ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

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VIA ELECTRONIC MAIL

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

Re:
Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

Dear Secretary Burgess:

Environmental Defense Fund (EDF) hereby submits for filing the following comments in response to the June 4, 2014 Ruling Posing Questions on Selected Policy Issues and Potential Outcomes, Establishing Comment Process, and Revising Schedule.

Respectfully submitted,

Elizabeth B. Stein

Cc: Administrative Law Judge Eleanor Stein
Administrative Law Judge Julia Smead Bielawski
Active Parties

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision

RESPONSES BY ENVIRONMENTAL DEFENSE FUND TO TRACK 1 REGULATORY CHANGES AND RATEMAKING QUESTIONS ISSUED JUNE 4, 2014

The Environmental Defense Fund (EDF) thanks the Judges and the Commission for considering these important issues and for the opportunity to provide comments.

I. Potential REV Outcomes

EDF is a national environmental nonprofit organization. We have a strong interest in reforming the regulation of electric distribution utilities because of the electric industry's significant contribution to climate change and other pressing environmental problems. We believe that major changes to the existing regulatory model are critically needed and applaud the Commission for opening this proceeding, which we believe is essential to jump-starting the evolution of the system in a more sustainable direction. However, we caution that today's environmental statutes and regulations – which we recognize are beyond the Commission's jurisdiction – have grown up in tandem with the legacy centralized electric system and the regulatory paradigm for electric utilities that went with that system. As a result, the fundamental thrust of this proceeding – the migration to distributed energy resources (DER), which has the potential to enable considerable environmental, efficiency, and resiliency benefits – also poses a clear risk of negative environmental outcomes. This risk is especially acute because the less-developed regulatory framework applicable to small fossil-fueled resources may give them an unfair cost advantage compared to other technologies, further contributing to their proliferation. Our proposals with respect to the Outcomes list are intended to support the beneficial outcomes that the Commission seeks while remaining mindful of, and safeguarding against, the risk of negative outcomes.

We share the Commission's goal of seeing clean energy meeting more of New York's needs. However, we would like to see a greater focus on the end state of a clean energy system, including the larger role that we anticipate clean energy playing in the overall system, and the effectiveness of the markets in which clean energy is procured. To that end, would recommend the following minor modifications to the Outcomes list matrix:

- We suggest modifying the "clean generation" goal to shift the emphasis from installation to the end state of renewable power sources providing a greater share of New York's capacity and energy needs.
- To further advance clean energy in New York, and in keeping with the Commission's interest in animating markets to improve outcomes, we would recommend the addition of a new subject, "Animation of clean energy marketplace", and corresponding goal, "Clean energy resources have the opportunity to compete in a marketplace where their superior environmental characteristics are fairly valued."

Similarly, EDF supports the Commission's inclusion of a goal related to reducing regulated air contaminants. This goal, however, could be strengthened by reference to a broader range of environmental considerations, public health effects and disproportionate impacts on particular communities. First, we recommend that the list of goals include negative externalities which may be associated with electric generation, including DER; these negative externalities are not limited to air emissions, and can include land and water impacts.[1] The very nature of the REV proceeding, with its focus on DER, demands that we be vigilant with respect to a broader range of externalities, because the fact that DER are by nature co-located with load means that adverse impacts -- including pollution as well as quality of life impacts, such as noise and heat island effects – where they occur, will occur in places where people are living and working. For that reason, we further suggest that a locational element be added to the list of goals, so that no communities – especially low income communities – are disproportionately burdened by adverse impacts.

- Change the "regulated air contaminants" goal to a goal that embraces toxic emissions of all kinds ("Reduce toxic emissions arising from the electric system"); and
- Add a new goal, in the "Clean Energy" category, concerning impacts on low income and underserved communities ("Ensure that adverse impacts relating to electric system infrastructure, including air

[1] The recent history of coal ash illustrates the danger of focusing exclusively on air emissions while ignoring other consequences. As a direct result of technology designed to prevent toxic air emissions from coal-fired power plants, the toxins that would otherwise have become air emissions have instead remained in the solid waste arising from coal-fired electric generation, which means that today's coal ash is more toxic than was previously the case; however, the disposal of coal ash has not kept pace with the changing character of the solid waste, with serious consequences for the environment and public health. A recent example of coal ash hazards is Duke Energy's February 2014 spill of 39,000 tons of coal ash from a holding basin into the Dan River in North Carolina. *See, e.g.,* Coal Combustion Residuals – Proposed Rule, EPA (Dec. 4, 2013), http://www.epa.gov/solidwaste/nonhaz/industrial/special/fossil/ccr-rule/index.htm and Coal Fly Ash, Bottom Ash and Boiler Slag, EPA (Feb. 4, 2014), http://www.epa.gov/radiation/tenorm/coalandcoalash.html and Bill Chameides, Coal Ash Ponds: How Power Companies Get a 'Bypass' on Regulations Against Pollution, National Geographic (Mar. 24, 2014), http://energyblog.nationalgeographic.com/2014/03/24/coal-ash-ponds-how-power-companies-get-a-bypass-on-regulations-against-pollution/.

contaminants, water pollution, and noise impacts, are distributed equitably across the state and do not disproportionately harm low income communities").

Regarding the outcome with respect to the DSPP platform, we recommend adding more color as to the nature of an "effective" DSPP platform, specifically the level of situational awareness that should be expected of a DSPP charged with making decisions about dispatching DER. If the DSPP is not aware of all DER that can be substituted for energy from centralized generation in real time, that could have serious implications for reliability and resiliency, as well as environmental performance. While some distributed generation will be emissions-free, some DER will likely use fossil fuels. Without knowledge about the availability and operation of such resources, including those located behind the meter, the DSPP will have no way of quantifying energy or environmental costs and benefits produced from those resources, and it will be impossible to quantify the associated emissions or price them appropriately. Moreover, a natural disaster or fuel supply problem could disable a whole category of DER simultaneously. With insufficient information about available resources, unexpected outages or restoration challenges could result. Therefore, we suggest expanding the DSPP platform goal to incorporate this system awareness; for example, "Implement an effective DSPP platform, incorporating knowledge of all DER consisting of generation, storage, or demand response, including those located behind-the-meter, in a timely manner."

Although fuel diversity has repeatedly been named as a priority in this proceeding – and has long been regarded as a legitimate end in itself for sound energy practice reasons – we caution that the concept of "fuel diversity" could become a mechanism for protecting the highest-polluting fuels as they become less and less competitive in a marketplace increasingly reliant on resources that come with lower environmental costs.[2] In this proceeding we have an opportunity to rethink the axioms of how electricity is regulated, and we suggest that the Commission shift its thinking away from "fuel diversity" as an end in itself, and toward the particular benefits that fuel diversity can yield. For these reasons, we recommend that the "fuel diversity" outcome and the associated goal be replaced with other concepts that highlight the reliability and price volatility goals without committing to fuel diversity as the mechanism for achieving those outcomes. The two new goals that we would recommend adding are:

- System reliability is kept within acceptable tolerances, including under conditions where supply of one [or more] fuels becomes constrained.
- Price volatility is kept within acceptable tolerances, including under conditions where supply of one [or more] fuels becomes constrained.

[2] Esther Whieldon, Exelon VP: New England States' Infrastructure Plan Could Harm Markets, SNL (Jun. 05, 2014 10:36 AM), http://www.snl.com/InteractiveX/article.aspx?id=28247383&TabStates=0.

In the future, innovative entities serving as the DSPP may find ways to achieve those goals by reliance on diverse resources of all kinds (not solely diverse fuels), energy storage, financial hedging strategies, and perhaps other strategies which we cannot yet imagine. Shifting the focus to the core concerns of reliability and price volatility would open the door for leveraging tools other than fuel diversity to achieve these critical goals, while avoiding committing indefinitely to the potentially pernicious downside of unqualified "fuel diversity."

If the goal of "fuel diversity" were modified to emphasize the reliability and price concerns that make fuel diversity desirable – *i.e.,* the need for adequate reliability and acceptable wholesale prices even when there is a crisis affecting one or more fuels – it could be seen as an analogue, in the generation market, for the transmission planning concept of being prepared for an "n-1" contingency (or perhaps "n-1-1", depending on risk tolerance.) In much the same way as an n-1 contingency can be addressed through transmission but also through a wide range of non-transmission alternatives, this approach would make room for fuel and resource diversity, but also invite creative problem solving. Conversely, committing in advance to fuel diversity as the only acceptable means for achieving these ends is analogous to committing in advance to transmission as the only means for meeting reliability needs.

On a related note, we also recommend close examination of the progress in Con Edison's North Central Brooklyn efforts, which the Staff Report recognized as a real-world example of a utility beginning to develop some DSPP integrated system planning functionality in response to an identified system need.[3] This empirical case may be illustrative of a range of possible DSPP behaviors and may be useful for developing additional meaningful goals for what is in fact expected of the DSPP.

Our analysis of the question presented in Part II, which concerns the Vertical Market Power policy, also prompts us to ask whether resource adequacy should be presented as a distinct outcome, separate from reliability, in the final version of the list of outcomes.

EDF has extensive experience working with utilities and commissions to develop effective metrics in the context of smart grid deployment plans, and we look forward to assisting the Commission in developing suitable metrics after the Commission has established the outcomes.

II. Optimal Ownership Structures for Distributed Energy Resources (DER)

The analysis at pages 26-28 of the REV Staff Report,[4] regarding the Commission's Vertical Market Power Policy implicitly raises some important questions related to ownership of DER, namely:

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[3] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, at p. 66 (issued and effective April 25, 2014).

[4] *See* Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, at pp. 26-28 (issued and effective April 25, 2014).

1. Is the Vertical Market Power policy serving New Yorkers well at this time? (If not, what is the nature of the issues that have arisen and what are options for addressing them)?
2. Should the Vertical Market Power policy be understood to preclude utility ownership of DER?
3. Are there other policy considerations that should preclude or limit utility ownership of DER?

Our analysis of each of these three questions follows below.

1. *Is the Vertical Market Power policy serving New Yorkers well at this time? (If not, what is the nature of the issues that have arisen and what are options for addressing them)?*

We recognize that the Vertical Market Power policy, which established a rebuttable presumption against generation assets being acquired by unregulated affiliates of the utility companies that had previously owned them, was adopted to ensure that market forces could function effectively in the electric generation industry and, through the workings of a competitive marketplace, drive down costs. However, in footnote 13, the Staff Report notes that "[t]he Commission is currently dealing with an unintended effect of strict application of the Vertical Market Power policy at the bulk distribution level, as the retirements of various plants not owned by utilities pose system reliability issues." This outcome should cause great concern, because one of the cornerstones of the regulatory compact is that utility companies are depended upon to provide "such service… as shall be safe and adequate and in all respects just and reasonable" and that the companies' charges for such service likewise "shall be just and reasonable".[5] If, as a result of the application of the Vertical Market Power policy, utilities are limited in their ability to furnish safe and adequate service – unable to fulfill their statutory duty – appropriate modifications to the Vertical Market Power policy to avoid such an outcome must be considered.

To avoid such unintended consequences in the future, the Commission must ensure that the markets that grow out of existing policy and the REV proceeding are capable of optimizing not only price and quantity of energy, but other values the Commission and consumers care about, including reliability, resource adequacy, and the other REV outcomes that are ultimately adopted. Although market-based solutions should be preferred due to the superior efficiency of markets compared to regulatory processes, where practical constraints prevent effective markets from being created in the near term, regulatory processes should be substituted and, where possible, should foster the creation of effective markets in the medium- or long-term.

2. *Should the Vertical Market Power policy be understood to preclude utility (T&D company) ownership of DER?*

The challenge that the Staff Report describes in footnote 13 is a close cousin of another market failure that is receiving considerable attention in the REV proceeding: just as the utilities may be hamstrung in their ability to provide safe and adequate service due to centralized generation assets on

[5] N.Y. Pub. Serv. Law § 65(1) (McKinney).

which they depend being ultimately beyond their control, they may be understandably reluctant to rely, for purposes of meeting their statutory obligation, on DER that are beyond their control.

To some extent, the distinction that the Vertical Market Power policy draws between generation and the distribution system is an artifact from another era, before cost-effective DER was available to provide reliability and demand-side management. Understanding the Vertical Market Policy to preclude not only utility affiliate ownership of those large resources that are capable of participating in wholesale markets, but also utility ownership of distributed generation that can enhance reliability or can be used as demand-side resources at lower cost than system expansion, would be an unfortunate gloss on a policy that may already be having adverse consequences. Indeed, uncertainty about whether utility ownership of distributed generation is permissible may be already contributing to the habit of building transmission and distribution infrastructure to serve peak loads that diverge more and more from base loads. Since distributed generation resources can sometimes address these rising peaks at far lower cost, while potentially yielding additional benefits such as greater system efficiency, increased resiliency and lower emissions, the consequences of prohibiting utility investments in distributed generation would have pernicious effects indeed.

Moreover, not all DER are generation. Energy efficiency, storage, and flexible demand are all DER that can improve overall system efficiency and should reasonably play a prominent role in efficient system planning and operation. Interpreting the policy to preclude ownership not only of DG, but of the full range of distributed non-transmisison and distribution alternatives, would undermine efficient system design even further and should be avoided. Indeed, to consider this question properly, it is useful to consider how each category of DER has developed to date – for better or for worse – and how each might change as a result of the regulatory changes arising from this proceeding.

Customer-Sited Energy Efficiency. Over the last 10-20 years, major technological developments have affected electric industry GHG emissions, tempering their growth. Efficiency of customers' energy consumption has improved dramatically due to significant and steady increases in the efficiency of building energy systems, lighting, household appliances, and electronic equipment. Federal, state, and local standards and codes applicable to equipment and buildings have supported this development.[6] Efficiency advances have suppressed increases in base load demand, even as new categories of power-consuming devices have proliferated. In downstate New York, base load is not increasing materially.

[6] *See, e.g.*, Appliance Standards Questions and Answers, Appliance Standards Awareness Project (May 2014), http://www.appliance-standards.org/sites/default/files/Progress_toward_3_billion_CO2_reduction_1.pdf *See also*, Julian Prokopetz & Rob Sargent, Building Better: How High Efficiency Buildings Will Save Money and Reduce Global Warming, Environment America (Mar. 2010), http://energycodesocean.org/sites/default/files/resources/Building-Better-vAME.pdf.

There is every reason to expect that improvements in building and equipment efficiency will continue whether the centralized electric utilities play a DSPP role, or compete with non-utility parties to market efficiency services, or not. That said, there are areas where the efficiency marketplace needs further support–notably, improving the energy efficiency financing marketplace, addressing market failures attributable to principal-agent problems (such as the split incentive), and reaching the poorest households with the benefits of energy efficiency.

The REV proceeding could significantly increase the uptake of energy efficiency by providing those who might undertake it with more meaningful market signals and encouraging all cost-effective energy efficiency. There is reason to suspect that even the recent improvements in energy efficiency uptake fall well short of what is possible or cost-effective, among other reasons because the owners and operators of customer premises that could benefit from energy efficiency do not receive price signals that accurately capture the cost of energy and the potential to avoid new grid infrastructure in their areas, meaning that the value of strategically located efficiency may go unrecognized. The only market signal facing the property owner is the opportunity to save energy over time, a market signal that has proven insufficient in spurring to action a significant number of building owners (which is especially likely if the problems are expensive to remedy and the payback based only on energy savings would be slow). Even if the property owner is somewhat motivated by energy savings, the market signals experienced by the property owner would fail to direct him or her to put resources toward buildings located in areas where there was a risk that significant grid investment would be needed in the foreseeable future, rather than other equally inefficient buildings in the same portfolio. If building owners directly benefit when they install energy efficiency by receiving a payment for the avoided cost of new grid infrastructure, significant improvements in building efficiency through operational improvements and capital improvements could yield significant savings for all ratepayers. Absent an appropriate market signal, however, energy efficiency opportunities may be left on the table even where the contemplated infrastructure investment is enormous. Indeed, at upwards of $1 billion,[7] the cost for a substation upgrade is sobering, and the urgency of capturing strategic efficiency opportunities is clear.

In this context, where an already somewhat successful resource type – one that poses no particular interconnection or integration challenges for the grid – is well-positioned for further growth, we are not aware of any way in which incumbent market actors would be in a position to erect barriers to entry to other parties.

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[7] Naureen S. Malik & Jonathan N. Crawford, Con Edison Seeks to Avoid Building $1 Billion Substation, Bloomberg News (Jun. 28, 2014 12:01 AS) http://www.bloomberg.com/news/2014-06-27/con-edison-seeks-to-avoid-building-1-billion-substation.html

Distributed Generation. As with energy efficiency, distributed generation is a growing resource class even without the help of the REV proceeding. However, there is reason to believe it could grow quite a lot faster and more economically. Customer demand for distributed generation being thwarted by "some clearly identified obstacles"[8] is an important consideration of the REV proceeding. As further discussed below, the conditions under which the DSPP should be able to own distributed generation resources implicate not only market power but also other competitive advantage that utility companies may have due to their regulated status (addressed later in this response).

Demand Response/Flexible Demand. Demand response ("DR") is distinct from the other categories of DER insofar as it has no reason to exist other than in the context of a dynamic macro-system. Whereas some customer-sited efficiency can be justified based on energy savings alone, and managing an individual facility's energy needs (even allowing for stand-alone operation in some cases) can be motivation enough for distributed generation, DR is a category of actions that only makes sense in the context of a system and market which are sometimes constrained. DR makes load, historically presumed inelastic, and makes it a partner with supply in balancing the macro-grid and operating it efficiently.

A utility should have an interest in DR programs insofar as, if its incentives are aligned properly, it should be concerned about expending large sums of money to expand transmission and distribution capacity to service time-limited peak demand. However, it may not be as concerned as one would hope with avoiding large expenditures in transmission and distribution capacity to serve critical peaks because its priority is reliability and its fundamental business involves earning a return on capacity that it builds to ensure reliability. If the utility's interest in system efficiency were properly aligned with customers' interests, one would expect utilities to procure a socially optimal level of DR. Presently, we believe that this is not the case. However, as discussed below, this may be a consequence of the throughput/rate base model of rate regulation. If the Commission, through the REV proceeding, definitively severs the relationship between asset cost and utility companies' earnings, that may go a long way toward giving the utility reason to share society's preference for lower cost solutions to peak management.

At this time, most utilities in New York State do not have DR programs of their own, except that some have programs for direct control of customer thermostats. We are not aware of instances in which the utility involvement in customers' DR has crowded out third-party participation in that marketplace. It seems a bit premature to be contemplating utility "ownership" of DR resources when they have, for the most part, afforded DR such minimal consideration in planning how to manage their peak conditions. For the most part, New York's utilities have yet to demonstrate that they are committed to working with all their customers to manage peaks, and that they have the expertise or competency to engage larger numbers of smaller customers in DR.

It is worth noting that Con Edison has recently modified its Direct Load Control (DLC) tariff, which previously was designed solely for residential customers with smart thermostats supplied with the utility. In its modified form, the tariff now permits customers who purchase their own smart thermostats (*e.g.*, a NEST thermostat) to participate in DLC. By making this change, Con Edison has proactively made a space for third-party equipment facilitating mass market DR. In this context, where the marketplace is inextricably related to grid operations – and where some good early work has been done by the utility companies – we are disinclined to recommend that utilities be kept out of the market for reasons of market power.

Regarding the recent decision at the D.C. Circuit Court of Appeals concerning FERC Order 745: this matter is very close to our hearts, and we share the Commission's concerns. EDF, together with Natural Resources Defense Counsel and Chicago Utilities Board, filed a brief of amicus curiae in support of FERC's position in this case,[9] and on Tuesday, July 8, 2014, we filed a further petition in support of FERC's motion for en banc review of the case.[10] We appreciate the Chair's letter to FERC, dated July 3, 2014, urging FERC to "seek clarification upon its petition for rehearing that the Court's decision does not abridge states' rights to work with FERC and the respective ISOs and RTOs in this regard."

The court decision's fundamental thrust seems to be that DR products can never be "wholesale" because they involve retail sales (or lack thereof). We see the decision as deeply flawed However, insofar as it could be understand to severely hamstring *FERC*'s ability to do anything at all relating to wholesale DR products, there is a risk that states might no longer find an effective, able partner in FERC, in this critically important area of ambiguous state and federal jurisdiction. If the states do not have jurisdiction over DR products that participate in wholesale markets, and neither does FERC, then who does?

Stepping back from the immediate issue, however, it may be worth noting that one of the primary reasons why wholesale DR is so important – and the reason it needs to be well compensated at the wholesale level – is the ubiquitous fact of retail-level market failure. Much as pricing all items in the grocery store the same way would lead inexorably to the over-consumption of filet mignon, the absence of economically defensible, time-based retail price signals leads directly over-consumption of electric

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[9] Brief of *Amici Curiae* Envtl. Def. Fund, Natural Res. Def. Council, and Citizens Util. Bd. in Support of Respondent's Petition for Rehearing *En Banc*, Elec. Power Supply Ass'n v. FERC, 2014 U.S. App. LEXIS 9585 (D.C. Cir. May 23, 2014) (No. 1501436 Sep. 05, 2012).

[10] Motion for Invitation to File Brief of Amici Curiae Envtl. Def. Fund, Natural Res. Def. Council, and Citizens Util. Bd. in Support of Respondent's Petition for Rehearing *En Banc*, Elec. Power Supply Ass'n v. FERC, 2014 U.S. App. LEXIS 9585 (D.C. Cir. May 23, 2014) (USCA Case 11-1486 No. 1501436).

service by retail customers during critical peak periods. Much of what we now call "demand response" consists of paying some customers quite a lot to reduce their consumption, in order to overcome other customers' failure to respond to scarcity pricing because they are not experiencing scarcity pricing. In fact, if retail customers everywhere always paid prices for electric service that reflected wholesale clearing prices in real time, it might turn out to be the case that DR *programs* were not necessary at all, because the innate elasticity of the demand curve would by itself yield load reductions during the most expensive periods. We urge the Commission to view the REV proceeding as, among other things, an opportunity to mitigate a major retail market failure – the failure to price electric service to reflect time of consumption – which has made DR necessary in the first place.

3. *Are there other policy considerations that should preclude or limit utility (T&D company) ownership of DER?*

To the extent the Vertical Market Power Policy and the opportunity to ratebase the investment encourages utility companies to prefer investments in transmission and distribution over localized generation solutions that they cannot control, that bias is exacerbated by the fact that under today's cost-based regulation, the utilities' own pathway for earning a profit is clear for distribution system investments, but less clear for all other solutions.

In its Statement of Policy Regarding Vertical Market Power, the Commission defined vertical market power as occurring "when an entity that has market power in one stage of the production process leverages that power to gain advantage in a different stage of the production process."[11] As described above, although we agree that vertical market power is a legitimate concern as a factor that could limit the functioning of markets, the "stages of the production process" in the context of the electric industry – the familiar three functions of generation, transmission, and distribution – are interdependent. Moreover, whereas "the stages in the production process" of a good (for example, extraction of raw material, transportation of that raw material, and fashioning that raw material into a finished good) may be quite distinct phases in a single process, in the context of an increasingly distributed system, the three functions that make up the traditional utility industry, as well as myriad new functions, may be substituted for one another. Given the complex relationship among these functions, it should not be surprising that barring the utilities from one or more of these functions may have adverse consequences for system planning and adequacy and/or costs.

Under the current regulatory paradigm, the ability of the utility to rate-base investments approved by the Commission, and thus earn a predictable return on such assets, gives the utility an advantage over third parties that is distinct from the anti-competitive effect of vertical market power: lower cost of

[11] Case 96-E-0900, Statement of Policy on Vertical Market Power, App. I, at p. 1 (issued and effective July 17, 1998).

capital, and the ability to charge lower prices over a long period. Unless the Commission acts decisively to sever the connection between utility asset ownership and compensation, these advantages will continue to exist, whether or not the utility serves as DSPP. For this reason, as also noted in our response to the Track 2 questions and above, we recommend that the Commission follow the example set by the United Kingdom in its adoption of the RIIO model, and move once and for all away from the utilities being entitled to earn a return on asset value, and migrate to a different regulatory model, one where companies are entitled to be paid for performance irrespective of the value of their assets. We also recommend that wherever possible, the DSPP be required to choose solutions through a competitive bidding process, with the utility and its unregulated affiliates permitted to bid. Although a risk of self-dealing would exist where the DSPP and the utility are one, this risk can be expected to be somewhat tempered by the fact that both functions are only fully compensated if they perform well, and by the fact that, as we would recommend, the utility's position as DSPP should be at risk. (Indeed, we note that if at any time the utility is *not* serving as DSPP, or not performing DSPP functions that allow it to influence project selection, market power concerns about wires company ownership of DER may evaporate entirely.)

However, it is not clear that a change in regulatory model alone would fully level the playing field for DER ownership as between utilities and third parties. Even in a radically altered ratemaking environment, utility companies (including new "utility" companies that may exist in the future – *i.e.,* DSPP entities that are distinct from the incumbent wires companies) may enjoy unique advantages, stemming from their scale, existing customer relationships, and potentially even a continued low cost of capital. For these reasons, the Commission should proceed with caution in opening the floodgates to ownership of DER by regulated utilities and their affiliates. To that end, we recommend that the Commission adopt an approach that balances the following guiding principles:

1. It is reasonable for a utility (DSPP) to own DER where the primary function of that DER is to advance that entity meeting its statutory obligations, including DER that primarily serves resiliency, reliability or demand-side management.
2. Utility (DSPP) ownership of DER must not be permitted to interfere with the emergence and functioning of robust third party markets for generation and other DER services.

III. DSPP Identity

The question posed is whether incumbent utilities or an independent entity should serve as the DSPP, and how and in what respect the Staff Report analysis provides an adequate basis for responding to this question. Our response has several parts. First, we clarify what the DSPP functions are. Second, we consider arguments for allowing the incumbent utilities to serve these functions. Third, we consider the negative consequences of incumbent utilities performing any or all of the DSPP functions, and whether changes in economic regulation, pricing and technology could address those concerns (and, if not, precisely what role another entity should play). Finally, we suggest a path forward for fostering the development of a discrete DSPP function in the context of today's regulated monopolies as the regulatory construct and business model of those entities are undergoing a profound transformation.

DSPP functions. The Track 1 questions do not describe what the DSPP function is or functions are. The Platform Technology working group identified three DSPP functions: grid operations/wires, integrated system planning and market operations. In formulating our response to the questions posed, we accept this description of the DSPP functions.

Arguments the support the incumbent utility performing all three roles. Basic metrics for performance of any electric service system include reliability and safety. Reliability means that the electric system has the capacity to accommodate the demand placed on it as a result of customer usage and the strain caused by maintenance problems that may affect particular components of the system. The performance of the electric system is driven by how the system is planned and operated. If the functions that together comprise the DSPP role are split among multiple entities, it is not clear who would assume the role of assuring reliability. If an incumbent utility provides grid services but another entity undertakes planning to determine what kind of distribution capacity is required in different networks to assure reliable service, then who assumes the reliability mandate? Yet on the other hand, we acknowledge that these reliability concerns may be manageable because we have seen generation split off from T&D, and T split off from D, without catastrophic reliability consequences.

In addition, conducting detailed planning and operational management of the system requires extraordinary expertise that improves with knowledge and experience. As a result, if a new entity assumed certain DSPP functions that required systems and/or knowledge that the utility already possesses (or built), it would either have to duplicate the incumbent utility staff's technical capacity, rely heavily on the incumbent utility's staff, or acquire systems and staff from the incumbent utility company. If so, the advantage of assigning those roles to a new entity is unclear. Without going into a lot of detail, the Staff Report looks at the role of knowledge, experience and technical capacity to perform the planning and operations functions and concludes that they cannot be efficiently separated. That reasoning supports combining these functions, and assigning them to the incumbent utilities, effectively enlarging their existing monopoly.

As discussed above, much DER activity (including customer-sited energy efficiency, distributed generation, and DR) currently takes place independent of the actions of incumbent utilities, although the utilities do have the capacity to take those DER actions into account in terms of planning and operations. At this time, incumbent utilities have had limited experience fostering DER. However, the incumbent utilities have the technical capacity to plan, make and encourage DER investments, *e.g.,* improvements in energy efficiency, and in performing infrastructure capacity planning. Similarly, due to their knowledge of their customers' power needs, they may be aware of DR opportunities.

Disadvantages to incumbent utilities performing DSPP functions and opportunities for mitigation. On the other hand, there are potential disadvantages to the incumbent utilities performing all of these roles. The incumbent utilities are inclined to invest in expanded traditional transmission and distribution capacity to solve peak demand problems. They could discourage effective DER actions by third parties, and thus prevent competitive markets from providing expanded DER services. Even if they do not actively discourage DER, their tendency to favor traditional transmission and distribution solutions may limit the attention and resources that they devote to animating the new markets through which third parties might furnish DER to address system needs.

A threshold question, then, is to what extent these inclinations on the part of the incumbent utilities are in fact driven by today's regulatory structures, rate and market signal regulation, and current electric service delivery and measurement technology. If the old regulatory paradigm and technology are the reason for the incumbent utilities' seeming inability to behave in a manner that would animate new DER markets, to what extent might these disadvantages by moderated through changes in that paradigm and the technology that they are authorized to use? In other words, would a full transformation of the regulatory paradigm from one that is based on the cost of assets to one that is based on performance by itself cause the incumbent utilities to become more supportive of DER? More broadly, what could be done by the Commission, NYSERDA, NYISO and the State to address some or all of these potential disadvantages of having the incumbent utilities play these roles? Considering these questions would reveal whether changes in the economic framework of utility regulation could resolve particular concerns, particularly as we develop a clearer sense of exactly what DSPP functions a new entity should play.

Economic Regulation. Current economic regulation would appear to create an incentive on the part of the incumbent utilities to invest in expanding distribution infrastructure capacity to solve peak demand challenges rather than investigating potentially more cost-effective and environmentally better solutions. This is because traditionally the Commission has assured incumbent utilities a rate of return on their assets, but has not provided incentives for incumbent utilities to search out and facilitate implementation of cost-effective DER.

There are two ways to change this bias. First, performance should ultimately be the only reason for future infrastructure investments. Performance-based ratemaking could move incumbent utilities to consider more closely the economic cost and environmental implications of alternative solutions where, for example, efficient or renewables investments could result in lower cost or emissions compared to infrastructure expansion. Additionally, the Commission could require utilities to conduct such investigations prior to undertaking major capital investments in the system.

This latter strategy is reflected in the Commission's February Order,[12] which calls upon Con Edison to investigate alternative non-traditional solutions to its proposal to expand substation capacity in North Central Brooklyn. The Commission could impose a requirement to investigate alternative DER-type solutions and compare their economic, social and environmental costs to more traditional investments applicable to utilities statewide. Performance-based ratemaking could then reward utilities for effective execution of the planning, project selection, operational implementation, and management tasks involved. Ultimately, if the Commission finds that a particular incumbent utility is not performing such a geographically focused planning function appropriately, it could find a new entity to perform this investigation.

Over time, we anticipate that the migration to performance-based ratemaking without reference to asset value alone should serve to reduce or eliminate the bias towards traditional infrastructure rather than DER investments. In a performance-based ratemaking regime in which capital assets were no longer the driver of revenues, the utility would be motivated to invest in the most cost-effective solution which would achieve the desired reliability outcome. If there is lingering concern about a bias against distributed solutions, Commission could even go further, allowing the incumbent utility to earn greater revenues in a PBR plan if it chooses a certain level of DER over grid investments, provided the DER value proposition is superior in terms of cost, environmental and other outcomes. The Commission could also begin to implement pilot programs where the Commission selects an independent entity to serve as the integrated system planner for a particular distribution circuit. The Commission could simply select one or more of the utility's worst-performing circuits as measured by standard reliability metrics.

Pricing, rates and market signals. Second, the practices for setting rates and pricing signals may encourage over-investment in traditional transmission and infrastructure, and under-investment (by all parties) in strategically-located DER. (*See* our responses to question 3, 4 and 5 under Rate Design in our Track 2 responses.) Today, a third-party DR aggregator can provide a service to NYISO, and obtain remuneration in the form of peak demand energy prices. That same aggregator may simultaneously (albeit inadvertently) be providing value to an incumbent utility and its customers by reducing the need to expand local infrastructure capacity to meet that peak demand. However, today, there is no systematic way for such an aggregator to be compensated for its role in helping an incumbent utility address a peak demand problem. The Commission should address this problem – and may have an opportunity to do so in the context of the North Central Brooklyn project – by allowing the aggregator to receive a payment from the utility for the avoided distribution system benefit.

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[12] Order Approving electric, Gas and Steam Rate Plans in Accord with Joint Proposal, (issued and effective Feb. 21, 2014) Case 13-E-0030 et al.

Similarly, property owners, building owners and businesses may have incentives to make energy efficiency investments because of savings in energy purchases, although those savings may not suffice to inspire action for various reasons. However, except for customers subject to a mandatory hourly pricing program or other granular time-differentiated price signal, most residential and small commercial customers have little systematic knowledge that their consumption of power during peak and critical peak periods is creating a need for infrastructure costs that they and other customers will bear in the future.

Thus, for example, if a third party were to replace/upgrade 50,000 inefficient air conditioners in the North Central Brooklyn area, or any network area experiencing capacity constraints, no market signal today would reward that party for its role in generating sizable savings for all utility customers by avoiding the cost of traditional infrastructure capacity expansion. In general, customers, third parties as well as the incumbent utilities might be inclined to make better and more efficient DER investments if market signals existed that conveyed information about the marginal capacity savings as well as peak demand energy savings of such investments.

Technology. Evolving technologies could improve the efficiencies and benefits of a range of DER activities, and competition bringing new players into the utility landscape, the pace of innovation could increase. As further discussed in our response to question 5, there is reason to hope that the newly animated markets, and the new players who come to those markets, will increase innovation. If the incumbent utilities play all of the DSPP roles for any period of time, it would be unacceptable for them to leverage those roles to thwart competition by third parties or discourage the development and adoption of technologies that could promote efficient and cost-effective DER.

As an example: Con Edison has a pilot residential smart appliance program that, among other things, provides devices (Modlets) that Con Edison can use to cut down on household air conditioning use when the system is under stress during peak demand periods at the system or network level. With the emergence of the NEST technology as a successful consumer product, one could imagine a third party providing a similar service using wireless smart thermostat technology and aggregating energy consumption savings for purposes of selling DR to NYISO. Additionally, as small-scale storage technology improves, one could imagine a third party investing in and aggregating residential or small commercial renewables and storage capacity. Such a third party could sell this power service to NYISO during peak demand periods at then prevailing rates. In theory, the incumbent utility and third party entities could be in competition with each other to furnish such technologies and services. The incumbent utilities should not have an opportunity to use their power as DSPP to discourage such competition.

The question is how to let both incumbent utilities and third parties harness evolving DER technology without the utilities, through the new DSPP functions, hampering competition through the DSPP role. Elsewhere we discuss the importance of requiring utilities that are considering DER solutions to address infrastructure capacity constraints to open up such solutions to other parties through bidding. The DSPP should enable third parties to offer innovative DER solutions to system planning needs as part of a systematic process while recognizing the benefits of the desired outcomes, including cost effectiveness and advancement of clean energy.

Another emerging technology that could expand DER opportunities for third parties and customers even with incumbent utilities performing the DSPP functions is advanced metering, be it wired or wireless, and related technologies. Advanced meters provide the capacity for time-of-day pricing and two-way communications. Third party investors and aggregators should have access to this information with customer consent. Though the subject of access to data is currently being considered in a separate case,[13] it is important to highlight the role this access can play in driving the desired REV outcomes. Providing meaningful and actionable data to customers in a timely and cost-effective manner can drive better energy use decisions. As customers have greater clarity of how their individual energy use impacts their own costs and costs placed on the system, they could be more open to a wide-array of tools of energy management, including DER. Whether the goals of this proceeding can be accomplished without advanced meters is an open question.

A Path Forward.

While initially we envision the incumbent utilities performing the DSPP functions, as proposed by the Staff Report, this should be a temporary expedient rather than an end-state. Most of the reasons given in the Staff Report support this initial assignment of the DSPP role, and not the permanent assignment. As we gain experience with the kinds of economic regulation and pricing reforms described above and as technologies evolve, we will be in a better position to define the DSPP functions and select among interested parties to find and retain the most eligible entity or entities to perform these functions.

To that end, we would recommend that the initial assignment of the DSPP role to the incumbent utility, if the Commission opts for that approach, be time-limited. Indeed, we would recommend that upon the assignment of this role to the incumbent utilities, those utilities should establish separate assets, accounting, and revenue requirements for each of the functions that the DSPP performs. The Commission, with input from the incumbent utilities and other stakeholders and with experience gained from regulatory and pricing reforms, could then begin developing an RFP for future assignment of these functions.

The RFP might expressly note that there may be synergies among the functions and that applicants may want or need to perform more than one of them in order to be maximally effective, and that respondents (including the incumbent wires company) should elucidate such synergies in their

[13] *See* Case 12-M-0476, Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State.

proposals. In considering various responses, the Commission might consider multiple possible configurations, together with their implications for reliability and competition – as well as the cost of regulating two or more separate monopolies. Through such a process, the proper scope of the DSPP functions, the complex relationships among them and the nature of PSC regulation of these functions could be properly elucidated. Finally, the PSC might want to make clear that it might review DSPP functions and assignments of roles periodically with the possibility of considering proposals from emerging companies.

We also recommend that the Commission begin to implement pilot programs which involve using an independent party to perform certain DSPP functions on a limited basis. For example, the Commission could issue an RFP to select an independent party to perform the integrated system planning role on each utility's worst performing distribution circuit. Using a limited pilot program would allow the Commission to "dip its toe in the water" of splitting apart the DSPP function rather than jumping in head-first. The learnings gained from these pilot programs would help inform the Commission regarding whether to move forward with a complete separation of any of these functions from the incumbent utility.

IV. Benefits and Costs

Cost-benefit analysis will remain an element of system planning for multiple reasons. Today, the absence of price signals about the cost of service during peak periods distorts load shapes from what they would look like if they were based on market equilibria that might exist at the time that consumption actually takes place. The fact that grid investments are socialized while customer investments in DER are not produces additional distortions. But even if these dysfunctions were addressed, price signals for electric service would be unlikely to be effective enough to fully drive system investment decisions, particularly since much of what is built, is built for future customers. We therefore recommend that for integrated system planning purposes, utilities should use an appropriate value for DER which incorporates all of the costs and benefits which the DER provide.

We have addressed specific aspects of cost-benefit analysis in our Track 2 responses, and reiterating here in summary form.

- Greenhouse gas impacts should be expressly quantified and monetized. As noted in our Track 2 responses, the Regional Greenhouse Gas Initiative (RGGI) offers a possible path for relatively low-cost compliance with the new 111(d) requirements, and may be relied upon for internalizing the cost of carbon in energy sales. However, because the purpose of the RGGI cap and trade approach is to identify low cost reductions, not to accurately quantify the negative externalities associated with carbon, we caution that it falls far short of assigning what is needed for accurate cost-benefit analysis. (RGGI permit prices are considerably lower that most economists consider a reasonable reflection of the social costs of GHG pollution, as revealed by a federal government taskforce charged with identifying these social costs.[14]) Therefore, in contexts where it is important that the full *cost* of carbon be considered, such as in system planning, a more defensible social cost of carbon number, such as the one identified by the Interagency Working Group on Cost of Carbon, U.S. Government, should be used.

- The benefits of DER should be assessed in a manner that reflects how DER benefits change over time – over the course of a day or a year, and over a longer term based on changing penetration levels.
- The benefits of DER should also be assessed in a locationally specific manner. This is particularly relevant in the context of benefits relating to avoided costs, as discussed further below.
- Criteria air pollutants, as well as water and land impacts, should be considered as part of the cost benefit analysis. (As further discussed above, these costs should to be considered in a locationally-specific manner to avoid disproportionate impacts on communities.) Other community impacts, such as noise, should be included as well.
- Resiliency benefits are critical to include in the analysis.

In addition to the matters addressed as part of our Track 2 response, we note here the need for consideration of additional factors in the cost-benefit analysis. Among the largest of the benefits that DER investments may involve is the cost of grid infrastructure that can be avoided through a particular investment under consideration. To the extent that DER investments are being weighed directly against grid investments, such that the cost of each is part of the analysis, this cost disparity may already be accounted for. However, where DER investments are considered by the DSPP on a stand-alone basis, it is important that this category of benefits not be neglected.

The analysis that Con Edison is currently undertaking in the context of the North Central Brooklyn load area provides a paradigmatic example. With the looming threat of extremely expensive grid upgrades that would be necessary under the business as usual approach, DER investments that might normally look too expensive, including investments that improve the load profile of buildings owned and operated by parties without a strong interest in energy savings on their electric bills, may well turn out to be cost-effective. Even energy efficiency upgrades on a massive scale, with very long payback periods – such as building envelope improvements to public housing – could be cost-effective (and less environmentally damaging than other alternatives) when the avoided cost is given proper consideration. It is essential that "avoided cost" benefits are systematically included in cost benefit analysis, and that

[14] Interagency Working Group On Social Cost of Carbon, Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866, U.S. Government, (last visited May 15, 2014) http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

they are reflected in the market signals experienced by those in a position to make change load profiles. We recommend that the Commission evaluate how Con Edison is conducting its analysis and examine whether the scoping is likely to have yielded a full accounting of energy efficiency opportunities, including those, such as building envelope improvements and other "deep" retrofit opportunities, that customers would be unlikely to undertake under business-as-usual circumstances.

V. Transition for Clean Energy Programs

We understand this question to address the risk of backsliding on environmental outcomes as a result of the changes to the RPS and EEPS funding streams that we understand that is a possible outcome of the Clean Energy Fund proceeding (14-M-0094), and are responding accordingly.

The vibrant market for DER that the REV proceeding endeavors to build is expected to yield market signals that make DER projects more feasible even without centralized procurement of clean energy resources, as currently occurs through the RPS and EEPS programs. We anticipate that this strategy is likely to succeed in increasing the investment in clean energy, if undertaken in accordance with proper attention to environmental outcomes. Depending on the success of measures that establish a level playing field for clean energy resources, it is unclear whether backsliding is likely. A reasonable expectation of a significant increase in the uptake of clean energy resources requires, at a minimum, that the new regulatory paradigm eliminate the pervasive bias in favor of distribution infrastructure, and that the negative externalities associated with fossil-fueled generation from all resource sizes be successfully internalized. However, since backsliding is a possibility, we appreciate the Commission's efforts to mitigate such backsliding. To avoid the risk of backsliding, we recommend that, if NYSERDA's direct expenditures on energy efficiency and renewable energy are to be reduced, that such reductions are effected gradually rather than shocking the market by removing them all at once. A sudden withdrawal of all funding for projects could abruptly move the demand curve down, with potentially negative consequences for supply over the medium term.

The Staff Report is silent on what market and technology transformative strategies NYSERDA might employ to foster the development of self-sustaining markets. However, we anticipate that NYSERDA is likely to increase its funding of research and development pertaining to cutting-edge clean energy technology and finance. We would suggest that such funding should focus on technologies and business practices that are somewhat further from being market-ready than those where the Green Bank, for example, is poised to provide just enough funding to push *almost* financeable projects over the finish line. As technology advances and more manufacturers enter the market, prices of low- and no-carbon DER can be expected to decrease, leading to more widespread adoption. More effective strategies for internalizing the cost of carbon and other negative externalities of fossil-based generation should further ensure that low- and no-carbon DER become increasingly competitive. There is reason to hope that new entrants will bring with them cultures and business models that involve higher spending on research and development than the incumbent utilities have been known for.[15] However, new technologies will continue to face difficulty bridging gaps between conception and creation, and between possibility and feasibility.[16] Ideally, as new entrants with significant capacity for R&D enter the marketplace, NYSERDA can remain flexible, adapting its efforts as appropriate to continue to play a useful supporting role.

As we agree with the Staff's expectation that even as the market matures, low-income residents may continue to face barriers to financing DER projects, we agree that NYSERDA should continue to provide access to clean energy for such customers. This continued commitment to lowering electricity costs for low-income residential customers may present a useful pathway for stepping down direct funding of clean energy gradually, without either hindering the development of new markets by maintaining the dependence on subsidies or shocking the marketplace. For that reason, we recommend a gradual shift in the direct funding of clean energy projects by NYSERDA; over time, such funding should be increasingly limited to types of projects for which a thriving, competitive marketplace exists outside the low-income customer sector, but where the economic disadvantages of low-income customers may be limiting those customers' access to such projects.

In addition to the foregoing, we recommend that the Commission closely monitor the environmental consequences of this proceeding and the programmatic changes at NYSERDA during the initial years. In the event of backsliding, as determined in accordance with pre-established metrics, we recommend prompt measures be taken to continue to prop up the emerging clean energy marketplace. One option in such event would be to restore the direct central procurement by NYSERDA for some set

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[15] As Paul Centolella observed in his testimony on behalf of EDF in Con Edison's recent rate case, "The Company's overall electric research and development budget is $10.54 million or approximately one-tenth of one percent of the Company's electric revenues. This is the same amount which the Company spent in the historical twelve months ending in June 2012. And, the Company proposes no increases in electric research and development spending through calendar year 2016. The Company plans to fund electric research and development activities at a rate that, as a percentage of revenues, that is far below that seen in many other industries. This may be understandable given the current regulatory model, but is inconsistent with the challenges and complex operational issues facing CECONY and the power industry generally." Testimony of Paul Centolella on behalf of Envtl. Def. Fund, 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, at 38 (May 31, 2013). For a look at R&D spending rates outside the utility industry, *see*, The Global Innovation 1000: Comparison of R&D Spending by Regions and Industries, Strategy & pwc http://www.strategyand.pwc.com/global/home/what-we-think/global-innovation-1000/rd-intensity-vs-spend (last visited July 14, 2014).

[16] Jeffery Harris et al., Crossing The Valley of Death: Policy Options to Advance the Uptake of Energy-Efficient Emerging Technologies in U.S. Industry, Energy Systems Laboratory (2011), https://www.ase.org/sites/ase.org/files/resources/Media%20browser/crossing_the_valley_of_death_policy_options_to_advance_the_uptake_of_energy-efficient_emerging_technologies_in_u.s._industry.pdf.

period of time, to the extent that that practice may have been scaled back. Another option would be to provide temporary subsidies to producers of clean energy (in addition to the implicit advantage we believe they should enjoy as a result of avoiding the cost of RGGI permits); such subsidies could be tied to the social cost of carbon, i.e., the full extent of the harm that clean energy avoids, which is and we anticipate is likely to remain well above the price of RGGI credits.

However: in addition to the risk of "backsliding on the State's environmental goals" presented by the transition from current renewable and energy efficiency programs, we must note that the transition to DER itself – a core tenet of this proceeding – presents its own risk of backsliding on the State's environmental goals. Not all DER are pollution-free, and if small DER fall outside regulatory regimes that make pollution costly, the migration to DER could have quite pernicious environmental effects. We could see this risk clearly in the immediate aftermath of Superstorm Sandy, when we saw an enormous surge in consumer reliance on back-up generation as a resiliency strategy,[17] and temporary, concentrated usage of highly-polluting generators caused serious air quality problems.[18]

An increased role for small resources that fall outside of pollution regulation regimes could undermine the effectiveness of those regimes. For example, the fact that DER fall outside the RGGI minimum-size threshold of 25 MW could undermine the effectiveness of the entire RGGI program; not only could distributed generation that isn't carbon-free operate without needing to acquire allowances, but the growing market share of such generation would reduce the number of allowances needed by large generators. This development would depress the market for allowances and reduce the effectiveness of the price signal those large generators receive from RGGI. Similarly, in light of the emerging federal policy for carbon reductions under Section 111(d) of the Clean Air Act under the EPA's Clean Power Plan – which focuses on the same large generation resources as are within the RGGI framework – there is even a risk that a large-scale transition to DER could effect an end-run around the Clean Power Plan – achieving its targeted reductions in emissions from large-scale generators while failing to advance the critically important goal of reducing carbon emissions overall. These two concerns go hand-in-hand, since RGGI may become a central tool in enabling the RGGI states' compliance with the Clean Power

[17] *See, e.g.*, Julie Satow, The Generator Is the Machine of the Moment, N.Y. Times, January 11, 2013, available at http://www.nytimes.com/2013/01/13/realestate/post-sandy-the-generator-is-machine-of-the-moment.html?pagewanted=all&_r=0. *See Also*, Caroline Winter, Hurricane Sandy Boosts the Generator Makers, Bloomberg Businessweek, November 5, 2012, available at http://www.businessweek.com/articles/2012-11-05/hurricane-sandy-boosts-the-generator-makers.
[18] *See*, Arlene Borenstein, Post-Sandy Air Quality Concerns Remind Some Manhattan Residents of September 11, N.Y. 1, December 18, 2012, available at http://www.ny1.com/content/news/174238/post-sandy-air-quality-concerns-remind-some-manhattan-residents-of-september-11.

Plan.[19] One way to avoid this perverse outcome might be for the DSPP to be required to hold RGGI allowances on behalf of the entire DER portfolio that it manages, even though the RGGI compact itself does not contemplate any obligation being placed on small generation sources.

A rise in small resources could also represent a undermine existing environmental regulations is with respect to toxic air contaminants. It is possible that the EPA's RICE NESHAP rules, when finalized, will address this concern in a useful manner.[20] However, as the state of this body of law remains uncertain, we recommend that New York's environmental regulators watch it closely and evaluate whether, as finalized, that rule is and remains sufficient to ensure that small generators are subject to toxic emissions controls at least as strict as those applicable to centralized generators. This is especially important due to the siting of DER, by its nature, in communities.

Additionally, the Commission should work with other New York State government agencies to ensure that the migration to DER does not undermine the effectiveness of existing environmental justice regulations as tools for protecting the health of vulnerable communities. For example, New York currently requires a detailed review of "environmental justice issues associated with the siting of a major electric generating facility." 6 N.Y.C.R.R. § 487.1. Major electric generating facilities, however, are defined as facilities with capacities of 25,000 kW or more (the same minimum threshold as contemplated by RGGI). 6 N.Y.C.R.R. § 487.3. The current proceeding could push smaller generating facilities that do not meet this criterion into low-income neighborhoods, with significant cumulative health impacts. This could result in some communities facing disproportionate health impacts and serious environmental justice concerns relating not only to emissions, but also to other health and quality of life issues, including water quality, noise pollution, and neighborhood aesthetics. In light of the risk that the REV proceeding will undermine the effectiveness of these existing regulations, we recommend that the Commission work with the Department of Environmental Conservation to ensure that strategies to avoid disproportionate impacts are implemented in tandem with the changes to utility sector regulation that we anticipate will be the outcome of this proceeding.

VI. Enhanced Services

In last year's Con Edison distribution base rate case, EDF's expert witness, Paul Centolella, provided testimony that is relevant to this inquiry:

> All of the Company's customers are entitled to adequate and reliable service. And, current levels of reliability should be maintained. Additionally, considering the value of enhanced reliability to different segments of customers may help identify the

[19] *See* EPA's Proposed Power Plant Regulations – Simpler Than You Think, Energy Business Law (last visited July 14, 2014) http://www.energybusinesslaw.com/2014/06/articles/environmental/epas-proposed-power-plant-regulations-simpler-than-you-think/.
[20] *See* Stationary Internal Combustion Engines, EPA (May. 29, 2014), http://www.epa.gov/ttn/atw/icengines/.

places where additional investments in resilience and adaptation would be justified and could be supported largely by the customers who could most directly benefit. Consideration of the value of uninterrupted service is relevant in benefit cost analyses. Moreover, there can be important system and societal benefits to ensuring service continuity to high value loads.

The value of uninterrupted service can vary significantly both within and between customer classes. There also can be important differences by region, season, timing and duration of outages.[21] Understanding these differences can play an important role in determining whether investments would be cost effective and in setting investment priorities.

The range of differences in outage costs for different customers is illustrated in part by an often cited Department of Energy report.[22] Consolidating outage cost estimates from nine utilities, the study finds that the cost of an eight hour outage on a summer afternoon, in 2008 dollars, to be $10.70 for an average residential customer, $4,768 for an average small commercial and industrial customer, and $93,890 for an average large commercial and industrial customer. However, within the large commercial and industrial class, the study finds that the cost of such an eight hour outage might range from $41,250 for an average agricultural customer, to $147,219 for average customers in finance, real estate and insurance, and up to $214,644 for an average customer in construction.[23] Individual customer impacts can be much higher. I am not suggesting that the estimates of outage costs from the Department of Energy study should be used in CECONY planning. Indeed, the results of the Department of Energy study may be conservative in the context of New York City. However, they illustrate that different customers will be impacted differently when their service is interrupted.

I am not aware of a well-developed estimate of the costs to CECONY customers from the interruption of electric service associated with Superstorm Sandy. However, these costs were clearly substantial. Appropriate consideration of the value of uninterrupted service might change investment planning and support the development of microgrids or other investments in areas where reliability is particularly important to customers. The Company and regulators could gain valuable insights by applying contemporary market research and customer segmentation methodologies to better understand how different customers value uninterrupted service....

While it is not uncommon for utility planners to consider judgments regarding the criticality or importance of different loads or circuits, I did not find indications that the Company had estimated or considered the value of uninterrupted service in the systematic manner that would be appropriate given the level of investment required. The testimony of the Infrastructure Panel indicates that the management used a numerical ranking methodology, and it is possible that manager rankings might have incorporated informal judgments regarding value to customers. However, other portions of the Panel's testimony suggest that the Company's objective was to maintain existing levels of reliability at the lowest cost and not to pursue further enhancements that could deliver value to customers in excess of the dollars expended.[24]

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[21] Centolella, et al., Estimates of the Value of Uninterrupted Service for the Midwest Independent System Operator, (2006).

[22] Sullivan et al. Estimated Value of Service reliability for Electric Utility Customers in the United States xxiv (2009).

[23] *Id.*at xxiii.

[24] Testimony of Paul Centolella on behalf of Envtl. Def. Fund, 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, at 12-15 (May 31, 2013).

Although enhanced service for some customers and customer classes may greatly improve the value proposition of the electric system, it is important to ensure that basic service keeps pace with customer expectations and technology. Simply because a service is not part of how electric service has been provided for the past hundred years (the electric analogue of "POTS", Plain Old Telephone Service) does not mean that every innovation should be made available only to those willing to pay a premium. For example, given the high cost of service interruptions but the relatively low cost of communications, outage notifications, which the Staff Report cites as an example of an "enhanced service,"[25] may be a service which (once the infrastructure is in place to provide it), could be made available to all customers as part of "basic service" at low or no cost (well managed notifications could cut down on calls to service centers), while providing high value to customers of all classes.

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[25] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, at p. 61 (issued and effective April 25, 2014).