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

Natural Resources Defense Council

Dated: August 21, 2015

Natural Resources Defense Council

Comments to New York State Department of Public Service

Benefit Cost Analysis White Paper

Case 14-M-0101

August 21, 2015

I. Introduction and Summary

The Natural Resources Defense Council ("NRDC") appreciates the opportunity to provide these comments to the New York State Department of Public Services' ("DPS" or "Staff") 2015 Reforming the Energy Vision ("REV") Benefit Cost Analysis White Paper ("BCA"), filed on July 1, 2015, in Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Proceeding").

In general, the Staff White Paper includes a comprehensive list of the costs and benefits of distributed energy resources ("DER"), and provides very useful guidance on many of the key elements of a BCA framework. In these comments we identify areas where additional guidance from the Commission will make for more useful, informative and effective benefit-cost analyses.

Specifically, we recommend the following:

- The utilities should coordinate with each other, with Staff, the Commission, the New York State Research and Development Authority ("NYSERDA") and other stakeholders in developing the details of the framework and the inputs and the assumptions used in the BCA framework.
- The Commission should provide more guidance regarding the development, the contents, and the application of the BCA handbooks. In particular, the Handbooks should be consistent in terms of contents, structure and format; provide detailed, up-to-date information on all types of DER (e.g., DER supply curves); detailed definitions of the business-as-usual case; and detailed descriptions of how to model a variety of DER scenarios. The DER scenarios should include several different levels of customer participation, to test the implications of this highly uncertain factor.

- The Utility Distributed System Implementation Plans ("DSIPs") process, because it is such a complex undertaking, should begin with a single utility. Further DSIP guidance should include criteria that allows regulators and stakeholders to evaluate the quality of DSIPs.
- The utilities should never use the Rate Impact Measure test to evaluate the cost-effectiveness of DER, because it suffers from several fundamental flaws.
- Instead, utilities should conduct bill impact analyses to identify the long-term bill impacts of DER scenarios. Utilities should also collect and provide information regarding the extent to which customers implement and participate in DER resources, including those customers who may be unable to respond or participate.
- The BCA should use the societal discount rate for the BCA framework, for both the Societal Cost test and the Utility Cost test.
- The utilities should use the social cost of carbon developed by the US Environmental Protection Agency to represent the value of avoiding CO_2 emissions, when applying the Societal Cost test.
- The Commission should require the utilities to work together and with NYSERDA to identify those non-energy benefits (NEBs) that are most important for planning purposes; estimate monetary values for those priority NEBs where possible; and develop proxies for those priority NEBs where monetary values are not available.

- The BCA framework should include estimates of any and all costs associated with third party DER vendors, including administrative, marketing, operating costs and profits.

II. Role of the BCA Framework

We first wish to emphasize the importance of protecting customers and maintaining an affordable and clean energy supply. The benefit-cost analysis has a critical role to play in ensuring that investments in DER and related infrastructure are cost-effective and in the best interests of customers, For this reason, the benefit-cost analysis must be given high priority and include a reasonable process with the opportunity for significant stakeholder input.

The White Paper indicates that one of the key purposes of the BCA is to indicate the extent to which utilities should solicit distributed energy resources from third parties and the marketplace in general (White Paper, p.5, p.6, p.7, p.8). The Clean Energy Fund and the Utility Energy Efficiency proceedings will also play an important role in identifying and implementing distributed energy resources, and the White Paper notes that the BCA framework should be used in all of the related REV processes (White Paper, p.8). Thus, the BCA framework will clearly be used by multiple parties across the state, and should be transparent and consistent across all parties that will be using it in all applications. The need for transparency and consistency is important not only for the BCA framework itself (e.g., the set of costs and benefits, the analytical methodologies), but also for the assumptions and inputs that are used in the framework (e.g., load growth forecasts, Location Based Marginal Price forecasts, Installed Capacity market price forecasts, transmission cost forecasts, the costs of different types of DER, etc.). Therefore, NRDC recommends that the utilities coordinate, with Staff, the Commission, the New York State Research and Development Authority ("NYSERDA") and other stakeholders in developing the details of the framework and the inputs and the assumptions used in the BCA framework. This issue of coordination across the state is addressed further in the section below on BCA Handbooks.

The White Paper also discusses the role of the BCA framework in setting tariffs. As the White Paper notes, there are some important differences between using a BCA to assess future resources and using a BCA to set tariffs. NRDC believes this is a significant issue. The BCA discussion as it relates to tariffs, however, should be discussed in the context of the REV Track Two Straw Proposal.[1] Thus, we do not discuss that issue at length here but expect to revisit it in our comments regarding the Track Two Straw Proposal.

III. BCA Handbooks and Distributed System Implementation Plans

BCA Handbooks Should Be Developed for Each Utility

NRDC supports the Staff's proposal for each utility to develop and make available a BCA Handbook. The handbooks will be an important tool for ensuring transparency and consistency, and will play an important role in supporting efficient and meaningful benefit-cost analyses. A BCA Handbook can be used to clarify many important elements of the BCA – before the utilities conduct their analyses and present them to the Commission for review. This will make for a much more efficient planning process, a more efficient regulatory review, and a much quicker path to implementing DER.

Given the importance of the BCA Handbooks, NRDC recommends that the Commission provide more guidance regarding the development, the contents, and the application of the handbooks. First, as noted above, the BCA Handbooks should be developed by all of the utilities and NYSERDA acting in coordination. Because the BCA framework will be applied by several

[1] State of New York Department of Public Service, *Staff White Paper on Ratemaking and Utility Business Models*, Case 14-M-0101, July 28, 2015.

different parties in several different applications, it is important that the methodologies, inputs and assumptions are consistent. In addition, a coordinated statewide approach for developing the BCA Handbooks will allow for more meaningful input to the handbooks from relevant stakeholders, and reduce the resources required for regulatory oversight.

Second, we emphasize again the importance of the Commission insuring that the BCA Handbooks themselves are consistent in terms of their structure and format, as well as the contents. It will also be easier for public and private market actors to engage with consistent and transparent BCA Handbooks. As acknowledged by the White Paper, the Commission should take great care to ensure that similar DER resources are not treated differently.[2]

We recommend that the Commission develop a standard template for the BCA Handbooks that would include a detailed outline with tables and charts for all the appropriate data. Further, any and all data inputs should be provided electronically, and provided in a database format so that the information can be compared across all of the utilities and aggregated for the state as a whole. This would include, for example, data regarding the different benefits and costs listed in Table 1 of the White Paper, as well as data regarding the different aspects of distributed energy resources (e.g., costs, operational profiles, and performance data). Several states and regions have begun developing this type of information in database format for energy efficiency resources, and these systems can be used as a foundation for organizing and disseminating data on all types of DER.[3]

[2] The Staff White Paper at 9.

[3] See, for example, the Northeast Energy Efficiency Partnerships, Regional Energy Efficiency Database (which includes NY, CT, ME, MD, MA, NH, RI, and VT), available at: http://www.neep-reed.org/Focus.aspx; as well las Massachusetts' database, available at http://masssavedata.com/Public/Home.aspx; and Connecticut's database, available at http://www.ctenergydashboard.com/Public/PublicHome.aspx.

Third, given the importance of accurate information on distributed energy resources in the BCA, as well as the likelihood that DER costs and benefits will change over time, we recommend that the BCA Handbooks give priority to providing useful, up-to-date information on these resources. For example, the BCA Handbooks should present a “supply curve” for each type of DER available: energy efficiency, demand response, distributed generation (such as rooftop PV), combined heat and power, electric vehicles, and storage. Each supply curve would indicate (a) the levelized costs of different types of each resource (in $/MWh), and (b) an estimate of the quantity available in the utility’s service territory (in MW and MWh).[4] The information provided through these supply curves will facilitate assessments of DER potential, and inform the selection of DER portfolios and scenarios for modeling in the BCA.

Fourth, NRDC recommends that the BCA Handbooks describe in detail the methodology and assumptions that the utility will use to define the “business-as-usual” case. This should include all forecasts required to build the business-as-usual case, such as energy growth, peak demand growth, customer growth, environmental requirements, replacement of aging infrastructure, transmission needs, and distribution needs. This should also include a description of the different future scenarios to analyze (e.g., high, medium, and low peak demand growth).

Fifth, we recommend that the BCA Handbooks provide details describing how the utility will analyze a variety of different portfolios of DER resources, independently and in conjunction with each other. Given the multiple permutations possible with the timing and types of DER alternatives, it is important to streamline the analysis where possible. This can be accomplished by utilizing standardized methodologies, inputs, and assumptions across utilities where possible (as noted above), and by conducting the analysis in a logical series of steps. In the first step, the

[4] This information is often depicted graphically with the levelized cost presented in the Y-axis and the amount of energy available in the X-axis.

utilities should analyze a series of resource portfolios that each contains a single resource type, rather than a combination of DER types. Each of these portfolios should also consider several different quantities of that DER resource type to assess how the costs and benefits associated with the resource change as the quantity is increased and decreased.. This set of analyses, with each DER type modeled in isolation, will provide very useful information regarding the amount of each DER that might be cost-effective, as well as how that amount might vary across the DER types.

The next step would then be to analyze several sets of portfolios with different combinations and quantities of DER, to identify the interactive effects of the different types of DER. These interactive effects can be significant, and can change the cost-effectiveness of DER. In some cases, the interactive effects might suggest synergies when different types of DER are combined (such as with storage and distributed generation); while in other cases the interactive effects might suggest diminishing returns from different types of DER (e.g., because avoided costs will likely decline as increasing amounts of similar types of DER are added to the system).

Distributed System Implementation Plans

Finally, we note that the distribution system planning process is a highly complex undertaking, particularly as new tools and methodologies must be developed. The initial DSIPs will likely require significant resources from utilities, regulators, and stakeholders to develop and review. For this reason, we recommend that the first DSIP be filed by a single utility, so that this DSIP can serve as a model for the other utilities.

Further, no two utility DSIPs will be alike and they will each have relative strengths and weaknesses on a range of factors, including but not limited to technology and platform design, transparency, goal and milestone setting, cost benefit, business planning and analytical quality.

Thus, it is critical that, while developing DSIP plan guidance, Staff and the Commission also develop a framework, with specific criteria, that enables regulators and stakeholders to evaluate the quality of utility DSIP plans. This will help ensure that DSIPs lead to intended outcomes. In an instructive example, Great Britain's Office of Gas and Electricity Markets have done significant work on distribution system plan assessment as a key part of well-justified business plan development under the revenue = incentives + innovation + outputs regulatory framework.[5]

IV. The Rate Impact Measure Test Should Never Be Used

Table 1 of the White Paper indicates that the Rate Impact Measure ("RIM") test should be used, along with the Utility Cost Test and the Societal Cost Test, as part of the BCA framework. Presumably, Staff recommends that the RIM test be used in order to provide an indication of how DER will affect electricity customers' rates. However, it is the impact on customer *bills* that the Commission should be evaluating, not the rates, which would not take into account the value of energy efficiency and other measures that reduce demand.

Impacts on electricity bills should certainly be considered as part of the evaluation of the costs and benefits of DER. However, the RIM test does not measure that and should not be used for assessing the impacts of DER. The RIM test suffers from several fatal flaws and does not provide the Commission and other stakeholders with information necessary to assess impacts or the distributional equity issues that go along with them. Other approaches, discussed below, are much better suited for assessing bill impacts.

Utilities Should Never Use the Rate Impact Measure Test

The only difference between the RIM test and the Utility Cost Test is that lost utility revenue is included as one of the costs in the RIM test. In New York, the electric utilities apply a

[5] *See*, for example, the Ofgem Assessment of the RIIO-ED1 Business Plans, Supplementary Annex, Nov. 22, 2013, available at: https://www.ofgem.gov.uk/ofgem-publications/84945/assessmentoftheriio-ed1businessplans.pdf.

revenue decoupling mechanism (RDM), which ensures that lost revenues as a result of DER, or other effects, are recovered from ratepayers with annual adjustments in rates. Consequently, as DER causes electricity sales reductions, relative to what they would have been without the DER, the recovery of lost revenues creates upward pressure on future electricity rates, but downward pressure on bills.

The RIM test suffers from several flaws, but here we focus on the three most crucial flaws. First, lost utility revenues are simply a result of the need to recover existing costs over fewer sales. These existing costs are “sunk” costs. Sunk costs should not be used to assess future resource investments because they have already been incurred and will be recovered regardless of whether the future project is undertaken. In other words, benefit-cost analyses typically include the comparison of a business-as-usual case with another case that includes some amount of DER. The net benefits are identified by taking the difference between the two cases. The lost utility revenue will be recovered from ratepayers in both cases. It does not make any sense, and will create misleading results, to include these costs in one of the cases but not the other.

Even presenting the results of the RIM test creates a risk of misleading stakeholders and resulting in poor decision-making. If the RIM test results indicate that the net benefits (in cumulative present value dollars) of a DER program are negative, in other words the costs (including recovery of lost utility revenue) exceed the benefits, then this implies that the DER investment will increase costs. However, the “costs” that drive this result are the recovery of lost utility revenues that will be recovered from ratepayers under any future scenario, with or without the DER. In other words, the RIM test result suggests that costs will increase, when in fact they will not. For all programs that pass the Utility Cost Test, costs will be reduced. For this reason, the results of the RIM test should never be presented in terms of net benefits (in cumulative present value dollars), because they are incorrect and misleading.

This brings us to the second fundamental flaw with the RIM test: we have already indicated that it is the bills, not the rates that should be measured, but the RIM does not even provide the information needed to understand the magnitude of the rate impact of DER investments. A RIM benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact. The RIM test does not provide any information regarding (a) the cents/kWh impact on rates; (b) the percent increase in rates; or (c) the amount that rates might increase from one year to the next. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of rate or bill impacts.

Which leads to the third fundamental flaw with the RIM test: it can lead to perverse outcomes. The RIM test can lead to the rejection of distributed energy resources that could significantly reduce utility system costs in order to avoid what may be insignificant impacts on customers' rates (thus the importance of looking at the overall bill impacts). For example, a particular DER program might offer hundreds of millions of dollars in net benefits under the Utility Cost Test, but be rejected as not cost effective with a RIM test benefit-cost ratio of slightly less than one. It may well be that the actual rate impact, if calculated properly, is so small as to be unnoticeable. Rejecting such large reductions in utility system costs that could reduce bills to avoid *de minimis* rate impacts is clearly not in the best interests of customers overall, nor is it consistent with New York energy policy goals.

Further, we note that NRDC and other parties have previously iterated opposition to the use of the RIM in the REV BCA context in response to the Staff Track 1 Proposal. There, NRDC recommended "that the RIM should be eliminated from the broader BCA framework".[6] NRDC was joined by several other parties in our opposition to the RIM during Track 1, including the Association for Energy Affordability, Clean Energy Advocates, Vote Solar and the Northeast Energy Efficiency Partnership.[7]

In sum, the RIM test should never be used for the purpose of deciding whether to spend ratepayer money on any particular DER. Instead, a customer bill impact analysis should be conducted separately from the BCA to help inform the Commission and others about the potential rate impacts and equity concerns of distributed energy resources.

Utilities Should Conduct a Customer Bill Impact Analysis

In some cases, distributed energy resources can lead to higher rates, but lower average customer bills.[8] Those customers that participate in a DER program, or install distributed energy resources in any way, will typically experience lower bills. While those that do not participate in cost-effective DER may be less likely to see bill reductions, cost-effective DER investment should reduce system costs and put downward pressure on all customer bills. The different impacts on DER participants and non-participants, however, can create distributional equity concerns that should be addressed in REV.[9]

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[6] Case 14-M-0101, Natural Resources Defense Council Track One REV Comments, September 22, 2014 at 13.

[7] *See, e.g.*, Association for Energy Affordability Track One REV Comments, September 22, 2014 at 15 ("RIM … is a test that will be opposed"); Advanced Energy Economy Institute Track One REV Comments, September 22, 2014 at 5 ("We do not support the RIM test"); Clean Energy Advocates Track One REV Comments, September 22, 2014 at 21 ("The Clean Energy Advocates caution against applying the RIM in the benefit cost analysis"); Vote Solar Track One REV Comments, September 22, 2014 at 4 ("Vote Solar cannot support the use of … the RIM in a BCA framework"); and Northeast Energy Efficiency Partnerships Track One REV Comments, September 22, 2014 at 3 ("The RIM test does not provide meaningful information to the commission about the bill impacts to customers of energy efficiency programs").

[8] This is not always the case. Some distributed energy resources can lead to reduced rates, depending upon program costs, avoided costs and lost revenue recovery.

[9] It is important to note that all customers experience some of the benefits of distributed energy resources regardless of whether they install DER. Those who install DER typically experience more benefits than those who do not.

NRDC recommends that, instead of using the RIM test, utilities should be required to conduct a long-term customer bill impact analysis. Such an analysis should primarily address two important factors: bill impacts, and participation impacts. Bill impacts provide an indication of the extent to which customer bills might be reduced for customers, both those that install distributed energy resources and those that do not. Taken together, bill and participation factors indicate the extent to which customers will be impacted (positively or negatively) from investments in distributed energy resources, and the extent to which distributed energy resources may lead to distributional equity concerns.

Information regarding customer participation rates is especially important for addressing distributional equity issues. Importantly, this should include information about, and identification of, customers or customer classes that may not have the capacity to engage with DER at a particular time, and why. This customer participation information can be used to indicate the extent to which customers are becoming engaged with distributed energy resources and are taking control of their electricity bills.

If this information on customer participation is not currently available, it should be collected as soon as possible, so that meaningful estimates can be developed in future years. The utilities should keep track of the percent of customers that install each type of DER: efficiency measures, demand response measures, CHP systems, PV systems, energy management systems, electric vehicles, storage and other technologies for modifying load. This information should be collected on a customer class basis, and it should be collected for DER measures that are provided by third party vendors as well as those that are delivered by the utility. This level of detailed information will be necessary to determine (a) the extent to which third party vendors are able to deliver DER; (b) the types and magnitudes of customers that will be benefitting from

DER; (c) the types of DER technologies that are suited for third party versus utility delivery; (d) the role that the utilities need to play in serving customers who do not invest in DER, and (e) the extent to which distributed energy resources are benefitting customers and achieving the New York REV goals.

V. Discount Rates

The Staff recommends that a single discount rate be used for all the BCA metrics, "based on the rationale that, whatever metric is used, a decision is being made on alternative utility expenditure plans, costs that are ultimately collected from ratepayers." (Staff White Paper, p. 10) The Staff recommends that the discount rate be based on the utility weighted average cost of capital (WACC), because this best reflects the "opportunity cost of capital for such expenditures." (Staff White Paper, p. 10)

NRDC agrees with the Staff's recommendation to use a single discount rate for all the BCA metrics (both the Utility Cost Test and the Societal Cost Test). However, we agree with this approach for a slightly different reason that what was articulated by the Staff. It is not only that the costs are ultimately paid by customers; it is also that the *resource planning decisions are being made on behalf of customers*. The ultimate objective of the benefit-cost analysis is to identify those electricity resources that will best serve customers over the long-term. The BCA framework should identify those electricity resources that meet the key goals of providing low-cost, safe, reliable electricity service. It should also help identify those resources that meet the key goals of the REV docket, including: enhanced customer knowledge; market animation; system-wide efficiency; fuel and resource diversity; reliability and resiliency; and reduction of carbon emissions. (Case 14-M-0101, Order Instituting Rulemaking, April 25, 2014, p. 2)

In determining the appropriate discount rate to use, it is important to consider these same two critical points: (a) that the resource planning decisions are being made on behalf of customers; and (b) that the resource planning decisions should meet the key regulatory goals of REV. If the discount rate is not aligned with these two points, then the resource decisions will not be in customers' best interests and will not meet the key regulatory goals.

It is important to note that a private firm will often use the cost of capital as a discount rate when evaluating projects, as this represents the opportunity cost of investing in a project. However, investments in DER are different in that some of the costs will be borne by the customers who install the measures, and some will be borne by third party providers who have different costs of capital than utilities. Also, those DER costs that utilities collect from customers through rates are not likely to be included in rate base and therefore will not have any cost of capital.

Further, the discount rate is more than just the cost of capital (for the utility, for the customers, or for society). [10] In essence, the discount rate represents an entity's "time preference," i.e., the relative importance of short- versus long-term costs and benefits. A high discount rate implies that short-term costs and benefits are valued more than long-term costs and benefits, and vice versa. In addition to the opportunity cost of making an investment (i.e., the cost of capital), an entity's time preference might account for future risks, for short-term priorities, or for personal priorities versus those of a group of people to which the person belongs. These are additional reasons why the utility cost of capital should not be the focus of the choice of discount rate.

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[10] For more discussion on this point, see Northeast Energy Efficiency Partnerships, *Cost-Effective Screening Principles and Guidelines*, November 2014, Chapter 5.

NRDC recommends that the utility WACC not be used as the basis for the BCA discount rate. The utility WACC represents the time preference of utility shareholders and bondholders; not the time preference that should be applied to utility resource planning. Utility shareholders and bondholders have their own perspectives regarding opportunity costs, risks, and personal investment goals. In general, they have their own perspectives on the value of short-term versus long-term benefits.

We recommend that instead the BCA discount rate be based on the time preference that reflects the interests of all utility customers as a whole and is consistent with New York's key regulatory goals. Such a time preference would give higher priority to long-term benefits, and would be lower than the utility WACC. When making electricity resource planning decisions, it is important to recognize that resource decisions made today have implications for customers many years into the future, and that utilities and regulators have a responsibility to ensure that resources chosen today will serve customers' interests well into the future. Also, many of the New York REV goals can only be met by recognizing the benefits that will be achieved over a relatively long period of time (e.g., market animation, customer engagement, fuel and resource diversity, and reduced carbon emissions). A discount rate based on the utility WACC will emphasize short-term costs at the expense of long-term benefits, and will make it more difficult to achieve these long-term goals.

NRDC recommends that the BCA framework discount rate be based on society's time preference, using a societal discount rate. The societal discount rate is best able to reflect the value of short- versus long-term costs and benefits to all utility customers, as well as the time preference associated with the state's energy policy goals. The societal discount rate is consistent with the use of the Societal Cost Test, which is one of the two tests used in the BCA framework.

Finally, the societal discount rate is also consistent with the discount rate used by EPA in the social cost of carbon (see below).

If the Commission instead decides that discount rates should be based on the utility WACC, then it should require the utilities to apply a societal discount rate to the Societal Cost test analyses. This will provide a more accurate indication of the societal costs and benefits, and the extent to which DER will meet societal goals.

Furthermore, for the Utility Cost test analyses, if the Commission decides that discount rates should be based on the utility WACC, then it should at least require the utilities to conduct sensitivities using the societal discount rate. The results of this sensitivity will provide very useful information regarding the optimal mix of resources from the perspective of all customers as a whole, not just from the perspective of utility investors.

VI. Valuing Benefits

NRDC agrees with the list of BCA framework benefits provided in the White Paper. Here we mention two types of benefits that require further guidance from the Commission.

Externalities

The Staff White Paper offers three different approaches for quantifying the value of environmental externalities, particularly the value of SO_2, NO_x, and CO_2 emissions. NRDC recommends that externalities be quantified using Approach #2, which is based upon the US Environmental Protection Agency (EPA) social cost of carbon.

First, note that environmental externalities should be included only in the Societal Cost Test. The Utility Cost Test should include all of the costs that are required to comply with current or anticipated environmental regulations; while the Societal Cost Test should include the additional environmental costs that are not internalized in utility costs.

Approach #1, which reflects the market price of purchasing emission allowances, should not be used to estimate environmental externalities because it does not reflect external costs. Rather, it reflects environmental compliance costs that are already internalized by the utility. The White Paper acknowledges this point by noting that these emission prices simply represent compliance costs, and are not meant to represent marginal damage costs (Staff White Paper, p. 32). These compliance costs should be reflected in avoided energy and avoided generation capacity costs (to the extent that compliance affects the mix of capacity in New York), and should be included in the Utility Cost Test as well as the Societal Cost Test, but do not accurately capture externalities.

We recommend that Approach #2 be used to determine the externality values of CO_2. This method is based upon the social cost of carbon estimated by the US EPA, which is used by the federal government for benefit-cost purposes. This CO_2 externality value is from a credible federal source, is widely used in other applications, and is transparent and relatively simple to use. We further recommend that the CO_2 values based upon a three percent discount rate for the social cost of carbon be used, because this is the central case used by the US EPA. We note that other methodologies will need to be developed by the Staff to estimate the externality values associated with criteria air pollutants, water impacts, and land impacts.

NRDC recommends against using Approach #3 to determine the externality value of CO_2. Staff notes that the price of renewable energy credits (REC) provides an indication of the state's willingness to pay for the societal benefits of large scale renewables, and thus could be used as a proxy for those benefits (Staff White Paper, p. 40). This is partly true. The NY REC prices represent a "floor" on the state's willingness to pay. That is, they indicate that the state is willing to pay at least that much for the societal benefits of large-scale renewables. The state may be willing to pay more for these benefits, and indeed may pay more for them if the renewable supply in the future becomes more expensive. Therefore, the REC prices can be considered as a floor for indicating the value of social benefits of large scale renewables (and DER), but Approach #2 should be used to indicate the actual externality value for CO_2 emissions.

Non-Energy Benefits

NRDC agrees with Staff that non-energy benefits (NEBs) should be accounted for in the BCA framework. These benefits can be very large for some distributed energy resources (particularly those NEBs that accrue to program participants) and can have a significant impact on the results of the Societal Cost Test. Properly accounting for NEBs is especially important for programs directed toward low-income customers and multi-family housing.

However, we recommend that the Commission provide more guidance on how to account for NEBs in the BCA framework in a systematic way. The Staff recommends that utilities weigh the impact of NEBs “quantitatively, when possible, and qualitatively, when not.” (Staff White Paper, p. 41) NRDC agrees that it is better to account for some NEBs qualitatively when quantitative data are not available. However, we are concerned that accounting for NEBs qualitatively will not be practical in the context of the utility Distribution System Implementation Plans (DSIPs). Such plans are likely to evaluate a variety of different types of DER, in numerous different combinations, and in multiple scenarios (see Section IV). When such a large number of variables are present, the possible permutations grow exponentially, and will likely require a systematic, quantitative means for comparing the net benefits across a vast array of portfolios. In this context it will be very difficult to incorporate a qualitative assessment of NEBs into the evaluation process, potentially leading to qualitative benefits being effectively excluded from much of the analysis.

To remedy this, NRDC recommends that the Commission require the utilities to work together and with NYSERDA to (a) identify those NEBs that are most important for planning purposes; (b) to estimate monetary values for those NEBs where it is possible to do so; and (c) develop proxies for those priority NEBs where monetary values are not available.[11] These monetary values and proxies can then be applied to the evaluation of DER portfolios in a practical and transparent manner, in a way that a qualitative assessment cannot. We further recommend that these proxies be updated as studies are conducted and better data become available.

VII. Valuing Costs

NRDC generally agrees with the list of BCA framework costs provided in the White Paper. Here we mention two types of costs that warrant comment.

First, the White Paper is clear that one of the key goals of the BCA framework is to identify those distributed energy resources that utilities should obtain from the marketplace, i.e., purchase from third party DER vendors. To the extent that third parties deliver the DER, there will be costs incurred by those vendors that should be accounted for in the BCA. These costs could be significant and could turn around the results of the BCA. For example, DER developers will need to recover their administration, marketing and delivery costs. They will also need to earn a profit for their owners and investors. Those third party vendor costs that are somehow passed on to ratepayers should be included in the Utility Cost Test, and all third party costs should be included in the Societal Cost Test.

At the same time, these costs may reduce or eliminate the utility program administration costs, in which case the utility program administration costs should be adjusted commensurately.

[11] For more information, see Northeast Energy Efficiency Partnerships, *Cost-Effective Screening Principles and Guidelines*, November 2014, Chapter 3.

Either way, the third party costs should be estimated and presented separately from the utility costs because they may be of different magnitudes and have different implications.

Second, the White Paper indicates that lost utility revenues should be included as one of the costs of DER. As noted in Section V above, the Rate Impact Measure test should not be used as part of the BCA framework, and therefore it is not necessary to report or use estimates of utility lost revenues.

VIII. Conclusion

NRDC commends the work of Staff and the Commission in developing the BCA framework. We urge the Commission to take additional steps to ensure that the analyses that ultimately emerge from the framework are as useful and effective as they can be. These steps include ensuring that: (1) stakeholders coordinate to further develop the framework, (2) the BCA handbooks are adequately consistent, up to date and detailed with regards to a wide variety of DER scenarios, including differing levels of customer participation, (3) the DSIP process should begin with one utility and DSIP guidance should include criteria to evaluate DSIP quality, (4) the RIM is never used and instead a customer bill impact analysis is undertaken, (5) the societal discount rate is used for the SCT and the UCT, (6) the EPA social cost of carbon is the method utilized to represent the value of emissions avoidance, (7) NEBS are investigated by the utilities, NYSERDA and stakeholders, and (8) estimates of third party DER vendor costs are included in the framework. Thank you.

[Signatures to follow.]

Respectfully submitted,

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