STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

ORDER ESTABLISHING THE BENEFIT COST ANALYSIS FRAMEWORK

Issued and Effective: January 21, 2016

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At a session of the Public Service Commission held in the City of Albany on January 21, 2016

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring

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BY THE COMMISSION:

BACKGROUND

In the Track 1 Order,[1] the Commission directed the Department of Public Service Staff (Staff) to develop and issue a Benefit Cost Analysis (BCA) Whitepaper for considering and evaluating proposals made within the scope of the Reforming the Energy Vision (REV) proceeding and related proceedings.
The Track 1 Order identified a number of goals for the BCA Framework, which were then developed in the BCA Whitepaper.[2] A BCA analysis will be applied to four categories of utility expenditures: investments in Distributed System Platform (DSP) capabilities; procurement of Distributed Energy Resources (DER)

[1] Case 14-M-0101, supra, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).

[2] Case 14-M-0101, supra, Staff Whitepaper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding (filed July 1, 2015).

through competitive selection; procurement of DER through tariffs; and, energy efficiency programs. An accurate and consistent analysis methodology is a prerequisite to the consideration and comparison of these opportunities, and through consideration of them pursuant to such an analysis would ensure that ratepayer funds are deployed in the most efficient way.

The BCA Framework enables the careful comparison of the value of the benefits obtained through a potential project or action against the costs incurred in effectuating that project or action, generally considered through the systematic quantification of the net present value of the project or action under consideration. Utilities, like other businesses, engage in some form of BCA continuously as they evaluate a variety of decisions, at different levels of complexity depending upon the significance and timeframe of the project or action. A useful BCA Framework in the utility context must address both the selection of the elements that comprise the components of the BCA analysis as well as the variation in the application of those elements across each of the specific projects or actions that comprise the universe of decisions utilities will confront.

In the BCA Whitepaper, the proposed BCA Framework is premised upon a number of foundational principles. The BCA analysis should: 1) be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular; 2) avoid combining or conflating different benefits and costs; 3) assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures); 4) address the full lifetime of the investment while reflecting sensitivities on key assumptions; and, 5) compare benefits and costs to traditional alternatives instead of valuing them in isolation.

The BCA Framework will rest upon the selection of methodological approaches, which include the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM). Those benefits and costs that should not or cannot be reflected in the Framework will be clearly delineated. The outcomes of the BCA analysis should allow for judgment and where appropriate a qualitative assessment of non-quantified benefits.

The interests in sustaining a stable investment environment to support the DER market would be balanced with remaining flexible and adaptive so that the valuation process does not become outdated or inaccurate. Over time, developing more dynamic and granular methods will require a continuous process, rather than a single decision. Therefore, the matters addressed here are only the first initial step in forming a robust and long-lasting BCA Framework.

That Framework will stand within the broader scope of REV implementation. Under REV, utilities will file Distribution System Implementation Plans (DSIP) by June 30, 2016 that identify opportunities to avoid traditional utility distribution and investments by calling upon the DER marketplace.[3] The BCA Whitepaper identifies means for evaluating DER alternatives as substitutions for traditional utility solutions, and against each other. Alongside cost avoidance and system efficiency benefits, the BCA Framework as proposed would reflect consideration of social values, also known as externalities, quantifiably when feasible and qualitatively when not. A full evaluation of alternatives over their expected lives, it is suggested, would be accomplished by stacking resources of

[3] Case 14-M-0101, supra, Staff Proposal – Distributed System Implementation Plan Guidance (October 15, 2015) at 4; a Supplemental DSIP Filing is also called for by September 1, 2016.

different characteristics into a portfolio that results in meeting system needs in the aggregate.

Besides evaluation of electric system alternatives, the BCA Framework should support the developments of tariffs that place a value on DER. The evaluation of tariffs, however, differs from the evaluation of utility system alternatives, because tariffs are more dynamic measures of near term benefits and costs. Dynamic tariffs may be self-adjusting or embed other mechanisms to address the concern of variation over time. The tariffs can serve as an incentive mechanism to promote the development of a more competitive behind-the-meter market, including the installation of the DER facilities currently promoted through the device of net metering tariffs. Through these processes, the BCA Framework will work in coordination with the DSIPs, upon the identification of processes for assuring fair, open and value-based decision making.

When utilities present their DSIPs, each utility will identify its system needs, proposed projects for meeting those needs, potential capital budgets, particular needs that could be met through DER or other alternatives, and plans for soliciting those alternatives in the marketplace. The BCA Framework principles the utilities deploy in analyzing these alternatives must be transparent to other stakeholders. As a result, the BCA Whitepaper proposes that each utility compile and make available to stakeholders a BCA Handbook. The BCA Handbooks would describe and quantify benefit and cost components and their application in evaluating DER projects.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on July 22, 2015 [SAPA No. 14-M-0101SP12].

The time for submission of comments in response to the Notice expired on September 7, 2015. Moreover, in a Notice Inviting Public Comment on Staff Whitepaper on Benefit-Cost Analysis issued July 2, 2015 in this proceeding, the filing of Initial Comments on the BCA Whitepaper was invited, due by August 14, 2015, with Reply Comments due September 10, 2015.

In response to the notices, a broad spectrum of organizations, institutions, utilities, and DER service providers submitted their views. The commentators are listed with abbreviations in Appendix A and comments and replies received are summarized in Appendix B. Some of the comments were highly-detailed and analyzed the issues at length; AEEI authored its own BCA Framework. Several replies also embarked upon extended analysis.

Comments may be categorized into several groupings; the Public Interest Intervenors (PII) consisting of national, regional and local environmental groups and other public policy advocates; DER providers and organizations, including many trade organizations representing groups and consortiums of DER providers and DER interests, utilities, including New York's major electric and gas companies; customer representatives, including industrial, commercial, and residential advocates; and, governmental entities, including NYC and DEC. The positions of the parties, however, diverge widely and an extensive variety of alternatives, modifications, suggestions, and criticisms directed to the Staff Whitepaper were presented.

DISCUSSION

As reflected in the comments, interest in this proceeding is high. The development of the BCA Framework, however, is best understood in the broader context of the overall REV effort, addressed today through initiation of the

Clean Energy Standards proceeding and other matters.

Effectuation of a BCA Framework requires resolution of issues that separate the commentators, which can be grouped into five categories. First, the purposes and principles of the Framework must be established. Second, the costs and benefits that will be recognized in the BCA Framework must be identified, and methods must be devised for calculating them. This includes deciding which externalities and non-energy benefits should be reflected in the BCA Framework, and devising methods for their quantification, or, if quantification cannot be determined, adopting proxies or deciding on the role qualitative analyses will play. Third, the issue of impacts on wholesale prices raises questions concerning the details and persistence of those impacts, and the effects of recognizing impacts on wholesale markets themselves. Fourth, since the BCA Framework will be applied to investments that endure over lengthy periods, a discount rate or rates must be established so that the investments can be reduced to a net present value comparable notwithstanding different periods of time over which different investments will be sustained. Fifth, the implementation of the BCA Framework, and the role BCA Handbooks will play in that implementation raises questions concerning uniformity and flexibility, timing, and extent and scope.

The REV Context

REV responds to the facts that technology, consumer demands, and environmental exigencies simultaneously allow and require the transformation of the energy sector to one that is consumer centric, is increasingly economically and environmentally efficient and sustainable, and embraces, rather than resists, market and business model innovation. The interdependent REV efforts will be built upon four major pillars of policy design and implementation.

First, clear and ambitious targets will be set. The 2015 State Energy Plan is premised upon meeting 50% of the State's electric consumption with renewable resources in 2030.[4] Given Governor Cuomo's recognition of the threat the damages attending climate change pose to New York's economic and environmental health, the achievement of the targets is of paramount importance. At the Governor's direction, a proceeding is instituted in a companion Order to determine how best to convert the target into an enforceable mandate through implementation of the Clean Energy Standard (CES).[5]

Second, policies and practices governing the regulation of utilities and their business practices must be consistent with the changes that need to occur. The REV decisions implementing regulatory, business and market reforms will ensure that regulation is consistent with the goals set for REV. Third, tools will be developed for promoting clean energy technology and markets that drive scale upward and reduce barriers to entry. The BCA Framework is the tool that enables the cost assessments crucial to the advancement of the markets for that technology. The fourth pillar consists of the State's actions as a participant in energy markets, which is present throughout State government. The State will act as a leader in those markets.

Though discrete, each of the four pillars embrace the fundamental precept that clean energy deployed at scale holds the potential to address pressing environmental and energy

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[4] The 2015 New York State Energy Plan, issued June 25, 2015, can be found at http://energyplan.ny.gov/Plans/2014.aspx.

[5] Case 14-M-0094, Consideration of A Clean Energy Fund, Order Authorizing the Clean Energy Fund Framework (issued today herewith).

challenges while opening enormous economic potential for New York. To tap this potential, all clean energy efforts need to become more efficient and strategic so that each dollar of clean energy spending achieves greater savings and animates market participation and investment. The BCA Framework is the vehicle for realizing those efficiencies through the strategic direction of investment.

Traditional clean energy program approaches have been oriented toward direct rebates and subsidies, to encourage individual customers or specific resource suppliers to employ more efficient, or “clean,” end-use equipment and systems, thereby acquiring energy savings. While this “resource acquisition” approach has resulted in significant energy savings to date, an approach focused solely on selective customer rebates can have the unintended consequence of fostering reliance on government-directed payments rather than on markets and entrepreneurial innovation, while inhibiting market transformation. The BCA Framework holds a key to transitioning from predominately government-directed resource acquisition approaches to market-based initiatives premised upon a long term commitment to the market, while spurring private sector involvement to reach the level of scale needed to realize REV objectives.

REV depends upon the translation of policy objectives into a series of outcome-based performance measures that follow from these policies. Six measures, described in the CEF Framework Order, will be used to gauge the effectiveness of the actions undertaken to implement REV. The BCA Framework accords with the six measures.

First, the BCA Framework furthers the management of energy costs. It is a new paradigm, replacing the business-as-usual approach, that will better assure reasonably priced electric power. Second, it protects consumers and ensures equity among customer classes by supporting the fair and robust evaluation of DER and utility alternatives. Third, its protocols for pricing and evaluating comparisons among alternatives will promote capital and operating efficiencies. Fourth, the outcome of the analyses conducted under the Framework will drive business model and service innovation. Fifth, the Framework is tied to and enables the DSIP process that will assure timely and appropriate investment in infrastructure and grid modernization. Sixth, use of the BCA Framework will assist in achieving greenhouse gas reductions. Therefore, the BCA Frame work, as described below, in thoroughly integrated into REV and furthers achievement of its goals.

The BCA Framework Principles

The Issues

The BCA Whitepaper lists a series of principles upon which it builds a BCA Framework. The principles guide the selection of the components that will comprise the BCA Framework as it is applied, as well as variation in the application of the components to accommodate varying circumstances and specific settings.

Commentators disagree over the purpose of the BCA Framework, as expressed in the BCA Whitepaper principles. FTC would add to the principles explicit recognition of benefits to society in opening up the electric grid to more competition and increasing customer engagement through the DSIP platforms envisioned in REV. JU believes that the Framework should be limited to an outcome-neutral approach that results in a level playing field and the selection of the most cost effective assets for addition to the electric grid. It would recognize environmental externalities and NEBs only after a potential project has demonstrated that it has passed a BCA review.

In the same vein, JU opposes including in the principles a goal of creating a stable investment environment for DER providers. It also suggests that some of the other principles may be biased in that they advantage DER over utility investment. JU would restrict life-cycle analyses and deploy BCA Framework more carefully to avoid the biases it alleges.

In contrast to JU, ASC maintains that the current regulatory framework is biased against clean DER, and that the status quo needs to change. ASC maintains that a level playing field can be established only if it is recognized that the purpose of REV is to create investment-grade market opportunities for DER. As a result, it would reject JU's proposed principles. Other PII and DER commentators make similar arguments in addressing BCA Framework implementation issues.

Conclusions

ASC and FTC are correct in pointing out that one of the purposes of REV, and the BCA Framework intended to implement it, is to open new opportunities to DER. JU's contentions to the contrary, and its proposed revisions to the principles, are rejected. Otherwise, no general revisions to the principles stated in the BCA Whitepaper are necessary. Those principles serve primarily as a guide to developing the BCA Framework, and do not decide implementation issues, which should be addressed based on the specific facts and circumstances.

One of the principles, however, does raise broader implementation issues. That is, the principles state that the BCA Framework should be applied to portfolios of projects rather than any one specific project. That implementation issue is discussed further below.

The BCA Framework Tests

The Issues

One of the recommendations of the BCA Whitepaper is that utilities should report the results of the SCT, UCT, and RIM tests. The Whitepaper also lists the benefits and costs of avoiding utility expenditures and impacts on society, and analyzes whether each of the benefits and costs would serve as a component within the scope of each of the three tests, respectively. As noted in the Whitepaper, the listing of the benefits and costs that should be included in the BCA Framework, and how they should be recognized and calculated, raise issues that commentators were invited to address.

In so addressing the tests upon which the BCA Framework would rest, JU would limit application of the SCT. Instead, it proposes as the primary test a Distributer Cost Test (DCT) that it would substitute for the traditional Utility Cost Test (UCT), which is premised upon generation, transmission and distribution costs the utility actually avoids if DER is substituted for utility investment. The distinction between the two is that the impacts on wholesale commodity costs are excluded from the DCT, which focuses on delivery costs. Those costs would include any incentive or administrative costs that a utility might pay to a DER provider or incur because of its relationship with a DER provider.

JU’s position is contradicted by various PII and DER commentators. Those commentators support the use of the SCT. Because the SCT recognizes the benefits to society as a whole if DER is substituted for utility investment, incorporation of the SCT would move recognition of externalities and NEBs into the BCA Framework itself, where they would affect the selection of projects. PSEG and ASC advocate use of Total Resource Cost (TRC) test, which is similar to the SCT except that it does not monetize, and so excludes, social out-of-market costs and their impacts on society as a whole. The TRC has been used for many years in New York for the evaluation of energy efficiency programs.

Representing customers, AARP and MI favor use of the RIM test, which addresses the effect of DER on utility rates. AEEI and other PIIs, however, oppose use of the RIM test because they claim its results are misleading. They complain that the RIM test recognizes utility lost revenues, which are a sunk cost not properly considered in the analysis of prospective investments. EDF asserts that the RIM test is lacking because it focuses on whether DER will increase or decrease rates, but does not attempt to evaluate the magnitude of the decrease or increase.

Conclusions

The Commission adopts SCT as the primary measure of cost effectiveness under the BCA Framework. The SCT recognizes the impacts of a DER or other measure on society as a whole, which is the proper valuation. New York’s clean energy goals are set in recognition of the effects of pollutants and climate change on society as a whole, and only the SCT would both properly reflect those policies and create a framework for meeting those goals.

The UCT and RIM tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. As a result, the role of these tests is to set indicators that a more detailed analysis is necessary. A DER or other measure that is flagged by the outcome of those tests may be beneficial to the public in the overall REV context, and so may not be rejected because of those tests.

Instead, if the UCT or RIM tests so indicate, the utilities must inquire further into the actual impact of the DER or other measure on customer bills, beyond merely the impact on utility costs or rate structures. As NRDC and others point out, a more sophisticated rate impact analysis than that realized through RIM, which shows only if a rate decrease or increase will be realized without addressing the magnitude of the impact, is needed. A measure might reduce customer bills, leaving them better off, even if the UCT and RIM tests are not satisfied, or might be otherwise acceptable. Therefore, rejection of a measure that passes the SCT test in the overall context of REV is independent upon a complete bill impact analysis demonstrating that the impact of a measure on customer bills is of magnitude that is unacceptable.[6]

The DCT test JU proposes is rejected as overly narrow and in any event its primary distinction from the UCT is recognition of wholesale market price impacts, an issue discussed further below. This effectuates the rejection, discussed above, of the positions of commentators who argue that the primary purpose of the BCA Framework is to further the selection of only the most cost-effective proposals while disregarding the effect of proposals on achieving environmental and other public policy goals. Finally, in light of the SCT and the subsidiary use of UCT and RIM, the TRC is not necessary.

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[6] To limit the burden of preparing multiple, hypothetical bill impact analyses, this requirement should applied to the DER portfolio identified through the BCA and DSIP Frameworks. The bill impact of that portfolio, selected via the SCT, should be compared to the traditional utility portfolio proposed in the DSIP. Once that comparison is made, a more granular analysis can be conducted, if necessary.

Externalities and Non-Energy Benefits

A. Externalities

The Issues

The externalities that would be recognized in the SCT raise considerable dispute among the parties. As noted in the BCA Whitepaper, too much of a public good, such as air or water that is free from pollution or a climate that is relatively stable, can be consumed when producers and consumers are able to disregard the effects of their actions on the public good. Because of the effect of these externalities, public goods are not priced at the marginal cost that their use causes, in that the commodity market price is missing some or all of the "marginal damage costs" related to these externalities. Those marginal damage costs can be internalized through means such as taxes, command and control regulation, Cap and Trade (C&T) programs and other environmental permitting or restriction regulations.

The most important disagreement over externalities is found in the debate over recognizing the impact of CO_2 and other air emissions pollutants. The BCA Whitepaper proposed three approaches to valuing the harms and social costs stemming from air emission pollutants: 1) using 20 year forecasts of location-based marginal price (LBMP) energy prices produced from the Congestion Assessment and Resource Integration Study (CARIS) model managed by the New York Independent System Operator, Inc. (NYISO), which reflect the portion of the externality costs in the model through forecasts of the impacts of existing air emissions control programs (Approach 1)(CARIS LBMP); 2) developing an adder based on estimations of net marginal damage costs (Approach 2)(marginal damage costs); and, 3) valuing environmental attributes at the prices paid for Renewable Energy

Credits (REC) under contracts with large-scale renewable (LSR) resources (Approach 3)(LSR RECs).

Under Approach 1, the CARIS forecasts of LBMP twenty years into the future reflect a trajectory of the costs of complying with regulatory programs for constraining CO_2, SO_2, and NO_x emissions over that period. Included among these regulatory programs are the existing Regional Greenhouse Gas Initiative (RGGI) and other C&T programs premised upon the creation and trading of allowances.

Under Approach 2, the marginal damage costs of emissions on society, net of the costs already internalized in the CARIS forecasts, would be added to the value of emission-free resources. While efforts to monetize marginal damage costs have resulted in a wide range of estimates and forecasts, a marginal cost damages adder could be derived from the estimates of the Social Costs of Carbon (SCC) developed by the Environmental Protection Agency (EPA) in coordination with other federal agencies, which recognizes the effects of the CO_2 emissions. EPA and its federal agency partners have undertaken extensive efforts to vet the SCC cost, which can be converted, as set forth in Appendix C to the BCA Whitepaper, to a value of about $20 to $35 per MWh above the value already recognized in CARIS LBMP.[7]

Approach 3 relies upon the RECs purchased from LSR generation facilities. These purchases are accomplished through the Renewable Portfolio Standards (RPS) Program implemented since 2004 by the New York State Energy Research and Development Authority (NYSERDA). The value of the RECs that NYSERDA has purchased in the recent auctions equates to about $25 per MWh. That figure could serve as an adder to the CARIS LBMPs.

[7] The actual value will vary from year to year and depend on the most recent CARIS database.

Discussing the three approaches, the BCA Whitepaper notes that Approach 1 (CARIS LBMP) reflects only the NYISO’s best estimates of the costs of compliance with existing programs for reducing or mitigating emissions. As a result, Approach 1 may not recognize full marginal damage costs. Approach 2 (marginal damage costs) would better capture those costs not reflected in CARIS LBMP but there are drawbacks. The range of estimates for an externality adder to the CARIS LBMP value varies widely. While the SCC value has been developed carefully using a transparent methodology that is readily replicable, other estimates put marginal damage costs at values considerably in excess of SCC, or below it to the point where no adder would be needed because the costs would be deemed already within CARIS LBMP. Using an adder also raises the issue of its application to small emission-free generation resources independent of the value larger resources receive.

Under Option 3 (LSR REC) an adder to CARIS LBMP would be based on the value of the RECs that LSR generation facilities have received through contracting for the REC value. Those contracts and REC prices have been obtained through an auction process that presumably correctly prices the REC. Those auctions, however, are affected by many variables, including oscillations in the price of natural gas.

The utility and consumer groups generally favored Approach 1 (CARIS LBMP). They argue that CARIS properly reflects the actual costs of complying with emissions reductions programs and that reductions to pollution beyond those contemplated in those programs will not actually be achieved by DER. They oppose Approach 2 because marginal damage costs, they claim, cannot be measured through market values and are not tied to actual reductions to pollutant emissions. JU concludes that a marginal damage cost value will simply raise electricity costs to consumers without any benefits.

Most PII and DER commentators, however, support use of Approach 2 (marginal damage costs). DEC also advocates selection of Approach 2. These commentators maintain that marginal damage costs properly reflect the impact of emissions on society and recognizing that benefit will promote the emissions-free DER desired to achieve social goals. Answering the concern that marginal damage costs are difficult to assess, these parties generally would rely on the EPA's SCC costs, which they characterize as well developed and structured to evolve in tandem with future emissions programs and social goals. Some PIIs, however, argue that even SCC is inadequate, because it does not recognize the impacts of methane and other greenhouse gases beyond CO_2.

No party supported use of Approach 3 (LSR RECs). It was criticized as unduly sensitive to exogenous factors unrelated to pollutant reductions.

Conclusions

While wholesale markets reflect the value of existing programs for controlling air emissions, they do not accommodate the full value of the externalities attending those emissions. Nor is it likely that future programs will be integrated swiftly into wholesale markets in a way that incorporates full value of the externality harm that is avoided. That this externality value is properly recognized is a fundamental purpose of REV and the SCT test cannot be properly implemented without that recognition. As a result, the positions of commentators who would limit the BCA analysis to utility costs under existing programs and disclaim recognition of externalities is rejected.

Commentators vigorously dispute the proper valuation of emissions even within the SCT. Recently, however, Governor

Cuomo announced New York's Clean Energy Standard (CES) mandate. This governmental program should hold the solution to properly valuing the impact of CO_2 emissions, because it would create a new category of costs that could be avoided through DER resources. Once those avoided costs are accurately valued, they could serve as a supplement to, or be incorporated in, the CARIS LBMP values that recognize only existing governmental programs like RGGI. The result would be an externality value that furthers the goals of REV in moving to an advanced energy future where reliance on carbon fuels is reduced.

The CES values that can be avoided, however, cannot be determined at this time because the program is only in the initial state of development. Therefore, a bridge to the future that recognizes the cost of carbon is needed. That bridge can be found in the EPA's SCC value. That value has been carefully examined by independent entities, and, at the $20 per MWh to $25 per MWh cost it supports, it resembles the value NYSERDA has realized for the RECs it has purchased in recent LSR auctions.

The actual value of the SCC used in the BCA analysis would be set at the difference between the EPA's SCC value and the RGGI price assumed in the CARIS LBMP model. That value can then be applied to the tons of CO_2 emitted per marginal MWh. Staff would calculate these figures each year and file them publicly for use in the BCA Framework. After the CES programs are established, those compliance costs would be substituted for the EPA estimates, where the costs can be avoided through a non-emitting DER alternatives or other measures.

In applying the SCC value, however, utilities must exercise care in ensuring that the value is not extended to DER alternatives or other measures that are themselves emitting resources. Only DER that is non-emitting should be treated as offsetting the costs attending existing emitting resources.

This distinction shall be made in the BCA Handbooks. Although emitting resources do not qualify for the SCC value, they remain eligible for the value of other offsets to utility costs, such as reducing line losses on a locational basis.

As to SO_2 and NO_x, the proper value is embedded in CARIS LBMP through the CARIS forecast of the costs of the existing programs that will continue to address control of these pollutants. As with the SCC value, utilities shall include in their BCA Handbooks means for assuring that the CARIS value is not extended to DER or other measures that themselves emit SO_2 and NO_x. To the extent that DER alternatives would produce greater benefits or costs than those forecast in a utility’s service territory because of local characteristics, including social or economic justice concerns related to emissions, that potential would be described and estimated in each utility’s BCA Handbook. DER providers would be required to submit information adequate to assess this net benefit or cost.

B. Operational and Societal Non-Energy Benefits

The Issues

Beyond emissions, commentators dispute the inclusion of benefits and costs in the SCT analysis, both within and beyond the BCA Whitepaper listing. JU, however, culls from the other comments a list of the benefits it sees as related to the operation of the grid, including some NEBs that go beyond the provision of energy itself, such as optionality, outage avoidance and system restoration. It believes these operational benefits could be recognized, but only if they can be properly quantified and it is demonstrated that the costs are actually avoidable and material.

Many of these benefits were proposed by AEEI and other PIIs, who also favor their recognition. Those commentators would go further, and recognize a variety of effects also related to grid operation, such as land and water impacts, avoided noise and odor benefits, and avoided customer care costs, like those related to service terminations and uncollectibles.

Commentators also disagree over NEBs not directly affecting the operation of the grid, but that would benefit societal interests. According to PII and DER commentators, these could include public health impacts, enhancements to property values, job creation and enhancements to economic growth, switching from burning fossil fuels to using less-polluting electricity, and increased personal comfort (experienced as a result of DER measures such as more effective insulation).

The utilities and customer representatives vigorously oppose reflecting these non-operational NEBs in the BCA Framework. They point out that NEBs can result in costs as well as benefits, and argue that impacts on jobs, for example, could actually result in lower levels of employment if increased utility costs reduce economic activity generally. Such job losses, they say, would offset any job gains that might be realized through employment increases at DER providers. They also claim NEBs are speculative and cannot be accurately valued.

Valuation, AEEI asserts, could be achieved through a generalized adder. Pointing to other states that use such adders in their evaluations, AEEI proposes that an adder of 10% could accommodate both the utility avoided costs that are difficult to quantify, such as NEBs. Utility and customer representatives oppose an adder, reiterating that it is speculative and will only increase electric costs.

Another approach to the difficulties in quantifying NEBs is to rank them qualitatively. These qualitative values could be recognized in breaking ties or revising a narrow failure to satisfy a test into a passing grade. Commentators favoring this qualitative approach argue that it would promote the social goals attending DER. Utility and customer representatives again claim the only result would be to increase costs without realizing benefits.

The BCA Whitepaper lists various benefits and costs and proposes quantifications for them, but does not distinguish between NEBs that are directly related to grid operations and those that represent broader societal improvements. While the Whitepaper notes that NEBs could include factors like public health impacts, property values, and avoided customer termination and uncollectibles costs, NEBs are characterized as difficult to calculate and are not generally monetized at this time. The BCA Whitepaper therefore proposes that NEBs be recognized when they can be quantified in particular circumstances, or can be incorporated into qualitative evaluations. For example, the BCA Whitepaper sets forth methods for quantifying avoided outage and restoration costs.

Conclusions

Benefits directly related to utility or grid operations that cannot be monetized generally shall nonetheless be reflected on a location-specific or project-specific basis where monetization is feasible at that level. The monetization process would be incorporated into the BCA Framework through the BCA Handbooks.

Where operational NEBs cannot be monetized generally or their value cannot be deduced through location-specific or project-specific analysis, they may be reflected on a qualitative basis. Utilities should use judgment rather than relying strictly on cost impact estimates that are of necessity less than adequate guides over the longer term. Because forecasting cannot be completely accurate, a qualitative approach will allow utility managements to respond flexibly to DER proposals and other measures that will achieve REV and SCT goals at a cost that is reasonable to ratepayers. Moreover, over time these direct externalities might be amenable to quantification as progress is made in their valuation. The Commission will be alert to changing circumstances that will admit monetization of operational NEBs where it was not previously available, and will update the BCA Framework accordingly.

No commentator has been able to value any of the proposed societal NEBs with sufficient specificity to include them in the BCA Framework at this time. Circumstances, however, may change. While it would not be reasonable to include in the BCA Framework societal NEBs, because they are speculative, that step could possibly be taken in a future for an NEB where more accurate valuation can be achieved. Again, changing circumstances can be reflected as the BCA Handbook is updated, and improvements will be incorporated as they become available. With operational externalities already recognized qualitatively, however, there is no reason to further complicate the BCA Framework with a qualitative approach to other NEBs.

Nor will a generalized adder be adopted to accommodate operational or societal NEBs on other costs that cannot be monetized at this time. Such an adder would increase the price of electricity without necessarily resulting in value to ratepayers.

Wholesale Price Suppression

The Issues

According to the BCA Whitepaper, while changes to electric usage could reduce wholesale market prices in the near term, it is difficult to accurately predict the duration, persistence, and degree of price variation across geographic locations resulting from that impact. As pointed out in the BCA Whitepaper, wholesale markets continually adjust to changes in supply and demand. Nonetheless, it cannot be demonstrated that the impact of alternatives to utility expenditures on wholesale market prices is zero, especially in the short run.

Commentators disagree over the recognition of wholesale market price suppression in the SCT. In the BCA Whitepaper, three options for quantifying wholesale market price suppression effects, for use in the UCT and RIM metrics, were proposed: 1) modeling estimated reductions to prices over a short time period, such as one year, using CARIS (Option 1)(CARIS short term); 2) modeling estimates over a somewhat longer period, such as three years, with the impact of the reduction declining over time, again using CARIS (Option 2) (CARIS medium term); and, 3) relying on estimates developed by each individual utility reflecting the effects on the wholesale prices it pays for the projects it evaluates (Option 3)(utility estimation).

Generally, PII and DER commentators support some recognition of wholesale price effects. They maintain that since price suppression occurs, it should be recognized in some fashion. Support for the various options among these commentators, however, varies. They concede that the term over which the price suppression would remain in effect is difficult to ascertain. Many urge that more study be given to this problem, and some point to efforts in New England to calculate the effects of price suppression on wholesale markets there. A few favor Option 3, whereby utilities would calculate the impact based on their wholesale purchases.

Utility and customer representatives generally oppose recognizing price suppression. They believe that since wholesale markets are intended to adjust to supply and demand, the impacts are mostly ephemeral. NYC also points out that recognizing price suppression could have unintended effects on the operation of the wholesale markets. Exelon in particular argues that these impacts could distort the market as the means for obtaining and sustaining least cost generation resources.

Conclusions

Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT.[8] Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there.

Price effects, however, are properly reflected in bill impact calculations. As discussed above, when the BCA Framework is applied, DER projects and other measures that pass the SCT test can still be examined further to ascertain their effect on customer bills. A method for calculating reasonable estimates of near term price impacts is necessary to properly accomplish a bill impact analysis. Determining the length of time over which wholesale prices will return to equilibrium conditions after the effect of a DER or other measure itself, however, is not essential to that methodology. With measures already evaluated through the SCT, which would not reflect price suppression, the

[8] Price suppression assumptions, however, must be made in the UCT and RIM; given the subsidiary role those test will play, utilities shall address the necessary assumptions through the BCA Handbook filing process discussed below. The price suppression assumptions are one of the issues on which utilities are expected to achieve uniformity in that process.

next step is to show the range in bill impacts caused by the presence or absence of the measure under evaluation in or on wholesale markets.

This can be accomplished through using the first year of the most recent CARIS database to calculate the static impact on wholesale LBMP prices of a 1% change in the level of load that must be met. That approach will capture wholesale energy market price changes, while capacity market price impacts will be met through the ICAP model presented in the BCA Whitepaper. This methodology can then be applied proportionately to the measure under evaluation. The evaluation would then be conducted showing separately the impacts both with and without the wholesale market price effect. Judgment would then be exercised in evaluating if the disappearance of the price impact as the market adjusts has a disproportionate effect on the bill impact analysis overall.

The Discount Rate

The Issues

Because the goal of REV is to integrate DER into utility investment and operational decisions, the BCA Whitepaper proposes that the weighted average cost of capital (WACC) be used in the BCA Framework. Utilities employ the WACC when evaluating their investment decisions. The BCA Whitepaper also suggests that a single discount rate should be used for all metrics. Because the purpose of a discount rate is for the evaluation of alternatives to utility expenditures, it should reflect the opportunity cost of capital for those expenditures, instead of varying through use of different discount rates.

The proper discount rate to be deployed in the SCT provoked substantial disagreement. PII and DER commentators criticize the WACC approach, arguing that a social discount rate, in the range of 2% to 3% should be used instead. Use of

WACC, AEEI contends, would significantly reduce the value of the benefits assumed in the later years of a DER alternative’s life. It also asserts that DER options are lower in risk in comparison to the risks utilities and generators encounter in adding resources. Pointing out that one objective of the BCA Whitepaper is more uniform methods of performing evaluations among utilities, AEEI adds that use of WACC runs counter to that goal because it varies among utilities. For its part, ASC complains that use of WACC will bias evaluations against DER alternatives.

JU, however, presents a detailed defense of WACC. It argues that it is the measure that best reflects the costs utilities, and thus their ratepayers, actually avoid. It criticizes, as speculative at best, AEEI’s assumption that DER investments are less risky than utility investments. Instead, JU maintains that utilities, because better capitalized, have a lower risk profile generally than DER providers, and that customers see the risk of DER more commensurate with WACC values than the very low social value that the PII commentators would use. JU also maintains that investments in DER present risks, well beyond the risks associated with utility investments, and that use of the social discount rate will bias evaluations against utility alternatives to the detriment of ratepayers.

Conclusions

Generally, the discount rate used for comparing utility investment and long term procurement measures to DER and other resource alternatives is the WACC. That is the cost each utility avoids when a measure that is an alternative to a utility service is deployed instead of the utility alternative. To use a rate other than the WACC would distort evaluation of the value of measures that are alternatives to utility service. Moreover, use of the WACC avoids the difficulty of arriving at specific discount rates attributable to specific measures, which, as JU points out, might vary significantly. On the other hand, the variation in WACC among utilities is appropriate, as it reflects actual circumstances in their service territories.

There is, however, one important exception to use of WACC as the discount rate -- the discount for calculating SCC. For that valuation, the EPA assumes a 3% real discount rate in considering the "central value" of damage costs of carbon over time. Following the EPA approach is appropriate in applying the SCT. The SCC is distinguishable from other measures because it operates over a very long time frame, justifying use of a low discount rate specific to its long term effects.

The Components of the BCA Framework

Conclusions

The implementation of the externality, NEB, wholesale price suppression, discount rate, and other components comprising the BCA Framework is set forth for each component Appendix C. As well as the externality and other components that were disputed, that Appendix details all the components that will be reflected in the Framework and the approaches to their valuations, including the many components that raised little or no controversy.

The approach to calculating the SCC value for inclusion in the SCT is set forth in Appendix C. It also addresses the location-specific and project-specific aspects of NEB benefits and costs. For example, operational NEBs that arise on a location-specific basis, such as land and water impacts, or project-specific impacts, such as reductions in uncollectibles due to a project focus on low income customers, would be recognized on that basis. Similarly, NEB costs, such as those incurred to reduce noise from a facility, would also be considered on a location-specific or project-specific basis. This process would be incorporated in the BCA Handbooks.

Other than the BCA components discussed above, however, the BCA Whitepaper analysis of components engendered little controversy. Calculating avoided energy and avoided operation and maintenance expenses, for example, may proceed as originally proposed in the BCA Whitepaper. Those proposals are reiterated and adopted in Appendix C, subject to the following modifications.

The BCA Whitepaper suggested a process for smoothing CARIS estimates. The smoothing process, however, could result in as many distortions as it cures, and so the estimates as promulgated by NYISO will be used instead. The calculation of avoided ancillary service costs will be adjusted to accommodate AEEI's suggestion that a two-year average of ancillary services costs should be used. Utilities, however, remain responsible for determining which DER projects will actually offset the utility costs in this category, and so should be valued including this component.

The BCA Whitepaper noted that participant opportunity costs used in evaluating demand reduction (DR) projects had often assumed participant opportunity costs amounted to approximately 75% of any incentives paid to participants. Those opportunity costs, however, have included detriments such as the reduced personal comfort allegedly attending some DR measures. Because societal NEBs that cannot be monetized are not included in the BCA Framework, costs that are not monetized should not be included either. Therefore, utilities assessing participant opportunity costs may not use generalized assumptions such as a 75% value. If the costs cannot be quantified, they should not be included in the evaluation. The method for valuing participant DER costs shall be included in the BCA Handbooks.

Appendix C also identifies the means for the calculation of avoided distribution capacity infrastructure benefits. As reflected in the BCA Handbooks, this analysis will permit utilities to move forward with their DSIPs. The conclusions that are reached in Appendix C on this point, however, are subject to re-evaluation and reconsideration in arriving at the "value of D" in Case 15-E-0571, discussed below. Other aspects of the BCA Framework as set forth at Appendix C may also be reconsidered in that process, whose purposes include arriving at substitutes for net metering tariffs to the extent appropriate.

The BCA Handbooks and BCA/DSIP Implementation

A. The BCA Handbooks

The Issues

The BCA Whitepaper proposes that utilities develop BCA Handbooks to guide DER providers in structuring their projects and proposals. The Handbooks would be developed in coordination with each utility's DSIP, where system needs, proposed projects, potential capital budgets, and plans for soliciting DER alternatives will be provided. Because market engagement should be consistent across New York, the Handbooks would establish methodologies based on common analytics and standardized assumptions, and would identify various sensitivities and synergies.

Flexibility, however, would be incorporated to allow for recognition of unique project features and regional variations. Utilities would be required to include an example of the application of all benefit and cost components to an illustrative portfolio of alternative resources. That analysis would depend upon the accurate characterization of DER resource profiles; the determination of the value of the resources in reducing energy or capacity and ancillary service needs; and, the optimization of long-term procurement and capital investment through recognizing synergies among the resources to be obtained.

The content, format, development, and implementation of these Handbooks engendered significant disagreement. JU would align BCA Handbook and DSIP development, and provide for timely and periodic updates to the Handbooks through a process that is not costly or administratively burdensome. As a result, JU proposes that the BCA Handbooks be filed at the same time as the DSIPs and updated annually. JU would limit the content of the Handbooks to describing the economic tests that would be employed, and listing key assumptions and inputs that would be used in a BCA evaluation of DER. NFG opposes developing Handbooks altogether, believing it would be burdensome and of little use in evaluating individual proposals.

Many PII and DER commentators support the development of more robust Handbooks. They would include in the Handbooks a transparent and detailed description of the formulas and modeling approaches that will be used; examples illustrating the deployment of the tests and their application to actual circumstances; and, toolsets and protocols DER providers can apply in assessing their proposals.

There was no consensus on the process for developing the BCA Handbooks. JU believes that the utilities should draft proposed Handbooks for review and file them at the same time as their DSIP filings on June 30, 2016. Most PII and DER commentators believe that additional collaboration is needed before the Handbooks are proposed. NRDC suggests that a single utility should be selected to develop a proposed model Handbook, which would then be evaluated and developed into a format suitable for use at all utilities.

Conclusions

The implementation of REV depends upon the platforms that will be adopted through the DSIP filing process. Utility DSIPs, however, cannot go forward in the absence of the BCA Framework. Therefore, the BCA Handbooks that set forth the BCA Framework must accompany the DSIP filings. Further collaborative efforts would unduly delay the production of the Handbooks and thereby slow progress towards accomplishing REV goals.

Accordingly, each utility shall file its proposed BCA Handbook along with its DSIP filing due June 30, 2016. The utilities, however, are directed to cooperate in the preparation of their Handbooks, and set forth common methodologies, including use of the SCT, for uniform application across the State to the extent feasible. The Handbooks should deviate from each other only where necessary to accommodate distinctions among the various service territories. Once the Handbook and DSIP filings are made, further proceedings will be conducted with the two tied together.

The content of the BCA Handbooks shall be as identified in Appendix C. Updating shall take place whenever a utility’s DSIP filing is updated, which is expected annually. A balance will be struck between standardized assumptions that engender a manageable and transparent BCA Framework and allowance for the flexibility necessary to recognize uniquely beneficial projects or resources where proposed.

Methodologies, illustrative examples, and the description of the sensitivity analyses that will be applied to key assumptions shall be set forth in the BCA Handbooks. This includes explicitly valuing different resource types. Effectively assessing the benefits of DER requires accurately assessing the amount of energy, capacity, and other benefits that those resources provide, and how often, when, and where they will be provided. Therefore, the BCA Handbooks shall detail a methodology that: 1) characterizes DER resource profiles, and 2) determines to what degree those resources reduce energy or capacity and ancillary service needs.

B. BCA/DSIP Implementation

The Issues

The BCA Whitepaper contemplates that the BCA Framework will be applied to a portfolio of projects the utility selects as alternatives to its investments. MI is opposed to the portfolio approach, on the grounds that uneconomic projects may be included in a portfolio to the detriment of ratepayers. JU implies that screening of specific projects cannot be avoided. NRDC, however, argues that screening each potential DER measure individually would be impractical and burdensome, while testing at the portfolio level will ensure that, on average, projects that provide benefits to society and ratepayers are pursued. It also points out that program costs, such as marketing and implementation, are incurred at the portfolio level but are sunk by the time individual projects are screened.

Proposals for implementing the BCA Framework also differ. JU suggests a four-step screening process to identify those traditional utility infrastructure projects that could be avoided through a DER alternative, subject to a BCA analysis. The screening proposal affects only the use of the BCA Framework in evaluating alternatives to traditional utility investments, not other uses of the Framework. The screen would: set a cost threshold for utility investments above which DER alternatives would be considered; establish a timeframe of at least three years in advance of project need during which DER would be solicited, evaluated and implemented; if a load reduction is contemplated, the utility would calculate it at a percentage of the relevant geographic peak load; and, require that the utility's need for infrastructure is driven by load rather than the condition of existing assets as candidates for replacement for reliability or safety reasons.

NYC, AEEI, and others oppose the screening proposal as overly restrictive. Other PII and DER commentators recommend a further stakeholder collaboration to establish the details of the BCA Framework's implementation.

Moreover, as discussed in the BCA Whitepaper, the BCA Framework could be used for purposes other than evaluating alternatives to utility investment in the DSIP process. Many PII and DER parties would apply the BCA Framework to a broad range of utility activities, including evaluating tariffs and energy efficiency programs. JU, however, would circumscribe the framework to addressing alternatives to utility facilities.

Conclusions

The parties opposing the adoption of the JU's screening proposal are correct in describing it as overly restrictive. The BCA Framework is best applied through a broader, more flexible screening process.

Instead of the restrictive screen JU proposes, the BCA Framework shall be applied whenever utilities propose to make an investment that could instead be met through DER alternatives. In many cases, those alternatives will consist of a portfolio of projects that must be matched against the costs of the utility investment. It is anticipated that these projects will be solicited through a competitive procurement process premised upon a Request For Proposal (RFP). Once responses to the RFP are obtained, the BCA Framework would be applied to the portfolio of the most promising projects to ascertain if the DER alternative is preferable to the utility alternative. That is, the SCT test would be applied to the portfolio as a whole and, if necessary, a detailed bill impact analysis would then be conducted next.

MI is concerned that applying the test to a portfolio could result in the inclusion within the accepted projects of individual proposals that are not cost effective. The portfolio approach, however, need not preclude application of the BCA framework to specific projects where appropriate. In some cases, a single large project or several large projects will call for individual evaluation as well as an analysis of overall portfolio effects. Conversely, however, some projects that fail an individual screen might become viable if included in a portfolio and shall proceed on that basis. For example, a storage project might be a valuable component of a portfolio and individual project costs would not justify its rejection if the portfolio as a whole realizes benefits upon its inclusion.

This approach to screening can be accomplished without the restrictive conditions JU proposes. Its first condition, to establish a threshold for consideration of DER alternatives, is not needed and could obstruct aggregation of smaller projects into a portfolio that would create opportunities for DER. JU’s second condition, which would establish a three-year solicitation period, is overly lengthy, and more nimble procurement procedures are both feasible and necessary. The effort under Condition 3, to establish minimum reductions to peak load, is vague and appears difficult to implement. Moreover, it would preclude a combination of utility and DER responses to increases in load. Again, the condition is overly restrictive and will not assist in achieving the optimal mix of utility and DER investment most beneficial to ratepayers. Finally, Condition 4, which would restrict DER alternatives to utility investment for purposes other than meeting load, is clearly unreasonable. DER should be considered whenever a utility investment is made, whatever the reason, albeit utilities are correct in pointing out that the DER alternative, or the portfolio containing it, must meet all applicable reliability and safety requirements.

JU's restrictive approach that would limit the BCA Framework to alternatives to utility facilities will not be adopted. The BCA Framework will inform the development and evaluation of tariff measures, including, most importantly, replacement for net metering. The Framework cited here will be used as guidance in constructing the replacement tariffs. Additional work, however, on the design and implementation of those tariffs remains necessary. That will take place in the "value of D" process set forth in the Interim Ceilings Order.[9] As discussed there, a process is needed for a new regulatory approach to valuing DER products and designing rates for DER providers, which will lead to alternatives for net metering where appropriate.

That process is underway. A Notice Soliciting Comments and Proposals on an Interim Successor Tariff to Net Energy Metering and of a Preliminary Conference issued December 23, 2015 in Case 15-E-0571 sets forth detailed questions for the refinements beyond the BCA Framework that must be properly valued before rates for DER providers and alternatives to net metering tariffs can be properly designed. Procedures necessary to a full and complete evaluation of costs, whereby all parties may present information and test that information provided by others, will be arrived at in that proceeding, commencing with a Preliminary Conference. While the "value of D" is likely a long-term effort, methodologies can be developed before the end

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[9] Case 15-E-0407, Orange and Rockland Utilities, Inc., Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (issued October 16, 2015).

of 2016 to serve as a bridge for rates offered to DER providers and alternatives to net metering while ongoing efforts to better evaluate the "value of D" continue.

<u>The Commission orders</u>:

1. The Benefit Cost Analysis Framework set forth at Appendix C to this Order is adopted as described in the body of this Order.

2. The Joint Utilities shall file Benefit Cost Analysis Handbooks by June 30, 2016 in conformance with the discussion in the body of this Order.

3. In the Secretary's sole discretion, the deadline set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

4. This proceeding is continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

CASE 14-M-0101 - BENEFIT-COST ANALYSIS

LIST OF COMMENTATORS
(Name and Abbreviation)

Public Interest Intervenors

Acadia Center	Acadia
Advanced Energy Economy Institute[1]	AEEI
Alliance For a Green Economy[2]	AGREE
Alliance For Solar Choice	ASC
Association For Energy Affordability	EFA
Citizens Environmental Coalition	CEC
Citizens For Local Power	Local Power
Clean Coalition	Clean C
Environmental Defense Fund	EDF
Institute For Policy Integrity	IPI
Natural Resources Defense Council	NRDC
Pace Energy and Climate Center	Pace
Pepacton Institute LLC	Pepacton
Sustainable Otsego	Otsego
The Nature Conservancy	TNC
Vote Solar	Vote Solar

Providers & Organizations

Advanced Energy Management Alliance	AEMA
Battery and Energy Storage Technology Consortium, Inc.	BEST
Energy Storage Association	ESA
New York Geothermal Energy Organization	NY-Geo
Northeast Clean Heat and Power Initiative	NECHPI
PosiGen Solar Solutions	Posigen
Pareto Energy, Ltd.	Pareto
Peak Power LLC	Peak

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[1] Advanced Energy is a charitable and educational organization affiliated with Advanced Energy Economy, a national business association, and represents the Alliance For Clean Energy New York (ACENY) and the New England Clean Energy Council, which are regional partners with AEE.

[2] AGREE represents the Binghamton Regional Sustainability Coalition, Center for Social Inclusion, DE-Squared, Green Education and Legal Fund, Good Old Lower East Side (GOLES), New York State Sustainable Business Council, Nobody Leaves Mid-Hudson, People United for Sustainable Housing (PUSH) Buffalo, and Solar One.

<u>Utilities</u>

Exelon Companies[3]	Exelon
Joint Utilities[4]	JU
National Fuel Gas Distribution Corporation	NFG
PSEG Long Island LLC	PSEG

<u>Customer Representatives</u>

AARP and PULP[5]	AARP
Consumer Power Advocates[6]	CPA
Multiple Intervenors[7]	MI

<u>Governmental Entities</u>

City of New York	NYC
NYS Department of Environmental Conservation	DEC
Staff of the Federal Trade Commission	FTC

[3] The Exelon Companies consist of Exelon Corporation and its subsidiaries, Constellation, NewEnergy, Inc., Exelon Microgrid LLC, Constellation Energy Nuclear Group LLC, Nine Mile Point Nuclear Station LLC, R.E. Ginna Nuclear Power Plant LLC, Exelon Generation Company LLC, Baltimore Gas & Electric Company, Commonwealth Edison Company and PECO Energy Company.

[4] The Joint Utilities are: Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

[5] Public Utilities Law Project of New York.

[6] CPA is an alliance of large not for profit institutions that includes Columbia University Medical Center, Mount Sinai Health System, Fordham University, New York Presbyterian Hospital, Memorial Sloan Kettering Cancer Center, New York University, The College of New Rochelle, and NYU Langone Medical Center.

[7] MI is an unincorporated association of approximately 60 large industrial, commercial and institutional energy consumers.

ANALYSIS OF COMMENTS

SUMMARY OF INITIAL COMMENTS

Public Interest Intervenors (PII)

A. AEEI

In detailed comments that address both Benefit Cost Analysis (BCA) Whitepaper policy issues and methods for making the various BCA calculations required to implement the policies, AEEI affirms its strong support for the Reforming the Energy Vision (REV) process. It also supports the general framework described in the BCA Whitepaper, with some exceptions, but believes the application of the BCA framework to actual utility investments and tariff development should be addressed more fully.

Tariff development, AEEI adds, is properly subjected to BCA analysis, since tariffs for distributed energy resource (DER) products and services can yield offsets to utility investment. AEEI voices its disagreement with the BCA Whitepaper proposal to exclude tariffs from strict application of the BCA on the grounds that tariffs are a shorter term proposition than DER investments. AEEI argues that, because tariffs can encourage deployment of DER assets that avoid or defer utility investments, the distinction between tariff-driven outcomes and utility investments is overstated.

AEEI asserts that societal values should be incorporated into the BCA framework, with the Societal Cost Test (SCT) serving as the primary measure for applying BCA. These societal values, AEEI explains, are experienced over the full life cycle of the DER option by consequently, properly spreading initial up-front investments that may be significant over following years where operating costs are low or zero is crucial to a proper net analyses.

AEEI believes the SCT is superior to the Utility Cost Test (UCT) and Rate Impact Measure test (RIM) alternatives. The SCT, it contends, is the most comprehensive of the screening tests and incorporates the broadest range of information on the impacts of DER. Under the SCT, AEEI emphasizes, all energy policy goals should be accounted for in some way, even if some are difficult to quantify or monetize.

The UCT, AEEI elaborates, is a good indicator of utility system costs, and therefore a good predictor of the effect of the reductions to customer bills that will be realized as a result of DER investments. But, AEEI cautions, UCT does not recognize energy policy benefits such as reductions to environmental and health impacts and enhancements to economic development. AEEI notes that even some benefits to the utilities themselves, including improvements to reliability, reduced risks of outages, and efficiencies realized through customer empowerment would not be reflected in the UCT.

Turning to the RIM test, AEEI argues it is a poor tool for assessing the rate impacts of DER. According to AEEI, the primary difference between UCT and RIM is that RIM recognizes the recovery of lost revenues, even though, according to AEEI, they sunk costs. Fundamental economic principles, AEEI maintains, exclude recognizing sunk costs in the analysis of prospective investments, since sunk costs have to be recovered whatever the value of a future investment. AEEI also fears that large reductions in utility system costs may be foregone under the RIM test even if rate impacts are relatively de minimis. Characterizing the RIM test as misleading, AEEI asks that its use should be avoided.

A proper approach to the equity issues that might arise out of the varying impacts of DER on participants and non-participants, AEEI posits, would be to more thoroughly understand the effects on non-participants. As a result, AEEI would proceed to an analysis of three important factors -- rate impacts, bill impacts, and participation impacts. Rate impacts should account for all factors that affect rates, while bill impacts should build on the rate impact estimates as they actually affect customers. Evaluations of participation should reflect the percentage of penetration achieved, year by year and compared across years. Through these measures, a picture of the effect of DER measures can be developed.

AEEI supports the creation of utility-specific BCA Handbooks to document the value of DER and establish DER resource profiles. The Handbooks, AEEI advises, should be consistent across utilities in methodology, but may recognize temporal or geographic variations. The methodologies, assumptions and model inputs used to calculate DER benefits and costs should be transparent.

According to AEEI, the BCA Handbooks should address a wide range of DER technologies, even if they cannot be considered comprehensive. The Handbooks would be applied to the entire portfolio of resources, and would reflect interactive benefits. For example, a Home Energy Report (HER) program would increase customer participation in other DER programs and technologies, while the co-location of distributed solar generation and flexible storage could create combined benefits. The handbooks should be updated periodically and provide for sensitivity analyses.

Describing the selection of a discount rate as critical because DER costs are incurred early while benefits accrue over time, AEEI opposes high discount rates that could significantly reduce the value of the benefits in the later years. According to AEEI, using the utility weighted average cost of capital (WACC) as the discount rate is an example of the harms attending an overstated rate. AEEI believes that DER options and energy efficiency programs are lower in risk in comparison to construction and market risks attending supply side resources. As a result, a discount rate comparable to the U.S. Treasury Bill rate of about 3% would properly reflect the risk. AEEI points to Maryland, where, under a total resource cost (TRC) test, a 4.7% discount rate was used to evaluate energy efficiency programs. As a result, WACC should be applied only to the UCT for its circumscribed uses, while the SCT should be the primary test at a lower discount rate.

AEEI also believes that wholesale market price impacts were substantially understated in the BCA Whitepaper. AEEI disagrees with the proposition stated in the Whitepaper -- that elasticity of demand will increase consumption if prices go down. AEEI also contends DER reduces market power, and forces new supply entrants to offer more competitively priced options. Existing models such as MAPS, says AEEI, would better capture the true market benefits of DER than any of the three wholesale market impact measures proposed in the BCA Whitepaper.

AEEI lists its additions to the benefits identified in the BCA Whitepaper. AEEI would recognize the DER effect on avoided transmission capacity infrastructure and avoided ancillary services. As to distribution system benefits, it would add voltage management and power factor improvement. It also finds benefits in avoided distribution capacity infrastructure beyond those stated in the BCA Whitepaper because greater DER penetration at higher capacity factors will reduce loading on distribution equipment, extending useful lives. Concomitant reductions in avoided O&M will be experienced. AEEI would expand avoided restoration and outage costs to include resiliency benefits, while external benefits would encompass avoided noise and odor pollution impacts.

AEEI also sees greater benefits to reliability and resiliency, beginning with DER that remains operational while islanded during an outage and thereby available to assist in restoration. DER can also avoid T&D upgrades otherwise necessary to enhance resiliency. AEEI believes another addition to benefits is the enhanced revenues utilities will garner because outages are avoided.

Emissions externality benefits, AEEI maintains, should be measured directly instead of relying upon markets developed for specific purposes, such as the Regional Greenhouse Gas Initiative (RGGI) and Renewable Energy Credits (REC) exchanges. Use of measures like REC not intended to measure marginal damage costs of emissions would understate the benefits of avoiding those emissions. Instead, the effect of reducing harmful air emissions can begin with the Congestion Assessment and Resource Integration Study (CARIS) model, enhanced by use of an adder set at the federal Social Cost of Carbon (SCC) damage cost estimates. Use of CARIS alone, EEEI maintains, would not recognize the value to society of reductions to air pollutant emissions, absent the development of highly sensitive production models. AEEI would also recognize other environmental benefits, including avoided real estate costs, reduced water and sewage use, and water quality improvements that result from substituting DER for generation supply.

Non-energy benefits (NEB), AEEI asserts, should be separated into utility benefits and societal benefits, including participant benefits. While conceding that societal NEBs are particularly difficult to quantify, AEEI would explicitly include them in the BCA framework. AEEI argues these benefits are particularly important for low-income customers, where energy efficiency improvements leading to bill reductions would avoid bill payment problems and attendant arrearages and write-offs, and termination and reconnection costs. AEEI also sees societal benefits in improvements to health and safety, customer comfort, property values and economic development. AEEI points to efforts to quantify some of these costs in Massachusetts and Maryland, and to use of 10% to 15% adders in other states. It adds that Colorado uses a 25% adder where low-income customers are concerned.

Addressing other issues, AEEI opposes using a simplified assumption for participant opportunity costs of 75% of any incentives paid. It believes a more nuanced approach is necessary, and would perform a detailed analysis of participant costs and benefits. Shareholder incentives should be included in program costs, but non-energy costs should be recognized only if NEBs are also reflected.

B. ASC

ASC generally supports the proposed BCA methodology and principles, finding it particularly important to recognize synergies and economies among DER measures through a portfolio approach. Another primary principle, ASC perceives is investment stability as a prerequisite to increased DER deployment.

ASC would add to the tests of cost effectiveness the Total Resource Cost (TRC) test, which it describes as the primary tool for measuring demand side management (DSM) benefits and costs. It opposes use of RIM because it does not encompass all of the benefits that can be realized from DER. It believes TRC appropriately balances system-wide benefits and costs, including externalities, for both DER participants and non-participants.

According to ASC, the WACC rate is not suited to serving generally as the discount rate in the BCA Framework, because it is a utility-specific measure intended to guide their managements and shareholders in selecting among utility investments, not a measure designed to capture all the costs and benefits from DER. An overstated discount rate like the WACC, ASC contends, would artificially discount the value of DER. ASC also sees the potential for double-counting in applying a discount rate first in determining the long-term damage cost to society under the SCT and again through the WACC when alternative DER portfolios are evaluated.

Turning to tariff development, ASC sees the interplay of retail rates and DER tariffs as a rate design issue more effectively addressed in Track 2 of REV rather than through the BCA. ASC again emphasizes the importance of creating a stable investment environment when devising tariffs but points out that tariff rates already reflect a degree of variability when applied to net metered resources.

As ASC describes them, the three options in the Whitepaper for quantifying wholesale market price suppression effects are: 1) modeling over a short time period, such as one year, using CARIS (Option 1)(CARIS short term); 2) modeling estimates assessed over a somewhat longer period, such as three years, at an amount that declines over time, again using CARIS (Option 2)(CARIS medium term); and, 3) relying on estimates developed by each individual utility reflecting the effects on it for the projects it evaluates (Option 3)(utility estimation). The Whitepaper, ASC elaborates, suggests market price suppression could be excluded altogether from the valuation on the basis that market price effects amount to a transfer payment from generators to consumers. ASC is concerned that the latter outcome may not be methodologically sound, but believes further investigation of the question is needed and that in the interim Option 2 (CARIS medium term) is the most appropriate for initial BCA implementation.

Addressing avoided energy costs, ASC proposes to apply sensitivities in a range of at least one standard deviation to the electricity price forecasts. It would value avoided O&M costs not solely on utility-specific cost-of-service studies, but also on standardized cost allocation methods.

Line loss allocations, ASC continues, could benefit from further investigation. Granularity would thereby improve over time. Fuel diversity, ASC claims, is also undervalued in the BCA Whitepaper, and it would establish a separate value for fuel price risk.

Describing the Whitepaper's approaches to monetizing externalities as: 1) using 20 year CARIS forecasts of location-based marginal price (LBMP) energy prices to reflect externality costs because they are embodied within CARIS (Approach 1)(CARIS LBMP); 2) developing an adder based on estimated net marginal damage costs (Approach 2)(marginal damage costs); and, 3) valuing environmental attributes at the price paid under contracts with large-scale renewable (LSR) resources that reflect REC values (Approach 3)(LSR RECs). ASC strongly opposes the Approach 1, because it would undervalue environmental benefits, and believes the Approach 3 results in a proxy that could be distorted by a host of exogenous factors. As a result, it favors the Approach 2 notwithstanding the difficulties in calculating the marginal damage adder. ASC would also recognize in the adder the damages resulting from methane and air toxics released in the production and transportation of natural gas.

As to NEBs, ASC would add to the list the benefits attending employment growth in the DER field as DER penetration increases. Finally, it would limit recognition of participant costs to evaluation of programs depending upon limited funding, while excluding the costs from when analyses of net metering or DER tariffs are conducted.

C. EDF

Evaluating the SCT, UCT, and RIM tests, EDF finds the RIM test lacking as an evaluation because it disregards the magnitude of the utility rate decrease or increase, and it also joins AEEI’s criticisms of the test. It would establish SCT as the primary test, with UCT and RIM limited to a secondary role in informing decision-making.

Turning to externalities, EDF agrees that wholesale LBMP prices reflect air pollutant emission costs but that an adder is needed where emissions themselves and not just costs are reduced. EDF would refine the analysis, however, for smaller generation units by valuing the carbon they emit through the net marginal damage adder while offsetting the benefit from their generation at the LBMP price.

EDF would set the marginal damage cost at the federal government SCC estimates, as the lower bound. EDF views favorably the prospect for growth in the SCC values over time, but suggests using a global value for carbon dioxide now as a better measure of its total externality value. It also finds the selection of the discount rate inherent in the SCC values, at about 3%, superior to using WACC.

EDF would recognize the value of emissions-free DER in offsetting DER that is not emissions-free, and would evaluate cumulative DER emissions in a locally-defensible way. Merely imposing on emitting DER the $25 per MWh parity value proposed in the BCA Whitepaper, EDF objects, is inaccurate. EDF complains that the $25 value may substantially understate actual damages, while, on the other hand, the value ignores the non-energy benefits that DER might provide. EDF also maintains that the benefit of DER in reducing demand for centralized generation should be valued by subtracting the results of the CARIS model from the parity value instead of adding the two together.

EDF supports modeling NEB. Where costs and benefits are difficult to quantify, EDF proposes proxies and alternative benchmarks. Its position on wholesale price effects is to modify Option 2 (CARIS medium term) by conducting a study on the decay of price suppression over time that would arrive at a more accurate determination of the length of that period than the three years assumed in the BCA Whitepaper.

D. IPI

The BCA Framework, IPI asserts, should be viewed from a societal perspective and reflect a societal discount rate. IFI would maximize net social welfare in preference to a goal of realizing for ratepayers the greatest benefits at the lowest costs. It also maintains that benefit cost ratios can be deceiving in the absence of an analysis of a net present value of the benefits and costs.

IPI would evaluate externalities through detailed calculations of net marginal effects instead of through market proxies, even though the latter requires less effort. IPI points to efforts in other states to monetize various externalities, which it says could be duplicated in New York. Where monetization or quantification are difficult, IPI proposes that a break even analysis could be used to estimate the point at which potential benefits outweigh potential costs. From that point, the unquantified benefits could be evaluated to determine if they are likely to exceed costs. Another alternative IPI proposes is Multi-Criteria Decision Analysis (MCDA) where net benefits are ranked. The alternative with the highest net benefit is then selected.

The monetization of marginal damage estimates, IPI believes, is independent of other emissions pricing policies, such as RGGI. IPI sees externality benefits beyond those described in the Whitepaper, where the RGGI allowance cap is used as the metric to quantify avoided emissions. IPI objects to the assumption that the substitution of DER for existing resources has only an effect on the costs of emissions compliance, rather than also actually reducing emissions. It premises its argument in part on pointing out that many RGGI allowances are unused, thus undervaluing the cost of emissions.

IPI therefore would value avoided energy use at the energy portion of the LBMP forecast without any of the CARIS recognition of the effects of emissions programs. According to IPI, this approach would avoid double-counting, with net avoided emissions are then properly priced at the full value of monetized damages. Like EDF, it would set that value at the federal SCC.

IPI also posits that greater granularity in performing BCA analyses is needed. It would incorporate the analysis of granularity from the REV Track 2 Whitepaper into the BCA framework.

E. NRDC

Stressing the importance of the BCA Handbooks, NRDC recommends a coordinated State-wide approach for developing them and additional Commission guidance on that development. NRDC believes that the Handbooks should follow a standard template and incorporate a standard database that can be used as a foundation for evaluating all types of DER. The Handbooks would also include information on DER and various tools that would assist in the analysis of DER proposals. Given the complexities attending the implementation to a single utility, at the time it files its Handbooks, NRDC would tie their Distributed System Information Plan (DSIP).

NRDC would exclude the RIM test from the BCA framework entirely, because it believes the test is fatally flawed. It does not, NRDC claims, recognize rate impact magnitudes or rate changes over time. A DER program, NRDC concludes, should not be rejected because of a de minimis rate impact.

Recognizing that rate impacts are an important factor in evaluating DER programs notwithstanding the flaws of the RIM test, NRDC would substitute for the test a customer bill impact analysis. Utilities would conduct an analysis of the effect on bills over a period of time and identify DER participation factors from which a more complete picture of the impact of a measure on customers may be identified.

Like other PII commentators, NRDC would reject use of the WACC as the discount rate for BCA. It would substitute a societal discount rate consistent with the federal government's SCC. NRDC also joins with other PII intervenors in favoring Approach 2 (marginal damage costs) to externalities.

As to NEB, NRDC would identify those that are most important to planning, estimate monetary values where feasible, and develop proxies where monetary values are not available. NRDC believes that proxies are superior to excluding an NEB from the calculation entirely because of the difficulty of quantification. NRDC would also identify separately costs DER vendors will incur and recognize those costs in the BCA evaluations, including any offsets against utility costs that might be realized.

NRDC lends its support to the SCC and its discount rate. It would expand the definition of greenhouse gas to accommodate a full suite of gases with global warming potential and would establish externality values through judgment, placeholders, and sensitivities where impacts are difficult to measure. It also believes that more work on valuing wholesale market price effects is needed, but supports Option 3 (utility estimation) for now.

According to NRDC, energy efficiency should receive special consideration in the BCA process. Pace argues that, while energy efficiency is often the lowest cost option by a large margin, more time may be needed to plan and make the investments needed to capture it. Pace would require utilities to develop resource planning practices that will enable energy efficiency to compete across a wide spectrum of services.

F. Pace

Pace favors the SCT as the primary BCA Framework tool, but would exclude individual customer costs and benefits from the calculation. Pace is concerned that individual customers may be motivated by non-monetary factors that adversely affect the reliability of their decisions as a basis for future investment.

G. TNC

After reiterating other PII commentator positions on the SCT and the discount rate, TNC advocates inclusion of all relevant benefits and impacts in the BCA analysis, even where quantification is difficult. TNC favors Option 2 (marginal damage costs) for valuing externalities, using SCC as the cost, but is concerned that SCC might be insufficient to drive cleaner energy choices. It would also recognize human health benefits attending reductions to emissions, saying methodologies have been developed for monetizing those benefits. TNC asserts reductions to property footprints, changes in property value, and avoided ecosystem impacts, including those affecting water consumption, should be reflected in the BCA framework.

Where direct monetization is not achievable, TNC believes that ecosystem service assessments, defined as the value stream that flows from ecosystems as a whole to the population generally, can serve as a basis for arriving at monetization. The benefits attending healthy ecosystems can thereby be recognized. More localized benefits should also be reflected through evaluation of data specific to each natural resources identified and developed through additional stakeholder processes. The BCA Handbooks, TNC asserts, should be standardized, either through imposing a template on all utilities or use of uniform calculators and methods.

H. Vote Solar

Vote Solar would reflect wholesale price impacts in the SCT, not just in the UCT and RIM as proposed in the BCA Whitepaper. It criticizes the conclusion reached there -- that wholesale price impacts merely shift dollars from generators to consumers instead of constituting a resource efficiency game -- by arguing that focusing on the impact on cost shifting from generators misses the impact on the overall New York economy. Vote Solar also believes that using CARIS in defining wholesale price suppression results in an excessive focus on congested areas, when reductions in demand anywhere on the wholesale system result in lower wholesale clearing prices, and it urges consideration of what it describes as price effects on wholesale capacity markets induced by demand reduction. Another factor disregarded in the BCA Whitepaper discussion, Vote Solar maintains, is the inelasticity of demand for energy that most customers confront.

While conceding that the monetary benefit associated with DER will vary over time, Vote Solar believes markets internalize the existence of DER and therefore costs are reduced as time passes. Vote Solar therefore objects to the assumption that DER benefits dissipate with time, and asserts that accurately modeling the effects of DER over time is superior to merely assuming those benefits degrade at a steady rate. Turning to missing benefits, Vote Solar would capture them by comparing a business as usual model to a model reflecting DER, with the difference between the two models establishing the value of DER.

I. Other PII Commentators

Acadia would recognize the consumer and societal benefits of converting from oil-based fuels to electric vehicles and high-efficiency heat pumps. AGREE would expand upon the recognition of external benefits proposed in the BCA Whitepaper, believing that these benefits can be quantified. It would measure the benefits of local ownership of renewable energy projects as well. Addressing the BCA process, AGREE would better leverage public research dollars in quantifying externalities and fund intervenors to help them in shaping the measurement and quantification of impacts.

According to CEC, the baseline for evaluating DER should be the cost of the electric system as upgraded to meet needs, not the cost of the electric system at present. CEC also believes the BCA process has not been sufficiently transparent, pointing to the complexity of evaluations it says are not easily understood and to CARIS forecasts which it complains are not readily available to the public. While advocating type-specific analysis of certain forms of DER, such as biomass and biofuels, CEC joins in the criticisms that too few externalities are recognized in the Whitepaper.

AEA largely supports AEEI, but would apply the BCA framework to tariffs as well as DER providers. For its part, Local Power supports Pace and NRDC. It also objects that the BCA approach is not consistent with achieving the goals of the 2015 State Energy Plan.

Clean C suggests that an approach to BCA that recognizes the value of options and encompasses a broader range of outcomes and co-variance among key factors would value DER better than a deterministic approach aimed at a single valuation. It posits that greater granularity could be achieved through better identification of circumstances at actual electric line circuits and sections.

Pepacton is concerned that leaving implementation of BCA to utilities might not achieve societal priorities and goals, especially if their actions are not carefully reviewed. It also urges that more attention be paid to cumulative and interactive benefits. Otsego asks that additional and expanded consideration be given to emissions not specifically mentioned in the Whitepaper, including methane, particulate matter, volatile organic compounds and formaldehyde.

Providers and Trade Organizations

A. AEMA

AEMA would limit the BCA Handbooks to defining appropriate formulas and establishing modeling techniques for the valuation of resources, rather than attempting to set out detailed output profiles or make frequency dispatch assumptions. AEMA believes DER performance and output characteristics are too varied and evolve too rapidly for treatment in BCA Handbooks that are only updated periodically. Instead, Handbooks should outline general guidelines and identify avoided cost assumptions.

More clarity, AEMA contends, is needed on determining the amount of capacity that DER can be credited with avoiding. It would also recognize aberrant events in estimating the avoided energy component, because DER assumes particular importance during such events, which are becoming more common.

Because establishing a proxy for difficult to quantify costs may be misleading, AEMA would recognize such costs only qualitatively. In particular, AEMA cautions that quantifying DER participant costs may be difficult, and if other difficult to quantify costs are excluded from the BCA calculations, such participant costs should be too. AEMA also contends that the costs customers incur in purchasing equipment should only be recognized where a program induces a customer to make a purchase it otherwise would not have consummated. Finally, because simple linear analyses are insufficient to recognize the benefits DER provides, AEMA urges accounting for covariance through use of probabilistic simulation modeling.

B. BEST

According to BEST, combining renewables resources with storage can significantly improve their capacity value. It also urges close alignment between the BCA Framework and the State’s energy goals and objectives.

Finding the Whitepaper’s reliability and resiliency category too restrictive, BEST proposes to add maintaining critical load to the benefits. The ability to island power is another factor BEST sees as a benefit.

Accurately modeling wholesale market price impacts, BEST contends, is particularly important to storage alternatives. Storage, it believes, can assist in shaping the wholesale load curve, reduce cycling of thermal units and reduce overall values of energy and capacity. Those impacts are best captured through detailed modeling, and can be accomplished through Option 3 (utility specific estimates).

BEST would expand upon the benefits recognized in the BCA calculation to incorporate additional items, including system optimization and customer and community engagement. To account for non-energy benefits in the BCA where monetary values are not available, BEST would develop systems that assign value. Sensitivity analyses, it adds, are needed to address factors that include commodity markets and pricing, legal and regulatory and policy changes, and locational load growth forecasts.

C. ESA

ESA joins with BEST in asserting that the benefit of optionality is crucial, as storage can be scaled and moved among locations to meet changing grid needs. ESA also reiterates BEST's listing of the benefits attending storage that should be recognized in the BCA framework.

D. NY-Geo

NY-Geo sees a distinction between distributed electrical resources and distributed energy resources. Energy resources, it declares, can reduce overall energy consumption even if their installation results in an increased demand for electricity. For example, NY-Geo asserts, fuel switching that eliminates fossil fuel consumption, for purposes such as space heating, should be recognized as a benefit even if electric consumption increases as a result. As to valuing emissions externalities, NY-Geo finds Approach 2 (marginal damage costs) best recognizes the cost estimation difficulties attending evaluation of the benefits of fuel switching and alternative methods of electric generation.

E. NECHPI

NECHPI is concerned that measuring and validating changes in values across a wide array of programs, projects and plans will be difficult in light of the absence of baselines or projections established through a State-wide integrated energy resource analysis. It also believes a circuit-by-circuit analysis of the electric delivery system is a necessary foundation to capturing DER costs and benefits. Warning that solar energy cannot on its own achieve a zero emissions future, NECHPI argues that CHP systems and storage are necessary to balance solar.

Establishing a common methodology across utilities, NECHPI emphasizes, is critically important to integration of higher levels of DERs and their proper valuation. Such a methodology will facilitate a technology-agnostic, fuel-neutral approach to DER.

NECHPI's methodology would begin with modeling on a feeder-by-feeder basis to establish a baseline. DER could be added until the point is reached where a security violation would occur; mitigation strategies are then implemented restoring circuit capabilities. The amount of additional DER that can be accepted can then be estimated anew. NECHPI believes this integrated grid approach can be successful if sufficient attention is given to detail.

NECHPI lists the costs and benefits attending DER, categorized as elements of the utility cost function, consumer and societal impacts, and reliability, resiliency and flexibility values. It also identifies the avoided cost components it would recognize in a BCA calculation and sets forth methods for calculating the requisite costs. It would apply the BCA framework across all State and utility programs, tariff structures, and compensation mechanisms.

F. The DER Providers

While praising the BCA framework, Pareto sees an opportunity to begin moving from the static computational modeling described there to a more dynamic optimization tool. Pareto sees that movement as consistent with the change to a DSIP platform model where interactions are more complex and interactive. It would also substitute, for the existing discounted cash flow analysis of economic impacts over time, an options analysis, which is premised upon valuing flexibility in making and supporting investments over time.

Focusing on low and moderate income (LMI) communities, Posigen argues that the benefits attending DER in those communities may be greater than elsewhere, because it could alleviate problems on the comparatively weaker infrastructure that often serves those communities. Posigen would monetize and quantify these benefits.

Maintaining that the BCA Framework should focus more attention on even very small costs, Peak would shift the focus to a realistic and dynamic assessment of the drivers of DER project costs. Peak would establish the benefit costs and values, convert the value to pricing, and evaluate the resulting DER provider bids. Different discount rates, Peak asserts, attend the different functions, and using utility WACC as the source of a uniform discount rate fails to recognize that variation, especially when DER providers evaluate paybacks at higher discount rates in the short term.

Concerned that regulatory uncertainty attending judicial review may discourage DER, Peak would counteract that disincentive with explicit, long-term commitments to incentive programs and rates, subject to performance guarantees. Approximating participant costs for DER at 75% of incentives, Peak protests, is a standardized measure of little value, and it would prefer a more dynamic approach. It would also recognize greater variability in calculating line losses at different times and circumstances.

Governmental Entities

A. DEC

In valuing environmental externalities, DEC would recognize a direct determination of the harm caused by an activity, achieved through marginal damage cost estimates. Compliance costs already internalized in power markets, DEC asserts, is not a full representation of marginal damages. As a result, DEC supports Approach 2 (marginal damage costs), premised upon the federal SCC measure.

DEC asserts, however, that a focus on bulk system benefits is misplaced because the resulting externality value may not be sufficient as an incentive for reducing emissions in the near term. As a result, all greenhouse emissions should be considered in evaluating externalities, not just those recognized as bulk system costs. DEC joins in criticisms of the WACC discount rate.

B. NYC

Instead of utility-specific BCA Handbooks, NYC would take a more uniform approach through a single BCA Handbook. It believes standardization is required to ensure a manageable and transparent BCA process and avoid disparities in treating the viability of DER projects in different utility service territories.

NYC would speed initial implementation of the BCA Framework, so that it can be used for all upcoming project evaluations, including implementation of the DSIP. On the other hand, NYC maintains that more work on BCA is needed following initial implementation, and it proposes additional processes for performing that work. NYC is also concerned that the BCA Framework will value DER that avoid utility investments and expenditures over DER dedicated to other purposes, such as serving low-income communities or improving air quality.

NYC also objects that accurate measurement of DER benefits must consider the period over which the benefits will be realized. This requires a comparison of the useful lives of DER to the lives of utility infrastructure, something NYC believes is not adequately addressed in the BCA Whitepaper.

Assessing wholesale market price impacts, NYC believes that reflecting any such benefits in BCA is speculative at best. Neither CARIS estimates of LBMP nor utility-specific modeling, NYC maintains, would result in accurate valuations. NYC also asserts that avoided transmission and distribution costs must be assessed on a more localized basis.

Turning to the value of emissions reductions, NYC questions the reliance on CARIS under Approach 1 (CARIS LBMP). Given the variability of estimates of the value of carbon, NYC believes more analysis of this issue is needed. It points out, however, that REC pricing may be reasonable as a measurement tool, but reference to the REC values achieved through the existing RPS program under Approach 3 (LSR RECS) is not, because RPS is limited to only a defined set of renewable resources and the program is expiring in any event. NYC also contends that costs have not received the degree of attention as benefits, and that costs leading to rate impacts require more in-depth consideration.

The Utilities

A. Exelon

Noting that its constituent companies are generators, fully regulated utilities and competitive energy service providers, Exelon states it can take a broad perspective on REV issues. Exelon believes that the BCA framework should recognize and maintain existing levels of utility grid reliability and resiliency; avoid speculative or inflated benefits; and fairly and accurately quantify the marginal costs and benefits of DER compared to traditional utility investments. According to Exelon, utilities are singularly well-positioned to take initiative to lead a guided expansion of DER where it can best contribute to the modern electric system of the future. Exelon cautions, however, that DER and other alternatives must be held to the same standards and evaluated on the same cost basis as utility solutions.

Because BCA must begin with granular local costs while remaining a dynamic and iterative process, Exelon believes the

BCA process will be complicated. Bias toward high price or high growth assumptions, Exelon advises, should be avoided, and it warns that the 2014 CARIS study may overstate annual energy price increases. Avoided outage and restoration costs, Exelon continues, are very difficult to quantify, and it may be necessary to conduct more work before a methodology can be derived.

Exelon believes that the potential for double-counting the costs of T&D investments necessary to accommodate DER may be overstated, because the types of system controls needed to manage high density DER are different from investments that enable the existing T&D grid to operate more reliably. Exelon also claims that achieving greater granularity and more pinpoint operational control is a long-term endeavor, given large volumes of data that must be processed and the magnitude of investments that must be made, especially in large metropolitan areas.

Turning to wholesale markets, Exelon contends that price suppression in those markets is not a benefit that should be recognized in the BCA calculation. It asserts that it would be economically inefficient to allow an otherwise uneconomic project to pass BCA review because it suppresses the competitive price of energy. That price, Exelon contends, is intended to bring forth needed investment on a least cost, most efficient basis, but that competitive market outcome would be distorted if uneconomic projects that are more costly are substituted for those developed in response to the market. Exelon also maintains that any depressive effect on prices would be temporary at best as would be offset by accelerated resource retirements or deferrals of new entry of projects that are likely more cost effective than those selected through a distorted BCA process.

As a result, Exelon concludes that price suppression is not properly included as a benefit under the SCT, which, Exelon contends, should be used as the standard a proposed project must meet. Price suppression also does not belong in the RIM or UCT tests either.

As to recognizing greenhouse gas externalities, Exelon supports Approach 1 (CARIS LBMP). That Option, Exelon insists, reflects RGGI allowances whose cost and supply ensure that emissions goals are reached. Options 2 and 3, Exelon perceives, disregard the RGGI allowance effect, and so are not accurate. Moreover, their use might magnify incentives beyond those needed to meet the emissions targets set in RGGI in a way that is not transparent. Exelon adds that the utility WACC should be used as the discount rate, and that the cyber security costs attending the risk of adding DER should be considered in the BCA maintenance.

B. JU

While generally supportive of the principles underlying the BCA Whitepaper, JU proposes that several principles be eliminated or revised because they appear biased in favor of DER over other options. In particular, JU objects that establishing a stable investment environment for DER is not a factor that should be recognized in the BCA framework, which should be limited to economic comparisons. Evaluating other principles, JU posits that it might be difficult to conduct a full life cycle cost analysis for every form of DER and that qualitative factors should not be used to assist otherwise uneconomic DER projects in passing BCA tests. JU also proposes some additional principles, including: 1)a fair and level playing field; 2) regular updates to the BCA Handbooks that are neither administratively burdensome nor costly; and, 3) the separation of BCA test results from the actual revenues a DER provider will receive.

JU would coordinate the filing of the BCA handbooks with the DSIP filing, because the handbooks would lack context if not coordinated with DSIP. JU reports that utilities will seek to use consistent definitions and templates in the Handbooks, and to the extent time permits, include at the time of the DSIP filings, roadmaps and initial costs. The initial Handbooks would identify the benefit and cost data that is available, with subsequent versions expanded as more data becomes accessible.

JU sees the BCA Whitepaper tests as consisting of SCT, representing the perspective of society as a whole; the UCT, representing the perspective of a vertically integrated utility; and, the RIM, representing the perspective of utility customers that do not participate in DER. Instead of those tests, the utilities would use a Distributor Cost Test (DCT), which would properly evaluate if potential DER portfolios are cost effective in comparison to T&D investments.

The DCT would deviate from the UCT primarily in that it would not directly include wholesale market costs and benefits. JU believes it is not necessary to recognize those benefits, because they will be passed through to DER customers directly, as a result of the offsets to their consumption realized from their DER projects. JU also notes that a program administrator cost (PAC) test could be used to reflect the perspective of non-utility program administrators when comparing alternative solutions to traditional generation and T&D investments.

JU believes that a screening process is necessary to implement the BCA framework. The process would begin with setting a threshold for the costs of a traditional utility solution above which a DER opportunity may serve as an alternative. At least three years would then be allowed to solicit and evaluate alternatives to the utility solution. If a load reduction is necessary, it would be established as a percentage of relevant peak load in the geographic area of need. That need for the utility solution available for DER offset must be driven by load rather than the condition or replacement of the existing assets. Utility infrastructure projects that satisfy the screen would be subjected to economic comparisons against DER through the DCT.

JU would not apply the screening and testing process to existing public policy programs, such as energy efficiency, that have been evaluated separately. The BCA process, however, would apply to the procurement of DER via tariffs. JU sees two types of tariffs; those for dynamic load management or retail demand response (DLM) or (DR) and tariffs to replace net metering.

A qualitative assessment would be reserved to selecting and ranking competing DER portfolios found cost effective under DCT. Investments in support of developing the DSIP capabilities required under REV, JU claims, are not suitable candidates for the application of the BCA test.

Listing the specific benefit and cost line items that should be included in BCA initially, and the costs and benefits that are more problematic, JU objects to taking into account additional benefits in BCA that are not currently monetized. According to JU, NEBs are difficult to quantify and so should not be incorporated in the BCA framework in the near term except in very limited situations. More work is needed before the recognition of NEBs can be expanded.

If its NEB proposal is rejected, JU would limit NEBs to those that can be monetized, and then apply them solely to scoring DER alternatives against each other. If that restriction is not adopted, the benefits, JU argues, should be shared among participating and non-participating customers as well as DER providers. JU also asks that the impacts of such monetizations on customer bills be carefully considered and that utilities be provided full and timely cost recovery of any monetizations that are allowed.

JU favors Approach 1 (CARIS LBMP) for recognizing the externality value of avoided air pollutant emissions. It believes LBMPs reflect the compliance costs of air emission reduction policies as well as policies related to water and land use impacts. Approaches 2 (marginal damage costs) and 3 (LSR RECs), it claims, are flawed in that they depend upon non-market values that are not tied to actual reductions to pollutants. Instead, JU claims, their values will simply raise electricity costs to customers without any benefit.

Turning to avoided wholesale capacity costs, JU points out that if DER is treated as a supply resource in the capacity market, then UCAP is the appropriate value. If treated as load modifiers, increasing DER penetration will affect load forecasts, but their impact will be uncertain. As a result, JU argues, a static demand curve such as proposed in the BCA Whitepaper may not be appropriate. JU concludes that more detailed analysis of this question may be necessary.

Avoided energy, says JU, is best based on CARIS LBMP. But, it contends, it may not be practicable to recognize sub-zonal costs at this time. JU supports use of the WACC as the BCA discount rate.

On the issue of wholesale energy price suppression, JU views those impacts as short term because supply and demand revert to equilibrium over time. While JU is not opposed to capturing impacts that are transitory, it again believes more work is necessary before a metric may be incorporated into the BCA framework.

C. NFG

It is not feasible, NFG contends, to accurately measure all potential environmental and societal benefits and costs that might affect a DER option. Instead, it would limit the BCA to administratively feasible methodologies. That approach, NFG claims, would render a BCA Handbook unnecessary. Instead, utilities should evaluate each DER project on an individual basis, with the results of those evaluations over time used to guide achievement of REV goals.

D. PSEG

PSEG agrees with the BCA Whitepaper conclusion that no one evaluation method should be used exclusively in the BCA Framework and it reports that the UCT is the most comparable test to its current methods for evaluating supply side additions, which is the TRC test. Expanding beyond the TRC to the broader societal purposes of the SCT, PSEG cautions, would require clear and transparent methods for establishing monetized values over a broad range of potential benefits.

According to PSEG, its Long Island service territory differs from the rest of the State in that its electricity supply needs are met through contracts. The result is that NYISO energy and capacity market prices have not indicated the actual cost of entry for new suppliers in Long Island markets. PSEG therefore believes that BCA Framework calculations in its region should reflect local circumstances. Nonetheless, PSEG supports Option No. 1 (CARIS LBMP) for evaluating externalities.

While PSEG voices its support for the concept of a BCA Handbook, it believes the Handbook should serve only as a general guideline. Additionally, the Handbook should be phased in over a period of time as BCA methodologies develop.

Customer Representatives

A. AARP

Its foremost concern, states AARP, is affordability for residential customers. With New York's electric rates among the highest in the nation already, the BCA Framework should not, it argues, result in cost increases.

Commenting on the principles underlying the BCA, AARP is concerned that delving into localized impacts could result in cross-subsidization to the detriment of the general body of ratepayers. AARP believes that care must be taken in identifying costs and benefits with specificity so that affordability of utility rates is not undermined. It would resolve doubts in favor of affordability.

To achieve that goal, AARP supports use of the RIM test, as a check on open-ended investments where the scope of benefits would be narrow. It is also opposed to using qualitative factors to evaluate projects, as running counter to its goal of affordability.

AARP believes that customer bill impacts should always be considered before investments are made. The effect of an investment on low-income customers, customers with different usage patterns, customer service and privacy, and the customer effort required to implement, should be incorporated into that consideration.

B. CPA

CPA believes the BCA Handbooks should be authoritative and allow developers to estimate the value of various projects with some certainty. The Commission, says CPA, should review and approve the Handbooks and should remain the final arbiter of all disputes arising from them.

Turning to externalities, CPA would reflect the full marginal damage costs, through Approach 2 (marginal damage costs), in estimating the value of emissions reductions. It would set the externality value at the federal SCC. It rejects use of Approach 1 (CARIS LBMP), because the CARIS values understate damage costs.

CPA would also recognize the effect of low or zero emission DERs on emissions reductions regardless of their participation in RGGI. The failure to recognize these reductions in RGGI, CPA posits, is a defect in RGGI design that does not justify a failure to recognize emissions reductions elsewhere.

C. MI

MI states its interest is ensuring that the value of DER is reflected as accurately as possible. Addressing the Whitepaper principles, MI would apply the BCA Framework to individual DER measures and investments as well as DER portfolios. If only portfolios are evaluated, MI is concerned that a project included in the portfolio that is not cost effective might go forward to the detriment of economic efficiency.

MI also points out that, although a full life cycle analysis is a laudable goal, quantification over a longer time period are difficult to accomplish accurately. As a result, near term projections of costs and benefits should be weighted more heavily than longer-term projections. Evaluating investments against alternatives, MI continues, is feasible only where the alternative is clearly defined, and so in some instances a potential investment must be evaluated in isolation.

Addressing the SCT, UCT and RIM, MI states the most important measure to it is the RIM. If a proposed investment would increase rates, MI would reject it, absent extraordinary circumstances. The focus of BCA, and REV itself, MI asserts, should be to reduce utility rates. MI questions qualitative analyses on that basis, and asks that if non-quantified benefits be reflected, non-quantified costs should be too.

MI would add one additional cost to the BCA evaluation. It contends that the poor capacity factors attending some forms of DER generation might necessitate increases to the State's installed reserve margin (IRM). The costs attending an increased IRM should be reflected in the BCA.

According to MI, environmental externalities are already reflected in the BCA without developing specific adders. MI contends that New York has some of the most stringent environmental requirements in the U.S., and that those costs are currently embedded in the cost of electricity. It also questions whether environmental externalities can be adequately quantified and notes that prior efforts at quantification have been exceedingly volatile. It adds that disputes over the science underlying externalities are contentious and will be expensive to resolve.

MI is also concerned that externalities that increase costs have been incorporated into the BCA while externalities that reduce costs have not. For example, MI posits that the adverse impact of increasing electric rates on economic development should be recognized as an externality cost.

REPLY COMMENTS

AEEI

AEEI begins by noting that many commentators agree with it that the SCT should be the primary test in the BCA Framework, because it furthers the societal goals inherent in REV. The majority opinion, it continues, is that the RIM test is too flawed for use. While agreeing that rate impacts are important, AEEI believes that better measures of evaluating both rate and bill impacts can be developed. As a result, AEEI urges rejection of MI's argument that the RIM test should be the most important element in the BCA Framework.

AEEI also opposes elevating JU's proposed DCT test to a position of primacy in the BCA framework. AEEI believes, however, that the DCT could be helpful in comparing more targeted traditional utility T&D investments to DER options. AEEI also counters arguments that the WACC should be used as the discount rate by asserting that the WACC is inconsistent with the evaluation of societal benefits inherent in SCT and that WACC differs among utilities, which is inconsistent with the goal of a uniform BCA framework.

While commending JU for putting forth a proposed BCA implementation framework, AEEI contends that framework is too narrow in scope. Instead, AEEI maintains that competitive solicitations for DER solutions should be the first option in moving forward with REV. Additional details on the implementation of the BCA Framework, it asserts, should be derived through a stakeholder process.

AEEI continues to favor calculating externality damages from emissions through Approach 2 (marginal damage costs). That measure, it asserts, captures impacts beyond the policy instruments already in place, which, it complains, only reflect the price of emissions in established marketplaces. AEEI also points out that it appears no commentator supports use of Approach 3 (LSR RECS), which is to use REC prices derived from LSR contracts as a proxy for emissions damages. AEEI finds that approach inferior to the quantification of actual damages inherent in Approach 2. AEEI would also study further NEB and wholesale market price impacts, and use proxies immediately where available, rather than dismiss them entirely from the BCA calculations.

ASC

Like AEEI, ASC opposes use of Approach 1 (CARIS LBMP) to value environmental externalities, because it believes DER resources can reduce emissions below the levels that are reflected in that measure, and should be compensated for doing so. It also points out that DER will offset emissions from greenhouse gases, such as methane, that are not subject to the existing reduction programs identified in Approach 1. ASC believes that the price differential that might arise between DER and traditional utility central station generation as a result of use of Option 2 (marginal damage costs) is appropriate, even where the latter generation is low in emissions, because, it asserts, an energy future cannot be built on large scale central stations, such as nuclear and hydroelectric resources.

Again joining AEEI, ASC opposes JU’s proposed approach to implementing BCA. In particular, ASC complains that the initial screen JU would employ favors utility investment over DER alternatives. ASC adds that use of JU’s DCT would further disadvantage DER because DCT effectively disregards the diverse set of benefits DERs provide. ASC also urges that wholesale electric price suppression be recognized now, avoiding the illogical conclusion that no benefit attends that suppression, and opposes the WACC because it biases the BCA in favor of utility investment.

EDF

EDF lends its support to Approach 2 (CARIS LBMP) for valuing emissions externalities. It believes that approach properly recognizes the value of emissions whether or not they occur within the scope of existing emissions reductions programs. It supports use of SCC as the measure of emissions externalities, subject to upward revisions as the federal government proceeds with its SCC analysis. EDF also urges that methane emissions, including pipeline losses, be specifically recognized for any resource, utility or DER, dependent upon natural gas.

FTC

The value of the BCA framework, FTC contends, could be improved through more robust sensitivity analyses and expansion of the benefits that are recognized. Sensitivities could include recognition of future shifts in relative fuel prices, climate change impacts, and the pace of technological change, which, FTC believes, will facilitate quicker and lower costs market responses to changing demand.

FTC would explicitly recognize in the statement of principles that the provision of electricity services is no longer homogonous, and that one of the benefits of the BCA Framework is the differentiation and proliferation of retail electric services to include dynamic pricing, resiliency, better energy conservation, efficiency, and management practices, and other elements. FTC does not propose methods for valuing these additional benefits. Increased competition, FTC asserts, will yield benefits over the full life of DER investments, and those benefits should be recognized accordingly. FTC believes, however, that these benefits could be treated within the scope of the net non-energy benefits mentioned in the BCA Whitepaper.

Exelon

Exelon supports use of JU’s BCT test, to the extent it excludes wholesale price suppression. Although it does not necessarily support JU’s proposed screening process, Exelon agrees that a workable screen to determine which distribution grid infrastructure projects warrant a BCA assessment would be useful.

Exelon continues to support use of Approach 1 (CARIS LBMP) to value externalities, and asserts that opponents of its use have been unable to refute the argument that new DER will not reduce overall emissions beyond that realized through RGGI so long as the RGGI price remains above the floor and below the cost containment reserve level. As a result, Exelon believes that Approach 2 (marginal damage costs), which is premised upon emissions reductions beyond that achieved through RGGI, is fatally flawed. Exelon dismisses non-RGGI resources, such as those sized at 25 MW or less, as too small to warrant recognition. Exelon also concludes that sending one signal for emissions reduction at the wholesale level through RGGI while sending another at the distribution level could inadvertently force mothballing or retirement of existing clean energy resources, thereby obstructing goals for achieving greenhouse gas reductions.

JU

According to JU, the BCA framework should be outcome neutral. AEEI and others, JU objects, believe BCA should instead advance DER over utility investments. This approach, JU cautions, could impose excessive costs on ratepayers and is unnecessary as a social goal in light of policies pursued outside the BCA Framework.

JU continues to advocate requiring an initial screen before DER is evaluated as an alternative to utility distribution solutions. The screen, it insists, is necessary to ensure that DER can displace the utility alternative without adversely affecting safe, adequate and reliable service. JU agrees, however, that various measures related to reliability that other commentators have proposed, ranging from line loss reduction to public safety, could be recognized if they can be adquately quantified.

Arguing in favor of its DCT test, JU maintains its is an objective approach to evaluating DER while maintaining safe and reliable service. Although not objecting to retaining the RIM test as well, JU maintains that if various criticisms of that test are accepted, an explicit valuation of customer costs remains necessary through an alternative approach.

JU objects that SCT is fundamentally flawed, in that the benefits various commentators would insert into the test that are difficult to quantify or contentious, and could result in effectively forcing customers to pay for resources on the basis of subjective valuations. Rate and bill impact assessments, JU stresses, are imperative if the SCT test is selected as the primary determinant for assessing DER.

Turning to the debate over environmental emissions externalities, JU asserts use of Approach 1 (CARIS LBMP) is clearly preferable because it recognizes actual costs for reducing emissions that are already in place. Other drawbacks to Approach 2 (marginal damage costs), JU asserts, include compelling ratepayers to fund costs when no emissions will actually be avoided; distorting the BCA framework to achieve environmental policy goals at a higher cost to customers than would be incurred if policies were properly pursued through other means; overvaluing DER by measures that may be nearly impossible to verify or calculate accurately; and, requiring additional funding to actually compensate the DER improperly deemed cost effective.

If Approach 2 were adopted, JU warns, at the higher end of the externality adders that could be justified under it, rates for some utilities would increase by 50%. Taking carbon dioxide as an example of the flaws in Approach 2, JU points out that the current RGGI allowance price is roughly $6.50 per metric ton. The federal SCC price, however, is about $46 per ton. If that value were reflected in the BCA framework, DER would be evaluated at the higher price while other resource decisions are tied to the RGGI price. Since achieving improvements beyond the RGGI assumptions is unlikely, the higher costs will be paid without obtaining greater benefits.

Those additional benefits, JU maintains, are best pursued through modifications to the RGGI program which, JU points out, has been praised by many of the same parties that urge adoption of SCC. Distorting the BCA framework for the purpose of subsidizing DER, JU concludes, will not deliver benefits at the lowest cost to utility customers and instead will impose costs disproportionate to the benefits realized.

JU continues to view wholesale market price suppression effects as speculative and exceedingly short-term in effect. Moreover, it suggests unintended consequences could result, including impacts that drive capacity market prices upward, which would offset any price reductions achieved through suppression.

JU lists the benefits to the grid from DER proposed by other commentators as including: line loss reductions, system efficiency and power quality improvements; optionality; maintaining critical load through islanding and local emergency power; voltage management and power factor improvements, avoided resiliency upgrades; avoided restoration and outage costs; extended equipment lifetimes, deferred replacements and other avoided O&M factors; and, improved public safety. JU believes some of these values could be recognized, but only to the extent data exists to reliably quantify the benefits and demonstrate they are avoidable and material.

JU opposes expanding the list of NEBs. While goals such as public health, economic development and job creation, land and water impacts, and avoided noise and odor pollution are worthy, it believes quantification of these benefits is not feasible but would again bias the BCA in favor of DER at the prospect of decreasing electric system reliability and increasing costs. Economic development in particular, JU warns, would suffer and job losses could be experienced if DER is overvalued and the costs of electricity rise unreasonably as a result.

JU continues to support using WACC as the discount rate in the BCA framework. It asserts that the WACC is the only discount rate that reflects actual costs to utilities and their customers. The use of a lower societal discount rate, JU claims, could favor DER over utility projects evaluated at the WACC. The societal discount rate, it contends, is also inherently speculative over the longer term proponents propose for its use.

Dismissing objectives to WACC, JU criticizes AEEI's assumption that DER investments are less risky than investments in utility solutions as speculative at best. The high level of uncertainty attending DER investments whose characteristics and risks are presently unknown, JU argues, justify a greater discount rate commensurate with the risk.

Parties such as NRDC favoring the societal discount rate, JU asserts, present little justification for it other than it will favor DER. NRDC, JU contends, in effect assumes that a societal discount rate of no more than 3% reflects the cost of capital for the JU customers that would install DER. That assumption is meritless, JU continues, because the utilities, as less financially risky than many of their customers, should have a lower cost of capital. In evaluating an investment in DER as an alternative to basic needs like food, clothing and housing, low and moderate income customers, JU asserts, would receive a discount rate at considerably more than 3%. The consequence of the unrealistic societal discount rate, JU concludes, is inefficient allocation of customer capital and upward pressure on utility rates and bills.

Noting that many commentators proposed a wide variety of sensitivity analyses, and that the BCA Whitepaper suggests sensitivities might include low, medium and high scenarios, JU agrees that sensitivities will be necessary. The application of sensitivities, however, should take place in the BCA Handbooks. JU cautions that sensitivities should not become costly or administratively burdensome to conduct and should be limited to those that are practicable.

JU also advises that some commentators would overly-burden the Handbooks, which cannot set forth quantitative tools applicable to all DER applications that might be envisioned. JU anticipates that the Handbooks will describe the economic tests employed and list key assumptions and inputs in a usable, transparent and consistent format. The Handbooks would be updated annually, and the initial versions would be concurrent with the DSIP filing currently due June 30, 2016.

Asserting that its constituent utilities should take responsibility for developing the Handbooks, JU opposes further stakeholder collaborative or other alternatives to preparing the Handbooks such as transferring responsibility for preparation of the Handbooks to a third party to achieve uniformity. While JU notes utilities will take the positions of all parties into consideration, attempting to develop these technical Handbook materials is best accomplished outside of a collaborative or other similar process.

NYC

Opposing the positions of JU and other commentators on limiting the externalities that are recognized in the BCA framework, NYC argues that the Whitepaper does not adequately consider the full panoply of appropriate externalities and so fails to value the full costs being borne by the public. NYC points out that most commentators support recognizing the full scope of potential externalities, including all greenhouse gases, land and water impacts, and a suite of NEBs. Recognition of the full array of externalities, it contends, is necessary to enable beneficial projects that would otherwise be deemed cost-ineffective to move forward, and, conversely, to weed out projects that would be detrimental even if otherwise deemed cost-effective.

NYC would not limit valuation of externalities to those recognized in markets. It contends that market measures, including RGGI, fail to depict accurately or fully the costs and benefits associated with various externalities. NYC would, however, approach each externality on an individual basis rather than consolidating them. Examining the contribution and value or cost of each component would further NYC and State goals of increasing efficiency and reliance on renewable resources.

Questioning the initial screen JU proposes, NYC points out the screen is limited to the goal of avoiding traditional utility investments. The goals of REV, NYC argues, are much broader, and encompass enhancing DER in underserved areas, such as low-income communities, and increasing electric system resiliency, as well as expanding the use of renewable resources and lowering carbon emissions.

NRDC

Continuing to oppose the RIM test as misleading, NRDC maintains that any legitimate concerns regarding price and bill impacts can be better accommodated through other methods. NRDC would also evaluate customer DER needs through participation analyses, with their outcomes reviewed over time to ensure that policy and equity goals are met.

The TRC test that ASC and PSEG propose is, NRDC contends, unnecessary and redundant. The TRC test, NRDC notes, is identical to the UCT test, except that TRC incorporates participant costs. In that sense, it is unbalanced because it does not account for NEB and other benefits that accrue to DER participants. NRDC also continues to oppose WACC reiterating its and other parties' arguments, and continues to support valuing emissions externalities under Approach 2 (marginal damage costs) at the federal SCC.

NRDC would quantify and incorporate NEBs into the BCA analysis whenever possible, and would include in the NEBs public safety and health benefits, avoided sick days for workers, reduced fuel price risk, reduced electric price risk, distribution system voltage management and power factor improvement and avoided resiliency upgrades. Employment impacts, it argues, can be reflected by using employment multipliers for each type of DER, thereby simplifying the analysis. NRDC continues to maintain that market price suppression effects are real and durable, and points to efforts in New England to quantify those benefits, which it believes should be repeated in New York.

Opposing assessing DER investments on an individual instead of a portfolio basis, NRDC argues screening each measure individually would be impractical and burdensome. Testing at the portfolio level, it asserts will ensure that, on average, projects providing benefits to society and ratepayers are pursued. It finds another advantage for the portfolio approach in the treatment of program costs, such as marketing and implementation, are both evaluated at the portfolio level and are sunk by the time the individual project is screened.

Its solution to developing the BCA Handbooks, NRDC reiterates, is to select one utility and have it develop a

Handbook first, to serve as a model for other utilities. The Handbook would be coordinated with the DSIP.

Pace

Pace, on behalf of the Clean Energy Organizations Collaborative,[1] supports setting a process and timeline for implementing the initial BCA Framework, including updates and reviews, notwithstanding that the development of the BCA is a continuing process. Pace asks that clear and firm milestones, including the time for conducting a comprehensive review, be established in order to ensure that BCA moves forward in a timely and transparent way.

Opposing MI, Pace argues that environmental externalities should be quantified now, with valuation beginning at the federal SCC. Pace would reject MI's argument that quantification is not feasible because state and federal policies may change, on the grounds that those changes should not be used as an excuse for inaction. Pace also reiterates the support of most parties who favor valuing externalities.

[1] Pace is thereby representing initial commentators AEA, CLP, Clean C, NY-Geo and TNC, as well as other organizations that did not file initial comments in this proceeding.

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APPENDIX C

Benefit-Cost Analysis Framework

Benefits and Costs Included in the Framework

Table 1: List of Benefits and Costs Components to be included in BCA Framework[1]

	BCA TEST PERSPECTIVE
BENEFITS	**Societal (SCT)**
Bulk System	
Avoided Generation Capacity (ICAP), including Reserve Margin	√
Avoided Energy (LBMP)	√
Avoided Transmission Capacity Infrastructure and related O&M	√
Avoided Transmission Losses	√
Avoided Ancillary Services (e.g. operating reserves, regulation, etc.)	√
Wholesale Market Price Impacts	--
Distribution System	
Avoided Distribution Capacity Infrastructure	√
Avoided O&M	√
Avoided Distribution Losses	√
Reliability / Resiliency	
Net Avoided Restoration Costs	√
Net Avoided Outage Costs	√
External	
Net Avoided Green House Gases	√
Net Avoided Criteria Air Pollutants	√
Avoided Water Impacts	√
Avoided Land Impacts	√
Net Non-Energy Benefits relate to utility or grid operations (e.g. avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts, to the extent not already included above)	√
COSTS	
Program Administration Costs (including rebates, costs of market interventions, and measurement & verification Costs)	√
Added Ancillary Service Costs	√
Incremental Transmission & Distribution and DSP Costs (including incremental metering and communications)	√
Participant DER Cost (reduced by rebates, if included above)	√
Lost Utility Revenue	--
Shareholder Incentives	--
Net Non-Energy Costs (e.g. indoor emissions, noise disturbance)	√

1 The UCT and RIM tests remain as set forth in the BCA Whitepaper, Table 1, p. 12.

Methodologies for Valuing Benefits and Costs

Valuing Benefits

Avoided Generation Capacity (ICAP) Costs, including Reserve Margin

ICAP costs are driven by system coincident peak demand. Thus, this component of benefits applies to the extent to which the resources under consideration reduce coincident peak demand.[2] To forecast avoided generation capacity costs, utilities shall use capacity price forecasts for the wholesale market. In order to ensure resources adequate to serve summer peak loads for the New York Control Area (NYCA), Load Serving Entities (LSEs) are required to procure sufficient Installed Capacity (ICAP) to meet their forecasted summer peak loads, plus an Installed Reserve Margin determined annually by the New York State Reliability Council. In addition, LSEs serving load in several "localities" (New York City (NYC), Long Island (LI), and the "G-J" region covering NYC and Lower Hudson Valley (also called the New Capacity Zone or NCZ)) are required to obtain a portion of their capacity requirements from resources located within those localities. The minimum Locational Capacity Requirements (LCRs) are determined annually by the New York Independent System Operator (NYISO),[3] but shall also be updated upon NYISO approved tariff changes. To enforce resource adequacy requirements, the NYISO operates monthly spot auctions for NYCA and the localities; the NYISO also operates forward auctions (monthly and 6-month strip auctions). Depending on the amount of capacity procured in the spot auction, the NYISO may require LSEs to procure additional excess capacity as determined by the Demand Curves.

The NYISO's spot auctions determine the amount of capacity that clears, or is sold through the auction, as well as the price of that capacity based on the intersection

[2] Avoided distribution costs, discussed below, will be related to demand reductions correlated with peaks that drive system needs at more granularly local portions of the distribution system.

[3] The effect of DER measures on LCR levels cannot be accurately forecast at this time, and will be captured in the annual updates in any event. To the extent that future developments render it necessary to forecast the DER effect, utilities may propose methods in future DSIP filings.

of resource supply offers and "Demand Curves" for the NYCA and the localities. The Demand Curves specify LSE valuation of capacity that reflects the "Cost of New Entry" (CONE) at the minimum requirements, but declines gradually if additional resources are available at lower prices. The auctions adjust the resource supply and demand for forced outages, yielding prices and quantities for "Unforced Capacity" (UCAP). However, this conversion does not change the overall capacity payments (that is, UCAP price x UCAP quantity = ICAP price x ICAP quantity). The Demand Curves are developed by the NYISO with stakeholder input and approved by the Federal Energy Regulatory Commission (FERC). They cover a "capability year" from May through the following April (6 months of "summer" from May - October and 6 months of "winter" from November - April). The Demand Curves are updated every 3 years.

To forecast capacity costs, utilities shall forecast the spot market demand curves and capacity resources for the summer and winter months of each capability year (May through April) without adjusting for forced outages (the ICAP prices and quantities can be converted to UCAP values if necessary). To forecast the demand curves, utilities shall use the most recent forecasts of NYCA and locality summer peak loads from the NYISO's Gold Book, published each April, and multiplying the megawatt (MW) values by the current minimum NYCA and locality (percentage) requirements to determine the minimum requirements. To forecast the Supply Curves, utilities shall use the summer and winter capacity forecasts from the NYISO's Gold Book, supplemented by the NYISO's monthly Generator Status Update.[4] In the event that forecasted resources fall short of minimum requirements, additional resources shall be assumed to enter at the Demand Curve reference prices, which are based on the cost of new entry (CONE).

The operation of the spot auction may be approximated by a spreadsheet calculation, which calculates the demand curves and determines the ICAP clearing prices assuming all available resources clear the market. The location of the spreadsheet model is at Attachment A. The results provide ICAP prices and quantities at the transmission level. It should be noted that a portion of the Transmission Capacity

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4 http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Generator_Status Updates/Updates_since_4-24-015/Generator%20Status%20Update%20-%2001-13-2016%20Revised.xls

Infrastructure costs are included in the ICAP price as zonal differences in the ICAP clearing price, and care should be taken not to double-count such costs. To the extent possible, the contribution of these avoided transmission capacity infrastructure costs to the ICAP price should be determined and included in the utility DSIPs and BCA Handbooks. To avoid double-counting, such costs should not also be monetized as part of the Avoided Transmission Infrastructure Capacity measure discussed later in this document.

Avoided Energy (LBMP)

To forecast avoided system energy costs, utilities shall use energy price forecasts for the wholesale energy market—Location Based Marginal Prices (LBMP)—from the most recent final version of the NYISO's Congestion Assessment and Resource Integration Study (CARIS) economic planning process Base Case. CARIS is a biennial collaborative process which starts with CARIS Phase 1 (CARIS 1), where 10 year forecasts are developed to evaluate transmission congestion on the bulk power system. This is followed by CARIS Phase 2 (CARIS 2) which develops 20 year forecasts to evaluate specific resource proposals. When these forecasts are developed, the first year of the forecasts undergoes a benchmarking process based on historical actual LBMPs.

These forecasts are developed by the NYISO in collaboration with market participants in Electric System Planning Working Group (ESPWG) meetings and are publicly available. To extend the LBMP forecasts beyond the CARIS planning period, if necessary, utilities shall assume the last year LBMPs stay constant in real (inflation adjusted) $/MWh. Five years of historical real-time hourly LBMPs shall be used to convert forecast average annual LBMPs into a forecast of time-differentiated LBMPs (for example, monthly, seasonal, or sub-period LBMPs).

It should be noted that the LBMP includes costs for a number of other factors: (1) compliance costs of various air pollutant emission regulations including the Regional Greenhouse Gas Initiative and now-defunct SO_2 and NO_X cap-and-trade markets; (2) transmission-level line loss costs; and (3) transmission capacity infrastructure costs built into the transmission congestion charge. To the extent possible, the contribution of these costs to the LBMP shall be determined and included herein. Such costs shall not be also be monetized as part of the Net Avoided Greenhouse Gases, Net Avoided Criteria Pollutants, Avoided Transmission Losses, or Avoided Transmission Capacity Infrastructure measures discussed later in this document.

Avoided Transmission Capacity Infrastructure and O&M

A portion of the Avoided Transmission Capacity Infrastructure and related O&M costs are included in both the Avoided Generation Capacity (ICAP) and Avoided Energy (LBMP) benefit categories. Transmission capacity and O&M costs are reflected in the difference between zonal ICAP clearing prices. Generation assets located in high load and congestion areas, such as New York City, the lower Hudson Valley, and Long Island, clear the ICAP market at a higher price in reflection of the fact that load serving entities in those areas are required to purchase generation from local assets due to restrictions on the transmission system, which precludes the purchase and transport of generation from cheaper assets further away from the load. Transmission congestion charges, related to the availability of transmission infrastructure to carry energy from zone to zone, are included in the LBMP. Both the ICAP prices and transmission congestion charges would be decreased in the event that additional transmission assets are built or load is reduced.

To the extent that there are values provided through avoided transmission capacity infrastructure and O&M beyond that which is included in the ICAP price and LBMP, such avoided costs should be considered separately herein. The sections on Avoided Distribution Capacity Infrastructure, and Avoided T&D O&M, below, describe how these avoided costs shall be monetized in general. The remaining Avoided Transmission Capacity Infrastructure and O&M beyond those captured in the Avoided Generation Capacity (ICAP) and Avoided Energy (LBMP) benefit categories shall be calculated in the same manner as that employed for determining avoided distribution capacity infrastructure and avoided O&M. Avoided Transmission Capacity Infrastructure and O&M benefits specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

Avoided Transmission Losses

A portion of the Transmission Loss costs are included in the LBMP, and are therefore partially counted already through the Avoided Energy (LBMP) benefit category as part of the costs included in the LBMP. To the extent that there are avoided transmission losses above and beyond what is included in the LBMP, such losses shall be considered separately herein. The section on Avoided Distribution Losses, below, describes how losses should be monetized in general. The remaining Avoided Transmission Losses beyond those captured in the Avoided Energy (LBMP) benefit shall be calculated in the same manner as that employed for determining distribution line losses. Avoided Transmission Loss benefits specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

Avoided Ancillary Services

Required ancillary services, including spinning reserve, frequency regulation, voltage support and VAR support would be reduced if generators could more closely follow load. Certain projects will enable the grid operator to require a lower level of ancillary services or to purchase ancillary services from sources other than conventional generators at a reduced cost without sacrificing reliability. For example, to the extent that reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, storage and distributed generation with sensors, controls, and communications systems can be better coordinated to reduce load, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities. Since ancillary services can vary significantly from year to year and are market based, utilities shall use a two year average of ancillary services costs. Similarly, local voltage support, local VAR support, and local power factor improvement could be impacted by increased levels of DER and therefore should be factored in to this benefit category. The Avoided Ancillary Services benefits are likely to be highly project-specific, and methods for their valuation shall be included in utility DSIPs and BCA Handbooks.

Wholesale Market Price Impacts

Department of Public Service Staff shall use the first year of the most recent CARIS database to estimate wholesale energy market price impacts of a 1% change in the level of load requirements. Such impacts shall be filed with the Secretary on or before July 1 of each year. For ICAP market price impacts, utilities shall use the spreadsheet model described at Attachment A.

Avoided Distribution Capacity Infrastructure

A utility's decision of what infrastructure to invest in, and when to make that investment, is generally driven by two factors: first, its need to meet the peak demand placed on its system; and second, the amount of available excess capacity on its system. The importance of these factors can vary depending upon the voltage at which an incremental load is connected to the utility grid. Traditionally, avoided transmission and distribution (T&D) infrastructure need is considered on a system average basis and is estimated as a single dollar-per-kW value. However this estimation may significantly over- or under-value load modifications. Detailed marginal cost of service studies are necessary to fully determine the value of incremental or avoided T&D infrastructure needs. Utilities shall include the most up-to-date version of detailed marginal cost of service studies in their DSIP filings.

Generally speaking, the primary driver of incremental need for T&D investment is additional incremental load during a single hour of system peak demand. However, need for marginal investment in the utility's T&D system can change based upon where load is interconnected. For example, the need to upgrade a transmission line primarily depends upon whether incremental load occurs during the single peak demand hour placed on the transmission system, whereas the incremental need to build additional secondary cable lines may be more dependent upon a new customer's peak demand, and less on its coincidence with the utility system peak demand. When estimating the value of a load addition or reduction, whether or not such load would actually trigger additional infrastructure need shall be considered based on the characteristics of the specific load, and its relation to the design criteria of the utility equipment that serves it.

The incremental need for investment in the T&D infrastructure is also driven by the current amount of excess capacity available on the system. Incremental load has a greater potential cost in areas of the utility T&D system which are already near, at, or above their design criteria compared to incremental load in areas where excess capacity is available. That is, the addition of load in areas with little excess capacity will cause the utility to invest in T&D infrastructure sooner than if the same incremental load were to be connected in an area of greater excess capacity. Similarly, load reductions will provide a large benefit in areas of the utility T&D system with little excess capacity compared to load reductions occurring in areas where greater excess capacity is available. That is, a reduction in load in an area which is near, at, or above its design criteria may allow the utility to defer needed investment whereas a similar load reduction in an area of greater excess capacity may have no impact on T&D costs. When estimating the value of a load addition or reduction, the amount of excess capacity in the area which the load is interconnected shall be considered provided that appropriately disaggregated data is available.

The voltage at which a load addition or reduction is interconnected is another factor which can influence the value of T&D investment related to a load addition or reduction. Generally speaking, load additions or reductions connected to the utility system at high voltage will not affect the need for lower voltage infrastructure, whereas the same load addition or reduction connected at a lower voltage may have an effect on the need for infrastructure investments at both lower and higher voltages. When estimating the value of a load addition or reduction, the voltage at which such load is connected, and whether it will affect the need for additional infrastructure at other voltage levels, shall be considered.

Utilities should include sufficient information in their DSIPs and BCA Handbooks to inform the developing DER market of system conditions, needs, and granular marginal values so that any solicitations for alternative solutions will be robust.

A simple example of calculating the avoided distribution capacity infrastructure cost is provided below.

EXAMPLE: Battery Energy Storage located at a Con Edison Area Substation

A 1 MW battery with a 5-year service life is attached to an area substation in the Con Edison service territory. The battery is operated to reduce the peak load experienced by the area substation between 6 pm and 8 pm, whereas the system peak generally occurs at 4 pm. What is the value of avoided T&D infrastructure need for 2016?

First, consider whether the load reduction of the battery aligns with the cost drivers of the utility equipment which it is connected to. In this instance, operation of the battery does reduce demand during the peak hours experienced by the area substation, but not those of the system as a whole. Further, since the battery is connected directly at the area substation, for simplicity assume its operation does not decrease peak load on Con Edison's primary or secondary distribution feeders. Therefore, only consider the battery's contributions to avoided Area Station and Subtransmission Costs.

To determine the value of avoided T&D for the battery, multiply the amount of load reduction caused by the battery by the marginal costs of the equipment that the load is being relieved from; this calculation should be done for the entire service life of the battery (calculations for 2015 and 2016 have been shown as a demonstration).

$$\begin{aligned}\text{Avoided T\&D}_{2015} &= \text{load reduction} * \text{marginal cost}_{2015} \\ &= (-1\text{ MW}) * \left(\frac{\$43.88}{\text{kW}}\right)\left(\frac{1000\text{ kW}}{\text{MW}}\right) = \$43{,}880 \\ \text{Avoided T\&D}_{2016} &= \text{load reduction} * \text{marginal cost}_{2016} \\ &= (-1\text{ MW}) * \left(\frac{\$82.90}{\text{kW}}\right)\left(\frac{1000\text{ kW}}{\text{MW}}\right) = \$82{,}900\end{aligned}$$

The lifetime Avoided T&D Infrastructure of the battery can then be determined by finding the Net Present Value of the value streams.

Table 2: Illustrative Example of the Avoided T&D Infrastructure Calculation

Year	Marginal Cost	Avoided T&D
2015	$ 43.88	$ 43,880
2016	$ 82.90	$ 82,900
2017	$ 49.68	$ 49,680
2018	$ 127.30	$ 127,300
2019	$ 119.43	$ 119,430
Discount Rate		5%
NPV		**$ 358,205**

Avoided O&M Costs

Methodologies used to develop operation and maintenance (O&M) expenses associated with marginal T&D investments, as well as an allocation of administrative and common costs, shall be sufficiently forward looking and granular to reasonably reflect the full potential value that could be obtained from the distributed opportunities. Certain projects could result in lower operation and maintenance costs, due to, for example, lower equipment failure rates, while other measures may increase operation and maintenance expenses due to, for example, increased DER interconnections. These changes in O&M shall be determined by using the utility's activity-based costing system or work management system. As an example, the impact of a particular measure could be determined by estimating the percentage of a field crew's time on a particular activity before the installed project and then estimating the time saved by the field service personnel after the project is installed. The method for valuing avoided O&M costs or benefits specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

Avoided Distribution Losses

The difference in the amount of electricity measured coming into a utility’s system from the NYISO or distributed generators and the amount measured by the Company’s revenue meters at customer locations is defined as the “Loss” or “Losses” experienced on the Utility’s system. Losses can be categorized as technical and non-technical losses, where technical losses are the amount of energy lost on the utility’s system as heat and the magnetic energy required to energize various pieces of equipment used by the utility, and non-technical losses represent energy that is delivered but not registered by utility revenue meters. For the purposes of these analyses, the focus will be on technical losses.

Technical losses can be further categorized into fixed and variable losses, and attributed to various pieces of equipment. Fixed losses take the form of heat and noise and are attributable to individual pieces of equipment, such as cables and transformers, and do not change with increasing or decreasing current. Fixed losses are generally a property of the equipment, and cannot be reduced except by replacing such equipment with lower-loss units, or simply removing such units from service. Variable losses are generally due to electric energy being converted to heat at a rate proportional to the square of the current running through the piece of equipment, or I^2R losses. I^2R losses are lower when less electricity is being delivered, and greater when more electricity is being delivered. I^2R losses to deliver the same amount of power are lower at high voltage, and higher at low voltage. While both fixed and variable losses are significant, actions taken by customers and the utility will have a greater impact on variable losses since fixed losses can only be reduced marginally by replacing equipment with lower-loss models or removing equipment from service. Therefore the focus is on estimating the value of reducing variable losses. Table 3 below shows illustrative examples of the relative magnitude of several different categories of losses in the Consolidated Edison Company of New York, Inc. (Con Edison) service territory. Utilities shall file similar line loss data with their DSIPs and summarize them in their BCA Handbooks.

Table 3: Line loss as a percentage of energy delivered on various system components in Con Edison's 2007 Electric System Losses study

Portion of T&D Delivery System	Voltage Segment	Loss Type	
		Fixed	Variable
Transmission	500 kV	0.00%	0.00%
	345 kV	0.32%	0.52%
	138 kV	0.34%	0.50%
	69 kV	0.03%	0.05%
	TOTAL	**0.69%**	**1.07%**
Distribution	Primary	0.02%	1.12%
	Secondary	0.00%	1.56%
	Metering	0.18%	0.00%
	Equipment	0.78%	0.39%
	TOTAL	**0.98%**	**3.07%**
Unaccounted For		0.00%	0.65%
TOTAL		**1.67%**	**4.79%**

Variable losses should be considered when a project increases or decreases the load served on a utility's system. The impact of the increased or decreased load should be considered for all levels which will be affected. For example, a self-supplying microgrid connected at a utility's transmission voltage would reduce transmission line losses, but not distribution line losses. Similarly, an energy efficiency project at a residential customer location would result in decreased line losses from the utility's secondary system all the way through its transmission system. In the same way, increased line losses should be considered for projects which ultimately increase the load on the utility system. Projects which shift energy usage from one time to another also have an effect on losses, since variable losses are proportional to square of the current travelling through a line. That is, the avoided losses from reduced usage during on-peak times are greater than the incremental losses caused by increased usage during off-peak times. Time varying loss impacts should be considered if ample data exists to quantify them, but these effects may be comparatively small in magnitude. Finally, if a project materially increases or decreases the need for system reinforcement, fixed losses related to the equipment which is to be placed into or taken out of service should also be considered.

Loss factors shall be applied to the prices of the avoided cost components based on the loss characteristics of the utility system on which the load addition or load is connected. System loss characteristics are vitally important to the calculation of these data, so the latest system loss studies available shall be used to determine the percentage of system losses. If such data is not available, efforts shall be made to engage in a loss study, or otherwise to use the most applicable data available from other utilities. First, a loss percentage, or the ratio of the amount of energy lost on the utility system divided by the total electric sendout, must be determined. The loss percentage is equal to the sum of each applicable loss category (fixed or variable losses, for example). The loss percentage is then applied to adjust the price of the avoided cost component being calculated; for example, the prices associated with Avoided Energy, Avoided Generation Capacity, Avoided Externalities, and Avoided Transmission and Distribution Capacity Infrastructure.

EXAMPLE: Energy Efficiency

A customer connected to the Con Edison secondary system installs energy-efficient equipment to reduce their total energy usage by an average of 1 kW per hour. The total annual kWh savings of the project would be approximately 8760 kWh. What would the associated reduction in line loss be, and what is its value?

Assume that the customer's energy efficiency is not enough to eliminate the need for transformers or other infrastructure, therefore there are no fixed losses reduced by this program. Since the customer is connected to the secondary system, the energy usage reduction at the customer's location does reduce load on all higher levels of the distribution system and transmission system, therefore variable load reductions on the secondary distribution, primary distribution, distribution equipment, and all transmission voltages should be considered: in this example, the loss percentage is 4.14%. This loss factor would then be applied to adjust the prices applicable to all of the associated avoided costs such as, avoided energy, avoided generation capacity, and any others that apply. For example, the avoided energy associated with this measure would be calculated as follows:

Since the customer is in the Con Edison service territory, use the NYISO Zone J average LBMP to determine the avoided energy, which in 2013 was $0.052/kWh.

$$\begin{aligned}\text{Avoided Energy Value} &= \text{Energy impact} * \text{LBMP} * \text{Loss Percentage} \\ &= (-8760\ \text{kWh}) * \$0.052 * 4.14\% = \$-18.86\end{aligned}$$

More granularly, or dynamically, the hourly marginal price at the relevant level of the system could be grossed up by the marginal loss % avoided for that hour, at that level of the system.

Net Avoided Restoration Costs

Projects such as automated feeder switching or improved diagnosis and notification of equipment conditions could result in reduced restoration times. To calculate this avoided cost, utilities could compare the number of outages and the speed and costs of restoration before and after the project is implemented. Such tracking would need to include the cause of each outage. The change in the restoration costs could then be determined. The minimization of restoration costs often factors into a utility's decisions to invest in T&D infrastructure, so some portion of restoration costs are already included in the Avoided T&D Infrastructure category described above. Net Avoided Restoration Cost benefits specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

Net Avoided Outage Costs

Avoided outage costs could be determined by first determining how a project impacts the number and length of customer outages then multiplying that expected change by an estimated cost of an outage. The estimated cost of an outage will need to be determined by customer class and geographic region. Outage mitigation often factors into a utility's decisions to invest in T&D infrastructure, so some portion of outage costs are already included in the Avoided T&D Infrastructure category described above. Net Avoided Outage Cost benefits specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

Externalities

As noted above, in addition to pecuniary costs and benefits, utilities need to consider out-of-market public costs and benefits that DER impose or provide. Many of these (such as land, water, and neighborhood impacts) will depend on the specific alternatives considered and will need to be weighed in a qualitative and judgmental way. However, the quantitative impact of three damaging gas emissions—SO_2, NO_x, and CO_2—are measured and modeled at the bulk level and can be estimated at the DER level.

SO_2, NO_x

To value the benefits associated with avoided SO_2 and NO_x emissions, utilities shall rely on values reflected in LBMPs. As noted, Cap & Trade programs have been used to "internalize" some social costs into wholesale LBMPs. In producing the CARIS 20-year LBMP forecasts, the NYISO assumes a trajectory of $/ton emitted compliance costs for each of the damaging gasses discussed. This forecast is modified in each CARIS update. Since the Cap & Trade programs that these estimates reflect are not applied to generators smaller than 25 MW, any smaller distributed generator (DG) that does emit these gasses should not receive these credits. Under this approach, any smaller DG that emits these gasses shall have its pecuniary costs increased by the allowance price forecasts assumed in the CARIS model when they are compared to emission-free DER or bulk power.[5]

To the extent that the portfolio of solutions being considered would produce greater SO_2 and NO_x benefits/costs in a given utility's local area than are reflected in

[5] To the extent that emitting DGs are more efficient than bulk generators, this will be reflected in the comparison of their pecuniary costs to the aggregation of the described benefits, including avoided LBMPs. The addition of CARIS compliance costs to the emitting DG's pecuniary costs simply adjusts for an inappropriate credit that these DG resources otherwise would get since they do not have to purchase the allowances assumed in the LBMP forecasts.

LBMPs, the methodology to determine that potential should be described in each utility's BCA Handbook.

CO_2

To value the benefits associated with avoided CO_2 emissions, utilities shall rely on the costs to comply with New York's Clean Energy Standard once those costs are known. Until then, the value of avoided CO_2 emissions shall be determined by a detailed calculation of net marginal damage costs. Such calculation shall be performed by Department of Public Service Staff and the results shall be filed with the Secretary to the Commission on or before July 1 of each year. The CARIS model and database shall be used by Staff to calculate the change in the tons produced of CO_2 by the bulk system when system load levels are reduced. Staff shall assume that this quantity of gas reduction would occur if DER "backed down" system load levels, then those quantity estimates shall be multiplied by an estimate of the $/ton value of marginal damage costs, net of the costs already internalized by CARIS. This will yield a $/MWh estimate of the adder emission-free DER should receive in addition to the CARIS LBMP when comparing emission-free DER to bulk energy sources. Equivalently, in the utility's DSIP planning BCA, the cost of the bulk power shall be raised by this net $/MWh adder when the emission-free DER's costs are compared to the alternative of purchasing bulk energy. In this approach, when comparing DER that emits quantities of CO_2 to emission-free DER, or to bulk level energy, the full marginal damage cost estimates, not net of the CARIS compliance estimates, should be added to the emitting DER's pecuniary costs per MWh. Attachment B describes in detail Staff's use of the United State Environmental Protection Agency (EPA) damage cost estimates and the CARIS database to estimate net marginal damage costs. The central case recommended by the U.S. Interagency Working Group, which is 3%, will be used.

Net Non-Energy Benefits

Non-energy benefits include, but are not necessarily limited to, such things as land, water and health impacts, property values, avoided outage and restoration costs, and reduction of termination of service and uncollectibles costs. Where such benefits related to utility or grid operations can be monetized generally, they may be included in the SCT test. But many of these benefits, especially those that are societal benefits only indirectly related to utility or grid costs, are difficult to quantify and so cannot be monetized or included in the SCT test at this time. However, when utilities consider specific alternatives, they should recognize those impacts directly related to utility or grid operations when relevant, and weigh their impacts, quantitatively on a location-specific or project-specific basis when possible, and qualitatively, when not. For example, if a DER proposal for low and moderate income customers results in a reduction in the number of utility service terminations, the corresponding resource savings should be reflected in the SCT results. Similarly, if the same proposal also reduced uncollectible bills, the corresponding transfer payment would be reflected in the RIM results. Impacts unrelated to utility or grids will not be recognized now, but could be considered if feasible in the future upon subsequent Commission action.

Valuing Costs

Program Administration Costs

Some projects undertaken will be more complicated than operating distributed generation and will require program administration performed and funded by utilities or other parties. The cost to administer and measure the effect of such programs shall be included in the determination of the program's cost effectiveness.

Added Ancillary Services Costs

Required ancillary services, including spinning reserve and frequency regulation, could be increased with greater penetration of intermittent renewable resources such as wind and solar power. Such projects may require the grid operator to establish a higher level of ancillary services or to purchase additional ancillary services from sources other than conventional generators. Similarly, local voltage support, local VAR support, and local power factor improvement could be impacted by increased levels of DER and therefore should be factored in to this benefit category. The increased level and cost of the ancillary services may be difficult to forecast and require modeling. Utilities shall include such modeling with their DSIPs and summarize the approach in their BCA Handbooks.

Incremental T&D and DSP Costs

Incremental T&D costs borne by the utility or DSP shall be considered to the extent that the characteristics of a project cause additional costs to be incurred. A project might cause such costs to be incurred by using energy or demand during peak hours and contributing to the utility's need to build additional infrastructure. Conversely, a shift of a large enough portion of load to off-peak hours might prevent transformers and other power equipment from experiencing the designed cool-down period necessary to maintain reliable operation of the equipment, resulting in a need for reinforcement. Any additional T&D infrastructure costs caused shall be considered and monetized in a similar manner to the method described in the Avoided T&D Infrastructure Costs section above.

Participant DER Costs

The equipment and participation costs assumed by DER providers should be considered when evaluating the societal costs of a project or program. For example, a participant in a bring-your-own-thermostat direct load control program assumes the cost of the controllable thermostat. While a participant's equipment costs should be relatively simple to monetize, comfort and other opportunity costs are much less apparent. Previous studies and programs have assumed that, in general, participant opportunity costs are approximately 75% of any incentives paid to participants.[6] That approach is no longer valid. Since benefits that cannot be monetized generally are excluded from the SCT and other tests, costs that cannot be monetized generally must similarly be excluded. Either the opportunity cost must be monetized generally on a fact specific basis, or, like benefits directly related to utility or grid operations, on a location-specific or project-specific basis. The methods reflecting these approaches for valuing Participant DER costs specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

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6 This approach has been employed by Con Edison in evaluating the cost-effectiveness of its Demand Response programs, and is detailed in the February 10, 2014 "Cost Effectiveness of CECONY Demand Response Programs Final Report

<u>"Lost" Utility Revenues</u>

Because of the presence of Revenue Decoupling Mechanisms (RDMs) at every electric utility in the State of New York, very little sales-related revenue is actually lost to the utility due to a decrease in electricity sales or demand. While the utility is made whole from the decrease of sales, the revenue which would have otherwise been recovered through the rates charged on those lost sales is instead recovered from other customers through the RDM, marginally increasing the costs of other electricity sales. The bill impacts on non-participating customers should be considered for the purposes of determining the bill impacts of a project or program.

<u>Utility Shareholder Incentives</u>

The costs to ratepayers of utility shareholder incentives that are tied to projects being evaluated using the benefit-cost analysis framework should be considered when determining the cost effectiveness of such projects and programs. The method for valuing Utility Shareholder Incentives costs specific to each utility shall be included in individual utility DSIPs and BCA Handbooks.

<u>Net Non-Energy Costs</u>

There may be a number of non-energy related costs which result from the various projects undertaken by utilities. These costs may include, but are not limited to, indoor air pollution and noise pollution resulting in siting of generators or other power equipment. At times, such impacts may fall disproportionately on one area or neighborhood over others. Like difficult-to-quantify benefits, costs that cannot be monetized generally cannot be included in the SCT at this time. However, when utilities consider specific alternatives, they should recognize those impacts directly related to utility or grid operations when relevant, and weigh their impacts, quantitatively on a project-specific or location-specific basis when possible, and qualitatively, when not. . . As with non-energy benefits, cost impacts on society not directly related to utility or grid operations cannot be monetized now, but could be considered if feasible in the future upon subsequent Commission action.

Attachment A: ICAP Spreadsheet Model

The Spreadsheet Model may be found at the Commission's website, www.dps.ny.gov, as filed herewith the issuance of this Order today under Case 14-M-0101, named as BCA Att A Jan 2016.xlsm. Updates will be filed in the same manner.

Attachment B: Technical Explanation of Staff's EPA-Based Marginal Damage Cost Calculation

This calculation relies on methods developed by the U.S. Environmental Protection Administration (EPA) to focus on the human health damages of increased emissions of CO_2 to estimate the environmental cost of electricity generation. Staff uses EPA's estimated social cost of carbon (SCC).

Social Cost of CO_2

The SCC is an estimate of the monetized damages to global society associated with an incremental increase in carbon emissions in a given year. It is intended to include changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change, etc.

In 2008, a federal court ruled that agencies must adopt nonzero monetary values when considering the effects of carbon dioxide pollution.[1] In 2010, the Office of Management and Budget and Council of Economic Advisers established an interagency working group to determine a single metric for all federal agencies, referred to as the Social Cost of Carbon (SCC). The most recent update to the SCC was released in 2013. As stated, the intent of the SCC is to "allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions"[2] The interagency workgroup and SCC were designed to incorporate multiple lines of evidence through interagency consensus. In 2014, the Government Accountability Office released an investigation into the interagency workgroup and 20103 SCC update and found that the process used to establish the SCC was robust.

To incorporate multiple lines of evidence, the SCC incorporates the outputs from 3 peer-reviewed economic models that employ different methodologies: DICE 2010 (Nordhaus), FUND 3.8 (Anthoff and Tol), and PAGE 2008 (Hope). By considering multiple models, the SCC represents a defensible approach to the uncertainties inherent to climate change and any other attempt to project into the future. However, as

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1 Reviewed in GAO REGULATORY IMPACT ANALYSIS: Development of Social Cost of Carbon Estimates GAO-14-663: Published: Jul 24, 2014. Publicly Released: Aug 25, 2014. Available at http://www.gao.gov/assets/670/665016.pdf

2 2013 Technical Support Document available at https://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

GAO and others have indicated, the SCC does not include all possible damages and is likely an underestimate of the true costs to society from climate change. Accordingly, the SCC values and underlying models are not static and will be regularly updated.

The SCC represents the net effect (damages and benefits) to society of a marginal increase in emissions and it is reported as a matrix representing model averages across different time periods and discount rates as well as a "4th column" that reports the 95th percentile of all models, or the most severe damages. Emissions that occur further in the future are considered to have an increasingly severe impact, so the SCC increases with time. However, larger discount rates, e.g., 5%, reduce this value. For example, the latest EPA cost estimates for emissions occurring in 2020 (in constant 2011 dollars) are $13 per ton when discounted at a 5% rate, $46 per ton when discounted at a 3% rate (the "central value" of the SCC), $68 per ton when discounted at a 2.5% rate, and $137 per ton when looking at the 95th percentile for all models, discounted at 3%.[3] The EPA Table is reproduced as Table A.

Estimating the Total Cost per MWh

To apply marginal damage cost estimates in a resource portfolio BCA, the $/ton damage estimates must be converted to $/MWh estimates. That is, Staff must estimate the increased tons of each emission caused by a marginal increase in the MWh of electricity generated (or tons saved by a marginal reduction in MWh generated).

To estimate total cost of CO_2 emissions on a per-MWh basis, Staff uses General Electric's Multi-Area Production Simulation Model (MAPS) to estimate marginal rates of emissions. The MAPS model includes detailed load, generation, and transmission representation for NY and neighboring areas and simulates electric energy production costs and associated CO_2 emissions while recognizing transmission constraints and import limits.

Staff uses a MAPS model input developed by the New York Independent System Operator (NYISO) that contains base case assumptions for load, energy requirements, capacity, and emission rates in NY as well as in PJM, NE, Ontario. Staff runs an alternative scenario by changing load and energy requirements in NY by 1 percent from the base case. Staff then calculates the changes in emissions in tons by region, or the

[3] Available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

differences in the MAPS outcome between the alternative scenario and the base case assumptions divided by the increase in the energy requirements in NY.

To get the gross damage cost of externalities per MWh, Staff multiplies these emission rates and the corresponding values of the health damages for CO_2.

As an example of how Staff calculates the annual values, in 2016 Staff runs these scenarios for MAPS for the years 2022 and 2026. The health damage values for 2022 and 2026 are directly from the estimates for these two years. The estimates for rest of the 2016 and 2032 are as follows. The values for 2022 are used for 2016-2022; the values for 2022-2026 are extrapolated; and the estimates for 2026 are used for 2027-2035.

Gross values are the estimates based on the EPA's models, weighted by the MAPS emission rates. They do not reflect the compliance costs assumed in CARIS or energy and capacity cost forecasts. The net values of the social cost of CO_2 are the net of these compliance costs assumed in CARIS.

Staff provides values at a 3 percent discount rate. Staff uses the GDP price deflator to convert EPA's SCC in to current dollars and a factor of 0.907184 to convert metric ton to short ton.

References

U.S. EPA (2010), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 - Interagency Working Group on Social Cost of Carbon, February 2010.

U.S. EPA (2013a), Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors, January 2013.

U.S. EPA (2013b), Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 - Interagency Working Group on Social Cost of Carbon, May 2013.

Table A. Social Cost of CO_2, 2015-2050 a (in 2011 Dollars per Metric Ton of CO_2)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

Source: EPA, http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

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Commissioner Diane X. Burman, concurring:

As reflected in my comments made at the public session, and only to the limited extent and without prejudice to take this up again in June 2016, I concur.