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Susan Vercheak*
Assistant General Counsel

December 5, 2016

Honorable Kathleen H. Burgess
Secretary
New York State
Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Burgess:

Enclosed are Comments of Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively the "Joint Utilities") in response to the *Notice Soliciting Comments on Staff Report and Recommendations*, issued on October 28, 2016 in the referenced proceeding.

If you have any questions, please contact me. Thank you.

Very truly yours,

Susan Vercheak

Enclosure

*Admitted only in New Jersey

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003 212 460 4333 212 677 5850 fax vercheaks@coned.com

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

COMMENTS OF THE JOINT UTILITIES ON THE STAFF REPORT AND RECOMMENDATIONS IN THE VALUE OF DISTRIBUTED ENERGY RESOURCES PROCEEDING

In response to the *Notice Soliciting Comments on Staff Report and Recommendations* in this proceeding,[1] Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), Orange and Rockland Utilities, Inc. ("O&R"), and Rochester Gas and Electric Corporation ("RG&E") (collectively the "Joint Utilities" or the "Utilities"), file these comments on the *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding* (the "Report"),[2] including Appendix C[3] and Revised Workpapers.[4]

The Joint Utilities support the New York Public Service Commission's (the "Commission") efforts to foster an increasingly clean energy system that promotes customer choice and enhances customer engagement in efficient energy use, as appropriately balanced with impacts on customers. The Utilities have demonstrated their support for these goals in

1 Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources ("Value of DER Proceeding"), Notice Soliciting Comments on Staff Report and Recommendations (issued October 28, 2016).

2 Value of DER Proceeding, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding ("Report") (filed October 27, 2016). The Joint Utilities also examined the spreadsheets underlying the Report which are unnumbered.

3 Value of DER Proceeding, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, Appendix C ("Appendix C")(filed October 28, 2016, revised November 30, 2016).

4 Value of DER Proceeding, Letter to Secretary Burgess from Ted Kelly, New York State Department of Public Service Staff (filed November 30, 2016) with attached revised workpapers related to the Report ("Revised Workpapers").

many ways, including their work with key solar developers via the Solar Progress Partnership[5] and the significant stakeholder outreach that shaped each utility's Distributed System Implementation Plan ("DSIP") and the jointly-filed Supplemental DSIP in the Reforming the Energy Vision ("REV") proceeding.[6] The expansion of customer choice and the growth of distributed energy resources ("DER") may provide many benefits to utilities and customers, from reducing greenhouse gas emissions to providing targeted load relief in constrained areas. However, not all DER provide the same benefits. It is essential for the State to develop a policy that will set the stage for future economically-efficient development of these resources, and to be able to differentiate the value of differing DER characteristics.

Current policies have made progress toward the State's objective of encouraging DER, but have not yet been transformed to enable differentiation among DER attributes and values. This is the objective of the current proceeding, including adoption of a transition plan that is fair to all customers as well as understanding and addressing implementation concerns of utilities and DER providers. It is important to recognize the impacts of policies adopted thus far. Current policies designed to encourage distributed solar photovoltaic ("PV") energy in New York already cost utility customers $41 million in utility bill increases and another $217 million in other costs each year.[7] If all resources currently in the Utilities'

[5] Value of DER Proceeding, Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering (filed April 18, 2016).

[6] E.g., Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Supplemental Distributed System Implementation Plan (filed November 1, 2016); see also, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Proceeding"), Con Edison Distributed System Implementation Plan (DSIP)(filed June 30, 2016); see also, REV Proceeding, Response by the Joint Utilities to the Order Adopting Distributed System Implementation Plan Guidance (filed May 2, 2016).

[7] This includes annual bill increases of $41 million associated with existing NEM generation from Table 3 below, plus additional annual spending of $82 million in Customer-Sited Tier funding, $45 million from Regional Greenhouse Gas Initiative ("RGGI") funds, and $91 million in property tax incentives. Through 2015, the State has expended $395 million provided by the customers of investor-owned utilities to support customer-sited resources (all of which are eligible for net metering) under the Customer-Sited Tier of the Renewable Portfolio Standard ("RPS") program; $353 million of the total expended amount was provided to PV systems. The New York State Energy Research and Development Authority ("NYSERDA") also administers programs

interconnection queues are built, these policies will add an additional $250 million of costs will be embedded in utility rates, without any differentiation or acknowledgment of the differing time-based, locational, and operational values that various resources can provide. The purpose of this proceeding is to modify one such policy, net energy metering ("NEM"), in order to better align DER compensation with the value it provides to the electric power system and mitigate customer bill increases.

The time is ripe to find an alternative to NEM. While the policy served its purpose in early years when solar installation costs were high and significant incentives were needed to develop the nascent distributed solar market, the solar market is no longer nascent. Numerous factors have since changed and many states, including New York, are reconsidering NEM.[8]

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for New York Power Authority ("NYPA") customers and in the PSEG-Long Island territory for Long Island Power Authority ("LIPA") customers who are funded using RGGI auction proceeds. Through March 2016, NYSERDA has spent an additional $57 million on solar incentives for NYPA and LIPA customers. Solar resources also receive subsidies in the form of property tax exemptions, sales tax exemptions, and the avoidance of sales taxes and gross receipts taxes that result from reduced utility bill amounts. *See* NYSERDA, *New York State Renewable Portfolio Standard Annual Performance Report through December 31, 2015*, p. D-1; *see also* NYSERDA, *New York's Regional Greenhouse Gas Initiative-Funded Programs Status Report Quarter Ending March 31, 2016*, p. 5. Estimating the value of avoided property taxes is challenging due to the varying property tax rates assessed throughout the state, and the uncertainty of the assessed value of the solar resources installed. Assuming an annual property tax rate of five percent, and an assessed value of solar of $1.8 billion (per the NY-Sun 2015 annual report stating 457 MW installed through the end of 2015, at an average installed cost of $4/watt), the property tax benefit can be estimated as $91 million annually.

[8] *E.g.*, in 2015 Nevada implemented a new solar tariff structure, once the state's net metering cap was reached, that reduced the compensation rate for exports to the grid from retail rate to the avoided cost rate with a grandfathering provision for residential customers who applied for systems before 2016. In 2015 Hawaii, while grandfathering existing NEM customers, all new NEM customers after October 12, 2015 are required to choose between a grid-supply and self-supply option. The grid supply option compensates customers at the reduced wholesale rate for excess electricity exported to the grid. Self-supply customers are not allowed to export (but may employ energy storage devices) with residential customers required to pay a minimum bill of $25/month and commercial customers required to pay a minimum bill of $50/month. In 2013 Arizona established a monthly charge for new rooftop solar panel installations connected to the grid through NEM (a basic service charge of $15 was recently approved in one utility's rate case) and in 2016 Arizona created an alternative to NEM called the renewable portfolio supply credit for solar exports. The credit is separated into a series of decreasing tranches, beginning at $0.11/KWh for the first tranche. New solar customers can lock in a 20-year contract at the going credit rate. A decision on mandatory charges for solar customers was postponed until the ongoing Value of Solar docket concludes. In Maine, a proposed new rule would change net metering compensation from the current rule where customer-generators are given a credit equal to the full retail rate of electricity to a rule that would gradually reduce the portion of the bill that a customer-generator is able to net against. Existing installations would be grandfathered under the current net metering rule for 15 years. New Installations would be allowed to net against 90 percent of the T&D portion of their bill in 2017, 80 percent in

Many studies, including an analysis by E3 Consulting for the Commission, as discussed in greater detail below, have found that NEM over-compensates DER in most cases, and perhaps undervalues in certain instances, compared to the value it provides. On the whole, the policy may result in increased costs to customers without commensurate benefits. These issues are exacerbated by the Commission's establishment of a Community Distributed Generation ("CDG") program, because these projects can be constructed at roughly half the cost of traditional rooftop solar,[9] yet receive the same level of compensation. This policy has created the opportunity for lucrative profits for developers, which is demonstrated by the more than 4,000 MW of interconnection applications filed in the six months following the start of the CDG program. As discussed in greater detail below, using New York-specific cost data from the U.S. Department of Energy's National Renewable Energy Laboratories, the Utilities estimate that developers will realize 90-95 percent gross profit margins in some areas of the State if this policy is not changed. Ultimately, customers bear these costs. A better solution is a fair result that encouragves technology development, provides appropriate compensation, encourages a DER market for third parties, and provides utilities an opportunity to manage costs and meet customer expectations for affordable, reliable, and clean energy.

The Report seeks to achieve these ends, and includes elements that will begin to replace NEM's imprecise valuation of DER with a more granular, value-based compensation mechanism. If enhanced along the lines discussed in these comments, the Report's framework has the potential to protect customers from paying increasing utility bills without

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2018, and the netting reduction would continue annually until 2026 when the customer would no longer be able to net against any portion of the T&D bill.

[9] IHS Consulting, *The Price of Solar* (April 21, 2016), https://technology.ihs.com/577318/the-price-of-solar-April-2016

receiving commensurate, quantifiable benefits. The Joint Utilities support the Report's goals of limiting annual bill impacts to two percent as calculated and discussed herein,[10] compensating DER based on the benefits it provides,[11] and providing a fair and appropriate transition to more sustainable compensation levels using a modified tranche structure.[12]

While it seeks to advance these shared objectives, the Report raises significant concerns due to inexact data and assumptions that result in levels of DER growth that cannot be sustained within a two percent customer bill impact. Without correction of faulty assumptions, the Report's recommendations would result in annual total bill increases of up to 25 percent in some utility service territories and unprecedented DER penetration levels, reaching nearly three times more than one utility's peak demand. Such an outcome is untenable, unrealistic, and harmful to all customers. In addition, the Report would provide compensation to all projects, irrespective of whether the project attributes are valuable to deferring generation or distribution system investments. Finally, the Report's approach would lock in these DER payments in some cases at levels greater than the current NEM construct[13] for 20 years, thereby shifting significant risks and costs to electric customers for decades to come.

Several key changes to the Report's framework can avoid these undesirable outcomes:

- In connection with the "hard" two percent cap on customer bills, simultaneously establish a clear circuit breaker mechanism that monitors actual bill increases on a quarterly basis and will initiate immediate and

[10] Value of DER Proceeding, Report, p. 25.
[11] *Id.*, p. 4.
[12] *Id.*, p. 8.
[13] *E.g.*, Public Service Law, Section 66-j. Most recently, the Commission ordered that the NEM cap be "floated." *See* Case 15-E-0407, Floating Cap Order, *infra* n. 15

predetermined actions if that cap is projected to be reached;[14] Update existing data with more accurate information to create a transition formula that will better approximate and limit incremental customer bill increases;

- Step down DER compensation levels in even increments over five tranches instead of three, and re-balance the available budget evenly over each tranche so that more resources can be built for the same customer dollars;
- Require that a portion of the Market Transition Credit ("MTC") be performance-based to encourage DER to align their output with electric distribution system needs;
- Shorten the period over which the MTC is paid to 10 years, with a proxy for distribution benefits set for 5 years, to limit the long-term shifting of risk from developers to customers; and
- Avoid increasing compensation above current NEM rates unless the DER's value to the electric system warrants such compensation.

The Utilities appreciate the opportunity to offer these comments.

I. Background

The basis for this proceeding is found in the Commission's October 16, 2015 *Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation* (the

[14] The Joint Utilities note that the Report's approach to calculating bill impacts is imprecise, as it equates a percentage of total revenue to a percentage of the customer bill. In reality, these impacts require much more careful analysis that takes retail access issues and other cost recovery approaches into account. Ultimately, actual bill increases must be monitored to avoid a divergence between modeled expectations and actual experience. Although the Joint Utilities agree with the Report's proposal to place a limit on NEM compensation and subscription to limit certain bill impacts to two percent, any actual costs associated with NEM and its successor should be fully recoverable by the Utilities consistent with long-standing Commission policy in the event that the circuit breaker does not adequately work to prevent Utility costs for DER above the cap.

"Floating Cap Order").[15] There the Commission directed that net metering limitations should "float" until completion of a proceeding to develop an interim method of evaluating the benefits of distributed energy resources.[16] The Joint Utilities petitioned for rehearing of the Floating Cap Order, expressing concern that an unlimited number of resources could materialize absent a cap, leading to unanticipated and unbounded bill increases for customers.[17] The Commission has not yet acted upon that rehearing request. Following the issuance of the Floating Cap Order and the launch of the CDG program,[18] the Joint Utilities experienced a surge in new applications for net metered resources, ultimately leading to more than 4,000 MW of interconnection applications.[19]

The Commission instituted the Value of DER proceeding[20] in response to the decision to float the net metering cap and the promise to adopt a "new regulatory approach" for DER valuation.[21] Under Administrative Law Judge Sean Mullany, a conference was held on January 7, 2016, and interested parties filed proposals on April 18, 2016 responding to questions posed by the Department of Public Service Staff ("Staff"). Among the twenty-two (22) filings were those of the Joint Utilities[22] as well as a proposal filed by the Solar Progress

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[15] Case 15-E-0407, Orange and Rockland Utilities, Inc. – Petition for Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law Sec.66-j ("O&R Net Metering Petition"), Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation ("Floating Cap Order") (issued October 16, 2015), Petition of Orange and Rockland Utilities, Inc., Consolidated Edison Company of New York, Inc., Central Hudson Gas & Electric, Niagara Mohawk Power Corporation d/b/a/ National Grid, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation for Rehearing ("Rehearing Petition")(filed November 16, 2015)(pending).
[16] O&R Net Metering Petition, Floating Cap Order, pp. 13-15.
[17] O&R Net Metering Petition, Rehearing Petition.
[18] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and conditions for implementing a Community Net Metering Program ("CDG Proceeding"), Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) ("CDG Order").
[19] Value of DER Proceeding, Joint Utilities Response to Staff Information Request DPS-4 (dated August 18, 2016).
[20] Value of DER Proceeding, Notice Soliciting Comments and Proposal on an Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015).
[21] O&R Net Metering Petition, Floating Cap Order, pp. 14-15.
[22] Value of DER Proceeding, Comments of the Joint Utilities on an Interim Successor to Net Energy Metering (filed April 18, 2016).

Partnership[23] (a filing of the Joint Utilities, SolarCity, Inc., SunEdison, Inc., and SunPower, Inc.).

On May 25, 2016 Judge Mullany issued a *Procedural Ruling* establishing an "informal and collaborative" process for the proceeding.[24] Thereafter, a series of collaborative conferences were held,[25] and Staff issued a Draft Straw Proposal.[26] Collaborative discussions followed, including a presentation by the Solar Progress Partnership on its proposal.[27] Most recently, as noted above, the Report was issued for comment followed by a technical conference on November 28, 2016.[28]

II. Net Energy Metering Must Be Reformed

Many states, including Nevada, Arizona, Hawaii, and Maine, have undertaken efforts to evaluate and modify NEM policies following significant bill impacts for non-participating customers. [29] Recent studies continue to find that NEM over-compensates DER for the benefits provided in most cases, although benefits may be higher, even possibly above NEM compensation, in some situations. Generally, this has resulted in increased costs to customers without commensurate benefits.[30] The recent paper, by Dr. Susan F. Tierney of the Analysis Group, Inc.,[31] supports this finding, as does work by Ashley Brown and Jillian

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[23] Value of DER Proceeding, Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering (filed April 18, 2016).
[24] During the May 10, 2016 Technical Conference, the parties were invited to respond to the suggestion of following this approach.
[25] Conferences were held on June 14, July 6 and 19, August 4, 10, and 29, September 7, and October 7, 2016.
[26] Value of DER Proceeding, Staff Straw – DRAFT, Estimates of the "Value Stack" for DER – Case 15-E-0751 (issued September 23, 2016).
[27] Value of DER Proceeding, Solar Progress Partnership Comments on Staff Straw (dated September 7, 2016).
[28] Value of DER Proceeding, Notice Scheduling Technical Conference (issued November 7, 2016).
[29] See status of evolving NEM policies in Nevada and other states, *supra*, n.8.
[30] *See*, *e.g*., Energy & Environmental Economics, The Benefits and Costs of Net Metering in New York, Prepared for NYSERDA and NYPSC ("E3 NEM Benefit-Cost Study") (December 11, 2015) available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0703&submit=Search+by+Case+Number
[31] Tierney, Susan F., The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability (March 31, 2016), p. xviii.

Bunyan of Harvard University,[32] the University of Cambridge Energy Policy Research Group,[33] and the Energy Institute of Massachusetts Institute of Technology ("MIT").[34]

A key finding in these and other studies is that the time-based performance of DER and their location on the electric system is critically important to valuation. One of the most critical flaws of NEM is that it compensates all eligible distributed generation at the same rate, regardless of when or where the power is generated, providing no incentives for DER owners or developers to propose projects that better support system needs. The Electric Power Research Institute ("EPRI") recently examined the value of DER to the electric distribution systems of Southern California Edison and Con Edison.[35] In network systems, EPRI found that the value of a DER in resolving a network need is highly contingent on the DER's electrical proximity to the network component need, and that little value is realized for resources that are not properly located.[36]

Regulators in both Europe and the United States have found this academic consensus persuasive, and are taking steps to reform NEM. In Europe, regulators are examining how to provide the appropriate price signals to DER owners and developers to better align their production with system value. In a recent position paper on renewable self-generation,[37] the Council of European Energy Regulators ("CEER") found that net metering should be

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[32] Brown, Ashley and Bunyan, Jillian, *Valuation of Distributed Solar: A Qualitative View*, Elsevier, Inc. (December 2014), available at http://www.ksg.harvard.edu/hepg/Papers/2014/12.14/Brown%20%20Valuation%20of%20%20Distributed%20Solar%20%2011.14.pdf

[33] Value of DER Proceeding, Public Comments by Pollitt, Michael. University of Cambridge Energy Policy Research Group. Electricity Network Charging for Flexibility (Report dated September 2016 and filed November 16, 2016).

[34] Massachusetts Institute of Technology Energy Institute, *The Future of Solar Energy* (May 2015) available at. http://energy.mit.edu/publication/future-solar-energy/

[35] Electric Power Research Institute ("EPRI"), *Time and Locational Value of DER, Methods and Applications* (Technical Update October 2016)(3002008410).

[36] *Id*., pp. 7-4 to 7-7.

[37] CEER Position Paper on Renewable Energy Self-Generation (September 2016), available at http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-SDE-55-03_Renewable%20Self-Consumption_PP.pdf

avoided because it does not enhance market design and cross-subsidies between self-generators and other consumers should be avoided. CEER also cautioned against net metering because adoption of self-generation should be based on efficiency and market principles and stated that network tariffs must reflect the value of the network – both costs and benefits – irrespective of whether the customer self-generates or not, because all consumers should face relevant price signals. CEER also noted that self-generators must recognize cost-reflective network tariffs in the same manner as consumers who do not self-generate.

In the United States, New York is striving to reform NEM and DER compensation by creating price signals that encourage efficient DER development and supports the electricity system as a whole as well as locational needs. Other states are also considering changes. In fact, the National Association of Regulatory Utility Commissioners ("NARUC") recently published a manual that considers the costs and benefits of DER and their impact on the utility grid, appropriate rate designs, and compensation policies.[38] The manual discusses the cross-subsidization of NEM participants by non-participants.[39] The manual finds that increased penetration of DER can affect cost recovery of a utility's assets with little, if any, reduction of the costs of the system in the near term and, in fact, that DER may increase operational costs for the utility, given the intermittency and lack of visibility of DER.[40]

The forthcoming comprehensive study conducted by MIT, *The Utility of the Future*,[41] will shed further light on ways that DER may be appropriately valued and integrated into the

[38] *Distributed Energy Resources Rate Design and Compensation*, A Manual Prepared by the NARUC Staff Subcommittee on Rate Design (November 2016), available at http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0
[39] *Id*., pp. 130-131.
[40] *Id*., pp. 66, 68, 80.
[41] Further information on the MIT study can be found at http://energy.mit.edu/research/utility-future-study. The study will officially be presented in Washington, D.C. on December 15, 2016.

power system. The Joint Utilities encourage the Commission and Staff to review and utilize these significant studies in determining the value of DER in New York.

III. The Report Makes Important Progress Toward Value-Based DER Compensation, But If Left As Is, Would Increase Customer Bills By As Much As 25 Percent, or $505 Million Statewide Each Year

The Report takes a significant step to reform NEM, including adoption of a compensation mechanism based on time-varying energy values (locational-based marginal price of energy ("LMP")), capacity values ("ICAP"), and environmental ("E") values. The Report also adopts a tranche-based approach that would step down CDG compensation over time to provide a gradual transition for these resources. Most importantly, the Report proposes to cap incremental customer bill increases at two percent for the transition period. In its calculations, the Report adopts a "snapshot approach" to establish a baseline compensation level for comparison, which the Utilities support. While these elements are positive, the Report makes a number of key assumptions and utilizes inexact data that dramatically understate the bill impacts that will occur should the quantity of resources proposed by the Report be compensated at the Report's proposed rates.

The issues identified by the Joint Utilities in their analysis of the Report's proposed rate-setting and tranche-sizing formulas are significant, and include both indisputable errors of fact (*e.g.*, the Report overstates customer class revenues by an order of magnitude in some cases) and certain methodologies that can be improved to better reflect actual costs to customers (*e.g.*, calculating capacity values) in an effort to better estimate the impact of such policies, and to right-size the transition. To reinforce the need for these changes, the Report's conclusions result in technically infeasible outcomes,[42] including more than 8,000 MW of new DER appearing on NYSEG's system, which equates to more than two-and-a-

[42] The Joint Utilities address this issue in further detail in Section IV of these comments.

half times the utility's annual peak demand of 3,190 MW.[43] Staff corrected several of these issues in a November 30, 2016 update of the Report's spreadsheets,[44] including:

- The Report used an estimated value for a Renewable Energy Credit ("REC"), which was subsequently valued by the New York State Energy Research and Development Authority ("NYSERDA") at $21.16/MWh for 2017.[45] The Report also increased the value of a REC by an adjustment factor for losses that does not align with the approach adopted in the Clean Energy Standard Proceeding[46] and was appropriately removed;
- The Report included an additional "0.8" factor in its tranche sizing calculation, which was appropriately removed.

While these changes address certain issues, further issues remain. As part of their analysis, the Joint Utilities corrected and adjusted certain figures in an effort to provide their best estimate of actual customer bill impacts. Several key drivers lead to the large difference between the projected bill impacts set out in the Report and the bill impacts the Utilities expect would result if the Report's proposed MW levels were realized:

- The Report's avoided cost of distribution investment is calculated by using the wholesale system peak coincidence, instead of distribution system peak coincidence. The Utilities support Staff's stated intent to update these

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[43] *See* http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Announcements/Info_and_Announcements/Info_and_Announcements/2016_ICAP_Final.pdf

[44] Value of DER Proceeding, Revised Workpapers.

[45] NYSERDA sent e-mails to all New York Load Serving Entities on November 2, 2016 establishing the 2017 REC price at $21.16.

[46] Cases 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* ("CES Proceeding"), Order Adopting a Clean Energy Standard (issued August 1, 2016) ("CES Order).

estimates with the appropriate granular local peak demand data.[47] For example, the network where the majority of CDG proposals in Con Edison's service territory have proposed to locate generally experiences its peak usage at night, and solar was operational for only three of its top ten peak hours at very low-output levels. Using the granular data changes the distribution value of that resource from two cents to less than one tenth of one cent per kWh and avoids significant overcompensation;

- The Report's approach to compensating DER for capacity creates a mismatch between actual costs incurred to procure capacity for customers and the compensation provided to DER for that capacity. The Report uses the service class capacity value as the DER compensation rate. A more equitable way to determine the ICAP value of a CDG project is to determine the average amount of solar kW output at time of the NYISO peaks for the last five (2011-2015) capacity years. This coincidence value would then be multiplied by the applicable monthly auction prices and divided by E3 Consulting's forecasted annual solar kWh production[48] to determine the volumetric (per kWh) rate that would be paid to CDG projects. This results in an ICAP value for CDG projects that is about one third less than the Report's assumption. As opposed to using the service class ICAP rate, this method more closely approximates the installed capacity benefits of the DER production;

[47] Staff indicated at the November 28, 2016 Technical Conference that these revisions would be necessary.
[48] *See* E3 Consulting's annual hourly solar production estimates ("E3 Consulting Solar Report") published in this proceeding at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={183B4FF4-58D0-4A96-8067-A2AC1C2C12B6}

- The Report uses revenue data from the U.S. Department of Energy's Energy Information Administration that reflects all residential customer classes and all commercial customer classes, but inappropriately e uses these numbers for single-family and small multi-family residential ("SC-1") and small commercial ("SC-2")49 customer class revenues. This results in certain revenue assumptions to be incorrect by an order of magnitude. For the purposes of this analysis, the Utilities have corrected this by multiplying the total kWh delivered by service class (using a three-year average) by the retail rate components, including energy, capacity, and delivery;
- The Report uses different solar capacity factors in different calculations. Using the E3 Consulting solar output estimates[50] as a consistent data set for each utility makes expected kilowatt-hour ("kWh") output per MW installed more accurate;
- The Report's approach to compensating CDG projects for energy plus an adjustment for line losses assumes every CDG project will avoid these losses. In reality, the benefits or costs will be project specific based on the project location and the facilities used to inject the supply into the grid. In fact, depending on the voltage level for interconnection, CDG systems may not reduce primary or secondary distribution losses and may lead to increased losses. Finally, the Utilities recommend the Commission consider the need for studies to understand how losses at levels of the system are impacted with increased use of distributed generation, especially CDG. Therefore, the Joint

[49] Small commercial customers in NYSEG's service territory receive service under NYSEG's Service Class 6.
[50] E3 Consulting Solar Report.

Utilities propose that the line loss adjustment be reconsidered, and that a lower adjustment be provided that reflects that most projects will not achieve the same line loss benefit as behind-the-meter resources. The Joint Utilities also suggest that the value be adjusted prospectively on a periodic basis within some defined parameters; and

- The Utilities could not replicate the Report's Value Stack energy values using the E3 Consulting solar output shapes and NYISO Day Ahead LBMP values for certain utilities. These were corrected.

The Joint Utilities made each of the corrections above for each utility to calculate expected customer bill increases, as shown in Tables 1 and 2, below:

Table 1: Incremental Annual Residential Customer Bill Increase Projected at the Report's Proposed Solar Compensation Rate and Megawatts ("MW") of Solar Installed
(Showing the Report's Projections and Actual Projections Based on Adjusted Formula Estimates and Data Corrections)
(in total U.S. dollars ($))

Utility	Report's Projected Increases	Expected Increases (Mass Market Solar Exports Only)	Expected Increases (All Mass Market Solar Generation)
Central Hudson	$6,746,318	$7,871,197	$9,686,178
Con Edison	$66,881,400	$291,557,691	$297,224,654
National Grid	$28,065,864	$42,717,517	$44,669,481
NYSEG	$14,151,912	$110,592,179	$111,856,263
O&R	$5,398,574	$10,126,517	$13,814,210
RG&E	$6,163,140	$16,461,350	$16,681,773
Statewide Total	$129,681,853	$487,171,362	$498,310,201

Table 2: Incremental Annual Residential Customer Bill Increase Projected at the Report's Proposed Solar Compensation Rate and Megawatts ("MW") of Solar Installed (Showing the Report's Projections and Actual Projections Based on Adjusted Formula Estimates and Data Corrections) (in percentage of volumetric charges (%))			
Utility	**Report's Projected Increases**	**Expected Increases (Mass Market Solar Exports Only)**	**Expected Increases (All Mass Market Solar Generation)**
Central Hudson	2.00%	2.77%	3.41%
Con Edison	2.00%	11.06%	11.28%
National Grid[51]	2.00%	3.28%	3.43%
NYSEG	2.00%	24.4%	24.6%
O&R	2.00%	3.59%	4.9%
RG&E	2.00%	6.77%	6.86%

The fourth column in the above tables, "Expected Increases – All Mass Market Solar Generation," shows even larger bill impacts that should be considered when viewing distributed solar technology holistically. A key assumption of the Report is that only solar *exports* cause bill increases to utility customers. In reality, all solar generation causes bill increases to utility customers. Because current rates are designed to collect fixed costs on a primarily volumetric basis, even energy efficiency measures cause these shifts. The impact associated with residential solar generation is particularly problematic, however, because it can dramatically alter consumption patterns and solar customers' utility bills without reducing or avoiding the costs incurred to provide reliable service. This leads to a mismatch between customers' use of the energy grid and their contribution toward its upkeep. Unlike

[51] National Grid's bill increase calculation includes an estimated value of D that is based on solar PV coincidence with the top ten load hours for the National Grid service territory as a whole, and therefore reflects a lower bound. A more location-specific and granular analysis may likely result in a lower value of D and a higher bill increase due to later peak hours and lower coincidence with solar PV output.

customer energy efficiency investments which incrementally reduce consumption whenever a new appliance or light bulb is used, solar generation DER customers continue to rely on the grid at night, and for multiple services during the day, including balancing minute-to-minute fluctuations in solar output, power quality services, start-up power needed to run many appliances, and export capability.

While the Report focuses on the bill impact for incremental installations only, a more complete view should recognize the impacts of all solar incentives built into customer rates. Table 3 below calculates the total bill increases that the Utilities expect will occur as a result of existing and the large amount of incremental solar installations envisioned under the Report. As discussed elsewhere, the Utilities support the Report's use of a two percent cap on incremental bill impacts, but seek to show here that the proposal does not meet the stated goal and must be adjusted to do so.

Table 3: Annual Bill Increases Expected at the Report's Proposed Solar Compensation Rate and Megawatts ("MW") of Solar Installed; Including Impacts of Existing Installations ($)

Utility	Bill Increases Resulting from Existing Net Metered Resources[52]	Expected Incremental Increases (Including Mass Market)[53]	Total Bill Increases[54]
Central Hudson	$3,803,809	$9,686,178	$13,489,987
Con Edison	$14,560,700	$297,224,654	$311,785,354
National Grid	$11,490,000	$44,669,481	$56,159,481
NYSEG	$4,597,573	$111,856,263	$116,453,836

[52] Annual bill increases resulting from existing NEM resources.
[53] Expected bill increases from Table 1.
[54] Sum of Columns 2 and 3.

O&R	$5,287,824	$13,814,210	$19,102,034
RG&E	$1,184,444	$16,681,773	$17,866,217
Statewide	$40,924,350	$495,442,638	$536,366,989

Correcting each of these issues results in significantly smaller tranche sizes than the Report indicates in order to limit bill increases to two percent, as shown in Table 3 below.

Table 4: Adjusted Tranche Sizes Following Corrections to the Report's Assumptions (MW)

Utility	Tranche 0 and 1	Tranche 2	Tranche 3
Central Hudson			
Report	68	32	55
Adjusted (Mass Market Solar Exports Only)	52	24	41
Adjusted (All Mass Market Solar Generation)	37	17	29
Con Edison			
Report	1,241	2,229	n/a
Adjusted (Mass Market Solar Exports Only)	297	254	n/a
Adjusted (All Mass Market Solar Generation)	275	235	n/a
National Grid			
Report	827	1,671	n/a
Adjusted (Mass Market Solar Exports Only)	712	1,275	n/a
Adjusted (All Mass Market Solar Generation)	670	1,201	n/a
NYSEG			
Report	360	236	7,202
Adjusted (Mass Market Solar Exports Only)	158	82	185
Adjusted (All Mass Market Solar Generation)	140	73	164
O&R			
Report	34	16	28
Adjusted (Mass Market Solar Exports Only)	16	7	9
Adjusted (All Mass MarketSolar Generation)	0	0	0
RG&E			
Report	148	91	598
Adjusted (Mass Market Solar Exports Only)	99	52	139
Adjusted (All Mass Market Solar Generation)	93	51	135
Statewide			

Report	2,678	4,275	7,883
Adjusted (Mass Market Solar Exports Only)	1,334	1,694	374
Adjusted (All Mass Market Solar Generation)	1,215	1,577	328

Several of these issues warrant further discussion. The first issue relates to wholesale ICAP payments and value. The Report's proposed volumetric usage-based ICAP credit will fail to reward projects that can reduce peak demand, and will increase customer bills without any commensurate benefit. The Joint Utilities propose using an actual ICAP valuation that will encourage peak demand reduction, such as by opting for a west-facing solar configuration or installing a battery. Furthermore, without a change, there will be a lag of up to two years before any capacity benefits are realized by customers because the NYISO re-sets capacity obligations only once annually.

To implement the proposal discussed above, the Joint Utilities propose to provide CDG projects with credits when they go into service based on expected production coincident with the NYISO's peak demand until actual production data becomes available. Alternatively, each utility could create a separate service class for its CDG projects to determine capacity credits based on the aggregate performance of all in service CDG projects. While either of these options would more accurately match capacity payments made to CDG projects with the benefits they provide, both reflect a compromise that would help provide financing certainty to CDG projects, but fall short of creating a performance-based price signal that would incent CDG projects to maximally benefit the system. Achieving this goal should be a key focus of the Phase Two[55] efforts under this proceeding.

[55] Value of DER Proceeding, Notice Soliciting Comments on Scope and Process for Phase Two of Value of Distributed Energy Resources (issued November 18, 2016).

A second issue relates to cost recovery of energy and ICAP payments, which should be recovered on the supply side of the bill instead of being included as part of the energy delivery charge. The Joint Utilities are currently participating in stakeholder discussions with the NYISO as part of its proposed DER Roadmap initiative that may ultimately expand the participation of DER in wholesale markets, allowing the energy from these projects to become an electricity supply resource, as opposed to a load modifier.[56]

The third issue relates to the value of DER to the distribution system. As discussed above, the Report uses NYISO wholesale system peak coincidence as an estimate for distribution coincidence. An alternative is suggested. By including this avoided cost in the MTC value, the Report provides some compensation for system-wide distribution value, as well as other undefined values. In addition to this measure, the Report recommends a longer-term effort for utilities to provide price signals to developers to encourage resources to choose higher-value locations on the distribution system, such as those nearing the need for infrastructure reinforcement. The Joint Utilities support the development of location-based compensation and will continue to identify targeted areas where technologies providing demand reduction may provide greater system benefit. Non-Wires Alternative ("NWA") projects ongoing in each of the Utilities' service territories under REV, including Con Edison's Brooklyn-Queens Demand Management ("BQDM") program[57] are examples of these efforts.

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[56] The NYISO draft DER Roadmap is available at http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/DRAFT%20Distributed%20Energy%20Resources%20Roadmap%20-NYISO%208-17.pdf ("NYISO DER Roadmap").

[57] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

To promote this further and include these incentives in the Value of DER compensation mechanism, the Report recommends that utilities increase locational granularity by de-averaging future updates to each utility's Marginal Cost of Service ("MCOS") studies to reflect the separation of high-value areas.[58] The Report envisions that these values would then be utilized to apply an incremental per kW-year compensation for projects within higher-value locations. By definition, however, any de-averaging to provide an incremental Locational System Relief Value ("LSRV") to CDG projects within specific locations must also be paired with a corresponding decrease in value to projects outside of the targeted areas. The reduction in value for projects in a non-valuable location is necessary to maintain an average system-wide value based on each utility's MCOS study.

In order to accommodate this change to the Report, the Joint Utilities propose that both positive and negative LSRVs be developed based on the identification of high-value locations. The LSRV would be an additional value or a reduction in value on top of the MTC compensation for all projects based on the location of the project and the corresponding distribution benefit detailed within each utility's MCOS. This methodology would provide the appropriate price signal to projects within high-value areas while appropriately limiting the near term customer bill impacts associated with LSRV payments.

Fourth, it is important to note that the Report assumes that DER distribution value will result in near-term avoided costs for utility customers. Due to the long lead time required to plan and install distribution infrastructure, however, these benefits, if they do materialize, will phase in over time. While the Utilities did not calculate these effects in their bill impacts analysis, this assumption will nonetheless contribute to reducing the near-term

[58] Value of DER Proceeding, Report, p. 37.

avoided costs associated with DER and therefore to larger near-term bill increases without commensurate benefits.

Finally, to resolve the understating or overstating of actual energy and capacity market prices caused by using the "snapshot" of current retail rates which includes utility hedges, the Joint Utilities suggest using the same values for energy and capacity in both the retail rate and the value stack calculations. Otherwise, if the service class supply price less capacity is used as the energy rate, the resulting MTC will be over- or under- stated based on the performance of the hedge. Hedges are designed to reduce overall price volatility, not to reduce or increase prices.

IV. Tranches Should Be Redesigned to Reduce Unnecessarily High Compensation and Allow More Projects to Be Built for the Same Customer Dollars

a. Tranche Structure

The Joint Utilities recognize that the adjustments discussed above have the effect of reducing the quantity of CDG that can be built in the State if a true two percent incremental bill impact limit is retained. Modifications to the Report's proposed tranche structure would help to offset these reductions. As it stands, the Report's proposal to allocate the majority of budget dollars to the first tranche of a three-tranche structure unnecessarily constrains the number of MW of CDG that can be installed and does not make the best use of valuable customer dollars. The Joint Utilities recommend two changes in that regard.

First, adding two tranches, for a total of five tranches, would provide a more gradual step-down in compensation and would help to stem the overcompensation of resources in the first tranche, as discussed in more detail below. The second recommendation is to allocate the budget dollars evenly across all tranches, or even to allocate more dollars to later tranches, rather than concentrating 60 percent of the budget in the most expensive tranche.

Together, these recommendations would increase the number of projects and customer benefits that can be realized for the same amount of customer dollars. Finally, the Joint Utilities recommend establishing an upper limit on the total MW of CDG that can be installed under Phase One that would recognize operational limits and allow room for industry development following the conclusion of Phase One, while providing a clear signal that there is still significant statewide opportunity for CDG development.

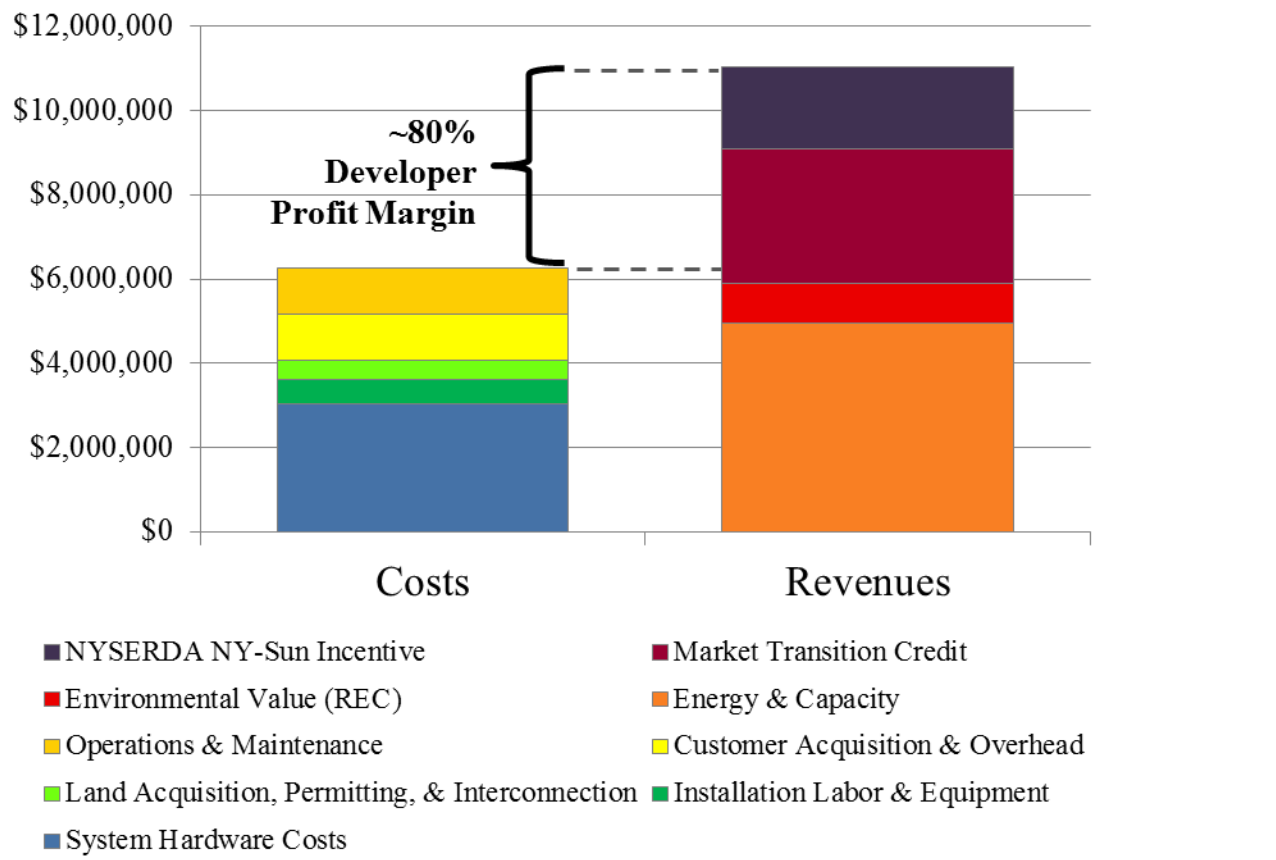
In communicating this significant opportunity, the Report should acknowledge that solar costs have declined 51 percent since 2009 and are projected to decline even further over the coming years.[59] Research by IHS[60] has demonstrated that CDG projects may be 50 percent less expensive to install than traditional rooftop solar.

b. Generous Compensation Is Unnecessary to Meet Policy Objectives

Using New York specific data from the National Renewable Energy Laboratories, the Utilities estimated profit margins for a 2 MW CDG project under a Tranche 1 compensation structure, as shown below. These calculations do not account for additional revenues that would be generated by the sale of federal investment tax credits, which would further increase project-level profit margins. Project revenues under full NEM are even higher than presented here,[61] leading to profit margins exceeding 90 percent. The extraordinary profit opportunity sheds light on the market dynamics that have led to an interconnection queue of more than 4,000 MW of CDG projects in the State.

[59] NYSERDA Solar Installation and Data Tools, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Solar-Data, filtered for 2009 and 2015 data.
[60] IHS Consulting, *The Price of Solar* (April 21, 2016), https://technology.ihs.com/577318/the-price-of-solar-april-2016
[61] This assumes utility delivery rates increase with inflation.

Chart 1: Estimated Costs and Tranche 1 Revenues for a 2 MW Community Distributed Generation Project in Orange & Rockland's Service Territory, Shown on a Net Present Value Basis[62]



This compensation level is not necessary to achieve the State's policy goals of bringing more CDG to New York and will lead to fewer clean energy resources being built

[62] Revenue calculations were developed using inputs from the Report's assumed Energy, ICAP, REC, and MTC values for O&R. NY-Sun Block 6 incentives were retrieved from https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Commercial-Industrial-MW-Block. Costs were calculated based on data provided in the U.S. Department of Energy National Renewable Energy Laboratories, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016* Published(September 2106), http://www.nrel.gov/news/press/2016/37745. Analysis was further informed by analysis of U.S. Department of Agriculture, *2015 U.S. Farm Crop and Pasture Land Values*, http://www.usda.gov/nass/PUBS/TODAYRPT/land0815.pdf. Net Present Value assumes a two percent discount rate.

for the same customer dollars.[63] If the excess payments to CDG projects contemplated by the Report were used to buy RECs[64] from large-scale renewable resources instead, the State would have the funding to meet 41 percent of its electricity needs with renewable energy.[65]

c. The Report Would Compensate Certain CDG at Rates Higher than Current NEM

Not only are the compensation levels in the Report's Tranche 0 and 1 well above the levels necessary to promote the growth of CDG, the Report would actually increase CDG compensation over current levels by assuming that 80 percent of subscribers are residential, and therefore eligible for the MTC, when it is more likely that only 60 percent of subscribers would be residential customers.[66] This would effectively increase the MTC payment for the project by 33 percent to levels greater than current NEM policy, which without commensurate benefits, would conflict with the Report's principle that future compensation should not be higher than current subsidization

d. Operational Limits Should Be Established to Maintain Reliability

The Report should be modified to include a reasonable limit on CDG development in any utility's service territory to account for operational limits that will be reached with high penetration of solar resources, and to allow the industry further room to grow at the

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[63] NY-Sun is a nearly $1 billion State commitment, launched in 2014, to stimulate the marketplace and increase the number of solar PV systems across the State over a 10-year period. NY-Sun aims to add more than 3 GWs of installed solar capacity in the State by 2023. NY-Sun, which is administered by NYSERDA, offers incentive programs that support solar projects for commercial and industrial companies, homes, multifamily buildings, small commercial, not-for-profit and municipal buildings.

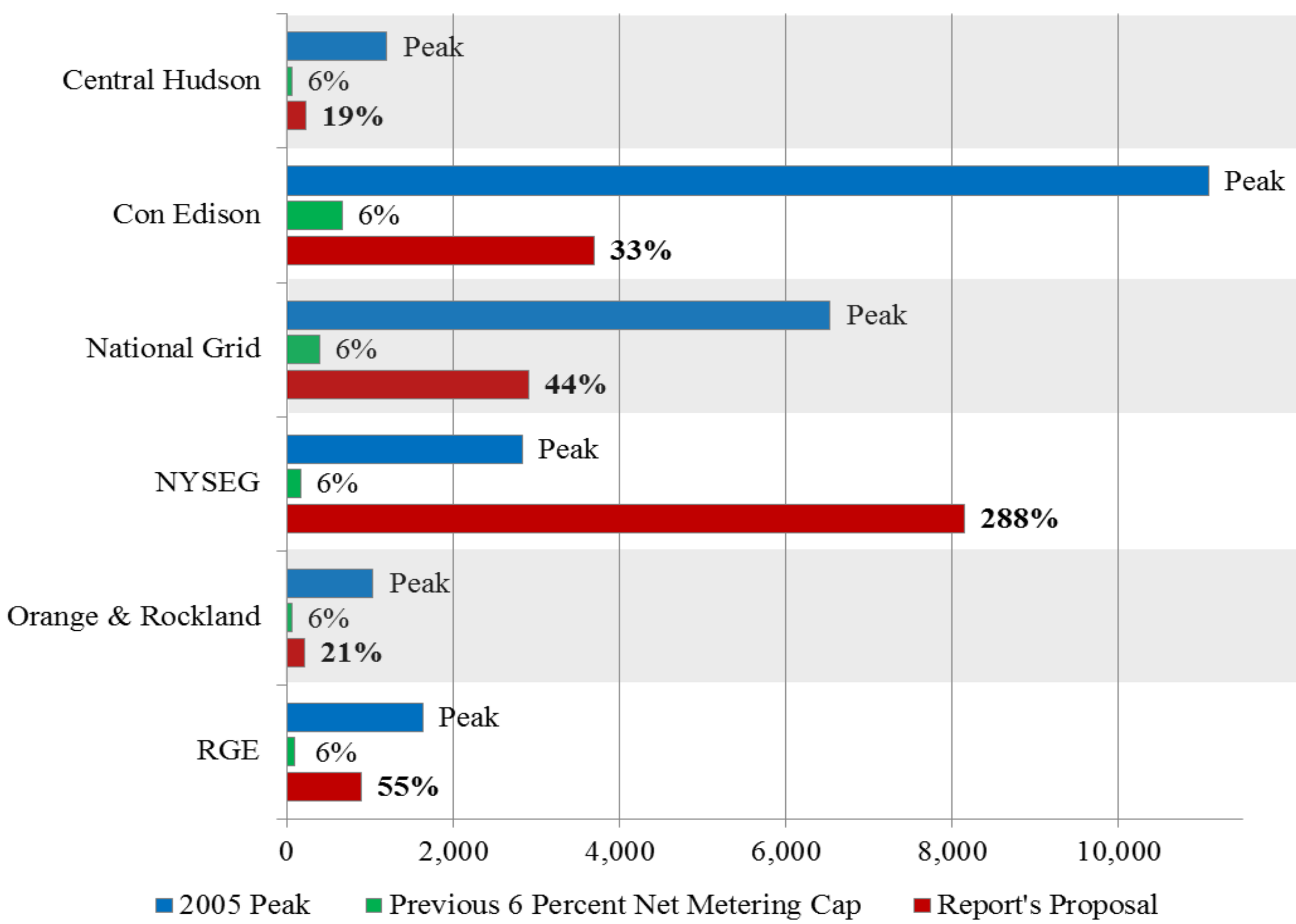
[64] At the Report's recommended compensation levels, CDG would receive more than seven times the value of a REC via the MTC and other solar subsidies. (This assumes a 2 MW project receiving a NY-Sun Block 6 Incentive, plus MTC in O&R's service territory, plus $21.16/MWh REC value.)

[65] This assumes spending $505,495,080 in bill increases on $21.16 RECs. This would purchase 23,889,181 RECs each year, equivalent to 15.2 percent of the 2021 New York Statewide Load as specified in the Clean Energy Standard Order. When summed with the existing 25.74 percent "baseline" renewables, 40.96 percent of annual load could be met with renewable energy if these funds were cost-effectively redeployed.

[66] *See* CDG Proceeding, CDG Order, pp. 7-8, where the Commission directed that the aggregate of members with demand in excess of 25 kW shall constitute no more than a 40 percent share of the CDG facility's output. Further, "each remaining member's share must not exceed 25 kW in demand and together those members at that size limit must aggregate to at least 60% of the DG facility's output."

conclusion of Phase One. If the Report's proposal were maintained, certain Utilities would experience distributed solar levels at an unprecedented 19 percent of peak demand and above, without any performance requirements or assurance the resources will be available when needed. System operators would be left with little visibility or control over these resources, as current interconnection requirements do not provide for real-time monitoring or control of these resources. These operational reliability challenges would be exacerbated during certain non-peak hours, when the Report's recommended number of MW of solar projects included in Central Hudson tranches would account for 29 percent of energy needs and more than 500 percent of energy needs during such hours in NYSEG's service territory.

Chart 2: Report's Proposed Distributed Solar Penetration Rates, by Utility



To address this issue, the Utilities recommend the Report include an additional criterion that would limit the total incremental distributed solar load in a utility's service territory to five percent of peak load. This five percent limit would allow for the Distributed System Platform ("DSP")[67] to naturally evolve and provide price signals to competing technologies that may provide similar or identical beneficial attributes. These competing technologies include demand response, energy storage, and other forms of clean generation, as well as technologies that are not yet known or commercially available. Finally, the five percent limit would reduce the potential for system reliability issues due to lack of visibility and control until such time as interconnection processes can be appropriately modified.

Finally, the Tranche structure should explicitly eliminate any opportunity for a rush of prospective applications seeking to receive Tranche 0 compensation levels. The Report's proposed approach of requiring projects to have paid 25 percent of the interconnection costs determined by the utility, or to have signed an interconnection agreement in the event that no such costs exist, within 90 days of the Order to receive Tranche 0 designation is reasonable and should be retained.

V. The MTC Should Be Modified to Encourage Performance That Aligns with Distribution System Needs, and Paid Out for Only 10 Years to Reduce Risk to Customers

As currently structured, the Report's approach would assign significant DER developer risk to customers over a 20-year period by fixing both the REC and the MTC payment based on a "snapshot" of current retail rate components. The Joint Utilities generally support the snapshot approach because it provides clarity to the marketplace.

[67] The DSP is a key element of REV. *See* Case 16-M-0411, *et al.*, *supra*, n. 6.

However, the downside to this approach is that does not allow any flexibility for future changes in wholesale electricity and renewable energy markets. In reality, however, these market changes will occur, and customers will have to take the risk, instead of DER developers or their customers.

While the Report allows DER energy compensation levels to match actual NYISO Day Ahead LBMP prices, a portion of this risk is indirectly fixed for 20 years through the REC price.[68] The MTC is similarly fixed for 20 years, including System Benefits Charge ("SBC")[69] and Merchant Function Charge ("MFC") components. SBC charges are currently at their peak levels,[70] and are will decline in coming years as the Commission's directives under the Clean Energy Fund and Clean Energy Standard proceedings are carried out.[71] By paying out both the REC value and the 2016 SBC value (as included in the MTC) to DER, customers will continue to bear these high costs twice for 20 additional years. To address all of these issues, the Joint Utilities recommend shortening the period over which the MTC is paid from the 20 years proposed in the Report to 10 years, with a proxy for distribution benefits set for 5 years.

To address the DER performance issues discussed throughout this document, the Joint Utilities recommend that a portion of the MTC be tied to DER performance. The Report's proposed approach encourages solar projects to maximize volumetric output

[68] In a perfectly competitive market, REC prices are established based on the difference between current and projected electricity market prices and the revenue requirement of the generator. During periods of lower electricity market prices, such as currently exists, generators earn less from the electricity market and therefore need a higher REC value to make their projects economic.
[69] SBC charges still embedded in the CEF collection amounts include SBC III, SBC IV, and EEPS 2 collections as well as RPS collections for the period 2016 to 2024.
[70] *See* Case 14-M-0094, *et al*., *Proceeding on Motion of the Commission to Consider a Clean Energy Fund*, *et al.*, Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016 ("CEF Order"). Appendix H, which establishes the annual CEF collection schedule by utility to 2036 and which includes previously authorized RPS collection through 2024.
[71] Case 15-E- 0302, *supra*, n. 48. The Clean Energy Standard was designed to continue and extend the Renewable Portfolio Standard ("RPS") by requiring load serving entities ("LSEs") to purchase RECs, instead of requiring delivery customers to fund further new renewable energy resources through the RPS surcharge.

(achieved with south-facing solar panels) instead of providing capacity performance (better achieved with west-facing solar panels), and disadvantages resources like solar tracking systems or batteries that could provide greater system benefits.

The Joint Utilities urge the Commission and Staff to take advantage of this opportunity to create a performance-based price signal for DER. This could be achieved by making a portion of the MTC payment performance-based, using Staff's earlier concept of weighting actual production at the time of the 10 highest distribution load hours. In order to smooth out any single year's calculation and provide an initial level of compensation until actual coincident performance can be measured, the Joint Utilities would propose to base the initial compensation on three years of modelled solar PV production coincident with the utility's 10 highest distribution peaks in each of the three prior years. The three-year rolling average would continue with actual project production data replacing "model" production data as it becomes available. The Joint Utilities would propose that, as a proxy for distribution benefits, the average coincident production be valued for five years at the utility's most recently Commission adopted Marginal Cost of Service Studies, at which time the then-current Marginal Cost of Service Study would be used.

VI. The Circuit Breaker Mechanism Should Provide a Hard Two Percent Cap on Bill Increases; Mass Market Grandfathering Should Be Reduced to 15 Years

The Report would establish a circuit breaker mechanism designed to trigger Commission review should the mass market segment grow more quickly than expected. The Joint Utilities recommend this approach be strengthened and expanded to create a hard two-percent cap on bill increases to customers for Phase One of this proceeding. For all of the reasons discussed in these comments, significant uncertainty exists as to the actual bill increases customers will experience as a result of this proceeding. In order to prevent unexpected excessive bill increases for customers, the Commission should proactively monitor bill increases by requiring utilities to file quarterly statements outlining bill increases that are occurring as a result of this policy, according to the formula ultimately adopted by this proceeding. Instead of triggering Commission review, the circuit breaker should incorporate concrete actions, such as limiting new applications or throttling back the compensation levels provided to all DER scheduled to take future service under NEM or the tariff resulting from Phase One of this proceeding.[72] This approach would provide both visibility and certainty to the market, allowing developers foresight into the growth of the market and allowing them to plan their businesses accordingly.

Furthermore, for all of the reasons discussed in these comments, including falling solar PV installation costs, the need for more precise valuation of DER, and the lasting bill impacts associated with the Report's proposal, the Joint Utilities recommend that the grandfathering period for new and existing mass market residential and small commercial DER be shortened from the Report's proposed 20 years to 15 years. This would reduce costs and long-term risks to all other customers and provide for a more effective transition to a more granular Phase Two valuation methodology in this proceeding.

VII. Further Work Is Needed to Resolve Key Cost Recovery Questions

Key questions regarding the recovery of costs associated with this policy remain unanswered. The answers to these questions will have a significant effect on the actual bill increases that any given customer class experiences. The Report recommends, for example, that energy and capacity payments to DER under this policy should be allocated only to those

[72] *See also*, *supra*, n. 14.

customers within the service class of the DER customer. This may result in undue impacts to residential and small business customers, when the benefits from that energy and capacity may actually benefit all customers.

The Joint Utilities also note that the Report's proposal will necessarily create new implementation costs. For example, DER metering is not currently adequate to implement hourly energy payments. Billing systems will also require significant modification. In particular, the complexity of the proposal's recommendation that each CDG will have a billing calculation unique to itself means that there will be significant additional billing costs to be borne by all customers. Allocation of these costs should be carefully considered so that costs are properly assigned to those benefited by them.

The Commission will also need to address mechanical issues related to the collection of costs. Accounting and cost allocation practices for recovering NEM-related costs vary among the Utilities, and will require further focus as the quantity of these resources grows on the system. Although the existing Revenue Decoupling Mechanism may be able to capture some of the revenue shift, other components, such as those related to RECs and wholesale benefits will likely require new mechanisms not yet envisioned.

The Joint Utilities propose that the Monetary Credits should be allocated on a percentage basis, based on the MWhs generated by the project each month. This allocation methodology will provide transparency for the CDG subscriber and provide a link to any future service class cost allocations. Additionally, allocation of the monetary credits based on MWhs would allow potential CDG subscribers to compare prices between competing CDG projects and provide a better comparison to their existing utility bill.

VIII. Conclusion

The undersigned Joint Utilities appreciate the opportunity to provide these comments in the interests of customers.

Dated: December 5, 2016

Respectfully submitted,

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. and ORANGE AND ROCKLAND UTILITIES, INC.

By: */s/ Susan Vercheak*

Susan Vercheak*
Assistant General Counsel
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003
Tel.: 212-460-4333
Email: vercheaks@coned.com
* Admitted only in New Jersey

CENTRAL HUDSON GAS AND ELECTRIC CORPORATION

By: */s/ Joseph Hally*

Joseph Hally
Manager, Energy Transformation & Solutions
Central Hudson Gas and Electric Corporation
284 South Avenue
Poughkeepsie, NY 12601
Tel: (845) 486-5373
Email: jhally@cenhud.com

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

By: */s/ Janet M. Audunson*

Janet M. Audunson
Senior Counsel II
National Grid
300 Erie Boulevard West
Syracuse, New York 13202
Tel: (315) 428-3411 Email:
janet.audunson@nationalgrid.com

NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION

By: */s/ Mark Marini*

Mark Marini
Director - Regulatory
89 East Avenue
Rochester, NY 14649
Tel.: (585)750-1666
Email: Mark_Marini@rge.com