Date: April 18, 2016

VIA ELECTRONIC MAIL
Hon. Kathleen H. Burgess
New York Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: **Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology**

Dear Secretary Burgess:

Environmental Defense Fund and the Institute for Policy Integrity at New York University School of Law[1] hereby submits for filing their joint comments in response to the Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference, issued December 23, 2015.

Respectfully submitted,

Elizabeth B. Stein
Senior Manager, New York Clean Energy Law & Policy
Environmental Defense Fund
257 Park Avenue South
New York, New York 10010
estein@edf.org
(212) 616-1327

Burcin Unel, Ph.D.
Senior Economist
Institute for Policy Integrity
139 MacDougal Street
New York, New York 10012
burcin.unel@nyu.edu
(212) 992-6285

Cc: Active Parties

[1] No part of this document purports to present New York University School of Law's views, if any.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology

JOINT COMMENTS OF ENVIRONMENTAL DEFENSE FUND AND THE INSTITUTE FOR POLICY INTEGRITY AT NEW YORK UNIVERSITY SCHOOL OF LAW IN RESPONSE TO THE NOTICE SOLICITING COMMENTS AND PROPOSALS ON AN INTERIM SUCCESSOR TO NET ENERGY METERING AND OF A PRELIMINARY CONFERENCE

DATED: April 18, 2016

Environmental Defense Fund
257 Park Avenue South
New York, New York 10010

Institute for Policy Integrity at New York University School of Law
139 MacDougal Street
New York, New York

Kristina Mohlin, Ph.D.
Economist
Environmental Defense Fund

Ferit Ucar, Ph.D.
Senior Clean Energy Economist
Environmental Defense Fund

Elizabeth Stein
Senior Manager, NY Clean Energy Law & Policy
Environmental Defense Fund

Burcin Unel, Ph.D.
Senior Economist
Institute for Policy Integrity

Jim Tripp
Senior Counsel
Environmental Defense Fund

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I. Introduction

As New York State continues to work towards achieving its ambitious clean energy goals and strengthen its role as a leading state in modernizing the electric grid, the New York Public Service Commission ("Commission") has been carefully considering how best to adapt rates and business models for the future through Reforming the Energy Vision ("REV") proceeding. In the White Paper on Ratemaking and Utility Business Models ("Track 2 White Paper"),[2] the Department of Public Service Staff ("Staff") introduced the approach of "LMP+D", where "LMP," the locational marginal price of energy, represents the energy value of DER, and "D" represents the full range of additional values provided by the distribution-level resource, in an effort to better determine the value of distributed energy resources ("DER").[3] As part of that effort, in January, the Commission issued the Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference ("Notice Soliciting Comments") inviting interested parties to submit proposals for full valuation methodologies that can be used for compensation in DER markets, as well as an interim methodology that can be used as a near-term transition tariff.[4]

Properly compensating DER is crucial to realizing the REV vision and achieving New York State's clean energy goals. Ideally, customers would pay for the value of the services they receive from the grid, would bear in full the external costs their consumption causes, and would receive compensation for the full value they contribute to the grid.[5] In a future in which electric service pricing is unbundled to value generation and transmission, distribution, and ancillary services separately, and is granular with respect to time and location of consumption, the main principle of net energy metering ("NEM") (the offsetting of on-site electric generation against

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[2] PSC Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, White Paper on Ratemaking and Utility Business Models (July 28, 2015), at 75 [hereinafter Track 2 Staff White paper].

[3] PSC Case 15-E-0751, *Proceeding in the Matter of the Value of Distributed Energy Resources,* Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (Dec. 23, 2015) [hereinafter Notice Soliciting Comments].

[4] Notice Soliciting Comments, *supra* note 3, Attachment A, at 2.

[5] *See* Case 14-M-0101, Initial Comments of Environmental Defense Fund (Oct. 26, 2015) at 23.

consumption at the same location) could continue to provide the basis for compensating distributed generation ("DG") and other distributed energy resources ("DER") that are co-located with load. Netting can be harmonized with a granular pricing future by making the netting intervals match the temporal granularity of the underlying price structure.[6]

Getting such an ideal structure in place will require new technology, new business practices, and new approaches to utility regulation. It will also require tools for requiring polluters to bear the full costs they cause on society, and a willingness by regulators to impose those costs upon them.

To begin to move the retail markets toward efficient and accurate recognition of the value of DER, we suggest that the Commission should:

- Enhance the existing net energy metering mechanism to align DER customers' compensation with particularized system benefits that DER provide by using time-variant pricing and/or a west-facing solar or equivalent temporal credit, and a distributional locational credit, as components of an interim tariff to be used until a full valuation methodology can be established;
- Establish a fully unbundled retail price structure based on the "LMP + D" construct that can dynamically and consistently value the benefits of all types of DER, including the clean energy benefits, without any cross-subsidy concerns;
- Clarify the structure of "D" and further refine this approach to capture "LMP+D+E," where "E" refers to environmental values provided by distribution level resources, in order to properly value environmental benefits or costs of different DER with the necessary degree of granularity.

[6] Richard L. Revesz & Burcin Unel, (2016) Managing the Future of the Electricity Grid: Distributed Generation and Net Metering 60-65 (Institute for Policy Integrity, Working Paper No. 2016/1, 2016), *forthcoming in the Harvard Environmental Law Review*, available at http://policyintegrity.org/publications/detail/managing-future-electricity-grid.

II. Responses to Questions Posed in the Notice

To ease Staff's review of our responses below, we have preserved the full list of questions in bold, and included our answers where applicable in regular type. There are some questions posed by Staff to which we are not furnishing responses.

A. Proposals for interim methodologies

1. Identify and describe, in as much detail as possible, a mechanism or mechanisms to more precisely value DER as bridge, as currently effectuated in tariff today, while the complete value of D tool and methodologies are developed.

As Staff recognized in the Track 2 White Paper, there is a close connection between the twin questions of rate design and DER valuation.[7] As Staff correctly points out, the large amount of investment that will be made by all stakeholders in the coming years should be economically efficient and further REV goals.[8] Achieving such a successful policy outcome requires structural solutions that generate accurate and precise economic price signals without any cross-class subsidy. In the absence of the advanced metering and communications technology that constitute the technical prerequisite for ideal pricing of electric service, there are steps that can be taken now to enhance the price signals that currently exist for DER, to begin moving the marketplace in the direction of pricing that more closely approaches the efficient ideal.

Before describing an interim approach to valuing DER, it is helpful first to review the limitations of current net energy metering policy in valuing DER properly.[9]

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[7] Track 2 Staff White Paper, *supra* note 2 at 75 ("The crux of the issue is that residential and small commercial customers are not provided with information about the true components of cost or the means to effectively respond to the price signals such information can provide. Similarly there is an incomplete understanding of the full value that DERs provide to the system, and thus insufficient information on which to base investment and usage choices. This situation requires us to better determine how customer behavior contributes to the entire bill, the disaggregated cost of delivery service, and conversely the benefit that should be provided to the customer in terms of total cost avoidance or reductions to the distribution system by DER, which the Commission has referred to as the 'value of D'.").

[8] *Id.* at 74.

[9] Revesz & Unel, *supra* note 6, at 60-65.

- First, a flat volumetric pricing structure that is geographically uniform across a service territory cannot communicate prices that reflect the actual societal value of energy at particular times and places. This is an inefficient structure that is unlikely to lead to the targeted DER investment that would create the highest net benefits to society overall.
- Second, a flat volumetric pricing structure that is uniform across a service territory fails to recognize the incremental value of DER that is located in areas where the grid is congested. The absence of a price structure that reflects locationally specific grid constraints conceals the potential benefits that DER can contribute by relieving congestion, and deferring or avoiding new distribution infrastructure investment targeted at relieving such grid constraints.
- Third, a flat volumetric pricing structure creates incentives for DG customers to install resources to maximize total generation from the resource rather than to maximize the total overall system benefits. For example, customers who pay for their electric service pursuant to a uniform flat volumetric pricing structure and are subject to traditional net metering will necessarily be incentivized to orient any solar panels toward the south rather than to the west. South-facing panels generate the most energy annually, but west-facing panels may nonetheless be more valuable to the system under some circumstances because they generate more energy during the times of day when the additional electricity supply is needed most.
- Fourth, a flat, uniform volumetric pricing structure cannot reflect the full value of the pollution reduction benefit available from certain DER because this value depends on the type of bulk system generator that DER displaces, and hence changes throughout the day depending on what bulk system generator is on the margin at a given time.
- Finally, in addition to these efficiency arguments, net metering policy coupled with inefficient retail pricing designs could lead to cross-subsidies within and between customer classes, and therefore raise equity concerns.

Any interim NEM successor that is adopted as a bridge solution should be forward-looking, and should address these concerns while facilitating the transition to full valuation and fair compensation for DER on a temporally and locationally specific basis.

As DER co-located with on-site loads provide different benefits than DER paired with off-site loads, the interim method should be different for these two types of DER.

Interim Methodology for DER that Are Co-located with Customer Loads:

As will be discussed later in these comments in more detail, properly valuing DER requires time- and location- variant price signals that are as granular as possible. This long-term vision, however, necessitates certain capabilities that are not currently available in New York, such as advanced metering, two-way communication between utilities and customers, and data sharing among customers, utilities, and third-party providers. Even though the Commission recently approved a full advanced metering infrastructure roll-out in the Con Edison service territory, this roll out is not expected to be complete until 2022,[10] and the timing of any deployment of similar capabilities in much of the state remains to be determined.

Consequently, a simple interim methodology that can be used to compensate the small-scale, non-emitting DER without requiring advanced metering and communications technology is needed. This methodology should recognize all the various categories of benefits that DER provide in accordance with the Order Establishing the Benefit Cost Analysis Framework ("BCA Framework Order"),[11] yet should be simple and easy to implement, and should address any efficiency and equity concerns. Further, transition to the interim tariff from the current net energy metering should require minimal methodology development and transition costs, as this

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[10] *See* Case 13-E-0030, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Case 13-G-0031, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Case 15-E-0050, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Con Edison Advanced Metering Infrastructure Business Plan (Oct. 16, 2015) and Case 13-E-0030, Case 13-G-0031, and Case 15-E-0050, Order Approving Advanced Metering Infrastructure Plan Subject to Conditions (Mar. 17, 2016).

[11] PSC Case 14-M-0101, Order Adopting Establishing the Benefit Cost Analysis Framework (Jan. 21, 2016) [hereinafter BCA Framework Order].

interim tariff would only be in effect for a limited time given the Commission's commitment to moving to valuation methods that can properly compensate DER for the full value they create.

Given the technological constraints that New York State customers currently face, it is pragmatic to use the current net metering mechanism as the foundation for the interim methodology for small customers with on-site DER, and add some modifications to ensure that more of the full system value of DER can be realized. Such an approach would be simple, and would provide much needed stability for DER investments.

It is, however, important to note that desirability of continuing to use net metering for customers installing DER at their premises rests on two crucial assumptions. The first assumption is that, as the Commission has previously stated, any potential negative consequence of net metering is expected to be minimal at low levels of penetration.[12] Research suggests that this assumption is valid; a recent study commissioned by NYSERDA ("the New York Net Metering Study") has estimated the potential cost shifting to non-net metered customers to be minimal, finding that the potential estimated rate impacts in 2015 for non-participants between $0.0001 (targeted scenario) and $0.0004 (untargeted scenario) per kWh based on a 500 MW penetration level of net-metered Solar PV systems.[13] The second assumption is that net energy metering as currently implemented provides compensation that is on an order approximately commensurate to its total value. Here, too, the research suggests that this is so; the same study found that New York average retail rate is roughly equal to the value of the benefits of solar power when non-financial societal benefits are included.[14] Once DER penetration starts to accelerate, however, transitioning quickly to a full valuation methodology becomes a policy imperative.

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[12] *See* Track 2 Staff White Paper at 92.

[13] Case 15-E-0703, *In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law*, §66-n, The Benefits and Costs of Net Metering in New York (Dec. 11, 2015) [hereinafter New York Net Metering Study] at 5. The New York Net Metering Study was prepared by Energy and Environmental Economics ("E3") for the New York State Energy Research and Development Authority and the New York Department of Public Service.

[14] New York Net Metering Study at 5 (showing that the New York State overall average retail rate is 18.5 cents per kWh with the total value of solar estimated at 10-23 cents per kWh depending on scenario).

The precise value of the various benefits of DER is time-dependent, and the lack of advanced metering and communications technology currently makes it infeasible to determine them precisely. Given this technological constraint, and the fact that the interim net metering construct provides a reasonable proxy for DER value with little downside at low levels of penetration, continuing to net against retail electric pricing may be a good foundation for an interim policy solution until a full and precise compensation approach is feasible. However, even if the today's retail electric pricing can be used as a rough estimate of energy and non-energy benefits of an average DER, its crudeness fails to provide incentives to optimize the deployment of DER where and when it is most valuable. The Commission can begin to address this failure in advance of developing a precise, full valuation methodology through the use of various enhancements that align the DER customers' compensation with practices that maximize system net benefits. The Commission should modify the methodology of net energy metering in a manner that is informed by the following recommendations.

- **Time-variant pricing for NEM customers.** Utilities should offer NEM customers the option of time-variant pricing that is reflective of the actual costs of generating and delivering electricity to them.[15] Enhancing the current NEM structure with such an underlying time-variant pricing structure would allow the net exports to be more accurately valued based on the time period in which they occur, which, in turn, would provide a more granular and efficient price signal to the customer.

Currently, NEM customers are discouraged from switching to Time-of-Use (TOU) rates offered by Con Edison because credits for excess electricity can be used only to offset consumption in the same time period that the credits were produced (in other words, credits earned during the peak period cannot be used to offset consumption during the off-peak period)

[15] An important consideration before putting NEM customers on time-variant pricing in the interim period is the cost of interval metering in the interim period during such time as advanced metering infrastructure is not yet available to such customers. If all customers will have advanced meters installed in the next few years, then the costs of installing the interval meters and billing to be used only for the interim period may outweigh the benefits of having NEM customers on time-variant rates in the interim period, especially for small customers. In that case, a simpler alternative mechanism can be implemented to recognize the time-varying nature of the value of distributed generation.

and at the end of the year any unused credits are compensated based on the utility's avoided cost of energy, which is almost always lower than the retail price of electric service at the time the credits were earned.[16] Providing monetary bill credits (instead of kWh credits) for the retail value of exports in each time period and allowing these credits to be used against grid consumption in any time period would remove this disincentive to opt for time-variant pricing. Unlike flat rate pricing, a well-designed time-variant price signal could encourage the customers to undertake the type of DER investment that is socially more beneficial. For example, such a price signal would likely provide more incentives for the solar DG customers to face their panels west instead of south, thereby reducing the need for flexible central generation resources for the late afternoon ramp-up during the months when the sun continues shining into the early evening.[17]

Ideally, a well-designed time-variant pricing structure would be the default option (with an opt-out right) for customers who own DER. An alternative might be to eliminate the practice of defaulting to flat rate pricing for such customers, and require that they affirmatively choose between a flat rate pricing and the time-variant pricing structure. At the Commission meeting at which the Con Edison AMI Business Plan was approved, Commissioner Gregg C. Sayre suggested that some form of opt-out time-variant pricing of electric service might be possible and desirable.[18]

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[16] See Con Edison Net Metering and Billing FAQ, *available at* http://www.coned.com/dg/Net_Metering_Billing_FAQ.asp (last visited Apr. 18, 2016).

[17] Barry Fischer & Ben Harack, 9% of solar homes are doing something utilities love. Will others follow?, OPOWER (Dec. 1, 2014), http://blog.opower.com/2014/12/solar-homes-utilities-love/.

[18] As Commissioner Sayre noted during the PSC meeting on March 17, 2016, "What moved me to agree with this item was not the operational savings, but the future benefits to all customers that will be accomplished when customers and third parties start using the data that come out of these meters. I'd like to express my strong hope that the Company and stakeholders, working with Staff, will find a way through a number of statutory and operational issues to set up a large-scale REV demonstration pilot of time-of-use pricing, which of course requires smart meters to be installed first. I think we're very likely to find in such a pilot that such pricing, just on its own – not on any kind of mandatory basis, but possibly on an opt-out basis – will advance several of the goals of Governor Cuomo's and the Commission's energy policy, including in particular energy conservation and peak shaving…. I hope you can make this happen." Video of this meeting can be viewed at https://www.youtube.com/watch?v=VCf8D2kya-A&feature=youtu.be, 25:00.

- **West-facing solar or equivalent temporal credit.** If a well-designed time-variant pricing for DER customers cannot be implemented in the near term due to lack of technology or other reasons, a credit specifically recognizing the value of west-facing orientation of solar panels, or other DER that has been configured to be particularly beneficial during peak periods, could be used. If west-facing solar would in fact create more value in some times and locations, this credit could be used to incentivize customers in such locations to make a decision that is more beneficial to the system overall.[19]

The west-facing solar credit should be structured to reflect the net incremental system and environmental benefit, if any, of a west-facing solar system compared to a south-facing one. A similar temporal credit can also be applicable to non-PV technologies currently eligible for NEM that generate a greater portion of its electricity during system peak hours.

- **Distribution locational credit.** This credit would apply to NEM-eligible DER projects located in areas of the distribution system in which constraints have been identified by the applicable distribution utility, in recognition of the fact that these DER can help defer or avoid expensive distribution infrastructure investment and create system-wide benefits. This credit would monetize this additional ratepayer value created and make it available to customers installing such DER capacity, and hence – unlike the current retail pricing – would incentivize deployment of DER in the locations where they provide the most value to the distribution system.

For this credit to work properly, utilities would need to identify and report locations for which a distribution locational credit is appropriate in their Distributed System Implementation Plan ("DSIP") filings. The amount of credit should be based on the estimated value of avoided or deferred infrastructure investments, and should be determined in a way that allows the DER owner, ratepayers as a whole, and the utility to share the net benefits of avoided costs. The value of DER service in a particular location will change as the grid develops and DER penetration

[19] California, for example, has recently announced a $500 incentive for the installation of west-facing panels on new homes. California Energy Commission, News Release: California Moves to Improve Solar Incentive Program for New Homes (Sept. 3, 2014), *available at* http://www.energy.ca.gov/releases/2014_releases/2014-09-03_nshp_incentive_nr.html.

levels at the applicable location increase. Therefore, credits earned will need to be adjusted periodically to reflect these developments until the full valuation method takes effect.

As REV transforms the marketplace, we anticipate that non-utility parties will increasingly possess information about system operation, obtained through the DSIPs, that may enable them to identify locational constraints other than those identified by the distribution utility. In the event that a party other than the distribution utility identifies a location where a distributional locational credit should be available, there should be a procedure by which such a party can make a showing that it should be eligible for enhanced compensation, and be granted such compensation if appropriate.

Interim Methodology for DER that Is Not Co-Located with Customer Load

In the case of net metering of distributed generation that is not co-located with load, the transition to an LMP+D valuation can and should occur more quickly. First, remote systems inject energy into the grid at a location that is different from where the corresponding consumption occurs. Therefore, the distribution level benefits of the actual energy injection will be different than the distribution level benefits of a similarly-sized hypothetical energy injection or load reduction that occurs at the consumption location. Consequently, using “D” values applicable to the consumption location would be inappropriate. Instead, the owners of such resources should receive compensation based on an approximation of the LMP+D value of the DER where it is located.

Second, with respect to the wave of community net metered projects that is on the horizon, such distributed generation facilities will be new – not hindered by what is already in place – and are likely to be relatively large, and thus worth the investment in modern telemetry from the outset. Therefore, a quicker transition to an LMP+D valuation is feasible. Similarly, customers with on-site DER should be encouraged to adopt the LMP+D construct as soon as they are equipped with advanced metering infrastructure.

2. **For each mechanism proposed, or for any mechanism ultimately adopted, identify the input assumptions and the types of benefits and costs relevant to the mechanism, including analysis of their relative significance in magnitude.**

3. **How can the contractual and financial expectations of existing projects be respected?**

A discussion of a new regulatory policy should necessarily be coupled with a discussion of a transition policy. At one extreme, there is a transition policy that offers no special treatment to current owners of DERs; and at another extreme, there is a transition policy that offers a policy of permanent grandfathering of net energy metering to current owners of DERs, never applying the new regulatory regime to existing actors.[20]

"Transition relief" is a general term for special treatment provided to a party that might be affected by a regulatory change. To determine the socially desirable transition relief rule, the Commission should first weigh two aspects of transition relief in deciding whether and how the new valuation methods would be applied to existing projects: efficiency and fairness.[21] While considerations of efficiency usually would point away from transition relief, concerns of fairness might justify some amount of transition relief. In addition to weighing efficiency and fairness, the Commission should recognize that social welfare maximization requires a joint-optimization approach to determining the interim successor tariff and the transition rule simultaneously, as

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[20] See L. Kaplow, *An Economic Analysis of Legal Transitions*, 99 HARV. L. REV. 509, 584-87 (1986) (discussing grandfather provisions as an example of legal transition relief, and a detailed examination of different types of partial relief).

[21] See J. Nash and R. Revesz, *Grandfathering and Environmental Regulation: The Law and Economics of New Source Review*, 101 NORTHWESTERN UNIV. L. REV. 1677 (2007) (providing an overview of the arguments for incentive effects and fairness) and R. Revesz, and A. L. Westfahl Kong, Allison L., *Regulatory Change and Optimal Transition Relief*, 105 NORTHWESTERN UNIV. L. REV. 1581 (2011) (providing an overview of the old view, which argues for transition relief on the grounds of settled expectations and fairness, and the new view, which argues against transition relief on the grounds of incentive effects and preferability of market-based solutions to government solutions).

opposed to a sequential approach that first determines the new pricing and then settles on a transition rule.[22]

In general, transition relief is inadvisable on efficiency grounds as it discourages actors from anticipating changes in rules and preparing to organize their businesses to maximize profits under the new rules, and instead encourages them to use their resources to maximize opportunities under the disappearing regulatory construct.[23] As a general matter, societal actors who do not actively anticipate changes are not afforded public relief from change, even though private relief in the form of insurance might be available.[24] For example, a business that loses profits if it does not modernize its technology is not entitled to relief from the technological change. As the possibility of a change in the policy regime is simply a subclass of the large set of risks that societal actors are subjected to, transition relief requires special justification.[25]

However, transition relief may be desirable for some period of time where investments are durable.[26] Assuming that investment decisions for existing DER projects were made in good faith reliance on the existing regulatory construct, fairness concerns may justify extending protection to societal actors for some reasonable period of time.[27] Indeed, allowing investors a reasonable return on their investments before subjecting them to a broadly applicable new regime, a practice known as amortization, is not uncommon in other contexts.[28] Investors who have already installed DER may similarly be offered the opportunity to continue on net energy metering for a specified reasonable period of time, based on the anticipated useful life of

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[22] Revesz and Westfahl Kong, *Id.*, at 1615-1621.

[23] Nash & Revesz, *supra* note 21, at 46.

[24] *Id.*

[25] *Id.*

[26] *Id.* at 48 (discussing time limited grandfathering in the context of New Source Review).

[27] *Id.* at 51.

[28] *Id.* at 51 n. 239 (discussing amortization of nonconforming uses that arise under zoning law).

technology, before they are obligated to move to the successor DER valuation methodology. Such a time-limited transition relief would be superior to indefinite grandfathering.[29]

With respect to the joint optimization exercise of determining NEM successor tariff and the transition relief, the desirability of grandfathering in joint-optimization of NEM-eligible DER pricing depends on two important factors. First, the Commission should consider the growth in demand for the product. If the demand for DER is expected to grow significantly after the change in compensation, the benefits of not compromising on the efficiency of the successor tariff will be more compelling – which means that the successor tariff may represent a more dramatic departure from its predecessor, making the grandfathering of existing DER potentially desirable.[30] If, however, the population of DER is not expected to grow over the long term, such that resources already in place at the time of the tariff change are expected to comprise a significant portion of the future population for a long period, it would be better to compromise on the efficiency of the successor tariff and to limit grandfathering of the existing sources. Second, the Commission should consider how long installations that are eligible for grandfathering are expected to continue to operate. Any reduction in social benefits arising from transition relief would lapse when grandfathered DER exit the market, so if the existing DER are expected to continue to operate under a grandfathered compensation structure for only a short time after the transition begins, the transition relief they would receive would be relatively unlikely to be sufficient to compromise the efficiency of the successor tariff in the joint-optimization.

These same considerations should inform the question of grandfathering when the Commission begins the transition from the interim compensation structure to a future LMP+D regime.

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[29] *Id.* at 48.

[30] Revesz and Westfahl Kong, *supra* note 21, at 1621 (discussing the joint-optimization approach in the context of new source standards).

4. **Bill impacts are a critical metric for assessing any proposal. How should bill impacts be identified and analyzed? What criteria should be employed to assess the bill impacts of a given proposal?**

5. **For each mechanism, describe with as much specificity as possible:**

    A) The benefits and costs to:

    i) participants;

    ii) non-participants; and

    iii) society

The proposed additional credits in the interim mechanism described in these comments are designed to move us closer to the targeted scenario modelled in the New York Net Metering Study. Therefore, the additional costs to other ratepayers of providing these credits are likely to be lower than the benefits that the new targeted DER investments will provide.

As an interim NEM successor for the mass-market customers, we are proposing a mechanism that will add time-variant and locational components to the current NEM structure. Time variant pricing designed to encourage efficient DER deployment would more accurately compensate participants (NEM customers) compared to the current flat rate, which should help alleviate cross-subsidy concerns between participants and non-participants. Time-variant pricing designed for this purpose should incorporate the time-variant costs of energy supply; the resulting reductions in demand for wholesale energy at peak times can reduce marginal costs and polluting peak generation resources. This would yield additional benefits to all parties. Participants would purchase less energy at the most expensive prices, non-participants would experience lower wholesale clearing prices, and society as a whole would experience reduced air pollution from peak generating sources.

The metering and accounting for credits in a time-differentiated manner may require updates to the utility billing system. The cost of such updates will need to be taken into account to determine the cost-effectiveness of time-variant rates for the NEM customers in the interim period. If time-variant pricing is not an option or is not cost-effective for NEM customers during the expected term of the interim period, then a west-facing solar credit, as an alternative to time-varying rates, might offer some of the same benefit by encouraging qualified NEM projects to be configured in a manner that maximizes system peak reductions. As this credit will be based on the incremental societal value of a west-facing solar resource over a south-facing one, it will create benefits for all ratepayers and the society.

The distribution locational credit, if properly designed and implemented, would provide benefits to both participants and non-participants, because it would specifically encourage the development of DER that could help defer or avoid expensive distribution infrastructure investments, reducing system costs borne by all customers in their distribution tariffs. The equity concerns with providing location-specific credits to DER should be limited. While universal reliable and affordable electric service is an important public policy objective, uniform DER opportunity at all geographic locations should not be, since the value of DER is highly location-specific. Insisting on it would cut strongly against the system efficiency outcomes that REV is designed to achieve. DER should be deployed at those locations where they can be integrated cost-efficiently to lower the cost of electric service for both DER and non-DER ratepayers, and should be compensated in a manner that provides incentives for targeting deployment in those locations.

B) How the benefits and costs vary when the customer is demand billed versus non-demand billed.

C) How the benefits and costs vary when the project is targeted to a system need versus randomly distributed.

The benefits of a project will be higher for a project that is targeted to serve a system need in constrained areas of the system compared to a project that is located at random. For example, a recent estimate suggest that the capacity deferral value of distributed solar panels is $6/kW-yr when averaged over Pacific Gas & Electric's whole service area, while it can be as much as $60/ kW-yr when analyzed at a more granular feed level.[31] Thus, a distribution locational credit should be designed to provide greater compensation for a project in areas where it brings more value to the system than in less-constrained areas of the distribution system. In the case of projects being funded by non-utility entities that might be in a position to choose among various possible DER locations, a distributional locational credit would be combined with the other income associated with the prospective investment, which would make a DER project at a location where there is a system need a relatively more attractive investment opportunity than a similar project in an area without such a need.

D) How the mechanism applies to energy injections into the grid, versus load reduction.

6. Describe how the mechanism would affect and reflect:

A) More accurate and precise value signaling

The interim NEM successor mechanism that we propose would lead to more accurate and precise value signaling compared to today's NEM mechanism. All DER projects do not provide the same level of benefits to the grid, yet the current NEM mechanism, which compensates customers based on a bundled retail rate, makes no distinction by location and provides little or no temporal variation (other than through the optional TOU rates the utilities currently offer, which are not designed for this purpose). By contrast, the interim NEM successor mechanism that we propose would recognize the diversity of values and target investment toward projects with higher system and/or environmental value.

B) Simplicity in the customer experience and ability to encourage customer adoption.

[31] Michael A. Cohen, Paul A. Kauzmann & Duncan S. Callaway, Economic Effects of Distributed PV Generation on California's Distribution System 16 (Energy Inst. At Haas, Working Paper No. 260, 2015), available at http://ei.haas.berkeley.edu/research/papers/WP260.pdf.

The distribution locational credit and west-facing solar credit would be simple and would help educate the customers about the locational and temporal value of DER. They would allow for a smoother transition to a valuation mechanism based on the LMP+D construct.

C) The Commission's REV policy objectives

According to the Department of Public Service, a key REV objective is to promote more efficient use of energy, deeper penetration of renewable energy resources, and wider deployment of "distributed" energy resources.[32] While maintaining a positive value for customers investing in clean distributed energy resources, our proposed NEM successor tariff would incentivize the deployment of NEM-eligible DER in locations and time periods that create the largest system value possible given the limitations of today's metering and system visibility.

7. Describe how the mechanism would be consistent with current or foreseeable enabling technology.

8. Describe the extent to which the mechanism relies on changes in rate design, including whether rate design changes to implement the mechanism would apply only to participating customers or apply to all customers.

The proposed mechanisms would apply only to participating customers in the interim stage. However, in the long term, it is important that the underlying rate structure for all – and not only participating – customers be more unbundled and more granular with respect to time and location, in order to provide all energy consumers with right price signals based on long-run marginal costs inclusive of external costs. Ultimately, customers within a customer class should face the same underlying price structure whether they are DER customers or not. This would provide efficient incentives not only for DER investment but also for energy consumption decisions.

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[32] *See* Department of Public Service website, About the Initiative, *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument (last visited Apr. 18, 2016).

9. **Describe the implications of the mechanism for fair, efficient, and sustainable recovery of distribution system costs.**

10. **Describe the implications of the mechanism for fair, efficient, and sustainable customer investment.**

11. **Describe the extent to which the cost of providing distribution service to individual customers utilizing DER is or could be avoided by the DER.**

12. **Describe how a mechanism would focus on, or apply to:**

    A) **Residential or small commercial (i.e., non-demand-billed) onsite projects.**
    B) **Demand-billed projects whose output is not substantially greater than the load at the meter.**
    C) **Large projects whose output is substantially greater than the load at the meter (e.g., remote Net Metering, Community DG).**

Remote net metering and community DG projects should be put on an LMP+D based valuation and compensation mechanism that values energy generated by these projects based on the location and the production profile of the actual facility. Until the complete mechanism and tools are developed for the value of D, the interim tariff can use system-wide average values, such as those estimated by the New York Net Metering Study, [33] as reasonable proxies for the benefits to be monetized in the value of D. Projects that clearly demonstrate that they are located at congested locations, have generation profiles that provide more distribution system value, or environmental benefits higher than the average project should be allowed to seek and qualify for additional compensation.

13. **Provide illustrations of how the proposed compensation mechanism would be applied. Issues for attention should include (but do not need to be limited to):**

    A) **Is accounting accomplished via bill credits or via some other mechanism?**

[33] New York Net Metering Study, *supra* note 13.

The accounting should continue to be done through a bill crediting mechanism. The credits should be monetary and based on a value of energy injections that is as time specific as possible.

B) Is generation netted against consumption or are energy flows accounted for separately?

In the interim, generation should continue to be netted against consumption for on-site facilities. However, for the reasons discussed above, netting against consumption is not appropriate for remote net metering because 100% of that energy is exported onto the grid while consumption at some other location is unaffected.

C) Is measurement and/or accounting of generation conducted on a volumetric or a monetary basis?

A monetary credit is more appropriate to reflect the dynamic nature of the value created by DER. This is especially important to help customers realize the system value of their DER investments and to help drive DER investment to maximize net social benefits.

If the accounting is not done on monetary basis, participating customers may not get compensated properly for the actual value of their DER systems. For example, consider a customer with a solar PV system and a volumetric (kWh) credit. When this customer exports energy to the grid during a peak hour time period, she will be credited a certain number of peak kWh credits. If the customer is only allowed to use these credits only during the same peak hours, she will not be able to reap the full benefits of her system if her peak period consumption is low. If she is allowed to use these credits during other periods, then that would mean that she would be exchanging her higher valued energy production during peak periods for a credit based on lower valued energy produced by the bulk system during off-peak periods. So, this customer would still not be earning the full value of the benefit she provided to the system. Therefore, regardless of how a customer is allowed to spend kWh credits, using kWh credits run the risk of restricting the customer from getting the full value for the benefits her DER has provided to the electric system. A better alternative is to provide the customer with a monetary bill credit based on the retail value of each kWh exported in each time interval.

14. Describe anticipated impacts on participating and non-participating low income customers.

The enhancements proposed for the current NEM structure would incentivize a more targeted deployment of DER, and the additional credits we propose are based on the additional system value created by the qualified DER. Based on the findings in the New York Net Metering Study, we expect the rate impacts from the interim NEM solution we propose to be minimal for the non-participating low–income customers.[34]

15. Describe how the mechanism would distinguish, if at all, between solar PV and other technologies currently eligible for NEM.

16. Describe how the mechanism would, if at all, account for the value of emissions reductions.

As both EDF and the Institute for Policy Integrity have noted in prior comments[35] and as we have suggested in the introduction to these comments, the most efficient way to value emissions reductions is to make polluters internalize the external cost of their emissions, in which event non-emitters benefit by not having to pay that cost. Even though rewarding non-emissions can be thought as the other side of the same coin in theory, an approach that rewards DER for avoided emissions rather than penalizing actual emissions is necessarily cumbersome and imprecise. Specifically, whereas actual distribution system constraints may be addressed through any combination of DER in various quantities, different DER avoid different amounts of emissions, and the amounts of emissions avoided by any given DER will vary based on time of day, season, and over a longer time period; the magnitude of carbon avoidance enabled by a non-emitting DER depends on the carbon intensity of the fleet of marginal bulk generation units, which is subject to change. Moreover, the estimation of emissions avoidance enabled by DER must be undertaken in a manner that is dynamic and tailored to the precise pollution profiles of

[34] New York Net Metering Study at 5

[35] Case 14-M-0101, Initial Comments of EDF regarding the Staff White Paper on Ratemaking and Utility Business Models (Oct. 26, 2015) at 7; Case 14-M-0101, Institute for Policy Integrity Comments on the Staff White Paper on Ratemaking and Utility Business Models (Oct. 26, 2015) at 23.

the particular resources that are eligible to be rewarded; otherwise, policymakers would have to pick winners by deeming only certain "good" resources to be eligible to be rewarded due to their superiority over conventional resources that give rise to the problem, which leaves open the question of how to treat resources that are less polluting than the system average, but not emissions-free, such as CHP. In a polluter-pays regime, resources such as CHP are automatically (and efficiently) advantaged compared to dirtier resources, but disadvantaged compared to cleaner resources, at all points in time; a regime that seeks to reward CHP for its better-than-average pollution profile will need to grapple with the fact that CHP is not cleaner than alternatives at all times, and that its advantages may decrease or vanish in the future.

Nonetheless, the Commission has stated in the NEM Interim Ceilings Order that the value of emission reductions can be quantified as part of value of D,[36] and our recommendations are tailored to the Commission's currently preferred approach. Because the external costs of pollution are currently not properly internalized into wholesale energy prices and therefore not reflected in retail prices paid by customers,[37] the value of emission reductions need special consideration compared to the other avoided cost categories included in the value of D. We will therefore refer to the approach as LMP+D+E, where E refers to the emission reduction benefits, with the understanding that the Commission will likely continue to subsume distribution benefits and environmental benefits within a single variable for convenience of reference.

In the initial phase, reasonable proxies based on marginal emission rates from the central generation could be used to estimate the avoided emissions by classes of DER for which an LMP+D+E based mechanism could be implemented, such as the community or remote net metered PV projects. The New York Net Metering Study,[38] which uses the SCC minus the NYISO monetized carbon costs to monetize the societal benefits associated with reducing

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[36] *See* Case 15-E-0407, Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law § 66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (issued October 16, 105) at 9 [hereinafter NEM Interim Ceilings Order].

[37] BCA Framework Order, at 17.

[38] New York Net Metering Study, *supra* note 10, at 61-69 (discussing the estimation methodology for avoided greenhouse gases and other pollutants).

marginal CO_2 emissions and EPA's estimates for the costs of SO_2- and NO_x-related health impacts, for example, could serve as the basis for the average avoided CO_2, SO_2, NO_x emission benefits for non-emitting DER. For technologies which potentially pollute less than the system average but are not non-emitting, analyses would need to be done to determine what emission benefits arise from these technologies and compensate them according to the same principles. When advanced metering makes it possible, more granular and precise estimates should be used as avoided emissions from distributed generation depending on the type of generator that the distributed generation is displacing – the marginal generator – an analysis that will greatly depend on the time and on the New York Independent System Operator ("NYISO") zone where the DG is located.

B. Developing a Full Valuation Methodology

The Notice Soliciting Comments quoted the NEM Interim Ceilings Order, which stated that the "value of D can include load reduction, frequency regulation, reactive power, line loss avoidance, and resilience. Other values not directly related to the distribution system are installed capacity requirements ("ICAP") and emission avoidance."[39] The BCA Framework Order specifically outlined that the bulk system benefits to be considered in a benefit-cost analysis are avoided energy costs, avoided transmission capacity infrastructure and related O&M costs and avoided ancillary services.[40] The reliability/resiliency benefits enumerated in the BCA Order were net avoided restoration costs and net avoided outage costs. Enumerated external benefits were net avoided greenhouse gases and net avoided criteria pollutants as well as avoided water and land impacts.[41] Once advanced metering functionalities are available, opportunities for more sophisticated approaches to more precisely valuing such benefits and compensate DER for these benefits open up. This proposal is intended to set forth such a more sophisticated, technology-enabled approach.

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[39] *Id.*

[40] BCA Framework Order, *supra* note 11, Appendix C, at 2.

[41] *Id.*

To provide incentives for economically efficient DER integration in locations and at times where they would produce the greatest total benefits, including external benefits, the underlying rate structure would need to be unbundled to reflect disparate values separately and to provide price signals which are based on cost causation and are granular with respect to both time and location. This granularity should inform supply charges as well as delivery rates. Ideally, retail energy supply charges should reflect the temporal and locational variation in the full social cost – private costs plus external costs – of generation and transmission of a given unit of energy. To successfully achieve this, energy wholesale market prices would need to internalize the full external cost caused by greenhouse gases and other pollutants, and resources that do not participate in the wholesale market such as small DER that are located at customer premises would also need to bear the full external cost of their pollution. On the delivery side of the retail customer's bill, the rate structure should provide price signals that in turn reflect the relevant local peaks that drive distribution system costs, as well as location- and time- specific volumetric charges that reflect energy losses on the distribution system.

Such a price structure, combined with the basic premise of current net metering mechanism – netting of on-site generation against consumption – would indeed make it possible for all customers to pay for the full cost of the services they receive from the grid, while getting paid for the full value of services they provide to the grid without any potential for cross-subsidization. Further, such a price structure would ensure that the prices customer face would actually signal the true societal cost of providing electric service at a particular time and location, and would incentivize DER investments where they are most valuable.

The premise of LMP+D directly speaks to the economic efficiency of such a price structure. However, the Commission will need to clarify the structure of "D" and refine the elements of this construct further to ensure that all the value categories provided by DER are properly reflected in price signals experienced by customers, so that the clean energy future envisioned by REV can be realized.

In particular, the Commission should further refine this approach as "LMP+D+E" where "E" refers to environmental values provided by the distribution level resource. As the Commission noted in the BCA Framework Order, while the wholesale markets reflect the value of existing programs for controlling air emissions, they do not accommodate the full value of the external costs related to those emissions. [42] Therefore, consideration of the full external damage costs requires an approach designed to address this undervaluation. Furthermore, different DER have different emissions characteristics which are independent of the value of their benefits to the distribution system, and these benefits therefore need to be separately considered and valued in an E value that does vary depending on the characteristics of the DER technology. With respect to the E value of avoided emissions, separate metering of generation would be required because wholesale market prices do not currently reflect the full external damage cost of emissions. Separate metering would make it possible to estimate how much carbon is avoided by non-emitting DER, how much is emitted by emitting DER, and correctly apply the E value to their generation. Paying close attention to how the "E" is handled is especially critical if the Commission intends the LMP+D valuation approach (unlike today's net energy metering) to apply to the full range of possible DER, which may include resources that are exceptionally highly polluting, even worse than the system average. NYISO's current "BTM:NG" proposal, which would permit 2MW, non-intermittent resources to sell energy in the wholesale market, provides a glimpse of what a not-so-clean distributed resource future could look like.[43]

Putting customers on an electric service price structure that is fully unbundled and granular so that it can recognize all the important values separately would provide incentives for DER deployment that would promote economic efficiency by driving DER to where and when they are the most valuable. Making such a price structure the default choice, however, may not be consistent with other policy goals or may present legal challenges. In addition, other aspects of the ideal LMP+D framework may not be the Commission's preferred course of action, for various reasons. A discussion of second-best mechanisms is set forth in <u>Appendix A</u> to these comments. In any event, if the Commission ultimately selects a default price structure other than

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[42] *Id.* at 17.

[43] *See* FERC Docket ER16-1213. *See also* Matt Christiansen and Elizabeth Stein, *The Rise of DG: Options for Addressing the Environmental Consequences of Increased Distributed Generation*, NYU SCHOOL OF LAW GUARINI CENTER AND EDF (February 2016), available at http://guarinicenter.org/wp-content/uploads/2016/02/DG-Policy-Br-Rough-Draft-vFINAL.pdf.

a true LMP+D structure, it should also ensure that the consumers have the option to opt in to an "LMP+D" price structure if they so desire.

Below we provide comments in response to the specific questions posed by Staff on the long term full valuation methodology.

17. Describe how a full valuation methodology should account for the following:

A) Variation in benefits and costs between generation that is dispatchable and generation that is variable or intermittent

Dispatchable generation should be eligible to receive credits for providing reliability services to other customers. The value of a reliability based credit should be limited to the extent to which DER provide reliability to other ratepayers or the system as a whole, by helping to avoid outage time and restoration costs that could otherwise be experienced by the utility and other customers. The private value of the reliability provided to the DER customer herself, if any, is already automatically enjoyed by the customer without the need for any payment by other ratepayers to that customer.

Intermittent distributed generation causes a challenge for system optimization as electricity supply and demand must be balanced in real time.[44] Addressing this challenge will be increasingly important as DER penetration increases. For example, smart inverters can generate or consume reactive power and mitigate voltage swings associated with PV systems. DER systems equipped with smart control technologies may bring more benefits to the system and should be compensated for the full value of any services they provide.

B) Which types of benefits and costs that should be valued on a fixed or a dynamic basis?

C) For those values where a fixed value is proposed, how often would the value be updated and by what process?

[44] Revesz & Unel, *supra* note 6, at 39-42.

D) For those components, where a dynamic value is proposed, identify the dimension(s) which should be variable (e.g., temporal, locational, service class, gross usage, and the like)

To provide a complete proposal without repeating concepts or interrupting the thought flow, the full proposed methodology as well as the answers for questions 17.B-17.C are provided below.

In establishing a methodology to fully value all the benefits that DER provide, and compensate DER properly for these benefits, it is helpful to go through each value category separately and illustrate how it can be incorporated into a price structure based on the LMP+D+E construct. Please note that the value categories we list and discuss below are not meant to be an exhaustive list of DER benefits.

Avoided Energy Costs. The avoided wholesale energy already has a dynamic value – the LMP. Therefore, any DER system that reduces the need for generation from the bulk system should be compensated using the LMP. In a future in which there are no technological barriers to netting on-site generation against consumption at frequent time intervals, and when there are enough enabling and programmable technologies to help customers adjust their behavior as well as automatically adjust their load patterns, this value should be updated as frequently as NYISO calculates it. Until such technology is widespread, a less frequent updating could be used. However, the number of settlement intervals should at least be high enough to recognize that there may be different peaks for generation and distribution, as well as "shoulder" periods.

If the LMP were reflected in energy supply prices, and the DER customers could net their production against their consumption based on the LMP at each time, those prices would correctly signal the energy value of DER services. Such an underlying rate would be particularly important for DER without exporting capabilities such as energy efficiency, the value of which is mainly determined by the underlying retail rate. Furthermore, the utility can assist customers in hedging against the risk of dynamic pricing by providing credits at flatter prices – and should be able to earn a premium from those customers for providing them with greater certainty. (If there is sufficient demand for such certainty from retail access customers, Energy Service Companies

("ESCOs") would likely follow suit, and if there is not, than that would mean this risk issue wasn't actually an issue for the customers.)

Avoided Losses. Energy losses can occur both on the transmission as well as the distribution system, and vary by both time and location because the amount of losses increases with both peak load and the distance to the central generation source. The value of each kWh lost between the generator and the consumer is the LMP, and therefore varies dynamically.

A portion of the value of avoided energy losses on the transmission system is already reflected in the LMP. However, to the extent that some portion of losses on the transmission system is not reflected in the LMP, it should be separately valued. Energy losses on the distribution system should in principle also be valued on a dynamic basis with values that differ depending on time and the location on the grid. However, the costs of implementing a system that correctly calculates the value of the avoided energy losses by time and location at the distribution system level should be weighed against the benefits of providing this additional level of sophistication.

Avoided Generation Capacity Costs. For efficient DER valuation, separate and unbundled supply capacity charges based on customer's contribution to ICAP requirements should be included in the underlying price structure. Such a price structure would allow the capacity benefits of DER to be netted against the customers' capacity charges, and hence value and compensate the DER properly for its generation capacity benefits.

Avoided Ancillary Service Costs. To properly compensate DER that provides ancillary service values, such as reactive power and frequency regulation, the underlying pricing faced by customers for electric service would also need to reflect their share of costs related to providing those services. Monetary bill credits should be provided for the full value of reactive power and frequency regulation provided by the DER. Because of the role of NYISO in controlling frequency regulation and reactive power, coordination with NYISO is critical in developing this component of DER compensation.

Avoided Distribution Capacity Costs. The maximum demand during peak system periods is the main driver of any new distribution system capacity investment.[45] The delivery rate structure for all customers should provide price signals that reflect the relevant local distribution system peaks that drive infrastructure costs. A DER customer would then be able to net against these prices and thus be compensated for contributing to avoiding distribution capacity investment. Importantly, these price signals would need to be location specific to induce economically efficient customer response. However, if such a delivery rate is not feasible, a time- and location-varying per-kW credit calibrated to provide the same net price signal together with the delivery rate structure could be used to compensate a DER system which reduces load during local distribution peak periods, as discussed generally in Appendix A (concerning second-best alternatives).

Because the benefits of avoided distribution capacity costs eventually arise from reductions in the utility's future load projections, these credits do not need to be updated to reflect real-time conditions. But they should be time and locationally variant to reflect at each location the time periods at which the utility expects local distribution peaks that are likely to drive the most costly distribution capacity additions.

Avoided Greenhouse Gases and Criteria Air Pollutants. Being able to properly value clean energy attributes of DER is crucial to the success of REV and achieving New York State's energy goals. Calculating the clean energy benefits of DER requires two important steps: quantifying the net avoided emissions, and then properly monetizing those net avoided emissions so that the externalities can be accurately and fully internalized.

1. *Quantifying Avoided Emissions.* Taking the example of carbon emissions, the quantity of carbon dioxide avoided, if any, by any DER depends on the type of generator that is on the margin in the wholesale energy market, and hence depends on the time at which the DER system provides its services (be it load reduction or generation). Therefore, it is important that a separate dynamic "E" component be developed which is based on the avoided emissions of a kWh of net load reduction.

[45] Track 2 White Paper, *supra* note 2, at 80 n. 81.

This would be calculated by looking at the amount of carbon dioxide that the marginal generator emits per MWh. Calculating avoided emissions dynamically in this way would allow a consistent applicability of the LMP+D+E construct to all DER, not just solar DG, and would help incentivize DER investment that is most beneficial for the society.

2. *Valuing Avoided Carbon Dioxide Emissions*. The Commission recognized that the Social Cost of Carbon ("SCC") values developed by the Interagency Working Group on the Social Cost of Carbon are the best available valuations of the marginal external damage of carbon dioxide emissions, although it further acknowledged that estimates vary and some have found marginal damage costs to be significantly higher.[46] The interagency established SCC should indeed be considered a lower bound since there are many climate impacts that are omitted in the integrated assessment models that were used by the interagency working group.[47]

   Even though New York participates in the Regional Greenhouse Gas Initiative ("RGGI") to help ensure that the external damage caused by carbon dioxide emissions is internalized by the polluters, the current RGGI cap is, as the Commission noted in the BCA Framework Order,[48] not stringent enough to provide a carbon price that corresponds to the full value of the external marginal damage. Therefore, distributed generation that emits less than central generation should be additionally compensated for avoided carbon emission benefits to ensure that externalities are fully internalized.[49]

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[46] BCA Framework Order, *supra* note 11, at 16.

[47] Peter Howard, Omitted Damages: What's Missing from the Social Cost of Carbon, *Institute for Policy Integrity Report,* 1 (2014), *available at* http://policyintegrity.org/publications/detail/omitted-damages-whats-missing-from-the-social-cost-of-carbon.

[48] BCA Framework Order, *supra* note 11, at 18.

[49] As EDF noted in their initial comments in response to the Staff Whitepaper on Ratemaking and Utility Business Models, to ensure that those reductions in carbon emissions are realized, the estimated quantity of avoided emissions

To ensure that this marginal external damage can be fully internalized, the avoided emissions should be paid the amount that is not yet been internalized by the RGGI program. As the Commission recognized in the BCA Framework order, LMP already internalizes the amount reflected by the RGGI price. Therefore, in determining the value of the clean energy benefits to be included for the "E," the RGGI price should be subtracted from the SCC.

Emitting DER. Some DER that could potentially be compensated through the LMP+D mechanism will also impose societal costs (i.e., negative externalities) in terms of GHGs and criteria pollutants. For example, fossil fueled DERs increase direct CO_2 emissions as well as local emissions of other air pollutants. However, not only can they not be expected to internalize these costs – they may actually undermine the regulatory framework that makes large electric generators internalize a portion of their pollution costs: the RGGI program, which is limited to generators of 25MW and above.[50] As the Commission recently concluded in its BCA Framework Order, CO_2 emissions from these resources should be valued at their marginal damage cost. For any given type of fossil fuel-fired distributed generation, average CO_2 emissions per kWh can be approximated based on the type of generator, in which case total value of the damage done by such distributed generation can be reasonably approximated on a dollar-per-kWh basis. For example, it would be possible to use average conversion efficiencies of a diesel generator to approximate the average amount of CO_2 emissions per kWh and then monetize it using the SCC. If the general LMP+D construct includes an E that is based on the emissions avoidance value of non-emitting DER, in the case of DER that produce emissions, the social cost of their actual emissions should then be subtracted from the compensation that the DER would otherwise be paid for their generation. Note however that the utility (or other energy-buying entity) should not be allowed to buy that power at that lower

should also be used to retire RGGI allowances or increase the stringency of the RGGI cap in the next compliance period.

[50] Christiansen & Stein (2016), *supra* note 43.

adjusted price because allowing that would create a perverse incentive for the utility to prefer to purchase higher-emitting generation because it would appear cheaper.

Other Pollutants. A similar approach would be appropriate for air emissions other than CO_2. It is important to note that the emissions of criteria pollutants from the emitting DER concentrated in densely populated areas would result in much larger marginal damage costs compared to the same amount of emissions from facilities that are not in population centers, though this might be addressed through rules that prevent such concentration of emissions rather than through pricing of DER services.

18. Describe whether a valuation mechanism should be adjusted for time-varying rates. If a customer is billed on a time-varying rate:

A) How would measurement and/or accounting for time-varying rates be handled? (E.g., how will generation be metered and credited against time-periods with differing rates charge to customers?)

If a customer is billed based on a time-varying pricing structure, the customer should be able to net her on-site generation against her load in each settling interval and thus be credited on a monetary basis with the time-varying pricing that applies in that interval. For each interval, on-site generation should be valued at the corresponding supply price and delivery prices applicable during a discrete time interval (since both supply and delivery service are avoided by the on-site generation), and therefore should be netted against both the delivery service charge (be it a demand charge or a volumetric rate) and the charge for the electric commodity. Monetary credits for net exports should carry over between billing cycles and be allowed to be used in any time period.

B) Would compensation be adjusted to reflect other time-varying elements of system value irrespective of whether a customer's consumptions is billed with time-varying rates?

Going back to our initial observation about the need to adapt the design of the compensation mechanism to the underlying pricing of electric service, compensation should reflect the time-varying elements of system value even if those are not reflected in the retail pricing for electric service experienced by a customer.

C) How would compensation be applied to other aspects of customers' bills? (e.g., fixed charges, demand charges, etc)

Customers should be allowed to apply any positive monetary credits against both fixed and demand charges. For example, in the context of any minimum bill requirement, if applicable, a rule that restricted how customers could apply positive monetary credits could risk undercompensating a DER customer for various societal benefits.

D) How would these mechanisms be applied to onsite DER compared to offsite or remote DER?

Generation should only be allowed to be netted against consumption for onsite DER. For offsite or remote DER, the LMP+D+E value assigned should be based on the actual location of the installation because the location of the installation is what determines the value (and costs) to the electric system.

19. Describe how the mechanism would balance price stability and risk mitigation (to facilitate market development) against the objective of accurate and dynamic price signals.

Utilities and ESCOs should be encouraged to offer tariff options for customers with different preferences for different services, and with different degree of risk aversion. Such tariff options allow customers the opportunity to select price offerings aligned with their needs. The options would range from a low risk, low variability option at one extreme to a higher risk, fluctuating LMP+D value at the other, allowing customers to choose the option that best suits their needs.

20. Describe the extent to which the system value of a single DER project may be a function of networked DER penetration (e.g., the total amount of DER on a particular circuit serving a similar set of system values).

III. Conclusion

Environmental Defense Fund and Institute for Policy Integrity thank the Staff for offering parties the opportunity to provide these initial recommendations concerning the valuation of distributed energy resources, and thank the Commission for its leadership in considering these important issues.

Respectfully Submitted,

Environmental Defense Fund
257 Park Avenue South
New York, New York 10010

By:

Kristina Mohlin, Ph.D.
Economist
Environmental Defense Fund
(212) 616-1284
kmohlin@edf.org

Elizabeth Stein
Senior Manager, NY Clean Energy Law & Policy
Environmental Defense Fund
(212) 616-1327
estein@edf.org

Jim Tripp
Senior Counsel
Environmental Defense Fund

Institute for Policy Integrity
New York University School of Law
139 MacDougal Street
New York, New York 10012

(212) 616-1247
jtripp@edf.org

Ferit Ucar, Ph.D.
Senior Clean Energy Economist
Environmental Defense Fund
(212) 616-1302
fucar@edf.org

Burcin Unel, Ph.D.
Senior Economist
Institute for Policy Integrity
(212) 992-6285
burcin.unel@nyu.edu

Appendix A

Second-Best Approaches

Putting customers on an electric service price structure that is fully unbundled and granular so that it can recognize all the important values separately would provide incentives for DER deployment that would promote economic efficiency by driving DER to where and when they are the most valuable. Making such a price structure the default choice, however, may not be consistent with other policy goals or may present legal challenges. In addition, other aspects of the ideal LMP+D framework may not be the Commission's preferred course of action, for various reasons. This appendix sets forth a discussion of some second-best mechanisms. In any event, if the Commission ultimately selects a default price structure other than a true LMP+D structure, it should also ensure that the consumers have the option to opt in to an LMP+D price structure if they so desire.

If value of D is not used as the basis for structuring the price of delivery service for all customers, a different crediting mechanism will need to be used, and the design of credits will need to be adjusted depending on the design of the underlying retail rate. For example, the value of the load reductions that DER can provide are higher in the case when non-DER customers are not facing a coincident demand charge (and therefore would not be moderating their demand during peak times) than in the case when they are. If the underlying distribution rate is suboptimal, any credits provided to DER work as a second-best alternative to an optimal distribution rate structure. Under such a second-best compensation mechanism, generation should still be allowed to be netted against consumption for onsite DER so that compensation corresponds to the avoided retail rate.

Unless the underlying pricing structure is changed to reflect underlying costs, exact valuation of each specific DER for their LMP+D contributions may require the installation of extra AMI metering equipment to monitor the total on-site generation at any location. For small DG owners for whom the deployment of such equipment may be cost prohibitive, reasonable estimates of the value of DG services may be developed by using a statistical sample and metering only the sampled cases for each type of DG in a given location. In any case, to ensure that the environmental costs or benefits of DER are correctly accounted for, it would be desirable even in this second-best construct to separately meter distributed generation output to ensure that its emissions benefits or costs are accounted for correctly. This is especially true in the case of any forms of DG which are dispatchable (and therefore cannot be expected necessarily to behave in the manner predicted by a statistical sample), especially if they produce emissions.

Just as we suggested for the interim solution, to the extent that the underlying retail rate cannot be designed to reflect the differences in the value of D across locations, credits provided to recognize particular values in a second-best construct for electric service pricing should be used to reflect such locational differences. For example, if the Commission sees value in levying a coincident peak demand charge that varies by location depending on local distribution peaks but it is not feasible to include that as an element in delivery pricing, a per-kW credit that varies by time and location could be calculated to approximate the same value. In especially constrained areas, such as the one for Brooklyn-Queens Demand Management program, credits that reflect the times at which the distribution capacity is approaching its maximum could vary dynamically (in the sense of reflecting real-time conditions) to reflect how close to the constraint aggregate load is at a given time, allowing for very high compensation to load relief when the need is critical. This would essentially be a dynamic and price-based alternative to a demand response program.