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Prepared Direct Testimony of
Bruce E. Biewald
On Utility Distribution Company Rate Design

On Behalf of
The Utility Reform Network
Utility Consumers Action Network
Natural Resources Defense Council

Synapse Energy Economics, Inc.
22 Crescent Street, Cambridge, MA 02128

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Attachment 1 Resume of Bruce E. Biewald

I INTRODUCTION AND SUMMARY

This testimony was prepared by Bruce E. Biewald on behalf of The Utility Reform Network, Utility Consumers Action Network, and the Natural Resources Defense Council. Mr. Biewald is president of Synapse Energy Economics, Inc., 22 Crescent Street, Cambridge, Massachusetts. Mr. Biewald's resume is attached to this testimony, and further information about Mr. Biewald's experience and Synapse is available on the Company's web site (www.synapse-energy.com).

This testimony addresses specific rate design issues that pertain to the installation of distributed generation (or "DG") in a utility distribution company's (or "UDC") service territory. The purpose of this testimony is to encourage reasonable ratemaking and rate design policies that will promote (or at least not hinder) appropriate installation of clean, on-site distributed generation as alternative to other customer supply options, and that will promote clean targeted grid-side distributed generation as an alternative to distribution system upgrades or expansions where more cost-effective.[1]

Rate design policies should give distribution utilities and customers the incentive to explore all possible options and tools for meeting distribution and power supply needs. Although existing rate design policies have emerged through years of proceedings and have been generally designed to ensure that distribution customers are well served by distribution utility companies, they must be adapted to address existing circumstances and technologies. Failure to modify existing incentives and disincentives pertaining to distributed generation will result in outdated distribution systems that do not take advantage of recent technological improvements. Rate design policies should promote and reward innovation and creativity in the application of new and emerging technologies, both for the utility distribution company and for retail customers, in a manner that benefits all distribution customers.

[1] This testimony includes proposals that apply to distributed energy resources generally and distributed generation specifically. Although the focus is on distributed generation, distributed energy resources should be addressed to the extent that they are similarly affected by various interconnection and policy issues.

In particular, this testimony recommends that rate design policies should foster rather than hinder opportunities for reducing use of grid electricity where such reduction results in benefits such as lower cost distribution service for all customers, improved customer supply options, and lower environmental impacts. Thus, I recommend the adoption of revenue cap performance-based ratemaking policies that leave the distribution utility company neutral to reductions in throughput. I also recommend usage-based distribution rates that provide an incentive to customers to reduce their usage. Finally, I recommend that rate design policies should compliment the utility distribution company's planning process, offering an opportunity and incentive to customers and distributed resource vendors to respond to distribution identified distribution system needs.

Section II describes an appropriate goal for rate design policies. Section III identifies certain principles that should underlie the development of rate design policies to achieve the stated goal. Section IV discusses specific rate design policies. Finally, Section V provides the conclusion to this testimony.

II GOAL

To ensure that rate design policies contain appropriate incentives for distributed resources ("DR") as a viable supply option for customers and for distributed resources as a viable distribution system component for distribution utilities, and enable non-participant ratepayers to benefit from the installation of DG in the distribution territory.

Rate design policies will determine whether distribution utilities and retail customers incorporate efficiently distributed resources into their decisions on distribution system expansion and supply options, respectively.

The question is not whether DR can offer value as a component of a distribution system or as an alternative to other supply options. Distribution utilities recognize the potential value of distributed resources. For example, both PG&E and SDG&E have stated that distributed generation can serve a distribution function (SDG&E Phase 1 Testimony at 20-34; PG&E Phase 1 Testimony, chapter 2, at 22-27). However, both are careful to state that the value of distributed generation to the distribution system is contingent upon locational, temporal, and capacity consistency with an identified distribution system need, and upon physical assurance (Id.). PG&E goes further to identify the types of distribution deficiency where distributed generation has the highest likelihood of being a valuable alternative to a distribution system wires upgrade or expansion. In addition, DG offers customers a certain alternative to grid-supplied energy; an alternative that can be appealing on economic grounds and/or on other grounds including reliability or power quality.

The important questions to consider are:

1. *Do ratemaking policies contain incentives that hinder application of distributed resources where it can bring benefits to customers either as distribution system users or as retail supply customers?*
2. *What ratemaking policies ensure that customers, as retail electric consumers and as users of the distribution system, will derive maximum available benefits from application of distributed resources?*

The remainder of this testimony seeks to answer these questions.

III PRINCIPLES

Appropriate ratemaking policies will conform to the following principles:

Provide proper price signals to promote efficient use of the distribution system and encourage on-site DR as a cost-effective alternative to customers' other retail supply options. Price signals must be accurate and useful to retail customers.

Equity among customers. Ratemaking and rate design should not result in cost shifting between customers who install DG and those who don't. Although the benefits of DG need not be allocated equally across ratepayers, all consumers should ultimately realize some benefits, or at least be no worse off, even when the adoption of DG is concentrated in particular customer classes.

Render the utility distribution company indifferent to customer installation of DG. A utility distribution company should not have an incentive to discourage retail consumers from installing on-site distributed generation where such distributed generation is an economic alternative to other available sources of energy supply. Utility distribution company revenue should not be tied to maintaining or increasing energy transactions across the distribution system; the link between revenue and throughput should be broken.

Enable the utility distribution company to benefit from efficient incorporation of DR into distribution system planning and operation. A utility distribution company should have an incentive to explore innovative technology applications, such as distributed generation, as a means of providing distribution service to distribution customers. Performance measures and the ability to derive financial benefit from the installation of distributed generation in place of more costly wires installations should be incorporated into a distribution utilities' performance-based ratemaking plan. Utilities should not have a financial incentive to prefer their own capital investments to contractual obligations with customers or 3rd party DR providers.

Recognize necessary conditions for distributed generation to fulfill a distribution function. Such conditions include coincidence of location, size and timing with identified distribution system capacity expansion, physical assurance, and firm sequential restoration arrangements.

Require the creation of a transparent planning process without imposing unnecessary procedures and excessive regulatory intervention. Utilities should be rewarded for DR utilization that results from a transparent planning process. Transparency is critical to the goal of providing opportunities for non-utility parties to innovate and approach the UDC with cost-saving alternatives to traditional distribution system investments.

Allow competitive forces to be brought to bear in the implementation of distribution utilities' system planning and operation. To the extent feasible, distribution utilities should rely on competitive procurement of distributed generation services rather than case-by-case selection of such services. Absent a competitive process for considering alternatives, it will be difficult for ratepayers or regulators to determine whether the utility is selecting the lowest-cost resource.

Support clean resources, other factors being equal.
There is great variability in the environmental impacts of the various distributed resources. Many of these differences, especially in air quality, should be addressed through air quality regulations to ensure comparability between large and small generators. Nevertheless, the Commission should ensure that the relative environmental impacts of the various distributed resources are considered in the planning and ratemaking process. For example, some customer-side renewable generators that are environmentally benign should be treated as demand reductions in order to encourage their reasonable deployment. When deciding between options that offer roughly comparable economic and reliability characteristics, the UDC should give preference to the generator that is environmentally superior.

IV RECOMMENDED RATE DESIGN POLICIES

To achieve the goal, in a manner consistent with the above principles it is necessary to address incentives for the utility distribution company, incentives for customer and third party installations, and translation of the planning process into useful signals. Policies must be very carefully considered particularly in these early stages of implementation of distributed generation. Distributed generation is a fairly new arrival to the retail electric industry and its value to customers, distribution utilities, and transmission utilities has not been fully explored or determined. Thus, it is important the ratemaking and rate design policies encourage rather than hinder exploration of efficient applications of distributed generation and other DR from an individual customer perspective, from a utility distribution company, and from a non-participant customer perspective.

A Rate design policies should give customers the incentive to consider alternatives to grid supply

(1) Volumetric distribution rates

In order for distribution rates not to constitute a barrier to consideration of alternative supply options for customers, distribution rates should remain usage-based (volumetric) average distribution rates. Such rate design offers customers useful price signals, as they are able to modify their usage through load reduction, energy efficiency and load management. In recent years, there has been some effort to increase the proportion of distribution costs that are collected through fixed customer charges. For example, some utility distribution companies in California are seeking large fixed customer charges.[2] This trend is alarming and detrimental to efforts to increase the degree of retail customer choice in energy services.

Retail customers, especially residential customers, are likely to see such a fixed price as a deterrent to modifying their electricity consumption in any way. While distribution charges are only one component of retail customer bills, charges of such magnitude are significant to retail customers. In addition, fixed charges would not accurately represent any individual customers' contribution to the peak load on the distribution system, which is one of the factors that drive costs of the distribution system. Finally, it is arguable whether fixed charges are consistent with cost causation on the distribution system over the long term. While a distribution customers load variations within a week or a month may not affect incremental costs of the distribution system, there's no question that load increases over the long term can result in increased distribution capacity needs.

[2] SCE has recently proposed a $17 per month fixed customer charge (Application of Southern California Edison Company for Post-Transition Rates, A.00-01-009, Filed January 7,2000).

(2) Other issues

Customer decisions will also be strongly affected by standby rates. While customers who rely on service from the distribution system should certainly pay appropriate costs consistent with their reliance on the system, standby rate policies should allow customers flexibility to choose different amounts of standby service and could include variations based on timing with appropriate provisions for physical assurance. Customers will also be influenced by other policies that would provide an incentive to install distributed generation in response to an identified distribution system need. These policies are discussed below in the section on distribution system certainty.

<u>B</u> <u>Rate design policies should give utility distribution company companies the incentive to maximize distribution customer benefits rather than throughput</u>

(1) Revenue Cap Performance Based Ratemaking

Rate policies that tie a utility distribution company's earnings to kilowatt-hour sales create an incentive to maximize kilowatt-hour sales. With prices at fixed levels (between rate cases in a traditional context, or with a price cap), profits are decreased by any decrease in sales. Thus a distribution utility company has a strong incentive to avoid and even discourage activities that result in reduced sales. Such an incentive is contrary to efforts to maximize customer choice of energy services (including load reduction and energy efficiency) and to reward utilities based on their performance.

A more appropriate rate design policy would include some form of revenue cap rather than a rate cap. A revenue cap will break the link between a utility's revenues and throughput on the distribution system, thus removing the financial disincentive to energy or load reduction activities. Revenue caps are based on the same general approach as price caps, but focus on allowed revenues rather than allowed prices. The regulatory commission begins by setting an allowed level of revenues based on actual costs for a test year. Over time, the allowed level of revenues can be adjusted to account for inflation and productivity, similar to price cap mechanisms. The fundamental difference between revenue caps and price caps is that the allowed level of revenues may change to reflect changes to sales levels. If revenues collected deviate significantly from those allowed, the difference would be returned to, or recovered from, ratepayers through periodic adjustments.

Revenue caps can be designed in a number of ways, and each will provide different incentives and signals to the utility. The primary difference between the types of revenue caps lies in how the allowed revenues are determined. In the simplest sense, a "total revenue" cap could be used to set allowed revenues at a level sufficient to cover costs in the first year, and then the allowed revenues could be adjusted in later years to account for inflation and productivity improvements. However, this approach does not account for the fact that a utility's costs can vary with the number of its customers. It is important for a utility to recover additional revenues when new customers are added to the system, and conversely, fewer revenues when customers are removed from the system.
To address the issue of customer shifts, a "revenue-per-customer" mechanism can be used, whereby the allowed revenues are adjusted over time, on the basis of the actual number of customers on the system. In other words, the utility is allowed to earn a fixed level of revenues for each customer on the system.

There are some drawbacks to the revenue-per-customer approach. The primary concern is that it can shift certain risks from the utility to the ratepayers. Under traditional ratemaking (and price caps) if electricity sales decline due to weather or economic cycles, the utility bears the burden in terms of lower revenues. Similarly, if sales increase from weather or the economy, the utility benefits from the additional revenues. However, under a revenue-per-customer revenue target the utility would still recover the allowed revenues, through the reconciliation process, because the number of customers has not changed. Hence, the ratepayers would bear the risks of sales swings that have traditionally been born by utilities. Another concern about the revenue-per-customer approach is that if the level of sales per customer (i.e., the customer's energy intensity) changes over time, then a utility may be over- or under-compensated, relative to traditional ratemaking.

In either revenue cap design, a utility will be rewarded for innovative technological applications that reduce costs of providing service rather than rewarded for increased sales. Nevertheless, while a revenue cap eliminates the incentive to increase sales, it can provide an incentive to maximize the benchmark upon which the revenue cap is set. Thus a distribution utility could have an incentive to provide low initial estimates of the cost to upgrade the distribution system in order to prevent competition from distributed resources, but then include the higher actual costs of the upgrade in establishing the next PBR benchmark. Accordingly, the commission should take steps to reduce the potential for systematically padding the benchmark and for developing unrealistically low estimates of wires upgrade costs.

One option for the Commission to consider would be to develop a mechanism that would hold the distribution utility company accountable for estimates of upgrade costs. For example, the Commission could require that the distribution utility make its estimate of the upgrade cost known to the Commission or to the public prior to implementing the upgrade or seeking a distributed resource alternative. Such a mechanism could preclude a utility distribution company from regularly including excess distribution system upgrade costs in the benchmark for the next performance based ratemaking ("PBR") mechanism when the actual costs of an upgrade exceed the projected cost of upgrade, against which DG options compete.

(2) Provisions for distribution certainty

Breaking the link between a utility distribution company's revenue and throughput addresses only one disincentive for installation of distributed generation. There are significant operational and planning issues associated with the potential uncertainty of distributed generation interconnected to the distribution system (such as responding to load fluctuation and ensuring adequate standby and system restoration capacity). An important policy for diminishing distribution utilities' resistance to distributed resources will include the development of standardized procedures to ensure operational certainty of distributed generation installations that provide distribution support services.

Efforts to facilitate the incorporation of distributed resources into distribution system planning and operation must address the significant issues associated with the potential uncertainties of distributed generation operation. In planning and operating their distribution system to meet accepted standards of reliability, distribution companies must consider the risks associated with various courses of action. Risk can be defined as the product of the likelihood of a particular outcome and the consequences of that particular outcome. Neither distribution utilities, who have primary responsibility for maintaining reliable distribution service, nor customers, who have come to expect a high level of reliability, will want to bear the consequences of a sustained outage. While the ultimate consequence would be a distribution system outage, inadequate or non-performance by a distributed generation installation could have lesser but still costly implications (e.g. additional capacity requirements or power quality reduction). Thus, a utility distribution company will favor "wires" solutions to distribution system constraints over distributed generation solutions unless there are adequate provisions to ensure that the distributed generation solution has a similar likelihood of success as the "wires" solution. Financial penalties to a distributed generation installation for inadequate performance may not be sufficient to overcome the consequence to the utility distribution company for the inadequate performance.

The requirement for certainty can and should be addressed. In parallel with rate design policies designed to provide incentives for distributed generation, it will be necessary to develop standard contract terms, such as physical assurance provisions, firm sequential restoration arrangements and requirements for maintaining operating records, to avoid uncertainties that would nullify the distribution value of a distributed generation installation. In addition failure to develop such policies will make impossible such policies as allowing flexibility in standby rate plans. The Commission should encourage and facilitate the development of such tools.

C <u>Rate design policies should reflect and compliment a transparent planning process</u>

Rate design policies can be used to translate information from the planning process into price signals that will expand the options for responding to identified and anticipated constraints on the distribution system. Proper rate design could enhance the effectiveness of planning and drive innovative and efficient solutions to identified needs. This is particularly important where a distribution or transmission company is required to meet established standards of system reliability. In the case of reliability planning, customers expect a specific level of reliability; their tolerance for interruptions has not been translated into price responsiveness. However, rate design could be used to encourage customer and third party actions where they would reduce the cost of meeting expected levels of reliability. Ratemaking policies and the planning process must be considered in tandem and must compliment each other for customers to be best served by the distribution utilities. Incentives for utility distribution company and customers will be ineffective if the planning process fails to generate price signals that will lead to appropriate DG deployments.

A sound planning process will incorporate consideration of distributed resources as an alternative to distribution system upgrades or expansion and will rely to the maximum extent feasible on competitive forces and customer response to achieve cost-effective maintenance and operation of the distribution system for retail customers. At a minimum, the planning process should identify opportunities where DR can serve a distribution support function and should allow for competitive procurement of DR services to the maximum extent feasible. In performing these functions, the planning process can serve as the basis for certain rate design policies that would maximize the benefits to non-participant distribution system customers by fostering non-utility responses to distribution system constraints.

In this time of transformation of the electric industry, it is not enough for distribution utility companies to assure the commission, customers and stakeholders that distributed resources are considered in the planning process. Rather there must be a transparent planning process that reveals how distributed resources are incorporated and allows an opportunity for competitive forces, and customer actions, to maximize the benefits of distributed generation to customers of the distribution system where feasible. A transparent process will establish clear understanding and expectations for stages of the planning process, frequency of the process, opportunity for participation in the process, and – most important for rate design – what information will be available to stakeholders. Without such transparency, stakeholders, regulators and retail consumers may not be confident that the utility distribution company is conducting an appropriate planning process in its customers' interest and they may request greater regulatory review. Furthermore, it will be extremely difficult to determine the least cost resource in the absence of information regarding the costs of alternative solutions available at the time.

While scrutiny of the planning process is necessary to ensure that it does indeed incorporate opportunities for reliance on cost-effective alternatives to wires solutions, it is not necessary to develop a process that would create excessive regulatory review and potential opportunities for delay. A transparent planning process, that establishes clear expectations for frequency, public information, and a process for third parties to offer competitive services to meet identified needs will minimize the need for regulatory intervention.

(1) The planning process should be transparent and provide useful information to stakeholders

Rate design policies that will enable a full customer response to conditions on the distribution system require a foundation of transparent distribution planning processes. In order for a planning process to be transparent, the essential components of the planning process should be understood by potential stakeholders and should be implemented in a consistent and predetermined fashion. The distribution planning process should identify areas where anticipated load patterns could require upgrades or expansion or where costs of distribution system could be reduced though modifying load patterns. These areas should be identified to customers and third-party distributed generation owners as areas where verifiable long-term load reductions are desirable. Rate design policies can be used to send appropriate signals to customers and distributed resource vendors. This identification should occur as far in advance as possible to allow enough time for 3rd parties and customers to plan DG installations and for the utility to be assured of distribution certainty.

Both SDG&E and PG&E have in place distribution planning mechanisms that follow generally the same steps of forecasting demands and distribution capacity, identifying constraints, and considering options for alleviating the constraints (PG&E Phase 1 Testimony, chapter 2 at 17-20; SDG&E Phase 1 Testimony at 22-26). Both processes provide for a case-by-case consideration of opportunities to incorporate DG in a distribution function (Id.).

The basic components of a transparent planning process should be as follows:

(1) Identify distribution-planning areas.
(2) Forecast annual peak demands for each area.
(3) Determine available distribution capacity.
(4) Compare forecast load to available capacity.
(5) Define the scope and characteristics of the distribution deficiency or identify area that may be good candidates for DG placement in five years. Defining the scope would include identifying such parameters as specific location, type of potential remedy (e.g. voltage support, capacity addition etc.), necessary time period, and magnitude of remedy (if capacity deficiency). In addition, the distribution utility company should identify the best "wires" solution to the constraint.[3]
(6) Identify capacity needs where DR may be a cost-effective solution. For example, PG&E identifies certain generic circumstances under which DG is likely to be cost effective (PG&E Phase 1 testimony, chapter 2 at 24-25). Such circumstances include: (a) minimal load growth with consistent seasonal peak demand; (b) small increases in demand that do not warrant lumpy wires solution; (c) geographically remote locations; or (d) time period too short for

[3] Identifying the best "wires" solution to the constraint would establish the option against which distributed resource alternatives would be evaluated. The "wires" solution could be identified in a sealed "bid" to the Commission, publicly as the option against which distributed resources compete, or through some other mechanism, and would serve as the basis for the locational credit described below.

wires solution. In addition, there may be circumstances under which the available lead-time offers an opportunity to explore DR options. For example, SDG&E states that final decisions to implement capacity projects are typically made 2 years prior to the in-service date on substation expansions, 1 year prior on circuit modifications (SDG&E Phase 1 testimony at 24).

(7) Seek DR applications to address capacity needs. Possible mechanisms include a standard competitive solicitation by the utility distribution company or rate design policies intended to trigger a non-utility response to a given distribution constraint. The UDC should be allowed to be innovative in soliciting alternatives.

(8) Select cost-effective solution to a distribution deficiency from all available options.

In order for regulatory intervention and review to be minimal during a planning cycle, there should be some mechanism for reviewing the distribution utility company's planning process, for example in the context of establishing or reviewing the utility's PBR. Such a review needn't be cumbersome or a formal proceeding; however, it would provide an opportunity for refinement of process, and would tap opportunities for improvement (bidder experience can be important source of improvement). The review would also be an opportunity for stakeholders to provide input between solicitations rather than reviewing a solicitation in progress. Improvements in the planning process, and in the process whereby distributed generation options are given a chance to serve a distribution function will shape the development of the distributed generation industry and will occur in tandem with improvements in DG applications and business practices.

(2) Rate Design tools

The planning components listed in the previous section are largely consistent with the planning processes that PG&E and SDG&E describe in their phase one testimony. The primary difference is that, rather than considering DR opportunities only on a case-by-case basis, the planning process would routinely include a step for explicit identification of potential opportunities for distributed resources and would rely on rate design as a central tool for soliciting a response to identified needs.

The process for addressing identified needs must allow for some flexibility and adaptation to changing circumstances. In addition, there may be situations, as the distribution companies have asserted, where conducting a competitive solicitation or fostering a non-utility response may not provide a timely response to an identified need. Nevertheless, these are not so much reasons for continuing to consider distributed resources on a case by case basis behind closed doors as they are for seeking innovative means of incorporating distributed resource solutions into distribution planning through competitive forces and rate design thereby expanding the set of potential solutions. Where an individual constraint can be identified with sufficient lead-time distributed resources should have a reasonable opportunity to remedy the deficiency for example, in response to a solicitation or price signals. However, the distribution utility company should also seek to minimize the administrative lead-time to bring distributed resources on-line through standardization, simplification of business practices and transparency. A transparent process will spur reaction and innovation in the distributed resources industry that will maximize the utility of distributed resources in distribution system support.

Steps 6 and 7 of the proposed planning process warrant further discussion, as they are the crux of the intersection between the planning procedure and the rate design policy. A distribution planning process should identify areas where anticipated load patterns could require upgrades or expansion or where costs of distribution system could be reduced though modifying load patterns or providing voltage support.

Once a utility distribution company had identified areas of potential distribution value from distributed resources, the utility distribution company could choose one of several mechanisms for seeking appropriate distributed resource applications. The mechanisms would identify to customers and third-party distributed resource providers areas where verifiable long-term or targeted load reductions are desirable. First, and most traditional, the utility could conduct a competitive solicitation for distributed generation or DR services. Beyond the competitive solicitation process, the PUC should establish rate design policies that foster a non-utility response to an identified distribution system need. In particular, the commission should consider the development of a locational credit mechanism and the establishment of distributed generation development zones.

(3) Competitive solicitation

Distribution utility companies should incorporate competitive elements in addressing any identified need of consequence. A competitive solicitation could result in a contract for distributed generation service rather than utility purchase of a distributed generation unit to the maximum extent feasible.[4]

A competitive solicitation need not be a labor intensive and time consuming process and would become increasingly efficient as utilities and non-utility respondents became increasingly familiar with the process. While a competitive solicitation process should be designed to ensure a vibrant response from competitors, distribution utilities have the expertise and are in the best position to determine the details of competitive solicitations. The Commission needn't be involved in developing the details, or in verifying the execution of the competitive solicitation; however, as discussed above, the Commission should ensure through periodic information gathering that competitive solicitations are indeed achieving competitive results and are fair. Finally, the level of Commission oversight would have to increase in the event a distribution utility company is permitted to own distributed generation units

(4) Locational credits

A locational credit mechanism would provide for a location- and time-specific sharing of cost-savings associated with distributed generation that serves a distribution function and avoids certain distribution costs. The Regulatory Assistance Project ("RAP") has proposed locational credits as a practical alternative to de-averaged distribution prices.[5],[6]

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[4] In phase 1 testimony, TURN provides some competitive reasons for avoiding distribution utility company ownership of distributed generation units.

[5] Regulatory Assistance Project ("RAP"), Issues letter, February 2000.

While de-averaged distribution prices to distribution customers would be impractical, particularly for residential customers, localized distribution credits would send useful signals regarding the value of installing and/or operating distributed generation at specific locations during specific time periods under the control and direction of the UDC. Deaveraged distribution pricing, by contrast, would force all customers in a constrained area to pay above-average rates despite the fact that only some would be able to alter their usage patterns to provide distribution system benefits. The broad parameters of a locational credit mechanism are described below.

A locational credit would provide a financial incentive to site new distributed generation in a particular area or to provide certainty regarding the operation of an existing installation in a particular area. The locational credit would be developed to address a unique constraint defined by location, time period, duration, capacity or operating characteristics, and other operational parameters (such as power quality or voltage levels). A utility distribution company would be able to place appropriate restrictions to achieve the intended distribution system result.

The location could be fairly broad (as in a traditionally high cost area) or could be quite small (as in a customer site) depending on the identified constraint. However, the location would be defined by specific elements of the distribution system (e.g. substation, substation transformer bank, or location on a feeder line). The locational credit could also be defined by temporal parameters including a specific duration (e.g. the credit would be available for 6 months) and/or by a specific period (e.g. time of day, time of week, or time of year). In addition, the locational credit would be available for a specific amount of capacity or operational characteristics.

[6] RAP has also proposed that variations of the deaveraged distribution credits could be a sliding scale standby rate or a hookup feebate. For example, standby rates could be on a sliding scale ranging from high to negative. Negative standby rates, which look like distribution credits to customers, would be charged in high-cost areas. A hookup feebate would be a revenue-neutral charge that collects from customers installing distributed resources in low-cost zones and pays customers who install distributed resources in high-cost zones. Id.

The magnitude of the credit would be proportional to the distribution value of the distributed generation where value is determined by costs that the utility distribution company would avoid due to the installation or operation of distributed generation to alleviate an identified constraint. The most obvious means of determining distribution value would be to evaluate the projected costs of distribution system upgrades or expansion that are identified in a distribution planning process. In the event that more distributed generation was available to remedy a particular constraint than was called for, competitive pressures could be used to reduce the magnitude of the credit. As part of its planning process, the utility distribution company should provide public notification of credits available where the lead-time preceding an investment decision would permit non-utility response from new or existing distributed generation. In some years there may be credits in multiple areas, in some years there may not be credits.

There may be other appropriate determinants of distribution value. For example, predictable and certain operation of distributed generation could avoid recurring maintenance or emergency costs incurred by the utility distribution company. In addition, analysis of data on sustained or momentary outages could be a useful indicator of distribution value for distributed generation installations (see e.g., PG&E Phase I testimony, chapter 2 at 8). Finally, distributed generation could have distribution value on portions of the distribution system where losses are typically higher than average system losses regardless of whether a utility distribution company operates its system to minimize losses. In order for the utility and customer to share the distribution value of the distributed generation, the credit to the customer would be some portion of the value with the remaining value accruing to the utility and ratepayers.

In order to ensure that distribution credits resulted in distribution value, eligibility for credits would be contingent upon making the appropriate commitment to distribution certainty as described above. Without such provisions, the distributed generation installation and/or operation would have no value to the distribution system, could receive money for no service, and could impose additional costs on the distribution system and thus on other distribution customers.

A locational credit system could only provide a useful price signal for the installation of new distributed generation in certain situations where avoidable distribution costs are high over an extended period and where the lead-time preceding an investment decision allows adequate opportunity for a non-utility response. However, locational credits could trigger a more rapid response from existing distributed generation units, factoring into the economics of operation, or for the temporary use of modular and mobile distributed generating units.[7]

(5) Distributed Generation Development Zones

Identification of distribution development zones could be a creative tool for a distribution utility company and could factor into the evaluation of a distribution utility company's achievement of service quality index measures under a PBR mechanism. A distributed generation development zone would be a finite area within which installation of distributed generation on the customer-side of the meter, with appropriate provisions to ensure distribution value, could defer the need for distribution system upgrade or expansion.[8] A distributed generation development zone would be different from a locational credit system in that it could serve as an early response mechanism where a constraint is likely to develop, but specific upgrades have not yet been identified. For example, a distribution utility company could identify development zones where it appears a constraint will emerge in the next five years.

The utility distribution company could assist distributed generation vendors in seeking customers for the installation of distributed generation[9] and could facilitate contracting. Alternatively, or perhaps in addition, customers installing distributed generation within that area would be eligible for specific distributed generation rate treatment such as sharing the costs of interconnection. The distributed generation rate treatment would

[7] The concept of locational credits may also be appropriate to spur demand-side response to a constraint. However, there are practical concerns that would have to be addressed.

[8] The Regulatory Assistance Project has suggested this concept in their February 2000 Issuesletter.

[9] In certain instances, for example where information on a distribution constraint could reveal competitively sensitive information regarding a customer, the utility distribution company could encourage that customer to contact distributed generation vendors, rather than vice versa.

depend on the nature of the distribution system constraint that led to the designation of the distributed generation development zone. For example, it may be appropriate to share interconnection costs between the distribution utility company and the entity installing a DG unit in a development zone when the utility determines that the DG installation will provide a distribution system support function.

Of course, this mechanism may not be useful to remedy a constraint that was modest in duration. However, installation of new distributed generation, with appropriate provisions to ensure distribution value, could be of significant value in areas of projected load growth.

(6) Customer charges for high reliability or power quality

There may be instances where an individual customer requires a higher level of reliability or power quality than is required by other customers in a distribution planning area or other specific location on the distribution system. In those cases, it would not be appropriate for other customers to pay for upgrades, expansion, or distributed generation services to meet an individual customer's service requirements. The distribution planning process should identify customer specific reliability or power quality enhancements so that appropriate charges may be assessed on the individual customer seeking this level of service. If the Commission decides to allow UDCs to acquire new DG units, then the placement of such units on or near a customer site to provide enhanced reliability should result in some charges assessed to the benefitting customer.

(7) Rate treatment for utility-owned distributed generation

As stated above, utility ownership of distributed generation units raises some competitive questions and would require a higher level of regulatory scrutiny of the distribution planning and competitive solicitation processes. Nevertheless, there may be limited instances where distribution utility company ownership of a certain type of distributed generation unit is appropriate. In those instances it will be critical for costs associated with those units be clearly identifiable in the accounting process for example, through placement in a discrete category in the FERC Uniform System of Accounts. The units should be included in the utility's rate base and subject to regulation. Further, net revenues from sales to the California PX should be credited to the distribution revenue requirement thereby benefiting all customers. The Commission should also explore ratemaking mechanisms that create proper incentives for efficient operation of the units, assign appropriate risk to the utility, and guarantee that ratepayers receive the maximum benefits from their use.

(8) Public Purpose Program Funding

The Commission has a long tradition of recovering system benefits investments in public purpose programs through usage-based electricity charges, which is reflected in at least two decades of electricity price regulation. The mandate of the Legislature in Chapter 854 of the Statutes of 1996 (Assembly Bill 1890 of the 1995-96 Regular Session of the Legislature) and Chapter 905 of the Statutes of 1997 (Senate Bill 90 of the 1996-97 Regular Session of the Legislature) continued this tradition and made the charge nonbypassable. These investments benefit all Californians and the collection of the public goods charge should remain non-bypassable.

Investments in energy efficiency funded from this usage-based charge help improve systemwide reliability by reducing demand in times and areas of system congestion, and at the same time reduce all California electric users' costs. They also significantly reduce environmental costs associated with electricity consumption. Renewables investments help alleviate supply deficits that could threaten system reliability, reduce environmental costs, and increase the diversity of the electricity system's fuel mix. Public interest RD&D investments are designed specifically to help ensure sustained improvement in the economic and environmental performance of the distribution, transmission and generation system, and end-use systems that serve California electricity users. Low income services investments reduce the cost of an essential service to low income customers and reduce bill defaults.

It is appropriate to apply this charge to all new on-site, generators (based on output) located on the customer side of the meter that provide power to offset the customer's consumption. Since the public purpose charges are levied on a consumption basis, only the output used to satisfy on-site demand would be subject to the charge. An exception should be made for the output of building-integrated PV systems and projects operating under the net metering tariff.

V CONCLUSION

In order to take advantage of new and emerging technologies, the Commission should encourage reasonable ratemaking and rate design policies that will promote (or at least not hinder) appropriate installation of clean, on-site distributed generation as an alternative to other customer supply options, and that will promote clean targeted grid-side distributed generation as an alternative to distribution system upgrades or expansions where more cost-effective. Rate design policies should promote and reward innovation and creativity in the application of new and emerging technologies, both for the utility distribution company and for retail customers, in a manner that benefits all distribution customers.

The proposals contained in this testimony are all intended to make progress toward the goal of ensuring that rate design policies contain appropriate incentives for distributed generation as a viable supply option for customers, and for distributed resources as a viable distribution system support element for distribution utilities, and that they enable non-participant ratepayers to benefit from the installation of DG in the distribution territory. Thus volumetric distribution rates are recommended as a mechanism to offer customers an incentive to consider distributed resources as an alternative to other retail supply options. Similarly, revenue cap PBR is recommended as a rate design mechanism to ensure that distribution utility companies do not have an incentive to oppose customer installation of distributed resources. Finally, the testimony discusses the importance of incorporating rate design tools into a transparent distribution planning process. A rate design mechanism such as locational credits will offer a distribution utility an important tool for ensuring that distribution system planning and operation take full advantage of available opportunities for providing distribution support service. Similarly, use of creative tools that may reduce costs in system planning and operation (such as designation of distributed generation development zones) can be evaluated and incorporated into PBR reviews.

Attachment 1

Bruce Edward Biewald

President
Synapse Energy Economics, Inc.
22 Crescent Street, Cambridge, MA 02138
(617) 661-3248 • fax: 661-0599
www.synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. President, 1996 to present. Consulting on issues of energy economics, environmental impacts, and utility regulatory policy, including electric industry restructuring, electric power system planning, performance-based regulation, stranded costs, system benefits, market power, mergers and acquisitions, generation asset valuation and divestiture, nuclear and fossil power plant costs and performance, renewable resources, power supply contracts and performance standards, green marketing of electricity, environmental disclosure, nuclear plant decommissioning and radioactive waste issues, climate change policy, environmental externalities valuation, energy conservation and demand-side management, electric power system reliability, avoided costs, fuel prices, purchased power availability and cost, dispatch modeling, economic analysis of power plants and resource plans, and risk analysis.

Tellus Institute, Boston, MA. Senior Scientist and Manager of the Electricity Program, 1989 to 1996. Responsible for research and consulting on all aspects of electric system planning, regulation, and restructuring.
Research Associate, later Associate Scientist, 1980 to 1988.

EDUCATION

Massachusetts Institute of Technology,
BS 1981, Architecture, Building Technology, Energy Use in Buildings.
Harvard University Extension School,
1989/90, Graduate courses in micro and macroeconomics.

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Expert testimony on energy, economic, and environmental issues in nearly seventy regulatory proceedings in two Canadian provinces, twenty four States, and before the Federal Energy Regulatory Commission.

Co-author of more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, and the National Association of Regulatory Utility Commissioners.

Papers published in the Electricity Journal, the Energy Journal, Energy Policy, Public Utilities Fortnightly, and numerous conference proceedings.

Invited to speak by American Society of Mechanical Engineers, International Atomic Energy Agency, National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Consumer Law Center, the Latin American Energy Association (OLADE), the Swedish Environmental Protection Agency (SNV), the U.S. Environmental Protection Agency, and others.

RECENT TESTIMONY

Illinois Commerce Commission (Docket No. 99-0115) – September 1999
Review of ComEd's nuclear power plant decommissioning cost estimates.

West Virginia Public Service Commission (Case No. 98-0452-E-GI) – August 1999
AEP and Allegheny Power restructuring, market power, divestiture of generation, electric system market price modeling, statistical analysis of comparable sales, and responsibility for stranded costs and gains.

Mississippi Public Service Commission (Docket No. 96-UA-389) – August 1999
Review of Entergy Mississippi, Inc. and Mississippi Power Company stranded cost filings, divestiture of generation, statistical analysis of comparable sales, responsibility for stranded costs and gains.

Connecticut Department of Public Utility Control (Docket No. 99-03-36) – July 1999
Connecticut Light and Power Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Connecticut Department of Public Utility Control (Docket No. 99-03-35) – July 1999
United Illuminating Company standard offer service, market prices for electricity and the influence of market power, simulation analysis of the New England electricity market.

Utah Public Service Commission (Docket No. 98-2035-04) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power.

Washington Utilities and Transportation Commission (Docket No. UE-981627) – June 1999
Cost savings expectations for the proposed merger of PacifiCorp and Scottish Power and assessment of whether the merger is in the public interest.

Federal Energy Regulatory Commission (Docket Nos. EC98-40-00, et al.) – April 1999
Horizontal market power and barriers to entry in consideration of the proposed merger of American Electric Power Company and Central and South West Corporation.

Connecticut Department of Public Utility Control (Docket No. 99-03-04) – April 1999
Market power, market prices, and simulation modeling as related to the application of United Illuminating Company for recovery of stranded costs.

Connecticut Department of Public Utility Control (Docket No. 99-02-05) – April 1999
Market power, market prices, and simulation modeling as related to the application of Connecticut Light & Power Company for recovery of stranded costs.

Maryland Public Service Commission (Case No. 8797) – January 1999
Simulation analysis of the ECAR market and projected market prices for electricity for estimation of Potomac Electric Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Case No. 8795) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Delmarva Power and Light Company's stranded generation costs and unbundled rates.

Maryland Public Service Commission (Cases Nos. 8794 and 8804) – December 1998
Simulation analysis of the PJM market and projected market prices for electricity for estimation of Baltimore Gas and Electric Company's stranded generation costs and unbundled rates.

Vermont Public Service Board (Docket No. 6107) – September 1998
Excess capacity, used & useful, and the economics of Green Mountain Power's purchase from Hydro Quebec.

Mississippi Public Service Commission (Docket No. 96-UA-389) – September 1998
Analyses of market concentration and market power, behavior of affiliated companies, need for an independent system operator.

California Public Utilities Commission (Application No. 97-12-020) – July 1998
Nuclear power plant decommissioning and radioactive waste disposal. Also, rebuttal testimony in August.

Federal Energy Regulatory Commission (Docket No. EC97-46-000) – June 1998
Affidavit on market power implications of the proposed merger between Allegheny Power System and Duquesne Light Company.

New Jersey Board of Public Utilities (Docket Nos. EX4120585Y, EO97070460, and EO97070463) – March 1998
Economic and environmental benefits of energy efficiency, including estimation of marginal air emissions from the PJM System. (Joint testimony with Nathanael Greene, Edward Smeloff, and Thomas Bourgeois.)

Vermont Public Service Board (Docket No. 6018) – February 1998
Excess capacity and the economics of Central Vermont Public Service Company's purchase from Hydro Quebec.

Public Service Commission of Maryland (Case No. 8774) – February 1998
Market power implications of the APS-DQE merger.

Federal Energy Regulatory Commission (Docket Nos. OA97-237-000 and ER97-1079-000) – January 1998
Market power in New England electricity markets.

British Columbia Utilities Commission – November 1997
British Columbia Hydro and Power Authority Wholesale Transmission Services Application.

Pennsylvania Public Utility Commission (Docket R-00973981) – November 1997
West Penn Power Company Restructuring Plan. Environmental disclosure, consumer education, and allocation of default customers.

Pennsylvania Public Utility Commission (Docket R-00974104) – November 1997
Duquesne Light Company Restructuring Plan. Environmental disclosure, consumer education, nuclear decommissioning, and allocation of default customers. Also surrebuttal testimony in December 1997.

Mississippi Public Service Commission (Docket No. 97-UA-496) – November 1997
Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing Construction of a Generating Plant in Jackson County.

Pennsylvania Public Utility Commission (Docket Nos. R-00973953 and P-00971265) – November 1997
Application of PECO Energy Company for approval of its restructuring plan and petition on Enron Energy Services Power, Inc. for approval of an electric competition and customer choice plan. Allocation of default customers.

Vermont Public Service Board (Docket No. 5983) – October 1997
Excess capacity and the economics of Green Mountain Power Company's purchase from Hydro Quebec. Also rebuttal testimony in December 1997 and supplemental rebuttal testimony in January 1998.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – September 1997
Joint petition for partial settlement of PECO Energy Company's proposed restructuring plan and application for a qualified rate order. Environmental disclosure, nuclear decommissioning and spent fuel.

Pennsylvania Public Utility Commission (Docket No. R-00974009) – September 1997
Pennsylvania Electric Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Pennsylvania Public Utility Commission (Docket No. R-00974008) – September 1997
Metropolitan Edison Company's Restructuring Plan. Environmental disclosure, customer education, and nuclear issues.

Indiana Legislature, Regulatory Flexibility Committee -- September 23, 1997.
Testimony on "Electric Industry Restructuring To Benefit Consumers and the Environment: Stranded Costs, Nuclear Issues, and Air Emissions."

Pennsylvania Public Utility Commission (Docket No. R-00973954) – June 1997
Pennsylvania Power & Light Company's Restructuring Plan. Environmental disclosure, customer education, PJM market structure, nuclear decommissioning and spent fuel, rate design for stranded cost recovery. Also, surrebuttal testimony in August.

Pennsylvania Public Utility Commission (Docket No. R-00973953) – June 1997
PECO Energy Company's Restructuring Plan. Environmental disclosure, PJM market structure, nuclear decommissioning and spent fuel.

New York Public Service Commission (Case 96-E-0897) -- April 1997
Consolidated Edison Company's Plans for Electric Rate Restructuring. Analysis of market power in the New York City load pocket.

Pennsylvania Public Utility Commission (Docket No. R-00973877) -- February 1997
Application of PECO Energy Company for Issuance of a Qualified Rate Order. Nuclear power plant decommissioning costs, stranded cost recovery, and securitization.

For a list of testimony prior to 1997 please see www.synapse-energy.com.

RECENT REPORTS

Electricity Market Distortions Associated With Inconsistent Air Quality Regulations, by Tim Woolf, Bruce Biewald, and David White for the Project for Sustainable FERC Energy Policy, November 18, 1999.

Avoided Energy-Supply Costs for Demand-Side Management Screening in Massachusetts, a Resource Insight report for the AESC Study Group, by Rachel Brailove, Paul Chernick, Susan Geller, Bruce Biewald, and David White, July 7, 1999.

Comments on the Scope of Issues for FERC Staff's Environmental Assessment of the Proposed Rule on RTOs by the Project for Sustainable FERC Energy Policy on behalf of Multiple Parties, prepared by Terry Black and Bruce Biewald, June 14, 1999.

Stranded Nuclear Waste: Implications of Electric Industry Deregulation for Nuclear Plant Retirements and Funding for Decommissioning and Spent Fuel, by Bruce Biewald and David White, January 15, 1999.

New England Tracking System, a report to the New England Governors' Conference, Inc., funded by a grant from the U.S. Environmental Protection Agency, prepared with Environmental Futures, Inc. and Tellus Institute, October 1998.

The Role of Ozone Transport In Reaching Attainment in the Northeast: Opportunities, Equity and Economics, a Synapse Energy Economics report for the Northeast States for Coordinated Air Use Management, by Tim Woolf, David White, Bruce Biewald, and William Moomaw, July 1998.

Competition and Market Power in Northern Maine Electricity Market, a Synapse Energy Economics report for the Maine Public Utilities Commission, by Tim Woolf, Bruce Biewald, and Duncan Glover, November 24, 1998.

Grandfathering and Environmental Comparability: An Economic Analysis of Air Emission Regulations and Electricity Market Distortions, a Synapse Energy Economics report for the National Association of Regulatory Utility Commissioners, by Bruce Biewald, David White, Tim Woolf, Frank Ackerman, and William Moomaw, June 11, 1998.

Analysis of Market Power in the APS and Duquesne Service Territories, prepared for the Maryland Office of People's Counsel, by Bruce Biewald and David White, February 9, 1998.

Performance-Based Regulation in a Restructured Electric Industry, a Synapse Energy Economics report for the National Association of Regulatory Utility Commissioners, by Bruce Biewald, Tim Woolf, Peter Bradford, Paul Chernick, Susan Geller, and Jerrold Oppenheim, November 8, 1997.

Massachusetts Electric Utility Stranded Costs, a Synapse Energy Economics report for MASSPIRG, Union of Concerned Scientists, Clean Water Action, Massachusetts Citizens for Safe Energy, and Public Citizen, by Bruce Biewald, Tim Woolf, and Marc Breslow, November 4, 1997.

Horizontal Market Power in New England Electricity Markets: Simulation Results and a Review of NEPOOL's Analysis, prepared for the New England Conference of Public Utility Commissioners, by Bruce Biewald, David E. White, and William Steinhurst, June 11, 1997 (a draft was published as Vermont DPS Technical Report No. 39 in March, 1997).

Zero Carbon Electricity: The Essential Role of Efficiency and Renewables in New England's Electricity Mix, a Tellus Institute report for the Boston Edison Company Settlement Board, by Bruce Biewald, Tim Woolf, Bill Dougherty, and Daljit Singh, April 30, 1997.

Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information, a Regulatory Assistance Project report funded by the Pew Charitable Trusts, the Joyce-Mertz Gilmore Foundation, the U.S. EPA, and the U.S. DOE, by David Moskovitz, Tom Austin, Cheryl Harrington, Bruce Biewald, David E. White, and Robert Bigelow, March 1997.

Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests, for the Maryland People's Counsel, by Paul Chernick, Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise, February 20, 1997.

Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring, a report to the New England Governors' Conference, by Bruce Biewald, Max Duckworth, Gretchen McClain, David Nichols, Richard Rosen, and Steven Ferrey, Tellus No. 95-310, January 1997.

For a list of reports prior to 1997 please see www.synapse-energy.com.

RECENT PAPERS

Follow the Money: A Method for Tracking Electricity for Environmental Disclosure," Bruce Biewald, David White, and Tim Woolf, The Electricity Journal, May 1999.

Book Review of "U.S. Utility Mergers and the Restructuring of the New Global Power Industry," in *Energy*, October 1998.

"Implications of Premature Nuclear Plant Closures: Funding Shortfalls for Nuclear Plant Decommissioning and Spent Fuel Transportation and Storage," Bruce Biewald and David White, prepared for the United States Association for Energy Economics and International Association for Energy Economics, 19th Annual North American Conference, Albuquerque, NM, October 1998.

"Efficiency, Renewables and Gas: Restructuring as if Climate Mattered," Tim Woolf and Bruce Biewald, *The Electricity Journal*, January/February 1998.

"**Green Electricity: Tracking Systems for Environmental Disclosure**," B. Biewald and J.A. Ramey, proceedings of WINDPOWER '97, the American Wind Energy Association's annual conference in Austin, Texas, forthcoming.

"**Competition and Clean Air: The Operating Economics of Electricity Generation**," *The Electricity Journal*, January/February 1997.

For a list of papers prior to 1997 please see www.synapse-energy.com.

RECENT PRESENTATIONS

(Note: Presentations that were accompanied by a written paper are listed in the section for "papers," above.)

Presentation on "How Green is Green? Verifying Energy Advertising Claims," at the New England Conference of Public Utility Commissioners Symposium, Bretton Woods, New Hampshire, May 25, 1999.

Presentation on "Consumer Perspectives on Market Power – Case Studies from New England, New York, PJM, and Mississippi," IBC Conference on Market Power, Washington DC, May 24, 1999.

Presentation on "Grandfathering and Environmental Comparability," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on "Tracking Electricity in the New England Market," at the National Association of Regulatory Utility Commissioners 1998 Summer Committee Meetings, Seattle, July 26, 1998.

Presentation on “Tracking Electricity in the New England Electricity Market,” at the National Council on Competition and the Electricity Industry National Executive Dialogue on Customers’ Right to Know, Chicago, May 13, 1998.

Presentation on “Comparable Environmental Regulations in a Restructured Electricity Industry: The Grandfathering Effect,” National Association of Regulatory Utility Commissioners meeting in Washington, D.C., March 1, 1998.

Presentation on “Market Power in Electricity Generation,” National Consumer Law Center Conference, Washington, D.C., February 9, 1998.

Presentation on “Electricity Market Power in New England,” Massachusetts Electric Industry Restructuring Roundtable, Boston, December 15, 1997.

Presentation on wind power development and air quality, National Wind Coordinating Committee New England Wind Issues Forum, Boston, November 7, 1997.

Invited speaker on market power, National Association of State Utility Consumer Advocates meeting in Boston, November 12, 1997.

Presentation on “Distortions to Future and Current Competitive Electric Energy Markets Due to Grandfathering Environmental Regulations of Electric Power Plants,” National Association of Regulatory Utility Commissioners meeting in Boston, November 9, 1997.

Presentation on “Electric Industry Restructuring as if the Environment Mattered,” Boston Area Solar Energy Association, October 9, 1997.

Invited speaker on “Modeling Market Power in Electricity Generation,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 22, 1997.

Presentation on “Performance-Based Regulation in a Restructured Electric Industry,” National Association of Regulatory Utility Commissioners meeting in San Francisco, July 20, 1997.

Presentation on “State Initiatives and Regional Issues,” New England Governors’ Conference Workshop on Restructuring and Environmentally Sustainable Technologies, Warwick, Rhode Island, March 25, 1997.

For a list of presentations prior to 1997 please see www.synapse-energy.com.