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Docket No. 4600 – Investigation into the Changing Electric Distribution System

Comments re: Benefit-Cost Assessment of Distributed Energy Resources

Introduction and Overview

Pace Energy and Climate Center ("Pace") appreciates this opportunity to submit preliminary framing comments regarding assessment of benefits and costs of distributed energy resources in this investigatory proceeding.

Pace Energy and Climate Center is acting as an expert advisor to New Energy RI in this matter. Pace Energy and Climate Center is a project of Pace University, located at the Elisabeth Haub School of Law in White Plains, New York, that has worked to advance clean energy policy for more than 25 years. Pace is an active participant in utility transformation and "utility of the future" proceedings in New York (the New York "Reforming the Energy Vision" proceeding) and other states. Pace's Executive Director, Karl R. Rábago, will primarily represent Pace in this matter. Rábago has more than twenty-five years of experience in electric utility regulatory issues, including as a Commissioner on the Public Utility Commission of Texas, as a deputy assistance secretary with the U.S. Department of Energy, and as a utility executive. Pace staff members include attorneys, engineers, economists, and analysts working to advance clean energy technology and market development, especially in the electric utility context. Pace has been an active party in all phases of the New York Reforming the Energy Vision proceeding. Pace is collaborating in this proceeding with members of New Energy Rhode Island.

At the stakeholders meeting held on May 4, 2016, participants were invited to offer comments regarding framing of issues and attributes to be addressed in evaluating the benefits and costs of distributed energy resources. Pace offers these comments in response to that invitation.

Appendix A includes detailed comments on DER valuation, extracted from testimony filed in Docket # 4568.

Appendix B lists additional recommended reading

Appendix C is a revised valuation template

Getting the Value Right is Essential

The "Value of DER" can be seen as the sum of costs and benefits associated with each unit of energy service realized from a DER operation or facility. This value can be seen as the sum of energy value (usually in reference to a locational marginal price for energy) plus any value above and beyond energy value, minus any integration costs borne by the utility or ratepayers. Full and fair assessment of value, and development of methodologies to assess the value of DER can be used to inform the setting of compensation rates or charges, to inform the setting of above market incentives to stimulate markets or overcome market failures, to benchmark competing resource options, and to inform market functions.

Establishing full and fair value of DER is essential regardless of the level of regulatory initiative under consideration—whether setting a net metering compensation rate, guiding development of new products and services at the "distribution edge," or informing large-scale utility transformation. Pace recommends that the Rhode Island PUC invest in developing a full and fair valuation methodology for DER now, regardless of how far the Commission currently envisions its transformation will reach. That is, valuation methods are foundational—they should be established now and prior to setting any charges for DER operation. Moreover, valuation methodologies should not be established under pre-conceived notions about particular policies or existing program structures.

It is also important to use the process of establishing a valuation methodology to inform judgments about the allocation of value created by DER among investors, owners, operators, utilities, non-owner customers, and society at large. Accurate allocation of costs and benefits is essential for ensuring fairness and economic efficiency in rates and charges.

Getting the value of DER right is essential for setting compensation rates and charges. Accurate valuation advances a number of important purposes:

- Full and fair valuation of costs and benefits advances economic efficiency and guides market participants to economically efficient investment decisions.
- Full and fair valuation of costs and benefits supports fairness to participating and non-participating customers. Compensation credit for DER at or below the full value of the DER resource can eliminate cross subsidies over the life of the resource, and drive reductions in rates for all customers.
- Full and fair valuation reproduces the well-understood avoided cost analysis previously limited to the wholesale side of the system. Avoided cost methods seek to establish an "indifference price" at which the utility is indifferent to self-build or procurement choices. With DER, the physical point for establishing indifference pricing is at the customer meter or the distribution system feeder, where the DER interconnects to the grid.
- Accurately setting compensation rates at the full and fair value of DER allows for more precise management of incentives, especially incentives designed to correct for market failures.
- Full and fair valuation of DER allows it to be evaluated as a resource in providing and ensuring reliable, safe, and affordable provision of electricity service.

- Periodic reassessment of DER value can reduce or eliminate regulatory lag and allow for capture of decreases and increments in DER benefits and costs.
- Full and fair value analysis, periodically updated, eliminates the need for market-distorting caps on DER deployment, and allows market and technology forces to deliver price signals to DER developers. If, for example, a distribution feeder is overloaded with other distributed generation, the integration costs for connection of another generator may be higher. On the other hand, a distribution feeder that is a "load pocket" with abnormally high load would translate into higher value for DER sited at that location.

A sound valuation foundation can allow for growth and improvement over time. For example, in Vermont, the Public Service Board used input from a Solar Siting Task Force to create value adjustments in Vermont's net metering policy for preferential siting of distributed generation on brownfields and other preferred development sites. Valuation methodologies that account for the time value of DER operation can also help shape generation and consumption patterns to more effectively address peak demand.

Approaches that Should Be Avoided or Rejected

In establishing an essential valuation platform for DER, the Commission should reject approaches that artificially constrain future options or take too narrow a view of DER market development. Approaches that should be *avoided* or *rejected* include:

- Efforts to evaluate costs and benefits on a program-by-program basis. Established programs have been designed to accomplish specific results, and often result from compromise processes that conflate fair compensation and incentives. This is a major defect in the table for valuation analysis submitted by National Grid. The universe of program offering is not static; the field is evolving. Rather than a program-by-program benefit cost analysis considering each program in isolation, a valuation methodology should establish a common foundation from which technology- or operation profile-specific adjustments can be made.
- Approaches that imply that the value of avoided delivered kWh at a particular meter at a particular time vary with the technology or service that avoided the need for the kWh—for example, based on whether the need for the utility-delivered kWh arose through distributed generation, demand response reduction in consumption, or discharge from a battery. Differences between technologies and operations of DER over time will determine the profile of value differences captured in a methodology that estimates the useful life of the DER technology or measure. Levelization analysis can be used to compare disparate resources, as in integrated resource planning.
- Approaches that overwhelmingly focus on the cost to the utility, including approaches that treat lost forecast sales as a cost. Benefit cost analysis is not complete without a comprehensive assessment of benefits. Both costs and benefits (often avoided costs) should be analyzed over the long-term and should be forward looking as well as estimate current values. When a solar system is installed, for example, it will operate and avoid costs for 25 years or more. Ignoring

this future stream of benefits, or quantifying those benefits on a year-by-year basis artificially makes such resources look less valuable than they actually are.

- Approaches that assume that particular attributes have a single cost or benefit driver. For example, a rigid focus on coincident peak in evaluating capacity value ignores the pre- and post-peak capacity benefits associated with DER operations, especially pre- and post-peak capacity value and DER that addresses non-coincident peaks in particular locations or for particular customers.
- Rigid application of short-term or least-price cost effectiveness tests developed primarily for evaluating utility-sponsored, mandated demand side management programs. Many DER technologies and services involve substantial private investment that is irrelevant to utility rate making and DER compensation levels, for example. As such, private investments typically included in the Societal Cost Test have no place in analysis of costs and benefits for ratemaking.
- Approaches that assign a value of zero for any component attribute because the utility has not collected adequate data to evaluate the attribute, or because there is some degree of uncertainty around the assignment of a precise value to the attribute. There are many ways to account for uncertainty beyond disregarding a cost or benefit category.
- Approaches that confuse “sunk costs” with “fixed costs,” and that ignore avoidable future fixed costs. The purpose of ratemaking is to enable a fair opportunity to earn a reasonable return on prudent, used, and useful investments. Imposing sunk cost recovery charges on new DER resources distorts benefit cost analysis and insulates utilities from the fair and eminently predictable consequences of over-building. Moreover, many DER technologies and services can extend the useful life of fixed cost investments, defer or avoid future capital investments, and transform the utility rate base toward lower overall cost for service.
- Approaches that ignore or dismiss the many societal and currently externalized benefits of DER and the increased market efficiencies that DER providers bring to the monopoly electricity service business model. Many DER options are financed with private capital, and private owners and operators bear insurance and operating risk. DER technologies and services face competition and therefore have a natural bias toward superior economic and operating performance compared to cost-of-service monopoly providers. Ignoring these benefits would undervalue increased deployment and operation of DER.

Optimal Order of Proceeding Stages

In order to prevent pre-decisional bias against DER, the Commission should proceed in an orderly fashion to develop and utilize valuation methodologies.

Step 1: Develop valuation methodologies for DER resources. Numerous resources provide templates and guides for fully and fairly determining DER value, or can be easily adapted from value of solar analysis to valuation of the broader family of DER. Several such resource are available at: http://www.growsolar.org/technical-assistance/value-solar-methodology/

Step 2: Assign value streams after quantitative methodologies have been developed to determine DER value on a technology- and operation-specific basis. Value of distributed renewables can easily be standardized across the entire state of Rhode Island, with adjustments for locational value. Value of distributed storage depends on the assumed operating profile. Value of distributed combustion-driven generation requires netting of produced and avoided emissions. Etc.

Step 3: Develop rate structures that internalizes calculated values.

Step 4: Evaluate the need for additional incentives or charges necessary to address market failures.

A Word on Decoupling

The stakeholders meeting included some discussion of revenue decoupling. The traditional approaches to revenue decoupling may not be appropriate in a changing electric distribution system. Traditional decoupling awards lost profits and revenues to utilities in an effort to make a monopoly provider somewhat indifferent to lost revenues associated with demand side management activities. Unfortunately, this approach compromises the savings produced by DER and does not create any incentive for utility investment in DER as an alternative to traditional utility revenue generation methods. Proper rate design incorporating levelized useful life valuation of DER can substitute for decoupling adjustments and move markets to more rational pricing with fewer distorting post-hoc adjustments.

Looking Forward

An ideal process to address costs and benefits envisions movement toward a more enduring means of compensating DER performance than existing systems like the Renewable Energy Growth Program or even Net Metering. Cost and benefit analysis also can inform the process of utility transformation and the achievement of broader societal goals associated with affordable, reliable, and environmentally responsible electricity service for all Rhode Islanders, today and tomorrow. Distributed energy resources must play a major part in that future, enabled by non-discriminatory rules and rates managed by distribution system operators. Current models for dealing with DER and the underlying utility business model are not sustainable, and cannot form the basis for the consensus-based transformation process. The status quo should be a point of departure, not a template for the future.

Appendix A

Valuation Template

Attribute Measurement or Evaluation Level	Benefit/Cost Category	System Attribute Benefit/Cost Drivers (Need to Develop List of All Significant Drivers)	DER Technology Type Adjustments (Adjustments Necessary to Capture Unique Performance Profile Attributes Associated with Specific DER Technology Types)
Draft framework for comparison of attribute-driven benefits and costs of Distributed Energy Resources			
Bulk System Level	Generation capacity costs (FCM)[1]	coincident peak demand & effective load carrying capability	
	Energy supply costs (LMP)[2]	energy to serve load	
	Avoided Transmission capacity infrastructure costs	coincident peak demand & effective load carrying capability	
	Ancillary services costs		
	Energy DRIPE[4]	energy to serve load	
	Capacity DRIPE[4]	coincident peak demand & effective load carrying capability	
	Greenhouse gas emissions costs (Avoided RGGI price embedded in LMP)[3]	energy to serve load energy supply mix	
	Criteria air pollutant emissions costs (avoided compliance costs embedded in LMP)	energy to serve load energy supply mix	
	Avoided fuel cost risk - hedging	fuel price forecast	
	Fuel diversification (avoided supply risk)	fuel price forecast	
	Avoided need for new gas pipeline infrastructure	planned capex & opex	
	Non-energy costs/benefits (e.g. economic development)	in-state economic value of DER	
Distribution System Level	Avoided Distribution capacity costs	local peak demand, capex over life of DER measure asset age/condition	
	Avoided Distribution operation and maintenance costs	opex over life of DER measure	
	Avoided Ancillary services costs	TBD	
	Distribution system reliability loss/gain	local peak demand asset age/condition energy to serve load	
	Distribution system resiliency loss/gain	resiliency-related capex & opex over life of DER measure	
	Distribution system safety loss/gain	safety-related capex & opex over life of DER measure	
	Program administrative costs	participation requirement incentive requirement	
	Reduction of utility arrearages	arearage rates	
	Reduction in the need for or cost of subsidies between rate classes and customer types	cost of service analysis, marginal cost analysis	
	Impact of time varying rates	coincident peak demand & effective load carrying capability	
	Value of peak shaving	coincident peak demand & effective load carrying capability	
	Impact of load control and demand response	coincident peak demand & effective load carrying capability	
	Impacts of distributed storage	netting of charging & discharging	
	Impacts of electric vehicles	controlled vs. uncontrolled	
	Non-energy costs/benefits (e.g. economic development)	in-state economic value of DER	
Customer Level	Program participant costs/benefits	behavior requirement - NOTE: Private costs or benefits are irrelevant in evaluating program for purpose of ratemaking	
	Ratepayer hedging of their own utility costs	NOTE: Private costs or benefits are irrelevant in evaluating program for purpose of ratemaking	
		technology requirement - only to the extent that costs are NOT paid by the participating customer	
	Program non-participant costs/benefits	Only costs/benefits not otherwise captured	
Society Level	Job impacts Reduction of utility shut offs Stabilize economic impact of utility costs on low income ratepayers Innovation impacts New business opportunity impacts Stabilized energy costs impacting RI Business retention and formation	Economic input/output analysis	

[1] FCM refers to the ISO New England Forward Capacity Market (see, http://www.iso-ne.com/markets-operations/markets/forward-capacity-market).
[2] LMP refers to the locational marginal price of energy (see, http://www.iso-ne.com/participate/support/faq/lmp).
[3] RGGI refers to the Regional Greenhouse Gas Initiative (see, http://www.rggi.org/).
[4] DRIPE refers to "demand reduction induced price effects."

Appendix B

Extracted and Edited Version of Testimony in Docket # 4568 Relating to Distributed Energy Resources (DER) Valuation, filed on Behalf of Wind Energy Development by Karl R. Rábago

DISTRIBUTED GENERATION VALUATION

Q. What is the benefit of comprehensive value analysis for distributed generation resources?

A. Full and regularly updated evaluation of resource value improves the chance that rates applicable to such resources will strike the economically efficient balance in charges and credits. If a renewable generation resource is under-valued by the utility, it will be over-charged. Overcharging or under-crediting results in under-selection and under-utilization by customers; ultimately society loses the benefits that the resource can provide. This is precisely the situation that would have resulted if National Grid's proposed Access Fee was imposed on distributed generation. In that case, National Grid did not account for all the value of distributed generation, and, as a result, National Grid reached an erroneous conclusion that distributed generation should be uneconomically burdened with charges. A full value analysis is necessary.

Q. How do utilities typically assess the value of Distributed Generation Resources?

A. Distributed generation resources have historically not fared well in traditional utility ratemaking systems, which often have a financial bias toward large, capital-intensive projects and infrastructure owned by the utility. Historically, these utility-owned projects, if successful, tend to maximize profits at the expense of the lowest cost and highest value for customers. Historically utilized preferences tend to assign higher value to dispatchable generation options with low capacity cost, while undervaluing several increasingly valuable and important components, such as fuel price volatility, regulatory (especially environmental) risk, water supply and availability risk, transmission infrastructure requirements, and others. Traditional avoided cost methodologies, designed to set energy payments based on current, short-run costs and wholesale prices, can reduce the value of low or zero-risk resources and long run marginal cost and risk reductions.

Q. Was this approach apparent in National Grid's Access Fee proposal?

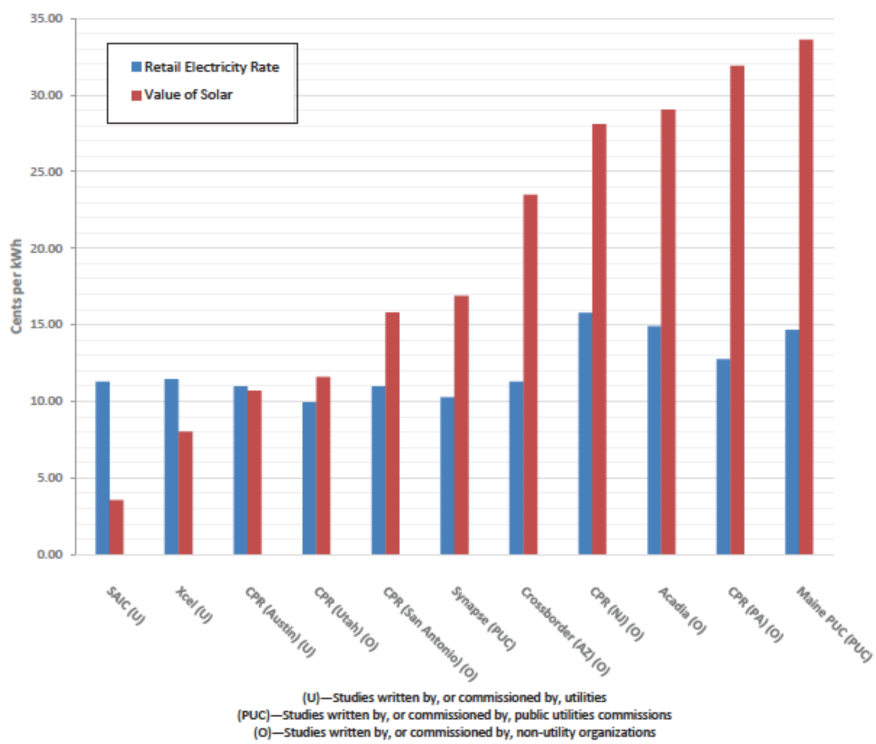
A. The absence of information in National Grid's Docket # 4568 proposal makes this question difficult to answer. National Grid appears to acknowledge that it did not assess and characterize the full value of distributed generation in providing energy, capacity, transmission and distribution, risk-reduction, and other benefits. It also appears that National Grid did not assign full credit to value created by distributed generation that will accrue to the utility and all ratepayers over the full 25+ year useful life of installed distributed generation systems. Finally, National Grid appeared to have assumed a "lost revenues" cost to distributed generation that fails to account for all costs that National Grid avoids. Such over-assessment of costs appeared to drive its proposal to double charge both distributed generation and ordinary consumption-only customers for distribution system costs. A modern, complete evaluation of the value of distributed generation is essential to proposing a fair charge or credit.

Q. How has distributed generation valuation evolved in recent years?

A. Over the past two decades, a number of state- and utility-specific studies have been conducted to calculate the benefits of distributed solar. These are generally termed "Value of Solar" studies, and offer insights and guidance in valuing other distributed generation resources. Today, Value of Solar analysis rests on a solid foundation of data that, if applied, would significantly improve the Company's rate proposals. At this time, valuation of DER proceedings are also underway in New York's Reforming the Energy Vision proceeding, and in California.

Q. What does the experience in recent years with distributed solar generation valuation teach us?

A. In the summer of 2015, the Frontier Group and the Environment America Research and Policy Center released the "Shining Rewards" report that compiled the results of eleven value of solar studies, and concluded that these analyses show that "individuals and businesses that decide to 'go solar' generally deliver greater benefits to the grid and society than they receive through net metering. The Shining Rewards report is available at http://www.environmentamerica.org/reports/amc/shining-rewards. The graphic below ("Shining Rewards," Figure ES-1, p. 6) aggregates the findings reported in the Shining Rewards study, including the fact that studies conducted through public processes open to stakeholder involvement produce higher value for distributed solar than the studies conducted internally by utilities.



Q. What are the basic elements of distributed value of solar analysis?

A. Properly done value of solar analysis is, and any distributed generation value analysis should be, an expansion on a full avoided cost approach that adds a long term valuation perspective, including, as appropriate and quantifiable, social costs and benefits. There are two basic steps: first, benefits and costs are identified and grouped, then, second, the benefits are quantified. These steps are essentially the same as traditional ratemaking functions inherent in cost of service analysis. The focus is on the net value that distributed resources bring to utility and grid finances and operations.

Q. Is proper valuation analysis market-driven?

A. Yes. Valuation calculations are, at heart, avoided cost calculations that embrace a full range of costs avoided by distributed generation, including savings over the life of the generation system. So the source of the value of solar is in the market costs avoided and market benefits received. As explained earlier, valuation studies offer improved market pricing signals over traditional avoided cost calculations, which ignore long-term risk, especially fuel price and environmental regulatory risk. My own experience with Austin Energy's value of solar methodology is that the calculated value of solar better reflects market conditions and the value of solar investments than short-term avoided cost calculations and base rate calculations established in prior years based on sunk costs.

Q. How can a valuation methodology better reflect the costs avoided by different technologies?

A. In order to justify the imposition of a charge on distributed generation, or to calibrate a credit for excess value, an analysis of full range of benefits, or avoided costs, and cost of distributed generation is required. In order to fairly value the avoided cost and other benefits of different technologies, the contributions they can each make must be objectively and quantitatively analyzed. Each technology must be fully characterized in order to understand the energy, capacity, transmission, distribution, line loss reduction, operating risk, environmental, and other known and measurable costs that can be avoided with their deployment and operation.

The location, scale, timing and other operating characteristics of generation and other resource options should also be recognizable and recognized in determining the avoided cost benefits. The use of technology-specific load shapes in modeling costs and benefits of distributed generation resources is one example of the application of this principle. National Grid recognized this principle in a very superficial and inadequate way in its differentiation among distributed generators according to capacity factor in how it proposed to assess its proposed Access Fee. The range of potential avoided costs and other benefits must be fully documented and incorporated into a flexible methodology that calculates benefits and costs for each unique technology configuration.

Q. What benefits of distributed generation should the Commission require to be addressed in its methodology?

A. The following values need to be quantified in order to calculate the full avoided costs of distributed generation:

- **Avoided Energy Cost** – this is the utility's energy cost that is avoided by distributed generation. Avoided energy cost should be calculated based on the difference between long-term production costs with the distributed generation, compared to the production costs without the distributed generation.

- **Avoided System Loss Cost** – the line-loss savings that accrue where distributed generation displaces generation from remote, central station plants. This should be calculated based on marginal losses, which should be load-weighted and distinguished between distribution and transmission losses.

- **Avoided Generation Capacity Cost** – the cost of generation that is deferred or avoided due to non-utility distributed generation. This should be calculated using Effective Load Carrying Capability[1] or similar analysis.

- **Avoided Transmission and Distribution Capacity Cost** – the cost of transmission or distribution that is avoided due to non-utility distributed generation, after netting the utility's costs to integrate distributed resources. This calculation should utilize the approach described for generation capacity, and should not be limited to large planning increments.

- **Avoided Financial Cost – Fuel Price Hedge** – the utility's costs associated with fuel price volatility that are avoided due to renewable distributed generation. Solar, wind, and hydropower generators do not have fuel costs that vary with market conditions. The fact that prices of energy will not vary for these resources offers distinct financial value beyond that captured in energy prices.

- **Avoided Financial Cost – Market Price Response** – the costs that a utility avoids due to generation from a distributed generator due to decreases in its average price of fuel and reduced peak demand. This impact is sometimes referred to as Demand Reduction Induced Price Effect (DRIPE) and is also a distinct financial value beyond that reflected in energy prices.

- **Avoided Environmental Costs** – the costs that a utility avoids due to generation from a distributed generator, including avoided costs related to environmental regulation not already reflected in energy costs. It is appropriate to consider whether these future environmental costs, though not

[1] ELCC is a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or outage events (considering availability and use limitations). It is calculated via probabilistic reliability modeling, and yields a single percentage value for a given facility or grouping of facilities. ELCC can be thought of as a derating factor that is applied to a facility's maximum output in order to determine its qualifying capacity. Because this derating factor is calculated considering both system reliability needs and facility performance, it will reflect not just the output capabilities of a facility but also the usefulness of this output in meeting overall electricity system reliability needs. See "Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources," California Public Utilities Commission Energy Division, CPUC Resource Adequacy Proceeding, R.11-10-023 (January 16, 2014) Available at: http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf

reflected in current energy prices through compliance costs, may be otherwise addressed through other incentive or pricing systems.

It is worth noting that the Company will likely have assembled most, if not all, of the technology-specific data necessary for calculating full avoided costs for distributed generation in the course of developing resource plans and other regulator activities. Where utility-specific data is not readily available, analysts may develop suitable estimation methods or use third-party data (such as SolarAnywhere® data for solar performance).

Q. How should the methodology calculate the avoided cost of energy?

A. The avoided cost of energy can be calculated by modeling the long-term production costs of the system with a distributed generator, compared to system costs without the resource. This method is generally appropriate, subject to certain parameters.

I recommend that the Commission calculate the avoided cost of energy based upon technology-specific and location-specific load shapes. For example, tracking photovoltaic ("PV") systems produce more energy late in the afternoon than south-facing fixed-mount PV systems. This same issue would apply to wind energy and other resources whose generation potential varies in a reasonably predictable manner across the hours of the day and the weeks of the year.

Q. Over what time period should the avoided cost of energy be measured?

A. Because intermittent resources such as solar and wind energy provide a long-term, reliable hedge against fluctuations in fuel costs, I recommend evaluation for terms of 25 and 20 years, respectively, which also match up well with typical terms of vendor guarantees and service agreements for distributed generation.

Q. How should the Commission value line losses?

A. A critical part of the avoided cost of energy is the degree to which line losses are incurred or avoided by the distributed generator. The Commission should calculate marginal losses specific to the Company's distribution and transmission systems. This calculation should be load-weighted, using the specific hourly generation patterns of various types and locations of distributed generation, correlated to the specific hourly line losses attributable to distribution and transmission lines in the utility system.

Q. How should the Commission value the capacity contribution of an intermittent resource?

A. The capacity value for distributed generation systems should reflect their expected contribution to peak system capacity needs.

Three principles should guide this determination. First, the capacity value should be based on the technology and location of the distributed generation facility based on a model of historical resource (wind or solar) availability correlated to historical system load during peak hours. The preferred approach is known as Effective Load Carrying Capacity ("ELCC"). Second, the capacity value should be fixed at the time that the system owner commits to interconnect the system to the grid so that the owner can be certain what value the utility will attribute to the distributed generation facility. Third, as distributed generation is scaled up on the system, the capacity attributed to new distributed generation sources will likely be different from that attributed in earlier years.

This capacity determination should, in turn, be applied to both the calculation of the avoided cost of generation as well as applicable avoided cost of transmission and distribution capacity.

Q. Are there quantifiable financial benefits that should be considered to be "avoided costs"?

A. Distributed renewable generation offers financial benefits, by hedging against fuel price volatility and escalation, and through market price response. Both of these effects have measurable impacts on the costs of utility service and should be included in valuing distributed generation.

Q. Please describe the financial benefit of fuel price hedging.

A. The cost of producing energy from renewable energy resources like wind, solar, and small hydropower will not fluctuate with fuel prices. Moreover, unlike "traditional" qualifying facilities that rely on natural gas or biomass fuels, with fuel-free resources like solar and wind there is no risk that the distributed generator's business will fail due to changes in fuel costs, because there are no fuel costs. While quantifying the fuel-price hedging benefits of renewable energy resources may be challenging, the value should not be set at zero.

Q. Please describe the financial benefit of market price response.

A. Generation from fuel-free solar or wind qualifying facilities allows the systems to dispatch their natural gas or coal power plants less frequently, which in turn decreases the average cost of fuel used to generate electricity in two ways. First, there is a reduction in the number of hours in which higher fuel-cost power plants are dispatched. Second, when conventional generators buy less fuel, this reduces the market price of fuel overall. These price response effects have been studied in several regions.

Q. Please discuss avoided environmental costs.

A. It is reasonable to assume that current energy prices reflect current environmental compliance costs. Long-lived renewable energy resources also avoid additional environmental costs associated with future compliance costs. While these costs must be estimated like any long-term avoided cost, planning numbers associated with regulation of greenhouse gas emissions reflect imminently real costs that are not zero.

Q. What costs associated with distributed generation should be assessed?

A. I believe it is appropriate to assess utility costs as well. These costs include direct utility costs and may include an assessment of lost revenues. I note that assumptions about administrative costs (such as billing costs) should reflect automated billing systems. Interconnection costs incurred solely by the customer should not be included. It is important that integration costs should not be based on unrealistic assumptions about distributed generation penetration rates.

Q. Are there general principles that the Commission should adopt in addressing distributed generation valuation going forward?

A. Yes. I would recommend two fundamental principles. First, the approach should be forward-looking. Second, the avoided cost process should be open, transparent, and collaborative.

Q. Please discuss what you mean by a "forward-looking approach."

A. The valuation methodology must value distributed generation and resources according to their ability to create both short and long-term benefits over the life of the resource. Such an approach can be configured to encourage long-term operation and performance of distributed generation resources. As previously discussed, longer evaluation horizons are appropriate for long-lived wind and solar generation resources, for example. It is important to note that over the long-term, distributed generation can and will defer and/or avoid future fixed cost investments. This benefit is often ignored by traditional utility entities like National Grid, when they limit evaluation of fixed costs to the quantification of embedded, sunk costs. The principles of electric utility regulation provide that utilities are entitled to a reasonable opportunity to recover prudently invested capital and a reasonable return on those investments. National Grid appears to operate under two key misconceptions regarding its capital investments.

First, National Grid appears to believe that it is entitled to recover any and all of its capital investments, and profit on those investments, regardless of whether those investments are reasonable. As distributed energy resources become increasingly cost-effective and market penetrations increase, utilities must account for this market development to prevent imprudent overbuilding of its system. National Grid's request to establish a non-bypassable Access Fee on distributed generation denominated as a fixed charge would have substantially reduced the consequences to National Grid of imprudent overbuilding. The proposed Access Fee would have insulated National Grid from the economic consequences of refusing to acknowledge the reduced sales due to distributed energy resource market growth.

Second, National Grid made the category error of assuming that all fixed costs are sunk costs, and refused in Docket # 4568 to evaluate the extent to which distributed generation will defer or avoid future capital investments associated with the maintenance and operation of the distribution system. Again, the economic consequence of such a refusal to evaluate the future fixed cost avoidance value of distributed generation is likely imprudent overbuilding of the distribution system. This uneconomic investment would in turn drive utilities to seek even greater fixed cost recovery, probably through more non-bypassable fixed charges.

Utilities should be held responsible for fairly evaluating the full range of benefits associated with distributed generation, and in ensuring that they pursue only cost-effective and prudent capital investments in its distribution system.

Q. Please describe the need for an open and collaborative process.

A. The types and performance characteristics of distributed generation and resources are constantly evolving due to the rapid evolution of technology. Utility costs are constantly changing, especially at the distribution edge of the grid. Any adopted valuation methodology should be structured to create a more open, collaborative, and transparent process for establishing and modifying, and updating avoided cost values. Calculation and estimation algorithms as well as source data should be open to full review by stakeholders on an ongoing basis, subject to reasonable requirements for confidential data. Rather than requiring utilities to come to a private internal conclusion about avoided costs and then requiring non-utility generators to contest utility data and methodologies in highly adversarial proceedings, the process for setting avoided costs should reflect technology and cost dynamics through more meaningful opportunities for non-utility participation in the early stages of the process. By adopting a framework for a more data-driven, technology-specific methodology for calculating avoided costs, the Rhode Island Public Utilities Commission can facilitate a more transparent and collaborative process going forward.

Q. Are you aware of any recent reports or research on the value of distributed generation for Rhode Island or neighboring states?

A. Yes. I call attention to an IREC whitepaper, a policy framework document, and two solar valuation studies, for Maine and Rhode Island, in particular. While these studies are specific to solar photovoltaic generation, they elucidate and demonstrate principles and findings that can inform the Commission's efforts to establish a comprehensive and transparent valuation methodology for distributed generation in Rhode Island.

Q. Please describe the IREC report and its relevance to your recommendations.

A. In October 2013, the not-for-profit Interstate Renewable Energy Council (IREC), published a paper authored by Jason Keyes and me, entitled "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," available at http://www.irecusa.org/publications/. I am a member of the Board of Directors for IREC. The Guidebook draws on many distributed solar valuation studies to recommend a framework for a methodology for performing a benefit/cost evaluation for distributed solar. The Guidebook recommended approach stands in stark contrast to the dearth of information or analysis provided by the Company. Key principles underlying the methodology that my co-author and I recommended include reliance on data, transparency, reasonable evaluation of costs and benefits, and consistency in approach. I note that while the Guidebook is focused on distributed solar generation, much of the information is fairly applied, with adjustments, to other forms of distributed generation.

Q. What does the IREC guidebook report recommend regarding the scoping of a benefits/costs study?

A. The Guidebook recommends that the Commission clarify a number of issues at the onset of a benefit/cost study, these include:

What is the appropriate discount rate for evaluation of costs and benefits?

- Studies typically use the utility weighted average cost of capital, though there is a strong argument for use of a risk-adjusted discount rate to reflect the performance characteristics of solar generation.

What is being considered – all distributed generation or exports to the grid only?

- Where net metering is in place, it may be appropriate to limit the evaluation to exported energy. However, for a two-part rate, all generation should be evaluated.

Over what timeframe with the study examine the benefits and costs of distributed generation?

- The timeframe for analysis should reflect the useful life of the resources, today typically 30 years for solar, for example. There is a strong argument that a sensitivity evaluation should consider a longer useful life, as long as 35 years for solar.

What does utility load look like in the future?

- Under traditional net metering arrangements, customer-sited distributed generation operates to reduce utility load. However, under a two-part rate approach such as a feed-in tariff, distributed generation can be seen as not reducing load, but instead contributing to energy and capacity requirements at or near the point of generation.

What level of market penetration for distributed generation is assumed in the future?

- It is unreasonable to assume a market penetration rate equivalent to 100% of residential class energy demand for the purpose of assessing integration costs, and to simultaneously assume insufficient market penetration to impact future fixed cost investments. Sensitivity analysis can be useful to gauge the impacts of reasonable penetration rate scenarios.

What models are used to provide analytical inputs?

- Utility models such as Strategist are extremely useful in conducting integrated resource plan analysis, but often are constrained in their ability to model small-scale resources. Extrapolation of results from such models can induce errors. Full transparency and sensitivity analysis at varying scales of deployment, and with variation in other assumptions (such as the penetration rate of distributed storage technology) is essential to accurately model distributed generation.

What geographic boundaries are assumed in the analysis?

- Distributed resources may demonstrate improvements in availability due to geographic dispersion. Solar insolation and wind resource values, which drive energy production, vary depending on location. These variations should be accounted for in study design.

What system boundaries are assumed?

- Integration costs for distributed generation may vary with the siting location. These factors extend beyond land and construction costs and should be accounted for in a study.

From whose perspective are benefits and costs measured?

- I recommend that the Commission use a combined test that incorporates ratepayer impacts testing and societal cost testing. That is, private investment costs are not relevant in evaluating distributed generation.

Are benefits and costs estimated on an annualized or levelized basis?

- A levelized analysis extending over the useful life of the generation resource is the best approach for fully capturing the avoided costs and delivered benefits of distributed generation.

Q. What data sets are required in order to conduct a full benefits/costs analysis for distributed generation?

A. The Guidebook recommends that the entity that conducts the valuation study obtain or develop the following data sets. Most electric service providers like National Grid already possess most, if not all, of this data. Where utility-specific data is not readily available, analysts may develop suitable estimation methods or use third-party data.

- The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the distributed generation system.

- Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of distributed generation.

- Hourly production profiles for distributed generators, including south-facing and west-facing solar arrays, for example.

- Line losses based on hourly load data, so that marginal avoided line losses due to distributed generation can be calculated.

- Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.

- Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of distributed generation, in order to capture the potential for avoiding or deferring circuit upgrades.

Q. How can the IREC Guidebook be applied to shape distributed generation market policy?

A. The Acadia Center has applied the principles and concepts in the IREC Guidebook in crafting a widely-supported "Next Generation Solar Policy Framework for Massachusetts. "[2] The Policy Framework is **Exhibit AC-4** to the Acadia Center's November 23 testimony in Docket # 4568, and illustrates how the Commission can adapt distributed generation valuation concepts into a comprehensive policy framework for Rhode Island.

Q. Please describe the Maine Distributed Solar Valuation Methodology and its relevance to your recommendations.

A. The Maine Public Utilities Commission transmitted a report to the Maine Legislature on the Value of Distributed Solar Energy Generation on March 2, 2015. The report can be found at: http://www.maine.gov/mpuc/legislative/archive/2014-2015ReportstoLegislature.shtml. During its 2014 session, the Maine Legislature enacted an Act to Support Solar Energy Development in Maine. P.L Chapter 562 (April 24, 2014). Section 1 of the Act contains the Legislative finding that it is in the public interest to develop renewable energy resources, including solar energy, in a manner that protects and improves the health and well-being of the citizens and natural environment of the State while also providing economic benefits to communities, ratepayers and the overall economy of the State.

Section 2 of the Act required the Public Utilities Commission to determine the value of distributed solar energy generation in the State, evaluate implementation options, and to deliver a report to the Legislature. The Commission engaged a project team comprising Clean Power Research (Napa, California), Sustainable Energy Advantage (Framingham, Massachusetts), Pace Energy and Climate Center at the Pace Law School (White Plains, New York), and Dr. Richard Perez (Albany, New York).

Under the project, the team developed the methodology under a Commission-run stakeholder review process, conducted a valuation on distributed solar for three utility territories, and developed a summary of implementation options for increasing deployment of distributed solar generation in the State.

Q. What are the major features of the Maine Value of Solar Methodology?

A. The Maine study assessed or created placeholders for future assessment of avoided energy cost, avoided generation capacity and reserve capacity costs, avoided natural gas pipeline costs, solar integration costs, avoided transmission capacity cost, avoided distribution capacity cost, voltage regulation, net social cost of carbon, SO2, and NOx, market price response, and avoided fuel price uncertainty.

[2] Available at http://acadiacenter.org/document/next-generation-solar-policy-framework-for-ma/.

Figure 1: Central Maine Power 25 Year Levelized Value of Distributed Solar

25 Year Levelized		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distr. PV Value D ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.076				6.2%		$0.081	
	Avoided Gen. Capacity Cost	$0.068		54.4%		9.3%		$0.040	
	Avoided Res. Gen. Capacity Cost	$0.009		54.4%		9.3%		$0.005	
	Avoided NG Pipeline Cost								
	Solar Integration Cost	($0.005)				6.2%		($0.005)	Avoided Market Costs
Transmission Delivery Service	Avoided Trans. Capacity Cost	$0.063		23.9%		9.3%		$0.016	$0.138
Distribution Delivery Service	Avoided Dist. Capacity Cost								
	Voltage Regulation								
Environmental	Net Social Cost of Carbon	$0.020				6.2%		$0.021	
	Net Social Cost of SO_2	$0.058				6.2%		$0.062	Societal Benefits
	Net Social Cost of NO_x	$0.012				6.2%		$0.013	$0.199
Other	Market Price Response	$0.062				6.2%		$0.066	
	Avoided Fuel Price Uncertainty	$0.035				6.2%		$0.037	
								$0.337	

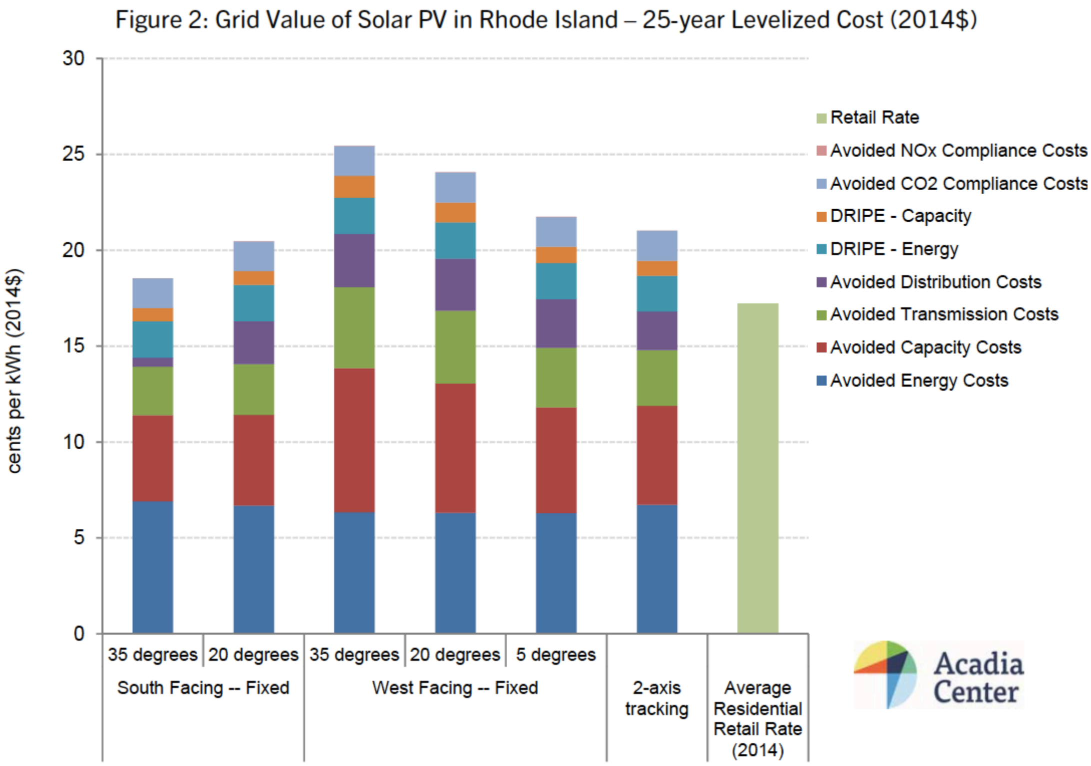
Q. Why do you recommend the Commission's and the Company's attention to the Maine methodology?

A. The Maine methodology stands in very stark contrast to absence of evidence offered by National Grid in Docket # 4568 to support its Access Fee proposal. The Maine Value of Solar Methodology demonstrates the kind of comprehensive, objectively verifiable approach that can be developed when a broad range of stakeholder and expert opinions are focused on the distributed generation valuation issue.

Q. Please describe the Rhode Island Value of Distributed Generation report and its relevance to your recommendations.

A. In July, 2015, the Acadia Center, a not-for-profit organization, published a valuation study for distributed solar generation in Rhode Island. The study, which used a methodology similar to that in the Maine study, found that the value of solar exceeds the average retail rate in Rhode Island. The Acadia Center Rhode Island Value of Distributed Generation report is Exhibit AC-5 to the Acadia Center's November 23, 2015 testimony.

Figure 2: Rhode Island 25 Year Levelized Value of Distributed Solar



Note: Where appropriate, avoided reserve capacity costs, transmission and distribution losses, and a wholesale risk premium or price hedge are included in the calculations.

Appendix C

Recommended Reading and References

Interstate Renewable Energy Council (IREC), "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," available at: http://www.irecusa.org/publications/.

Maine Public Utility Commission, "Value of Distributed Solar Energy Generation," available at: http://www.maine.gov/mpuc/legislative/archive/2014-2015ReportstoLegislature.shtml.

Karl R. Rábago, "Rethinking the Grid," Building Energy Magazine, available at: https://www.dropbox.com/s/7iv4wq5ky66vh51/Rethinking%20the%20Grid%20BEMAGS15_rabago%20150217.pdf?dl=0

Environment America Research and Policy Center, "Shining Rewards," available at: http://www.environmentamerica.org/reports/amc/shining-rewards.

Pace Energy and Climate Center, "Value of Solar Center of Excellence." Pace maintains a public website with more than 250 references relating to Value of Solar, available at: http://voscoe.pace.edu.