be economically viable with this approach, and thus would be more suited to Option 1.

iii. Environmental Value

The Solar Parties support Staff's recommendation to use the higher of the REC value based on the NYSERDA published price and fixed for a term consistent with grandfathering and tariff term length, or the social cost of carbon (SCC). Because the Solar Parties recommend that projects remain their applicable tariff for at least 25 years at a minimum, the REC price should be fixed for a 25-year term at a minimum as well. Regardless of the term that is ultimately settled upon, it is absolutely essential that this value be fixed. Even with the SCC floor, E could otherwise fluctuate as low as \$0.01/kWh (the current value for this floor per the BCA order and NY current consumption mix). For financing, the lower bound is used in viability analysis and planning, rendering the potential up-side virtually worthless. Therefore, clearly fixing the REC value is key to making the tariff financeable.

Additionally, the Solar Parties recommend that E value assigned to a project be that of the year in which the 25% interconnection upgrade payment is made. This is an appropriate point in project maturity when knowing the E value is essential for moving forward with financing, and is consistent with the 2% interconnection upgrade payment threshold used for reserving placement in the tranche.

The Solar Parties are also supportive of Staff's recognition of the importance of the voluntary market and effort to accommodate those customers. Additionally, it is critically important that the REC value be firm for Phase One, as it lends needed stability to the rate. Therefore, the Solar Parties urge the Commission to monitor CES implementation for any potential impact on the REC price. Finally, it is important to note that the REC price will be lower than originally anticipated by Staff, which amounts to further erosion in the compensation for solar.

iv. Demand Reduction Value (DRV)

The Solar Parties oppose the DRV as currently proposed. While the Solar Parties recognize Staff's effort to move to unbundled values, the DRV is structurally flawed and based on incomplete information. More work is needed to understand how the DRV will be developed, including de-averaging of the marginal cost of service (MCOS) studies, and to stabilize the value

so it can be captured by intermittent resources. Further, this work should be done through a sufficiently robust regulatory process to allow meaningful stakeholder input.

As it is currently proposed, it would be very difficult to finance around the DRV, resulting in lost value from the overall stack and an eroded value proposition for the customer. Additionally, it is critical that a strong foundation be set for each component in the value stack, as the foundation established in Phase One will inform the later phases. Further, Staff has acknowledged that de-averaging is a complicated and a potentially long-term project. Given that Staff is still considering how to approach de-averaging, there is a very good chance that the methodology and values may not be available by the time the Commission plans to implement the Phase One Tariff.¹⁵

Therefore, the Solar Parties recommend that Staff adopt a proxy DRV based on the full territory-wide MCOS value, a greater number of hours, and a multiyear average for the interim tariff, and leave the further development of the DRV to Phase Two discussion. If the Commission decides to include a more detailed DRV in the interim tariff, then the Solar Parties recommend that the Commission adopt a proxy value as described above until such time as the DRV can be developed. This would be a flat per kWh value.

To stabilize the DRV, the Solar Parties recommend the following:

First, the DRV should be based on at least 25 hours, not 10. This will reduce the risk that an unavoidable event, such as a cloud passing overhead, will result in zero value.

Second, the DRV should be determined by using a multi-year performance average during the 25 hours, rather than a single year. The Solar Parties recommend an average of 5 or more years, as this is an appropriate window to capture a meaningful average. This will reduce the risk that revenue could drop significantly during certain years due to single events that skew when peak hours occur, and will help developers and their financiers better model and project the average value they will be receiving, which will facilitate financing and ultimately deployment.

¹⁵ VDER Technical Conference 11/28/16

Third, the DRV should be determined by using an average based on performance by all projects of a similar profile within the same load zone of each utility's service territory.¹⁶ Because it is an average, in which some systems will over-perform and others will under-perform, this approach should be revenue-neutral.

Finally, the Solar Parties recommend that the entire methodology used for determining DRV be continued for the same period of time on which a project remains on the Phase One Tariff (i.e. the methodology should be applied on a vintage basis). For example, if the Commission were to adopt the minimum term length recommended by the Solar Parties of 25 years, the methodology to determine DRV should be applied consistently for a given project for 25 years. Otherwise, changes to the methodology, such as increasing the granularity of the MCOS to a granular substation level, would be very disruptive and make the DRV so unpredictable that it could not be counted on in the project revenue stream for financing.

To summarize, the Solar Parties recommend the following approach to DRV. First, the Commission should direct Staff to use a proxy DRV based on the full MCOS in recognition that a demand reduction value exists but that it has not been established at this time. Second, the Commission should direct Staff to undertake a proceeding to develop the DRV (which could be done in tandem with development of the LSRV) and if necessary deaverage the MCOS with input from stakeholders. Once the DRV has been developed, it can supplant the proxy DRV in new projects going forward. During this process, the Commission should explore the stabilizing techniques discussed above.

v. Locational System Relief Value (LSRV)

The Solar Parties supports Staff's recommendation for a fixed locational value based on the MCOS and values put forward by the utilities. The Solar Parties agree this value should be fixed for ten years at a minimum, although we believe it is more appropriate to align this value with

¹⁶ Load zone is important for utilities with significant north-south variation. E.g., the northern reaches of NYSEG, Grid, and RG&E will have very different solar performance profiles than the southern reaches.

the other fixed components of the value stack and fix it for 25 years at a minimum. Further, the Solar Parties are concerned that the LSRV value cannot be determined until the utilities put forth the necessary information. This should be done through an open regulatory process incorporating utility proposals, stakeholder comment, and Commission review that will likely run well into the Phase One timeframe. Therefore, it is likely that this value will not be available for much of Phase One unless the Commission takes other action to accelerate the development and adoption of these values. The Solar Parties recommend that the Commission establish a proxy value based on locations put forward in other REV initiatives. This value can be a placeholder until such time as the utilities put forth their locational information. The Solar Parties will provide a proposal for a proxy locational value in our reply comments.

vi. Virtual Generation Portfolio

The Solar Parties support the concept of aggregating DERs into portfolios, but do not support this being the exclusive province of the utilities, as suggested in Staff's report. The REV proceeding has consistently considered the role of competitive aggregators, and there are multiple companies that are interested and capable in the aggregation role, and their innovation and investment should be leveraged in this regard to optimize the value of groups of DERs to the grid. In either event, the Solar Parties are concerned that due to the short timeframe and complexity of the Phase One Tariff implementation, a virtual generation portfolio cannot be relied upon to stabilize the D value in Phase 1. However, such an approach could be an effective opt-in component for some projects.

vii. Market Transition Credit

The Solar Parties support the MTC as both a market transition mechanism and as a placeholder for values that have not yet been fully identified or quantified. This mechanism adheres to the principles of gradualism and transparency that are so vital to the success of this proceeding. However, the Solar Parties are deeply concerned by Staff's proposed application of the MTC. If adopted, it is likely that the CDG market will see anemic growth and will not achieve the scale necessary to achieve the state's objectives.

- **The Solar Parties Recommend that the MTC be Set at Full Residential Retail Rate for CDG Projects and Step Down at 5%**

In its report, Staff identifies some key principles that guide its approach. Among these principles are gradualism, support of public policy, equity and fair access. Staff goes on to state that CDG solar projects will receive an MTC that is intended to make their estimated compensation (i.e., value stack plus MTC) equal to NEM in a first tranche, 10% less than NEM in a second tranche, and 20% less than NEM in a third and final tranche.¹⁷ In other words, Staff intends that compensation be equal to NEM for projects in Tranche 1 and then step down by 10% of NEM for projects in each of the succeeding two tranches. However, contrary to its stated intent, Staff recommends that CDG generation in each tranche be paid only 80% of the residential MTC for that tranche.

Staff's proposal does not achieve the stated objective for the Phase 1 tariff discussed in the collaborative and plainly stated in its report, and risks derailing the CDG market before it can scale. Therefore, this approach should not be adopted.

Instead, the Solar Parties recommend that CDG generation be paid 100% of the residential MTC for each tranche, rather than 80% as proposed by Staff.

The Solar Parties make this recommendation for the following reasons. First, a foundational principle of Phase 1 is gradualism. The Phase 1 tariff is not a gradual shift from net metering to a new paradigm, but in fact a steep step down. It is a stark departure from the status quo that will significantly impact project revenues, the cost of financing projects, and ultimately the value proposition for solar customers. During the collaborative, the MTC was discussed as a mechanism that would slowly move the market away from retail rate net metering. However, as proposed by Staff, payment of 80% of the MTC immediately reduces compensation to Tranche 1 projects relative to compensation under NEM, in addition to the significant value reductions

¹⁷ Staff also proposes a "Tranche 0" where CDG subscribers will continue under NEM volumetric crediting. Under Staff's proposal, there won't be a Tranche 1 if Tranche 0 is filled. (Staff Report at 44)

associated with variable energy rates and the added complexity of the tariff.¹⁸ This is not what was contemplated during the collaborative and would be a significant reduction in value on a known and tested tariff, let alone on a novel and wholly untested tariff that is more volatile than anything the industry has dealt with before, anywhere in the country.

The Solar Parties recognize that the Commission has a stated goal of moving away from net metering for large distributed resources, and that cost containment is an important policy objective. However, the proposed upper limit on revenue impact serves this very purpose, allowing the state to implement gradual policies that help scale the CDG market, another state policy objective. While it is true that at higher levels of penetration, CDG projects enjoy lower costs due to economies of scale than smaller systems, this is not the case today in New York at this very early stage in the market. New York CDG developers are facing very high soft costs that are typical with early stage solar markets, such as customer acquisition, marketing, program management, customer turnover, land acquisition, and permitting costs. Additionally, New York's interconnection process is still being refined and updated, and thus New York currently has much higher interconnection costs than other states.

Further, even with 100% MTC, there would be a drop in value for solar projects from retail rate because the MTC rate as proposed will be fixed and not rise in tandem with retail rates. Therefore, over time Phase One projects will be subject to a discount from retail rates even at 100% MTC.

Additionally, the Solar Parties' approach is more equitable for residential customers than Staff's proposal for two reasons. The Solar Parties' recommended approach puts residential CDG customers on equal footing with mass market customers. If residential CDG customers receive a significant reduction at the outset of the program, they are immediately disadvantaged vis a vis onsite customers. This will reduce the ability of residential CDG customers to participate in the

¹⁸ For example, if the MTC amounts to 40% of the retail rate, then Staff's proposal to pay 80% of MTC would provide compensation equivalent to 92% of NEM for Tranche 1 projects, 84% of NEM for Tranche 2 projects, and 76% of NEM for Tranche 3 projects.

program, which undermines the primary policy objective of community solar to extend solar access to otherwise non-participating ratepayers.

Finally, Staff acknowledges that the value of D has not been established, and that under its current proposal to apply only 80% of the MTC to CDG projects, it is likely that C&I customers will not receive full delivery value. However, a 100% MTC, which includes both a transition credit and a placeholder value for D, would ensure that C&I customers participating in CDG projects are more fairly compensated for their delivery value to the system. This will ensure that C&I/RNM customers that subscribe to CDG projects are not treated differently from C&I/RNM customers that do not participate in CDG projects.

The Solar Parties further recommend that the MTC step down from NEM by 5% per tranche in Tranches 2 and 3. This more gradual approach is consistent with Staff's principles and will allow the market to scale as is needed in Phase One.

- **Assume That MTC Compensation is Allocated Commensurate with Subscription**

As discussed below, Staff's analysis for sizing CDG tranches assumes that 100% of CDG MTC payments for Tranches 2 and 3 will be recovered from the residential class, even though the analysis also assumes a residential subscription rate of 80%. This assumption is contrary to Staff's recommendations for allocating MTC compensation and overstates the likely impact on residential revenues from CDG MTC payments. Instead, tranche sizes should be derived assuming that MTC compensation will be recovered from the residential class commensurate with the assumed residential subscription rate.

- **Additional Adjustments to How the MTC is Calculated Should Be Adopted**

Additionally, the Solar Parties recommend the following adjustments be adopted for calculating the MTC.

- a. The Solar Parties requests that Staff clarify that MTC will be determined once for each utility, rather than on a project-by-project basis. The Solar Parties recommend that this process be done by DPS.

- b. The process by which the LBMP value is calculated for the purpose of sizing the MTC is critical to the economics of projects. The Solar Parties will provide input on this in the future.
- c. Similarly, the process by which the Capacity value is calculated for the purpose of sizing the MTC is critical to the economics of projects. The Solar Parties will provide input on this in the future.
- d. Use geography- and market-differentiated load curves to map PV production onto LBMP, D, and capacity values as this can vary widely across the state (due to average insolation, snowfall, latitude, typical project design, etc.).
- e. Use full MCOS values for D if the Commission decides not to de-average. If deaveraging, the PSC should use the lower, de-averaged D values for setting the MTC, which means that MTC cannot be set until MCOS values have been deaveraged.

- **C&I/RNM Should Receive a Placeholder Value that Represents Unknown Values**

The Solar Parties agree with Staff that the value stack is composed of a rough approximation of values, and further work is needed to refine values in Phase 2 and beyond. Staff recognizes this to be the case for CDG projects and therefore recommends an MTC as a placeholder value.¹⁹ However, Staff does not recommend a similar placeholder for C&I/RNM projects. This is not consistent with the approach taken for CDG projects and does not reflect Staff's stated recognition that some values are not included in the value stack. Therefore, the Solar Parties urge the Commission to consider adopting proxy DRV and LSRV values as discussed above in recognition of the delivery value of DERs that has yet to be established through a more granular approach. While we recognize that the Commission seeks to achieve more granular valuation of locational and temporal delivery value of distributed resources by deaveraging the MCOS and potentially other methods, we do not believe this will be possible for the beginning of Phase One, and therefore recommend the use of proxy values for DRV and LSRV.

¹⁹ The Solar Parties also recommend a 100% MTC to be applied to generation from CDG projects in part to recognize the value delivered by C&I customers, as discussed earlier in these comments.

- **The Commission Should Not Rely on Storage to Drive the Market at This Stage**

Finally, the Solar Parties support Staff's proposal to allow CDG w/storage to receive MTC. The Solar Parties agrees that incentivizing and driving storage deployment is a good investment for New York ratepayers. However, it is important to recognize that storage economics continue to be challenging, so the Commission should not expect dramatic adoption of storage in Phase One as a means to make otherwise uneconomic solar projects economic.

- **Section 2.6 - Treatment of Mass Market²⁰**

- a. 2020 Safe Harbor for Mass Market

The Solar Parties strongly support Staff's recommendation to maintain retail rate net metering for projects put in service until 1/1/2020. Mass market customers do not have the metering and communications systems, nor the strong incentives, to respond to the more complex price signals created by the VDER tariff, and as a market segment more reliant on small customers for whom energy is not a primary budget driver, this industry requires a more gradual transition from retail rate net metering.

The Solar Parties believe Staff's proposal to apply the Phase Two Tariff to new projects placed in service after 2020 is reasonable. However, it is still very early in the tariff development process and it may become apparent in Phase Two that 2020 is an unrealistic transition date. Additionally, it should be noted that a one size fits all approach may not be realistic going forward. It may be necessary to develop a tariff for mass market customers to address the limitations and needs of this customer type. The Solar Parties looks forward to exploring this further in Phase Two.

- b. MW Trigger

The Solar Parties supports Staff's recommended approach to the MW trigger. Specifically, the Solar Parties support the requirement that utilities provide notice at 85% of the MW trigger, and again when the trigger is reached. Additionally, the Solar Parties supports the proposal that the trigger initiate Commission review, rather than any specific Commission action.

²⁰ Staff Report at 40

However, the Solar Parties are concerned that the MW trigger is based on an overly conservative projection of market growth. It is the Solar Parties' understanding that the MW trigger was set assuming a 30% growth rate during Phase 1. The Solar Parties believes this is too conservative for some utility service territories. The Solar Parties' member companies will provide additional comments on this issue as this proceeding progresses.

Finally, the Solar Parties support Staff's recommendation that the trigger will not impact projects put into service prior to Commission action. This is consistent with Staff's approach to grandfathering and will ensure continued market confidence going forward.

c. Smart Inverters Report

The Solar Parties support Staff's recommendation to launch an initiative reviewing smart inverter requirements. The Solar Parties believe smart inverters will play a crucial role in the development of REV markets and supports a thorough approach to this topic.

d. Time of Use Rates

The Solar Parties support Staff's recommendation to consider time of use rates as Phase Two proceeds. The Solar Parties urges the Commission to consider rate design options to achieve some of its Phase 2 goals for mass market customers, as rate design changes may be more suited to the mass market than an entirely new paradigm.

• **Section 2.7 - Treatment of CDG²¹**

The Solar Parties supports Staff's recommendation to apply the Phase One Tariff to new CDG projects, with appropriate mechanisms for projects currently in development to access NEM and the early tranches of the Phase One tariff.

• **Section 2.8/2.9 - Treatment of Remote Net Metered Projects/Treatment of C&I²²**

The Solar Parties do not agree that C&I/RNM should receive no placeholder value. For more, see discussion of these issues above.

²¹ Staff Report at 41

²² Staff Report at 42

The Solar Parties support the treatment of behind the meter energy as load reduction. The Solar Parties support the option for two-way metering in which customers have the choice to be compensated for all generation at the Phase One rate.

- **Section 2.10 - MTC and Tranches²³**

See discussion below.

- **Section 2.11 - Next Steps²⁴**

- a. Information Needed from Utilities

- i. **High value areas of LSRV**

See our discussion of this issue above.

- ii. **Demand Reduction Value**

See our discussion of this issue above.

- iii. **Virtual Generation Portfolio**

See our discussion of this issue above.

- iv. **Unbundling Values**

The Solar Parties encourage the Commission to direct utilities to provide the values necessary to flesh out the full value of DERs. The Solar Parties are uncertain how this initiative differs from other REV efforts such as the BCA handbooks and seeks further information on this recommendation.

- b. Non-NEM Eligible Technologies

The Solar Parties support developing an application of the VDER tariff for projects larger than 2 MW in Phase Two.

- c. Process for Developing Phase Two Tariffs

²³ Staff Report at 43

²⁴ Staff Report at 46

The Solar Parties will file comments on the process for developing Phase Two Tariffs in response to the Staff's Notice filed on November 18, 2016.

- **Section 3 – Evaluation of Phase One Impacts and Design²⁵**

Staff recommends the capacity size for each of the proposed four tranches be based on the results of an analysis of the impact on utility revenue requirements from MTC payments for CDG capacity in each tranche. Specifically, the Staff's proposed analysis estimates the maximum amount of CDG capacity that could be accommodated in each tranche such that the combined "net revenue impact" (as a percent of total revenues) from the total CDG capacity across all tranches and from new mass-market on-site capacity would not exceed 2%. For the purposes of this analysis, Staff defined net revenue impact as the difference between: (1) the reduction in utility revenues from CDG and mass-market exports (i.e., the product of the volumetric retail rate and energy injections into the grid); and (2) the reduction in utility costs from CDG and mass-market exports (i.e., the product of the full value stack, inclusive of DRV, and energy injections into the grid.)

The net revenue impact estimated in Staff's proposed analysis does not represent revenue losses to the utility, since any difference between revenues and costs would be recovered through either a decoupling rider or an increase in base rates. Nor does the net revenue impact represent the shift in revenue recovery from CDG participants to non-participants, since the net revenue impact would be recovered from all ratepayers in proportion to each ratepayer's energy usage.²⁶ Staff's analytical approach for estimating net revenue impacts is generally reasonable. However, a number of the study assumptions overstate the net revenue impact of MTC payments to CDG generation and thereby understate the amount of tranche capacity that could be accommodated under the revenue cap. These assumptions are discussed below.

²⁵ Staff Report at 48

²⁶ For example, if CDG subscribers represented 10% of retail sales, then 90% of the net revenue impact would be shifted to non-participants.

a. Analysis Overstates Allocation of MTC Costs to Residential Class

According to the Staff report, Staff recommends that MTC compensation to CDG subscribers be recovered from customer classes commensurate with those classes' CDG subscription rates:

MTC compensation will be recovered from the service class of the project subscribers for CDG projects, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class.²⁷

Staff's analysis assumes a residential subscription rate of 80%. However, contrary to its own recommendation regarding allocation of MTC compensation, Staff assumes for the purposes of its analysis that 100% of CDG MTC payments for Tranches 2 and 3 will be recovered from the residential class. This assumption overstates the likely impact on residential revenues from CDG MTC payments.

b. Analysis Fails to Account for Market Price Suppression

As noted above, Staff's analysis calculates net revenue impact as the difference between (1) the reduction in utility revenues from CDG and mass-market exports; and (2) the reduction in utility costs from CDG and mass-market exports. This approach overstates net revenue impact because it does not account for the reduction in utility costs recovered from non-participants due to market price suppression. To the extent that CDG and mass-market exports reduce wholesale energy and capacity prices, non-participants will benefit from lower rates and bills. Such price suppression-related rate reductions will serve to offset the recovery of net revenue impacts from non-participants and should therefore be treated as a reduction to net revenue impacts.

c. Recommended Tranche Sizes

Using Staff's model for deriving tranche sizes, the Solar Parties propose the following tranche sizes for each utility. The Solar Parties' recommended tranche sizes were derived assuming a 4% cumulative revenue impact limit, 100% MTC payment to CDG generation, 5% MTC step down, and 80% allocation of MTC compensation to the residential class (commensurate with the assumed 80% residential subscription rate). The rationale for the Solar Parties proposal has been laid out in the corresponding sections above.

²⁷ Staff Report, p. 24.

	<u>Tranche 0/1</u>	<u>Tranche 2</u>	<u>Tranche 3</u>	<u>Total</u>
O&R	86	34	41	161
CHG&E	154	60	73	287
NYSEG	742	328	486	1,555
RGE	298	129	184	612
NiMo	1,695	850	1,713	4,257
ConEd	2,511	1,222	2,261	5,993

CONCLUSION

The Staff report puts forth a promising framework for development of the solar market in New York State. However, the final Commission Order should adopt our recommendations to more fully value the contributions solar brings to the grid, ensure a more gradual transition from retail rate NEM, and ultimately build a stronger solar market in the Empire State. Our recommendations are put forth in the spirit of optimizing the proposed framework to ensure that New York achieves its solar goals. In summary, the Solar Parties recommend that the Commission:

1. **Expand the program to allow more customers to participate in community distributed generation.** The Staff report and recommendations seem to set two different allowable utility net revenue impact limits, one at 2% over the entire mechanism and one at 2% annually for the two years. The allowable utility net revenue impact should be set to the 2% annual, or 4% in total, that is stated in the report but not represented in the illustrative tranche sizes. This increase will lead to more valuable distributed energy resources being developed in the state and more customers having the opportunity to participate in the energy transition those resources are delivering for our electric grid.
2. **Allow more customers to reap significant economic benefits from their participation in community distributed generation.** The Staff report and recommendations will lead to a steep drop in value from retail rate net metering to the new value of distributed energy resources. This drop in value will limit project development and reduce customer

savings from the projects that do get built, thereby putting customers who cannot put solar on their own roof at a disadvantage as compared to those that can.

3. **Fully compensate commercial and industrial and remote net metered customers for their valuable distributed energy resources.** The Staff report and recommendations admit that some values brought to our state by distributed energy resources are hard or impossible to quantify at this time. To address this, they created the Market Transition Credit to accommodate those unquantified values and continue market growth. Specifically, the Market Transition Credit represents the value of distributed energy resources to the delivery of energy through our electric distribution and transition grids. However, for commercial and industrial and remote net metered customers, a highly variable and incomplete delivery value is used as compensation and no Market Transition Credit is provided. This delivery value should be made significantly more stable and predictable, and 100% Market Transition Credit application should be assumed for CDG projects to ensure that commercial and industrial and remote net metered projects continue to be developed and these customers are fairly compensated.

The Solar Parties would like to thank the Public Service Commission and Staff for their dedication to distributed energy resources, like solar, and their open and transparent process for creating new policies and regulations.

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