UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

H. Edwin Overcast

New Hampshire Public Utilities Commission

Docket No. DE 16-384

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Director of Black & Veatch Management Consulting, LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for over 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission (FERC) on a number of electric, gas pipeline and oil pipeline issues.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION (THE COMMISSION)?

A. No.

Q. PLEASE PROVIDE A LIST OF STATE AND CANADIAN JURISDICTIONS IN WHICH YOU HAVE TESTIFIED.

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas, Maryland, and Arizona. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board, The Régie de L'énergie and the British Columbia Utilities Commission. I have also testified before the FERC on electric, gas and oil pipeline matters. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition, cost and rates for net metering and rate unbundling. I have also testified before state and federal legislative bodies.

Q. DURING YOUR CAREER HAVE YOU MADE PRESENTATIONS TO ENERGY RELATED TRAINING AND OTHER PROGRAMS?

A. Yes. I have been an instructor for the Edison Electric Institute (EEI) Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor for the American Gas Association (AGA) Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the Association of Edison Illuminating Companies (AEIC) Load Research Committee, the Society of Utility and Regulatory Financial Analysts (SURFA), the Solar Electric Power Association (SEPA) and other industry sponsored programs. I have made presentations to the National Association of Regulatory Utility Commissioners (NARUC) events and events sponsored by academic institutions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. There are multiple purposes for my testimony as follows:

1. I provide the theoretical and conceptual background for the preparation and application of the cost of service for utilities.
2. I discuss the critical concept of cost causation that underlies the development of cost of service allocations for utilities.
3. I present the results of an embedded cost of service study that I recommend as the most appropriate method for Unitil Energy Systems Inc. ("Unitil Energy" or "the Company").
4. I present the results of a marginal cost study for Unitil Energy and explain why I that cost study should not be used to allocate the Company's revenue requirements to its classes of service.
5. I make recommendations related to the use of unbundled customer, demand and energy components in the Company's cost of service study for establishing certain components of a modern, 21st century rate design.

6. I make recommendations related to the use of a cost of service study for allocating the Company's revenue deficiency among its classes of service and establishing certain components of a sound, contemporary rate design.

7. I provide the theoretical and conceptual background for developing a sound rate design for a utility.

8. I propose rate designs for use by Unitil Energy in this filing and recommend the transition to a fully unbundled rate design in its future rate proceedings.

9. With respect to rate design, I also propose a new rate offering applicable to new[1] distributed generation customers who, by adding generation, have become partial requirements customers. I also propose that new outdoor lighting rates for LED fixtures be added to the Company's existing Outdoor Lighting (OL) Rate.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sixteen sections:

I. INTRODUCTION
II. EXECUTIVE SUMMARY
III. COST OF SERVICE TYPES, PURPOSE AND USE
IV. COST OF SERVICE AND ECONOMIC THEORY
V. PRINCIPLES OF COST CAUSATION
VI. DEVELOPING CLASSES OF SERVICE
VII. THE COST OF SERVICE PROCESS
VIII. DESCRIPTION OF THE CLASS COST OF SERVICE STUDY

[1] For customers that install distributed generation after the Company has reached its net metering cap.

II. EXECUTIVE SUMMARY

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. My testimony discusses the fundamentals of cost of service and rate design for utilities with particular attention to the principles of cost causation and matching as well as providing appropriate price signals. I explain why using a traditional embedded, average cost of service study to allocate a utility's revenue requirements among its classes is superior to using a marginal cost study that does not match the revenue requirements and is not a true reflection of cost causation (other than for growth at the margin). I discuss the foundation I used to design the Company's proposed rates and recommend that the rates as proposed be adopted by the Commission. I discuss the need to develop 21st century rate designs that include multi-part rates for all customers, but I do not recommend that ratemaking approach at this time for the Company's domestic and G-2 energy-only rate classes. I also recommend a separate class of service for all new Distributed Energy Resources (DER) customers based on a monthly customer charge and a distribution-related demand charge. Finally, I recommend rates for new LED lights that are much more energy efficient than existing comparable streetlights.

III. COST OF SERVICE TYPES, PURPOSE AND USE

Q. PLEASE DESCRIBE THE VARIOUS TYPES OF COST OF SERVICE STUDIES THAT MAY BE USEFUL FOR RATE DESIGN AND THE ALLOCATION OF REVENUE REQUIREMENTS.

A. In general, cost of service studies may be based on embedded costs or marginal costs. Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period), the estimated book value of costs for a forecasted test year or some combination of actual or forecasted costs. In this case, the test period for the cost of service study is an historical period consisting of the twelve months ended December 31, 2015. The test period is adjusted for known and measurable changes and is normalized and annualized. The total cost of service used for the cost of service study is also used to determine the Company's total revenue requirements. Typically, embedded cost studies are used to allocate a utility's revenue requirement between jurisdictions and classes of service and between customers within a class. In addition to providing information related to the allocation of revenue requirement changes among customers, the cost of service study provides valuable information for rate design purposes. The fully unbundled cost of service study I recommend for use in this proceeding provides the fully allocated costs for each of the various services provided by the utility. These unbundled service costs are increasingly important in rate design based on the customers' ability to choose to use particular utility service(s) in combination with other competitive market services. The customers' ability to choose utility services fundamentally changes the end-use load characteristics for those customers, but does not change the embedded (or even the marginal cost) of some services the utility provides.

Marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels. Marginal cost studies are forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost is also important for determining optimal seasons and time-of-use (TOU) periods when designing TOU rates.

Q. PLEASE DISCUSS THE ACCOUNTING COSTS USED TO DEVELOP EMBEDDED COST OF SERVICE STUDIES.

A. The accounting cost used in a utility's cost of service study represents the costs for the test year or for the most recent period available. Test years differ by jurisdiction and even by utilities in a jurisdiction. Historically, the most common test year was an historical test year. The logic behind any historical test year is that it represents a reasonable forecast of costs and revenues for the "Rate Effective Period." The Rate Effective Period is defined as the twelve months after the effective date of the utility's new rates. Subsequently, historical test years are subject to normalizing and annualizing adjustments to reflect normal weather[2] and the annualization of expenses to reflect payroll and other cost changes. Additionally, historical test years are normalized and annualized and subject to pro-forma adjustments to reflect known changes that would occur after the test year, but before or during the Rate Effective Period. Each of these adjustments represented improvements to the historical test year as a forecast of the utility's total cost of service in the Rate Effective Period. A modern approach is to use a complete forecast of the costs during the Rate Effective Period. As an element of the cost of service analysis, the future test year better satisfies the "Matching Principle" of rates and costs than any form of historical test year. Regardless of the accounting basis for the cost of service study, the unbundled class cost results provide important guidance for the class allocation of revenues and the level of specific charges that taken together create just and reasonable rates.

Q. PLEASE EXPLAIN THE VARIOUS PURPOSES OF COST OF SERVICE STUDIES.

A. Embedded cost of service studies may be used in regulatory proceedings in a variety of ways as follows:

1. The cost of service study may be jurisdictional to split costs between regulatory jurisdictions such as wholesale and retail or between regulated services and non-regulated services.

[2] It is my understanding that New Hampshire does not weather normalize sales for ratemaking, although that is a common adjustment.

2. The cost of service study may be a class of service cost study within a single jurisdiction and be used to allocate costs among the different rate classes or even to allocate costs within a rate class. In this application, the cost of service study may serve as the basis for determining the allocation of additional revenue requirements among classes or even to allocate no revenues or reduce revenues from a class of service.

3. The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within a class and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable.

4. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates when charges for specific services (i.e., unit costs) are calculated as part of the cost study.

Q. PLEASE EXPLAIN HOW EMBEDDED COST OF SERVICE STUDIES CAN BE USEFUL IN DEVELOPING JUST AND REASONABLE RATES.

A. Just and reasonable rates must avoid undue discrimination and must reflect the principle of user pays, which is the functional equivalent of those who cause the costs should pay the costs. Undue discrimination occurs when similarly situated customers receiving the same service pay different amounts for the same service. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. I say "on average" because the cost of a service line may vary for two different customers based on the side of the street where the customer premise is located relative to the location of the transformer that serves the customer. This would occur where the customer located on the side of the street with the pole and transformer has a shorter service line than the same customer across the street, even if the premise set back is the same. Thus, it is appropriate to base the cost for services on the average cost for each premise. If those costs are not properly recovered in the monthly customer charge, the customers who use more than average energy consumption within a class subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess rates to determine if they are just and reasonable and do not discriminate based on the particular rate structure.

Q. DOES THE COST OF SERVICE STUDY PLAY A ROLE IN DEVELOPING ECONOMICALLY EFFICIENT RATES?

A. Yes. In order for rates to be efficient, the concept of customers being charged for the distinct services they use is important since different customers use different services even if they are in the same class. For example, an all-electric customer may use the same level of electricity in the summer as an air-conditioning customer, but uses much more energy and requires a greater level of distribution capacity in the winter. That added distribution capacity costs much less per unit of capacity than the summer capacity requirement because of scale economies in distribution. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates as does marginal cost analysis.

Q. ARE MARGINAL COST STUDIES USEFUL FOR ALLOCATING A UTILITY'S REVENUE REQUIREMENTS?

A. No. Marginal cost bears no relationship to the costs that comprise the utility's revenue requirements. Marginal cost cannot reflect the fundamental nature of the utility's sunk costs because it assumes current technology; it assumes current input prices; and it assumes only incremental capacity requirements. The utility's revenue requirements are based on investment in different technologies at the time of the investment. Those same sunk costs represent decisions made based on different relative input prices and represent the total capacity of the system. Marginal costs only reflect cost causation for growth at the margin. Since marginal costs do not equal embedded costs, any allocation must adjust the marginal cost to match the utility's revenue requirements. Theoretically, the adjustments should be made using the concept of Ramsey Pricing that says the extra revenue should be recovered from the least elastic classes and the least elastic rate components. That process is exceedingly complex when one understands that end-use applications in a class likely have different elasticities based on competitive options. While it would be a relatively safe assumption that the monthly customer charge is the least elastic component of any rate structure and that the residential class may well be the least elastic class of service overall, there is no intuitive reason to believe that allocating a larger share of revenue requirements based on marginal costs would be perceived as just and reasonable by customers. The economist and former regulator Alfred Kahn reaches this same conclusion when he states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[3] He goes on further to conclude that, "For those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[4] Kahn concludes by noting, "The respective average historic cost responsibilities of the various classes of service plus proportionate contributions to overhead will most likely strike the various rate-payers as equitable and non-discriminatory."[5]

IV. COST OF SERVICE AND ECONOMIC THEORY

Q. PLEASE DISCUSS THE REASON THAT COST OF SERVICE STUDIES ARE USED IN THE UTILITY RATMAKING PROCESS.

A. Cost of service studies are a basic and necessary tool of utility ratemaking. A properly developed cost of service study provides a quantitative analysis to determine which customer or group of customers causes the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility's electric system, as well as the basic economics of its unbundled functional components.

The requirement to develop cost of service studies emanate from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs[6]. In

[3] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150
[4] P. 158
[5] P. 158
[6] Common costs occur when the fixed costs of providing service to one or more classes or the cost of proving multiple products to the same class use the same facilities and the use by one class precludes the use by another

addition, utility costs may be fixed or variable in nature[7]. Finally, utility costs exhibit significant economies of scale[8]. These characteristics have implications for both utility cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, either marginal or embedded, requires an understanding of the operating characteristics of the utility's electric system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. PLEASE DISCUSS THE IMPORTANCE OF DISTINGUISHING BETWEEN FIXED AND VARIABLE COSTS.

A. Utilities are relatively unique in the relationship they exhibit between fixed and variable costs. The only variable costs for Unitil Energy are the costs associated with providing Default Service including transmission charges. All other costs are fixed. The fixed costs represent the sunk costs of the utility to deliver capacity and energy and other services to customers. The portion of fixed and variable costs to the total cost of service varies among the utility's customer classes based on the types and quantity of the services used by customers. Large, high load factor customers usually have the highest percentage of variable costs to total costs. Residential customers as a class tend to have the highest percentage of fixed costs to total costs. This is relatively intuitive when you consider that residential customers use many more types of services than larger customers

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class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[7] Fixed costs do not change with the level of output, while variable costs change directly with the utility output. Most non-fuel related utility costs are fixed and do not vary with changes in load.

[8] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

including all of the distribution system from substations to primary, secondary and local facilities such as transformers, service lines and meters. For residential customers, fixed or sunk costs represent nearly 100% of the total cost-based revenue requirement that comprise Unitil Energy's base rates. Despite this high level of fixed cost, only 30% of residential fixed delivery costs are recovered in fixed charges under the Company's current rates. For G2 demand and G1 customers, all fixed costs are recovered in fixed charges.

As a practical matter, failure to recover fixed, demand related costs in fixed charges results in unreasonable outcomes for classes that are not almost perfectly homogeneous. This is particularly true when customers within a class are both partial and full requirements customers, thereby having unique end-use service requirements, or require different combinations of services from the utility. When fixed costs are recovered through variable charges, high load factor customers in a class subsidize low load factor customers in the class, large users subsidize small users in the same class and full requirements customers subsidize partial requirements customers. These subsidies are economically inefficient. Since kWh billing for smaller customers is no longer the only economic option for measuring electricity use, the issue of cross subsidy within a class may be partially resolved with cost-based rates that recover the cost for each service provided by the utility in separate rates, as will be discussed below. Cost-based rates for each utility service provided, serve to reduce or eliminate cross subsidies and also provide the utility with a reasonable opportunity to earn its allowed rate of return. This is particularly true when customers use different amounts of utility provided services

Q. PLEASE DISCUSS THE ECONOMIC THEORY UNDERPINNING COST ANALYSIS.

A. Economic theory holds that efficient prices equal short-run marginal cost. For an electric utility characterized by economies of scale, setting prices based on marginal costs will not produce adequate revenues, because marginal cost is below average cost. Stated another way, utilities are declining cost industries. Given the nature of rate cases, it is often hard to understand the concept of a declining cost industry, particularly when rates increase because of new capacity additions or other investments such as adding equipment to existing substations to meet load growth or replacing aging infrastructure to maintain reliable service. The fact that rates increase as a result of higher costs does not change the fact that from an economic perspective the electric industry is a declining cost industry. To understand this issue requires an understanding of the long-run average cost curve (LRAC). The LRAC assumes that all input prices are fixed as is the available technology. In the real world, we have inflation and changing technology as well as policy changes that impact costs. As a result, costs rise over time as the LRAC shifts upward with inflation, downward with changes in technology, and upward or downward with policy changes depending on their impacts.

Q. PLEASE CONTINUE.

A. Utilities must be allowed to collect revenues that are adequate to provide the utility a reasonable opportunity to earn a return of and on the assets used to serve customers. Since the utility could not achieve that objective with prices based solely on marginal cost, economists developed a theoretical approach to reconciling marginal cost-based prices with the revenue constraint. The theory of Ramsey Pricing discussed above resolves the revenue adequacy issue by suggesting that raising prices above marginal cost in relation to the inverse of the price elasticity of the product or service provided results in the least societal welfare loss from prices that differ from marginal cost. This means that under Ramsey Pricing (a form of differential pricing), customers' rates are increased above marginal cost until the rates produce adequate revenues. This concept has direct impact on rate design considerations particularly relevant for utilities where sunk costs (the fixed cost of the system) represent a substantial portion of the revenue requirement.

The theory of multi-part pricing suggests that it is possible to recover average costs from infra-marginal prices while setting the marginal price equal to marginal cost. Thus, the use of declining block rates permits efficient prices while recovering total revenue requirements. Other examples of efficiency-based rates includes the concept of fixed variable rate design where fixed cost recovery occurs through fixed charges (since fixed costs do not contribute to marginal cost) and variable charges recover variable costs.

The theory of pricing also requires a theory of class or service cost allocation. However, the existence of joint and common costs makes any allocation of costs arbitrary. This is theoretically true for any of the various marginal or embedded cost methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy free (in the economic sense) as long as the price exceeds marginal cost but is less than stand-alone costs (SAC).

Indeed, this theoretical discussion provides useful insight into the regulatory process where, as a practical matter, costs must be allocated between a utility's classes of service and within each class of service. For example, if the process of cost allocation results in rates that exceed SAC for some customers, prices must be set below the SAC but above marginal cost to assure that those customers make the maximum practical contribution to common costs. SAC plays a role in addressing issues such as discounting rates to retain customers with competitive service options. SAC represents an element of the allocation process for cost of service studies and is an alternative to the concept of fully allocated costs. Unlike other more conventional allocation methods, SAC relies on estimated replacement costs rather than actual costs.

Ultimately, a utility's cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. This latter constraint is often ignored when setting rates for a class of service because of a perceived conflict with the concept of fairness. Fairness, however, is an elusive concept that has been debated historically since the time of Aristotle. The medieval scholastics spoke in terms of a "just price" that essentially bore a relationship to the cost of producing the product without putting it in context of the value of the service. As a result, the guidance of the fairness concept cannot be of any help in addressing undue discrimination. Rather, we must rely on "who causes costs" and "how those costs are recovered within a class of customers" as the basis for determining rates that result from the utility's cost of service study.

Q. IF ANY ALLOCATION OF COMMON COSTS IS ARBITRARY, HOW IS IT POSSIBLE TO MEET THE PRACTICAL REQUIREMENTS OF COST ALLOCATION?

A. As noted above, it is a practical reality of utility regulation that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Under traditional embedded cost allocation, the process follows three steps: functionalization, classification, and allocation. This three step process underlies the determination of cost causation. By identifying the functions of utility service-production or generation, transmission, distribution, and customer for electric service- and the costs of these functions, the foundation is laid for classifying costs based on the factors that cause the utility to incur these costs - energy, demand, and customers. In the case of Unitil Energy, its cost of service study deals with essentially only the costs of the distribution function that will be reflected in base rates. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. If these factors properly reflect cost causation, the fully unbundled allocated cost of service study is a reasonable tool for use in assigning revenue requirements to each class of service and for determining the cost of each service provided by the utility.

V. PRINCIPLES OF COST CAUSATION

Q. WHY IS THE PRINCIPLE OF COST CAUSATION IMPORTANT?

A. Cost causation is the key element to selecting an allocation factor. This has been the standard by which an allocation method is evaluated and it continues to be the gold standard for assessing cost allocation. For example, The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has defined the cost causation principle as follows: "[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[9] The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on that definition, stating, "All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[10] It is not surprising that the D.C. Circuit sets the standard for this principle since they hear all of the appeals from the FERC and therefore would have more expertise related to these matters.

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[9] K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).

[10] Illinois Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009) (Illinois Commerce Commission) (citing K N Energy, 968 F.2d at 1300; Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 708 (D.C. Cir. 2000); Pacific Gas & Elec. Co. v. FERC, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Midwest ISO Transmission Owners); Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009); Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (Sithe); 16 U.S.C. 824d).

Q. HOW DOES ONE DETERMINE THE FACTORS THAT CAUSE COSTS?

A. In many cases determining cost causation it is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWh increases, does the cost of some input such as miles of conductor increase with more kWh? Since the miles of conductor do not change with kWh either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of that cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Q. IF THE CONCEPT OF CAUSATION IS AS SIMPLE AS YOU DESCRIBE, WHY IS THERE SO MUCH DEBATE ABOUT THE PROCESS?

A. First, the art of performing cost of service studies is often driven, not by logical analysis of cost causation, but by the outcomes the party is seeking to accomplish through regulation. As a result, the cost analyst may not be driven by the engineering and operating realities of a utility's system but rather by the nature of the analyst's preferred outcomes. Typically, for cost of service advocates, the preferred outcome is a lower allocation of revenue requirements to the customer(s) represented by that party. Second, some analysts use the cost of service process as a means to promote a particular policy objective such as discouraging a use of a particular service or promoting the use of some service. In some cases, it is as simple as the desire to capture benefits for some customer or group of customers at the expense of other customers. In any event the result is always lower costs and therefore rates for the preferred group. The utility has no reason to favor one group over another and seeks to match cost causation with rates.

Q. PLEASE DESCRIBE THE ALTERNATIVE MEASURES OF COST CAUSATION THAT ARE FUNDAMENTAL TO COST OF SERVICE.

A. There are three fundamental cost classifications that are the basis for cost causation: customer, demand and energy. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three factors. That is, a utility incurs costs based on the number, size and type of customers, a combination of several measures of customer demand or a measure on the energy used by customers. Within these three classifications there may be different measures of this factor based on how costs are incurred when allocation factors are developed. For example, customer meters have differing costs based on the size, type and complexity of the meter and associated equipment used to measure customer load. Thus, it is common to allocate meter costs to customers either by direct assignment where the meter investment can be determined directly for each customer class or by using a weighted customer allocation factor where the weights are determined by the relative costs of typical meters or meter installations.

Q. YOU NOTE THAT THERE ARE SEVERAL MEASURES OF DEMAND THAT MAY BE USED IN COST ALLOCATION. PLEASE EXPLAIN.

A. The demands used to develop allocation factors essentially fall into three fundamental categories:

1. Coincident Peak (CP) Methods
2. Non-Coincident Peak (NCP) Methods
3. Average and Excess Demand (AED) Methods.

Within each of these categories, there are numerous specific formulations of the allocation methods. Further, to reflect the costs of an electric system, a complete cost of service study requires application of more than one demand category for these allocation factors. For Unitil Energy the only issues relate to classification and allocation of distribution plant since base rates do not include production and transmission plant.[11] The choice of a demand allocation method relies on the concept of cost causation to choose the most appropriate method that reflects those costs. Transmission expenses are allocated using a CP method. NCP methods may use a variety of peak demands other than the actual system peak demand based on the peak demands of individual service classifications or individual customers. Cost causation requires the determination of the cost to serve each class of customers in a way that recognizes relative cost responsibility and reflects the engineering and operating characteristics of the utility's electric system.

Q. PLEASE DISCUSS THE USE OF ENERGY ALLOCATION FACTORS.

[11] Unitil Energy has transmission expense that must be allocated.

A. Energy allocation factors are used for variable costs that change with kWh consumption. In Unitil Energy's cost of service study, energy allocation factors have very limited use. Typically, energy-related costs include predominantly fuel and purchased power expenses. The energy allocation factors should ideally be based on seasonal and time of day components at the generation level, adjusted for losses associated with line losses for the voltage level of service. Where utility data does not support this preferred allocation method, the costs should be allocated on loss-adjusted energy consumption. For Unitil Energy, the energy cost allocator is used for a few expense-related cost elements that are fixed costs but where energy allocation represents a reasonable allocation method.

Q. PLEASE DISCUSS COST CAUSATION FOR THE ELECTRIC DISTRIBUTION SYSTEM.

A. The utility system's distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility costs are directly the result of the individual customer and are caused by the customer unrelated to its demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer, but utilities do not install every possible size of transformer. Basically, transformers, like other components of the utility system, are added in "lumpy" amounts. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies.

This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity. For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus transformer demand is related to the individual customer's NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer such as transformers, secondary conductor and poles and even single phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate cost allocation method. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductors. The substation-related investment is based solely on the class NCP allocation factor. In fact, any number of substations peak at different times and even during different seasons from the coincident peak demand of the utility.

Q. DO DISTRIBUTION COSTS DIFFER BY CLASS AND TYPES OF SERVICE?

A. Yes. Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require additional facilities to serve a load based on unique load characteristics. In that case, the customer may require special rate provisions such as a facilities charge to pay for the additional investment. When customers have common load characteristics (i.e., "homogeneous" load characteristics), they are grouped in the same class and served from the same rate. When load characteristics differ, customers warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics.

Q. YOU HAVE NOTED ABOVE THAT A PORTION OF DISTRIBUTION COSTS ARE CUSTOMER-RELATED. PLEASE EXPLAIN WHY CUSTOMERS CAUSE A PORTION OF DISTRIBUTION COSTS THAT ARE UNRELATED TO LOAD.

A. For distribution costs found in Account Nos. 364- 374 either all or a portion of the costs are customer-related because they are caused by the existence of customers on the utility's system. There is no rational basis for arguing that Account Nos. 369- 373 are not customers-related. For Account No. 369 - Services, each customer has a service designed to meet that customer's own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a single customer and each customer causes the cost of its service even if the customer never consumes any energy beyond that needed to light a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, that situation will result in unduly discriminatory rates unless that customer charge allows for the recovery of the service line costs and a portion of all the other distribution costs related to providing the customer with access to the utility's electric system. Even in that circumstance, the customer does not pay for the capacity components of the system it uses.

Q. PLEASE DESCRIBE THE OTHER FACILITIES NEEDED TO PROVIDE ACCESS TO THE UTILITY'S ELECTRIC SYSTEM.

A. Electricity will not flow into a customer premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition, Account Nos. 371-373 represents facilities that are also customer-related. In the case of these facilities, the customers who request the additional service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369- 373, a customer cannot be connected to the system and receive service without a minimum level of distribution services provided through the assets in Account Nos. 364-368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under the utility's current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

Q. WHAT OTHER COSTS ARE CUSTOMER-RELATED AND SHOULD BE INCLUDED IN THE CUSTOMER COST ALLOCATION?

A. First, a portion of the Operation and Maintenance (O&M) expenses associated with the distribution plant accounts that are allocated on both customer and demand are appropriately classified and allocated proportionately on a customer basis. In addition, where all of an account is allocated as customer-related, all of the O&M costs should also be allocated on a customer basis. Second, customer service related expenses should be fully allocated on a customer basis. Third, a portion of general plant costs should be allocated on a customer basis to include such items as customer service facilities and other types of facilities such as the meter shop, stores and tools and equipment. Fourth, a portion of Administrative and General (A&G) expenses should also be allocated on a customer basis. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but also pension and benefits cost and other items related directly to employee costs.

VI. DEVELOPING CLASSES OF SERVICE

Q. HOW ARE A UTILITY'S CLASSES OF SERVICE DETERMINED FOR USE IN COST OF SERVICE AND RATE DESIGN?

A. Historically, the use of fully bundled rates made it necessary to base classes of service on the principle of homogeneity.[12] Typically the basis for rate classes has included such elements as class of service - residential, commercial; end-use classification - residential regular, residential all electric; voltage level of service - secondary, single phase primary, three phase primary; quality of service - firm or interruptible; type of service - full requirements, partial requirements and so forth. Having customers with the same or similar usage characteristics allowed the relative simple fully bundled rate to track costs closely with a limited number of rate components such as a customer charge and an energy charge (also known as a two-part rate). The importance of homogeneity is lessened by the ability to unbundle and use separate rates for each service provided and to set charges for unbundled rates at the cost of service for each customer class. At some point the development of service classifications will rely less on classes of service and

[12] Composition from like parts, elements, or characteristics. Dictionary.com

more on the voltage level of service, the quality of service and the type of service being provided by the utility.

Q. PLEASE EXPLAIN WHY A UTILITY'S CLASSES OF SERVICE TRADITIONALLY USED TO GROUP CUSTOMERS IS NO LONGER USEFUL WHEN DESIGNING RATES ON AN UNBUNDLED BASIS..

A. Current rate designs were developed based on economic and technical constraints on the measurement of billing units. As these constraints erode with smart meters, the necessity for traditional classes of service is lessened. The more important change occurring in the electric market is the development of a mix of competitive service offerings and the continued monopoly status of other components of electric service. Where there is a mix of competitive and monopoly services in the market, the definitions of classes of service and the current rate designs must evolve to provide for more efficient markets and for rates to be just and reasonable and not unduly discriminatory. The first step in this process is developing fully unbundled cost of service studies that separate the costs for each service to provide a foundation for unbundled rates that track cost causation more accurately. This means that there would be separate rates for each service such as distribution to recover the costs for services provided at the secondary and primary level. Energy charges would recover the variable costs of the utility based on differences between seasons, time of use, voltage level of service and other considerations.

Q. PLEASE PROVIDE AN EXAMPLE OF THE DIFFERENT SERVICES THAT ARE CURRENTLY BUNDLED IN A UTILITY'S RATES.

A. A utility's current bundled rates include all of its functional components from production capacity and energy in the Default Service to a variety of delivery services bundled into a single inverted block delivery rate. Delivery service in this context may also include bi-directional power flows. Thus, a customer who acquires a competitive service offering such as solar photovoltaic (PV) distributed generation (DG) causing a substantial reduction or elimination in energy consumption and who pays only a nominal customer charge does not compensate the utility for the full level of costs it imposes on the system. For example, this customer must remain connected to the delivery system or must install excess generating capacity and on-site storage to have reliable service. Matching solar capacity to load capacity makes it impossible for the solar generation to start the customer's air conditioning motor loads without connection to the utility grid. The customer also needs frequency control from the grid, real time reserve, load balancing and delivery capacity for excess generation even if there is no net energy consumption. The customer with a solar PV system and no storage capacity must have standby service from the utility at to accommodate the times during the day when there is no solar PV service available to the customer and, obviously, that customer will also require utility service at night. The solar DG customer is also likely to require supplemental service when DG cannot meet the full load of the premise. There is no reason to believe that solar service will permit the utility to reduce its distribution costs as a result of solar DG and in fact, those costs may increase. A utility's traditional bundled rate cannot recover the actual distribution costs for these types of customers unless those costs are unbundled and billed separately. The Company's unbundled cost of service study that separates costs between services provides the basis for determining the level of these unbundled costs. This is just a partial example of unbundled service.

Q. HOW SHOULD CLASSES OF SERVICE BE DEVELOPED IN THE FUTURE BASED ON A UTILITY'S UNBUNDLED COST OF SERVICE?

A. It turns out that some of the same concepts that matter today will also matter even more in the future as costs derived by class of service are evaluated. The following list provides the major elements that will be used to develop a utility's rate classes:

1) Voltage level of service- secondary and primary for example
2) Size of load
3) Unique load characteristics and service attributes
4) End-use load characteristics.

The voltage level of service is necessary to reflect the cost of distribution facilities and the loss adjustments for both energy and capacity related costs at the point of delivery. The size of the load will be a driver of the appropriate customer related costs because of the higher total cost of local facilities for larger facilities and also lower unit costs for those facilities. Unique load and service attributes also impact costs. For customers that have unique service requirements, there will be a need to assure cost recovery for the specific facilities required to provide that type of service. Certain end use load characteristics must also be identified and managed such as leading or lagging power factor considerations or extra reliability requirements.

Q. SHOULD SOLAR PV CUSTOMERS BE INCLUDED IN A SEPARATE CLASS FROM OTHER CUSTOMERS?

A. Yes. As partial requirements customers, they have load characteristics that differ dramatically from full requirements customers. Among the differences, solar PV customers use the utility's delivery system differently.

Q. WHAT IS THE RATIONALE FOR INCLUDING PARTIAL REQUIREMENTS CUSTOMERS IN A SEPARATE CLASS FROM FULL REQUIREMENTS CUSTOMERS?

A. Under two-part rates, the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cost causative factors and the load characteristics were the same. Over time, the end use load profiles of residential customers have changed and electric rates evolved to reflect different load characteristics through declining block rates and through separate rate classes for different end-use residential loads such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and inverted rate designs and fewer special provisions made rates less cost-based as end-use load profiles continued to be more diverse because larger groups of customers were served under rates that were simple, but not capable of reflecting costs for less homogeneous groups. With the addition of partial requirements customers within a class, Unitil Energy's customers are no longer homogeneous, as the following table illustrates by comparing two identical premises with the same demographic characteristics:

Table 1
Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Demand	8 kW	8 kW
Annual Energy Consumption	21,024 kWh	21,024 kWh
Annual Billed kWh	21,024 kWh	7,708 kWh*
Load Factor-Delivery	30 %	15%

* Based on 21,024 kWh less the energy produced by an 8 kW Solar PV system operating at a 19% annual capacity factor.

From a cost perspective the delivery cost is the same for these two customers. The difference in cost recovery under the current Unitil Energy electric rates is calculated in Table 2 below based on the current local delivery component of the current rate alone.

Table 2
Delivery Service Subsidy

Billing Determinants	Partial Requirements	Full Requirements
Customer Charge	$123.24	$123.24
Energy Charge* Block 1 (<250 kWh) Block 2 (Excess 250 kWh)	 $102.12 $703.66	 $102.12 $183.83
Annual Bill	$929.02	$409.19
Billed Usage	21,024 kWh	7,708 kWh
Difference	$519.83	
Difference per installed kW (8kW)	$64.98	

*Priced using Distribution Charge only ($0.03404 kWh, $.03904 kWh); assumes DG energy netted from Block 2.

Table 2 shows that the annual delivery subsidy under current rates is about $65 per kW of installed solar capacity. This subsidy is based on equal treatment for equal cost causing delivery characteristics. It is not tied directly to a measure of the cost subsidy which may be even larger as a result of the inverted block rate where excess costs are recovered from the largest non-DG customers. In that event, the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings at all. That NCP may potentially result in even higher distribution costs associated with the class NCP for DG customers occurring at a later hour.

Q. ARE THERE OTHER ISSUES THAT MAKE THE SEPARATE RATEMAKING TREATMENT OF THE COMPANY'S DG CUSTOMERS NECESSARY IN THE CURRENT PROCEEDING?

A. Yes. The unequal treatment of customers who have the same costs, but provide very different levels of revenue to recover those costs, is a perfect demonstration of undue discrimination and that the Company's current rates are no longer just and reasonable. This is the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous. DG customers avoid paying a significant portion of the utility's fixed costs even though these customers continue to use the grid. Further, it is imperative to convert the two tiered energy rate to a flat kWh rate for all full requirements customers and to eliminate the net metering provision, as I will discuss below.

Q. WHAT RATE DESIGN DO YOU PROPOSE FOR THE COMPANY'S PARTIAL REQUIREMENTS DG CUSTOMERS?

A. I propose the use of a three-part rate to apply first to DG customers and ultimately to all customers. Using a three-part rate is actually consistent with the best practices approach to designing rates for DG as noted by a number of organizations, such as e-Labs of the Rocky Mountain Institute, which states: "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[13] This is consistent with the implied credit calculated in Table 2 above.

A report from the MIT Center for Energy and Environmental Policy Research states the following:

> "Allocating network costs primarily on the basis of volumetric energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: few price signals to incentivize optimal network utilization; cross-subsidization among network users; and business model arbitrage of rate structures."[14]

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[15] In a report prepared for EEI titled, "Retail Cost Recovery and Rate Design," Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> "To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence,

[13] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design
[14] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf
[15] Ibid. p. 16-20

> the customer never receives the economically efficient price signal for either one."[16]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and properly reflecting cost causation. Current two-part rate designs, as recognized by Unitil Energy, are inefficient and include subsidies. The subsidies under net metering with two-part rates create undue discrimination that needs to be addressed *today* in the current proceeding and not postponed or implemented under a phased approach over time that does little or nothing to address the problem over the coming years.

Q. PLEASE DISCUSS THE CLAIM MADE BY CERTAIN PARTIES THAT SEPARATE RATE TREATMENT FOR DG IS DISCRIMINATORY.

A. This is a common claim made by solar advocates who want to maintain the extremely favorable ratemaking treatment (and profitable marketing opportunity created by the current combination of net metering and largely kWh recovery of fixed costs) accorded to solar DG customers. The best way to address this claim is to analyze the meaning of discrimination within the context of utility regulation. The Merriam-Webster Dictionary defines discrimination as *the practice of unfairly treating a person or group of people differently from other people or groups of people and the ability to understand that one thing is different from another thing.* As applied to solar DG, and as discussed above, customers who become partial requirements customers are clearly different from

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[16] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26.
http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

full requirements customers, and in that sense the discrimination is not inconsistent with the basis for designing rates for homogeneous classes of service. While there may be reluctance for solar advocates to acknowledge that solar DG customers differ from full requirements customers, the reality based on the evidence is that this is precisely the case. Indeed, all DG customers differ from their class of service in different ways for each type of DG. The customers are different based on load characteristics and in terms of cost causation. The question becomes: Does singling out these customers for different rate treatment result in those customers being treated unfairly? The simple answer is no. This answer is supported by a review of the evidence as it relates to cost causation and the contribution of these customers to that cost compared to full requirements customers. This is an empirical question that requires nothing more than the basic analysis of whether the solar DG customers contribute the same revenues toward the costs they cause as other customers who have the same cost causative characteristics.

Regulatory policy is not required and in fact is prohibited from picking winners and losers when discrimination becomes undue. The goal of efficient regulatory policy is to develop a system of rates and charges for customers so that, as they choose between full and partial requirements services, the utility and its other customers are indifferent between those choices. Such a standard requires that the customers who choose different aspects of utility service pay the full costs of the services they do choose to use. It is unreasonable for a customer to use the same distribution services as another customer and pay approximately $520 less per year for that same delivery service.

Moreover, DG customers also impact the distribution system relative to VAR (volt-ampere reactive) requirements and reduced life for voltage regulation devices. These operating conditions serve as examples where additional costs may be incurred by Unitil Energy to satisfy these unique service requirements. As a result it is reasonable to conclude that the differences between full and partial requirements customers using solar DG are real, empirically verified and thus not discriminatory. It is also reasonable to conclude that separate treatment is a reasonable step to eliminate the rate discrimination that currently exists between solar DG customers and full requirements customers.

VII. THE COST OF SERVICE PROCESS

Q. PLEASE EXPLAIN THE THREE BASIC STEPS IN THE PROCESS OF DEVELOPING A UTILITY'S COST OF SERVICE STUDY.

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

A systematic process for identifying utility functions is used based on the traditional categories of production, transmission, distribution and customer. To the extent permitted by the accounting data, this functionalization process may include subcategories such as primary distribution and directly assigned plant investment based on unique facilities that need to be assigned to customers rather than allocated to classes of service. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts. That is not to say that all of the issues have been resolved. For some utilities, certain accounts such as intangible plant still require some level of analysis to functionalize individual cost elements included in this plant account. Cost classification is driven by as detailed an analysis of a utility's plant and expenses as the accounting data permits. Costs are classified as demand, energy and customer. Only costs that vary with energy are classified as energy. For Unitil Energy, energy costs are not part of a base rate proceeding but are recovered separately through the Default Service charge. The costs classified as demand are those costs that are a function of some measure of customers' demands. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be classified between the portion that is demand related and the portion that is customer related. That classification is based on the principles of cost causation, as discussed above. The functionalized and classified costs are then allocated among the Company's various rate classes.

Q. PLEASE DISCUSS THE APPLICATION OF THE THREE STEPS IN THE COST OF SERVICE STUDY.

A. Cost are functionalized and classified in the cost of service study based on data from the Uniform System of Accounts (USOA). Allocation is based on the factors that cause costs to be incurred.

Q. PLEASE EXPLAIN THE FUNCTIONALIZATION PROCESS IN DETAIL.

A. The process of functionalization requires determining the utility costs associated with each of the functions provided by the utility. The typical functions used in a cost of service study are as follows:

- Production or Supply (not applicable to Unitil Energy)
- Transmission (Unitil Energy has no transmission plant but does book some expenses)
- Distribution
- Customer service.

Each of these functions is described below.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power is also functionalized as production. This function is served under the Default Service provision of the rates and is not included in the Company's cost of service study. There is a minor amount of plant in Account No. 343 Prime Movers included in the cost of service study and is allocated on CP demand. In addition, there is small amount of cost in Account No. 557 Other Expenses included in the cost of service study that is allocated on energy.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load as I discussed above.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. Thus, it is common for the distribution system to be divided into sub-functions such as sub-transmission, primary and secondary. In addition, some distribution facilities serve a customer function and are further subdivided based on the type of facilities used by customer groups.

The customer service function includes plant and expenses associated with individual customers and include meter and service along with meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles. Once costs are functionalized, they must be classified based on customer, demand and energy. The classification step is critical to develop allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs, but the engineering and operation analysis of the system as it is planned, built and operated.

Q. PLEASE DISCUSS THE PROCESS OF CLASSIFICATION.

A. Costs are classified as demand, energy and customer. Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand. Energy costs are those costs that vary directly with the production of energy such as fuel cost; other fuel-related expenses or purchased power expense such as those recovered in the Company's Default Service. Customer costs are those costs that vary with number of customers such as meters and service lines. Some costs may be classified into more than one category. For example, some distribution costs may have both a demand and a customer cost component. Overhead conductor is a function of customers, because the miles of line required changes with customer density. That is, some portion of the system is directly related to the number of customers per mile of line. The actual size of line is related to either the class non-coincident peak demand for lines remote from customers or to the customer non-coincident peak for lines in close proximity to the customer. The difference in classification results from the increased level of diversity occurring in customer loads as facilities become more remote from the customer. In addition, the classification of costs also includes the fully loaded A&G costs associated with the plant and payroll portion of the accounts. That is, expenses such as post-retirement benefits associated with payroll dollars are classified in the same way as the underlying payroll expenses.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

A. Cost of service studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on actual data extracted from the utility's accounting and other records such as billing and load research data. The allocation of distribution system costs, both the demand and customer components use external allocation factors. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and is adjusted to equal system peaks. For some classes the peak data for the class comes from billing data and represents the sum of actual customer loads occurring at the system peak. As smart meter technology becomes available, the need to estimate the class load will no longer be necessary as meter data will be available for the population. Internal allocation factors (i.e., internally generated within the cost of service study) are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factor for property insurance costs is based on plant investment amounts assigned to each function; therefore it is necessary to compute the amount of plant by function before property insurance costs can be allocated.

VIII. DESCRIPTION OF THE CLASS COST OF SERVICE STUDY

Q. HAVE YOU PROVIDED A SUMMARY OF THE FUNCTIONALIZATION AND CLASSIFICATION OF THE COMPANY'S ACCOUNTS ACCORDING TO THE UNIFORM SYSTEM OF ACCOUNTS?

A. Yes. Attachment HEO-1 provides a summary of the functionalization and classification of each of the Company's plant and expense accounts. This summary provides an overview of the entire process underlying the Company's cost of service study.

Q. WHAT METHODOLOGY DID YOU USE TO ALLOCATE COSTS IN THE COMPANY'S COST OF SERVICE STUDY?

A. I used a CP allocation factor to allocate the transmission expenses and an NCP allocation factor for the demand portion of distribution plant. I also used a variety of other allocation factors that are identified in the cost of service study exhibits.

Q. PLEASE DESCRIBE THE COST OF SERVICE STUDY PRESENTED IN SCHEDULE HEO-2.

A. Schedule HEO-2 consists of six schedules that present the results of the embedded cost allocation study and include the following:

- Schedule 1 consists of 11 pages and represents the results of the class cost of service study for the test year. Each page contains an account description or label for the accounting data indicating the category of cost. The total jurisdictional amount for each account is also provided. Class rates of return and net income may be found on page 7. The revenue requirement for each class at the Company's uniform rate of return by rate schedule is also shown on page 9 of this schedule.
- Schedule 2 consists of 11 pages and provides the summary of account functionalization.
- Schedule 3 consists of 54 pages and summarizes the classification and allocation of the accounts.
- Schedule 4 consists of 84 pages and provides the allocation of each account by classification and by rate class.

- Schedule 5 consists of 27 pages and provides a summary of the allocation factors by account and function.
- Schedule 6 consists of one page and provides the unbundled unit costs for each rate schedule.

Taken together, these schedules provide the results of the embedded cost of service study.

IX. PRESENTATION OF THE CLASS COST OF SERVICE STUDY RESULTS

Q. PLEASE SUMMARIZE THE RESULTS OF THE RECOMMENDED COST OF SERVICE STUDY.

A. The following table provides a high level summary of the results of the Company's embedded cost of service study. Column (B) below provides the rate of return for each rate class based on current rates. Column (C) provides the revenue deficiency or excess for each rate class at the uniform system rate of return of 6.28% (at current rate levels).

Table 3
Rate of Return by Class

(A)	(B)	(C)
Rate Class	**Rate of Return by Rate Class**	**Revenue Excess or (Deficiency) in Million $**
Domestic	-1.54%	($12.1)
G2	28.49%	$5.4
G1	26.69%	$2.2

OL	-12.03%	($1.8)
Total System	6.28%	($6.3)

Q. WHAT INFERENCES MAY BE DRAWN FROM THESE RESULTS?

A. First, the only classes producing a negative rate of return are the Residential and Outdoor Lighting classes. All other classes are producing rates of return at current rates in excess of the system average rate of return actually requested in this case. This conclusion is used below to inform the allocation of the proposed revenue increase. The results are not uncommon in the electric industry, except that the magnitude of the subsidy that results in a negative rate of return on net rate base is lower than one typically expects to find for any class of service. I consistently recommend that embedded cost of service studies be used to allocate a utility's revenue requirements based on the sunk costs of the utility that must be recovered in its revenue requirements. As noted below, I recommend that marginal cost studies be used to inform rate design. In this case, nothing in the marginal cost of service study discussed below would cause a change in the allocation of revenues.

X. REVENUE ALLOCATION

Q. PLEASE EXPLAIN THE METHOD USED TO DETERMINE THE PROPOSED CLASS INCREASES IN REVENUE.

A. The revenue allocation was determined as follows:

1. Identify the classes of service that do not generate revenues to recover their allocated costs.

2. In recognition of the principle of gradualism, establish a maximum percentage increase for each class' total revenue for those classes identified in step 1 above.
3. Determine the allocation of the residual revenue requirement to the other classes.

Q. PLEASE EXPLAIN YOUR PROPOSED REVENUE ALLOCATION METHODOLOGY.

A. The concept of gradualism is typically assessed along two dimensions. The first and most common dimension for calculating the allocation of a utility's revenue requirements is to use a percentage of the proposed rate increase to act as a cap on the overall increase to individual customer classes that produce rates of return below the system average. The other dimension is the dollar magnitude of the rate increase to individual rate elements such as the demand charge or the customer charge. In the case of specific rate elements, it is not useful to discuss proposed changes on a percentage basis because a small increase applied to a low charge could be a significant percentage increase. A simple example will illustrate this point. If a new billing determinant is introduced, the current charge is zero, so setting the new charge at $0.01 would be an infinite percentage increase. Also, percentage increases for one charge may result in a reduction of another charge and the percentage increase does not reflect the full impact. As a result, both the percentage increase and the dollar impact serve as measures for gradualism.

Q. PLEASE DISCUSS THE GRADUALISM PROPOSAL AS IT APPLIES TO THE COMPANY'S CLASS REVENUE REQUIREMENT INCREASES.

A. After careful analysis and discussion with Unitil Energy, I recommend that the maximum increase for any class of service be capped at 1.25 times the overall proposed level of increase in the Company's revenue requirements. Typically, this would be the lower end of a gradualism measure, and 1.5 times would be the upper-end. That increase would be applied only to classes below the required rate of return. In this case those classes are the residential and outdoor lighting (largely streetlights) classes.

Q. PLEASE SUMMARIZE THE PROPOSED REVENUE ALLOCATION FOR EACH RATE CLASS.

A. Table 4 below shows the proposed increases by class of service in both percentage terms and the aggregate dollar increases.

Table 4
Proposed Revenue Requirement Increase by Class

Rate Class	Percent Increase	Dollar Increase
Domestic	15.09%	$4.0 million
G2	8.45%	$1.4 million
G1	8.45%	$0.6 million
OL	15.09%	$0.2 million
Total System	12.07%	$6.3 million*

*Totals may not add due to rounding

The class increases range from 8.45% to 15.09%. Although these revenue adjustments represent a gradual move toward cost of service for classes below the system average rate of return, the relative large disparity in the earned rate of return between the classes makes it impractical to make a major change in the relative rates of return in one rate case. It will be necessary for the Company to make further adjustments based on the application of fully allocated cost of service study results developed on a consistent basis as a reflection of cost causation over time to eliminate the large disparities in class rates of return.

XI. MARGINAL COST OF SERVICE STUDY

Q. WHY HAVE YOU PREPARED A MARGINAL COST OF SERVICE STUDY?

A. Marginal cost studies are useful for informing rate design particularly as it relates to customer and demand related costs for a utility that provides default energy services to retail customers who do not elect an alternate energy supplier.

Q. PLEASE DESCRIBE THE COMPANY'S MARGINAL COST STUDY.

A. Studies used to calculate marginal costs are part of rate case filings in some states and use relatively consistent methodologies. Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. Marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer or load on average. Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration customer density and the expected design loads of those customers. For example, an area with all-electric homes may have different design standards than an area where the homes are not electrically heated. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include: substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment, such as that required for all electric homes, is installed, the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

Q. HOW HAVE YOU IDENTIFIED THE MINIMUM SIZE COMPONENTS USED BY UNITIL ENERGY IN ITS DELIVERY SYSTEM?

A. Yes. We worked with distribution engineering and operations personnel at Unitil Energy to gain an understanding of the smallest standard size of facilities used. In addition, we worked with the Company's accounting function to determine the fully loaded installed costs of these components. Schedule HEO-3 provides the cost of the minimum system components. The cost of substation equipment was considered fully demand related. For primary system, transformers and secondary system, minimum system study was used to classify costs as customer-related or demand-related. Meters and services are considered entirely customer related. The schedule also provides the economic carrying charge rate for each plant component. This schedule produces the marginal revenue requirement for Unitil Energy associated with customer and demand related capital expenditures. The economic carrying charge rate uses Unitil Energy's marginal capital costs based on the current filing. The forward-looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis not on embedded costs.

Q. DID YOU IDENTIFY THE GENERAL PLANT RELATED TO THE MINIMUM SYSTEM?

A. Yes, I identified customer and demand related general plant based on average embedded costs as a proxy for long-run marginal costs

Q. WHY ARE AVERAGE EMBEDDED COSTS A REASONABLE PROXY FOR MARGINAL COSTS?

A. General plant costs do not vary directly with either demand or customers. That is the reason that in the allocated cost of service they are allocated on composite allocation factors. For example, customer growth only impacts the number of employees and therefore payroll expense when large discreet blocks of customers are added. If we used a pure marginal cost allocation factor, the payroll component growth related to customers or demand would be zero for a number of years and would be the full cost of a new employee only when the threshold number of customers requiring additional employees reached the tipping point in the level of services provided. By using an average cost value, the marginal cost study recognizes the contribution of each new customer to the future requirement of a new employee or new office space.

Q. HAVE YOU IDENTIFIED THE CUSTOMER RELATED EXPENSES?

A. Yes. The customer related expenses may be found in Schedule HEO-4, which presents the Company's full marginal cost study. These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short-run, these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. DID YOU IDENTIFY THE A&G COSTS RELATED TO THE MINIMUM SYSTEM?

A. Yes, I identified customer and demand related A&G costs based on embedded costs as a proxy for long-run marginal costs.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S CUSTOMER AND DEMAND COSTS ON AN EMBEDDED AND A MARGINAL COST BASIS.

A. The results are summarized in the table below.

Table 5

	Unit Customer Costs ($/Month)		**Unit Demand Cost ($/kW-Month)**	
Class	**Embedded**	**Marginal**	**Embedded**	**Marginal**
(A)	**(B)**	**(C)**	**(D)**	**(E)**
Domestic	38.84	40.99	5.69	6.44
G2	41.38	50.03	5.55	6.44
G1	184.46	182.95	5.54	6.40
OL	29.63	N/A	5.41	N/A

As the table illustrates, the residential customer costs calculated in both cost studies are significantly greater than the current facilities charge. Thus, a substantial facilities charge increase is warranted and consistent with the indicated cost of service. Increasing the customer charge and reducing the kWh charge is also consistent with both marginal cost pricing and achieving just and reasonable rates. The full results of the marginal cost study are contained in Schedule HEO- 4.

Q. WOULD THE PROPOSED ALLOCATION OF THE COMPANY'S PROPOSED REVENUE REQUIREMENTS DIFFER BASED ON USING MARGINAL COSTS INSTEAD OF EMBEDDED COSTS?

A. Any differences would not be material. With the cap based on gradualism as proposed, the end result would have been the same. Nevertheless, I believe that there is more long-term stability in embedded costs and it is more reflective of the cost causation principle, so I would have used the embedded cost of service study as a more reasonable alternative.

XII. RATE DESIGN PRINCIPLES

Q. PLEASE DESCRIBE THE PROCESS USED TO DESIGN RATES IN THIS CASE.

A. The rate design proposed in this case follows a multi-step process designed to produce economically efficient rates that provide a utility with a reasonable opportunity to recover all of the system costs. The process is based on the concept that it is the principles behind the development of the actual rates that make the rates effective in satisfying the often conflicting goals of rate design, and meeting the just and reasonable standard. The process we use is based on considerations developed by J. M. Clark,[17] as follows:

1. Rate design should be directed to rationally conceived goals and objectives.
2. Rate design should be based on a systematic and thorough analysis of the factors that impact the achievement of the goals and objectives.
3. Rate design should apply all necessary factors that can be identified as accurately as the available means of knowledge and empirical data will justify.
4. Rate design should recognize and conform to any factors required by practical conditions impacting the goals and objectives, even if those

[17] "The Possibility of a Scientific Electrical Rate System", American Economic Review-Proceedings, Vol. 27, March 1937, pp. 243-253

factors may not be deemed essential to the end view. Distinguishing those factors is important to identify potential obstacles to ideal results and as far as possible, find ways to provide tools to mitigate those obstacles.

5. Rate design should not push the pursuit of one end beyond what its relative importance justifies, just because that end can be treated by an attractive formula, and to disregard other ends that cannot be treated in the same way.

The process discussed above is useful because it requires the types of objectives spelled out by James C. Bonbright[18] in his criteria of a desirable rate structure, often cited by utility rate design experts. The Bonbright criteria, and in particular the three primary criteria of capital attraction, consumer rationing and fairness to customers,[19] are all sound objectives for designing a utility's rates. Each one has a basis in the principle elements noted throughout this testimony, including the opportunity to recover prudently incurred costs, economic efficiency and rates based on the principle that whoever causes cost should pay those costs. These principles are consistent with both the matching principle that requires rates to match costs during the rate effective period (the first twelve months after the rates become effective) and the principle of cost causation. I should also note that the reflection of cost causation has become much more important as classes have become less homogeneous and metering more sophisticated to allow measurement of the factors causing costs.

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[18] Principles Of Public Utility Rates, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, Public Utility Reports, Inc., 1988

[19] Ibid. p 385

Q. PLEASE DISCUSS THE STEPS TAKEN TO ASSURE THAT THE RATE DESIGN PROCESS IS CONSISTENT WITH THESE FIVE CONSIDERATIONS.

A. Obviously, the primary objective of any rate case is to secure revenue requirements that recover all prudently incurred costs of the utility. In addition, Unitil Energy has an objective of rate and revenue stability that requires more cost recovery through fixed charges and introducing demand charges for all new partial requirements customers, including those in the residential end-use class.

Q. DOES UNITIL ENERGY'S RATE DESIGN PROPOSAL ACCOMPLISH THE GOAL OF RATE AND REVENUE STABILITY?

A. Not completely, as it is only a first step. Based on the evolution of the utility market from monopoly service to a mixed monopoly (wires) and competition (energy and capacity) model, the Commission will be required to seriously consider the full unbundling of utility rates. Such unbundling will allow for the recovery of all fixed costs through fixed charges, which in my opinion will fully achieve the goal of rate and revenue stability. As I noted above, there is broad-based support among the academic community, as well as within other organizations such as the Rocky Mountain Institute, for unbundled multi-part rates.

It is important to note that Unitil Energy's proposal here to increase the demand (i.e., facilities) charge is completely justified under the traditional principles of cost causation and is required independent of the changing energy landscape. Unitil Energy's rate design proposals are aimed at being both fairer and more efficient, while at the same time beginning to mitigate the impact of increased solar DG penetration in its service territory.

XIII. UNBUNDLED COST OF SERVICE AND RATE DESIGN

Q. DOES AN UNBUNDLED COST OF SERVICE STUDY PROVIDE USEFUL GUIDANCE IN DEVELOPING A UTILITY'S RATE DESIGNS?

A. Yes. When a cost of service study is fully unbundled, another output from the cost study is the cost for each service actually provided. From the Company's cost of service study, Schedule HEO-2, Schedule 6 contains a summary of the unit costs for each of the Company's rate schedule. The following costs are calculated for each rate schedule:

- Production Demand;
- Production Energy;
- Distribution Demand;
- Distribution Customer;
- Total Revenue Requirement- Demand;
- Total Revenue Requirement- Energy;
- Total Revenue Requirement- Customer; and
- Total Distribution Revenue Requirement Per Bill.

These costs, when restated on a unit basis, form the basis for beginning the process of designing rates when coupled with marginal costs. Marginal costs provide insight in to the decisions related to the level of charges.

Q. HOW DID YOU CALCULATE THESE COSTS?

A. For each functional category of costs, the cost of service study calculates the costs classified as demand, energy or customer and sums those costs. The limit on unbundling details is based on the type of account information provided. For example, if detailed data exists to unbundle distribution assets into primary and secondary facilities, the demand component of each voltage level of distribution service may be unbundled. Each rate is based on the unit costs resulting from the allocation of class costs in each classification.

Q. WHY IS IT IMPORTANT TO DETERMINE THE UNBUNDLED COSTS OF A UTILITY?

A. Historically, most all utility customers could be identified as full requirements customers, i.e., the customers purchased all of their electric capacity and energy needs from the utility. As was described earlier, a single rate applied to a homogeneous group of customers was adequate to recover the costs of this service. Today, more customers make the choice to be partial requirements customers. These customers want to explore generation self-supply options for a portion of their energy requirements. In this mixed monopoly and competition model, in order to avoid subsidization of DG customers by non-DG customers, it is important that customers who elect to self-supply a portion of their energy needs continue to pay the costs caused by these customers' service selections.

The electric industry is quickly evolving into a mixed monopoly and competition model as a result of the wider availability of DG technologies. DG can take many forms, including renewables such as wind or solar, combined heat and power, fuel cells and other forms of generation. Each of these forms of DG makes different use of utility service in general, and even different uses within the same technology, all based on the economics of the competitive options. Efficient decisions require that customers know, understand and pay for the costs of the portions of the system they use and any additional costs they cause the system to incur to support their technology being interconnected to the system.

In an environment of increasing DG penetration, current rate designs do not provide economically efficient price signals to customers and instead create artificial and unsustainable cross subsidies that result in misallocation of resources. In addition, rates as they are currently designed create undue discrimination for DG customers using the very same services but paying different effective charges for those services.

Q. WHAT SERVICES WILL A UTILITY PROVIDE UNDER THE MIXED MONOPOLY AND COMPETITION MARKET CONCEPT?

A. To begin, so long as the customer is connected to the utility system, the utility must provide that connection capacity, and that connection capacity must be large enough to deliver service to the customer based on the maximum demand of the customer. Some form of maximum demand of the customer determines the generation, transmission and distribution facilities that are required even if that demand only occurs a few times in the year. Additionally, the utility will need to meter and bill for service that is provided and to account for energy delivered by the DG customer to the utility. Thus, customer-related costs will also continue and may even increase when customers install DG.

Since the maximum demand of a partial requirements customer may be no different than a full requirements customer, the partial requirements customer will pay far less to have the utility available to provide service than a full requirements customer when the fixed costs associated with standing ready to provide service are in per kWh charges. The simple reason is that a class that includes both full and partial requirements customers is no longer homogeneous. Even separating the classes cannot solve the fundamental issue that different customers require different services and even different levels of those services. Rates need to be redesigned to provide an economically efficient and just and reasonable pricing solution to the issue, even if the classes of service do not change.

Q. WHAT ARE SOME STEPS THAT CAN ADDRESS THE ISSUES OF CROSS SUBSIDIZATION IN RATES CAUSED BY THE ABOVE-DESCRIBED MARKET ACTIVITIES?

A. The issues in the residential service market are more complex because the simple bundled rate design that is used does not typically differentiate on any basis for differences in service characteristics within the class. In the case of residential rates, an initial step would be to separate all full requirements customers from partial requirements customers. The Company, as discussed below, is not proposing an immediate separation for all customers. Rather, its proposal is to begin the separation with new partial requirements customers and to initially grandfather the existing customers. The proposed changes in the Company's residential rate structure will help to address the fixed cost recovery problem I described earlier. The result will be both a better, more efficient price signal to customers and a move toward rates which will properly recover the Company's fixed and variable costs.

Q. IS IT REASONABLE TO ULTIMATELY INCLUDE DEMAND CHARGES IN THE RATES FOR ALL CUSTOMERS?

A. Yes. The recovery of fixed costs in volumetric rates violates the principle of cost causation, the Matching Principle and is economically inefficient because it sends an incorrect price signal to consumers that these fixed costs change with energy consumption. As I explained earlier, fixed costs do not change with energy consumption.

XIV. PROPOSED RATES FOR UNITIL ENERGY

Q. PLEASE EXPLAIN THE GENERAL PRINCIPLES YOU HAVE USED TO DESIGN THE COMPANY'S PROPOSED RATES.

A. This rate case seeks to recover the costs for delivery service that are entirely fixed in nature. As a result, the Company's rate design proposals have all been targeted toward increasing its fixed charges, where feasible. The fixed charges for delivery service include both customer and demand charges. As with the gradualism principle in revenue allocation, a gradualism principle has also been applied to the increase in the customer charge component of rates. The proposed rate design has capped the customer charge increase at 150% of the current customer charge, rounded down to the nearest whole dollar. The remaining increase for rates with kWh charges has been included in a flat energy charge. For rates with a demand charge, the remaining increase after the customer charge increase has been added to the demand charge. This emphasis on fixed charges is consistent with the nature of the costs being recovered.

Q. IS THE COMPANY PROPOSING ANY NEW RATES?

A. Yes. A new mandatory demand rate is being proposed for all new residential partial requirements customers who install any form of DG on their premise. This proposal is discussed in detail below. In addition, the Company is proposing new rates for LED fixtures under its existing Outdoor Lighting rate schedule.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE COMPANY'S DOMESTIC RATE SCHEDULE.

A. The domestic rate schedule as proposed consists of a $15.00[20] per month customer charge and a flat per kWh charge. The flat energy charge is consistent with the Company's marginal and embedded costs. Given the level of customer costs, the proposed customer charge recovers only 37% of the embedded costs and even a smaller percentage of the marginal costs. Further, the inverted block energy charge effectively transfers the unrecovered costs mostly to larger use customers who do not cause a greater level of such costs compared to the lowest use customers. Also, low income customers who are also low use customers are protected under the terms of the Company's Low Income Electric Assistance Program Discounts from adverse impacts of this change. For high use, low income customers (using over 750 kWh), the lower flat rate as compared to the current

[20] The current charge of $10.27 times 1.5 rounded down to $15 per month.

inverted block rate also provides an additional benefit. Finally, the proposed flat energy charge provides a better price signal for all domestic customers.

Q. PLEASE EXPLAIN THE RATE PROPOSAL FOR THE G-2 NON-DEMAND SCHEDULE.

A. The G-2 non-demand billed customers are extremely small. The proposed customer charge of $19.00 per month, which is an increase of less than 150%, generates over 99% of the revenue requirement in the fixed charge so the increase was capped at $19.00. It should be noted that 66% of these customers are billed under the water heating/space heating provision of the rate schedule and represent over 90% of the kWh for this customer class. Using a flat customer charge for this rate schedule would result in a customer charge of $19.16, which is still less than half of the embedded or marginal cost based customer costs. This implies a large intra-class cost subsidy that the proposed rate design will gradually move to eliminate.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE COMPANY'S G-2 AND G-1 DEMAND RATES.

A. Both the customer charges and demand charges were increased to produce the revenue requirements for each rate schedule. The other change was to increase the transformer ownership credit from $0.39 per kW to $0.50 per kW based on the unit cost results of the Company's unbundled cost of service study.[21]

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[21] See the secondary demand cost per kW on the unit cost page for G-1 and G-2. Secondary demand represents the cost of transformation.

Q. PLEASE EXPLAIN THE PROPOSED RATES FOR THE COMPANY'S OUTDOOR LIGHTING RATE SCHEDULE.

A. Outdoor lighting rates were increased by a flat amount per fixture to reflect the fact that the Company's unbundled cost of service study shows that the largest portion of the costs assigned to this class is customer-related. As a practical matter, this class is receiving a substantial subsidy under either the embedded or marginal cost of service study. Given the fixed cost nature of outdoor lights and the inherent economies of scale in lighting costs, this approach moves rates closer toward actual cost causation providing more efficient price signals.

Q. HOW WERE THE NEW LED LIGHTING RATES DEVELOPED?

A. As described in the testimony of Company witness John Closson, Unitil Energy is proposing to offer existing lighting customers an option of replacing their current fixture with a new LED fixture. The Company proposes that any customer wishing to convert to LED will be converted based on the following:

1. Customer will pay the cost of the new LED equipment,
2. Customer will pay the actual cost of installation, and
3. Customer will pay the depreciated book value of the current lighting equipment being removed.

The Company proposes to charge separately for any maintenance cost relating to the new LED fixture on a per-visit basis.

In order to develop a fully-allocated rate for the LED replacement rates, two costs were removed from the cost of service: (1) the depreciated book value of the current lighting equipment being removed; and (2) Account 585 maintenance costs. With those costs removed from the embedded cost revenue requirements, new unit rates were developed for the LED lighting class which reflects the payments being made for embedded costs by those customers wishing to convert their lighting to LED. These new unit rates were then used to develop the LED Lighting rates as shown on Schedule HEO -5.

Q. HOW WERE THE NEW UNIT RATES USED TO DEVELOP THE LED MONTHLY FIXTURE COSTS?

A. The embedded cost of service study classifies the revenue requirement for lighting between customer related costs and demand related costs. The customer related costs are on a per fixture basis, so for the LED rates these costs were included on a per fixture basis. The demand related costs are summarized in the embedded costs of service on a kilowatt basis ($/kW per month). The costs were adjusted to reflect the same portion of costs as proposed for all of the current lights. This cost level was applied to the specific wattage of the LED lights to develop updated demand related costs. The result is that any costs classified as customer will be fully recovered from any customer that is switching to new LED equipment. However, the demand related cost recovery would reflect the LED's lower wattage, which will reduce demand related revenues. While the lower wattage may reduce the Company's demand-related costs in the long run, these costs are fixed for the near future. As a result, when an existing light is replaced with an LED and the customer begins paying the LED rate, the lower recovery of demand-related costs embedded in the LED rate design will cause the Company to under-recover these costs until the next rate case when rates are set.

Q. HAVE YOU PREPARED A SCHEDULE SUPPORTING CALCULATION OF PROPOSED RATES?

A. Yes, proposed rate design calculations are provided in my Schedule HEO-6.

XV. DISTRIBUTED ENERGY RESOURCES BASIC ECONOMICS

Q. PLEASE DESCRIBE THE ECONOMIC PRINCIPLES YOU APPLY IN EVALUATING RATE DESIGN.

A. The matching principle and the principle of cost causation are fundamental principles for setting just and reasonable rates. That is, rates must be set so that customers pay for those costs they cause on the system. As Witness Mr. Thomas Meissner describes in his testimony, under the Company's current two-part rate design for Residential customers and net energy metering requirements, the energy produced from PV facilities of DG "Prosumers" is not charged any distribution costs. This condition fundamentally violates the principle of matching and cost causation, since DG "Prosumers" customers indeed rely on the Company's distribution to serve its full load requirements.

Q. DOES THE COMPANY AVOID ANY DISTRIBUTION COSTS BY SERVING DG CUSTOMERS?

A. No. It is important to note that the power delivery system is designed, constructed and operated to provide safe and reliable service to all customers and to serve their maximum demand on the delivery system. More specifically, delivery system planners size the requirements of transformers, circuits, and feeders in order to meet the system's maximum demand and the bulk of these costs are fixed. The Company must have personnel and equipment and facilities in place to serve all customer demands 24 hours a day, 365 days a year. Because the majority of these costs are fixed, a rate design that recovers costs primarily on a volumetric basis will always violate the matching principle and the cost causation principle since no delivery costs will vary based on changes in energy consumption.

Q. HAVE YOU ANALYZED THE PEAK DEMANDS OF THE COMPANY'S RESIDENTIAL CLASS AND DG CUSTOMERS TO DETERMINE WHETHER ANY OPPORTUNITIES FOR CAPACITY SAVINGS EXIST?

A. Yes. I reviewed the 8,760 hours of demand data for the Residential class and the DG hourly demands for the same period (using the hourly production profile of the Concord Airport location). Please see the summarized results in Table 6 on the following page.

Table 6 – Residential Peak Profile

Month 2015	Hour of Peak	% Maximum PV Generation	PV Generation @ Peak (kW)*	Class Peak (kW)	% Peak Reduction
January	19:00	0	0	109,029	0%
February	19:00	0	0	115,318	0%
March	19:00	0	0	100,772	0%
April	20:00	0	0	80,119	0%
May	19:00	2.9%	32.6	108,576	.03%
June	21:00	0	0	101,928	0%
July	19:00	2.7%	30.3	135,341	.02%
August	19:00	2.0%	22.5	129,006	.02%
September	20:00	0	0	131,156	0%
October	19:00	0	0	87,778	0%
November	18:00	0	0	97,224	0%
December	18:00	0	0	103,091	0%

*Based on 1,123 kW of installed PV capacity as of July 2015.

As this table indicates, the System peaks in the late afternoon to early evening in all months of the year and with the exception of the months of May, July and August, PV facilities are not operating at the times of the monthly residential peaks in the other months. Further, during the months in which PV is producing at system peak, the production of the facilities is so low to almost minimal given the later hour of the peak (between 2-3% of maximum output). It is clear from this data that any offset to Residential monthly class peaks is negligible at best with capacity offsets of less than

3% of peak class load. This reduction on the distribution system is far too small to impact local facilities and is unlikely to even aggregate enough to save load at any distribution point when one considers the lumpy nature of distribution capacity. It also means that there is no avoided distribution costs associated with solar DG loads because these changes are too small to impact the required size of the Company's distribution assets.

Q. HAVE YOU ANALYZED THE SYSTEM PEAK DEMANDS AND DG CUSTOMERS TO DETERMINE WHETHER ANY OPPORTUNITIES FOR CAPACITY SAVINGS EXIST?

A. Yes. The results are similar to those presented in Table 6 above for the Residential class. Please refer to Table 7 below. Due to the load characteristics of the G1 and G2 classes of service, with the exception of the fall months and March, the system peaks earlier in the day than the Residential peak. However, based upon the installed capacity of the PV facilities in place at end of July 2015, the effect upon system coincident peak reduction continues to be insignificant from any system planning perspective.

Table 7 – System Peak Profile

Month 2015	Hour of Peak	% Maximum PV Generation	PV Generation @ Peak (kW)*	Class Peak (kW)	% Peak Reduction
January	18:00	0		209,818	0%
February	18:00	0		206,567	0%
March	19:00	0		189,572	0%
April	11:00	64.9	729	166,622	0.4%
May	16:00	25.2	283	233,851	0.1%
June	16:00	54.6	613	217,670	0.3%
July	15:00	63.3	711	268,272	0.3%
August	16:00	56.7	637	265,389	0.2%
September	16:00	12.0	135	265,208	0.1%
October	19:00	0		170,091	0%
November	18:00	0		184,685	0%
December	18:00	0		193,496	0%
*Based on 1,123 kW of installed PV capacity as of July 2015.					

Q. HAVE YOU ANALYZED THE ENERGY LOAD, USAGE AND PRODUCTION PATTERNS OF THE COMPANY'S DG "PROSUMERS" CURRENTLY ON ITS SYSTEM?

A. Yes. I analyzed the monthly metered demands and net energy usage (deliveries and surplus returned to system) of the approximately 290 DG customers (with installed capacity of nearly 2,000 MW) on the system as of December 2015; in addition, I evaluated the typical 8760 hour production profile of a solar DG location in the region.

My analysis confirmed that based on this data set, the full requirements annual energy load of the DG customers well exceeds the amount produced by their PV facilities and that deliveries of energy to customers in total exceed the amount of surplus energy returned to the system. See the following Table 8.

Table 8 – Annual Usage Profile Estimate of Domestic DG Customers *

Load Component	Energy (mWh)	Notes
Full Requirements (FR) Load	1,711	FR = Production + Deliveries – Surplus
Production	1,204	Based on proxy production profile 735 kW @ 18.7% LF, Concord Airport location
Deliveries	1,080	Company metered data
Surplus	573	Company metered data
Consumed at Premise	631	Production – Excess

*Reflects load of Domestic DG customers that had 12 months of billing data in 2015.

As this table shows, as a group, the DG customers continue to be heavy users of the Company's delivery system with energy deliveries from the system almost equal to the amount of energy produced by their PV systems. This means that these customers are pulling almost as much energy from the utility grid during hours when their facilities are not producing as they are producing during daylight hours. In total, their annual full requirements load of 1,711 mWh far exceeds what their facilities produce. These facts highlight the fundamental difficulty with pricing delivery service on a two-part rate for DG customers: that is, due to the timing of PV production (only during daylight hours) there is no possible opportunity for these customers (without fully functioning battery storage), to disengage from the Company's grid for energy delivery purposes; and in turn, for the Company to avoid any fixed delivery costs for the purposes of serving energy load needs.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THESE CUSTOMER LOAD ANALYSES?

A. My findings from analyzing the peak and energy data of the DG customer class in relation to the System and Residential class support Witness Meissner's testimony which states that the grid connection is vital to the Prosumers. Any net metering subsidy just makes solar installers more profit since they target costs to the full avoided net metering rate. My analysis presented above proves that in 2015 the DG Prosumer set of customers as a whole heavily relies upon the delivery system for meeting its full requirements energy load and that in fact, based upon the timing of class peaks, very little, if any reduction in system peak could be measured. Based on this data and consistent with my discussion above, I conclude that the current two-part rate for DG Prosumers significantly violates the matching principle and the cost causation principle of rates, and creates undue subsidies for these customers that must be absorbed by non-DG customers.

Q. WHY IS THE SUBSIDY ISSUE IMPORTANT FROM A POLICY PERSPECTIVE?

A. There are several reasons the subsidy issue is an important policy issue. First, rooftop solar DG is not a least cost alternative for renewable solar energy generation. Both community solar and utility scale solar are lower cost renewable alternatives. In addition to being lower cost alternatives, both of these alternatives may be single axis tracking facilities that permit greater energy production during the late afternoon and early evening peak hours and thus create more customer value for the solar DG investment. Second, the cost of solar is such that low income customers end up providing subsidies to higher income customers. In addition, certain groups of customers such as renters and those who cannot install solar also must subsidize these solar DG customers.

Q. DOES AN ECONOMIC RATIONALE EXIST FOR A TWO-PART RATE DESIGN FOR PARTIAL REQUIREMENTS SOLAR DG CUSTOMERS?

A. No. The load characteristics and cost causative characteristics of DG customers (by their nature partial requirements service customers) are much different than those for full requirements customers

Q. WHAT RATE DESIGN DO YOU RECOMMEND THE COMPANY ADOPT FOR ITS PARTIAL REQUIREMENTS CUSTOMERS?

A. The evidence I have presented in this testimony demonstrates that under the Company's current two-part rate design, there is no possibility of avoiding undue subsidies between its DG and non-DG customers. This situation exists because the current rate design fundamentally ignores the fact that most of the system's costs to serve customers are fixed and do not vary with the units of energy sold. The current net metering provisions as described in Witness Meissner's testimony in which surplus energy produced by a PV facility is credited against the next month's deliveries for that customer further exacerbates this inequity. To resolve this inequity, I proposed the Company implement a three- part rate structure for its DG customers consisting of a demand charge (the rate would be based on a 15-minute integrated demand reading as captured by the Company's Advanced Metering Infrastructure (AMI) system); a customer charge; and an energy charge (or Default Service component) billed per kWh, including time-of-use (TOU) based charges in the future.

Q. HOW DOES THIS TYPE OF MULTI-PART RATE PROVIDE EFFICIENT PRICE SIGNALS FOR CUSTOMERS?

A. Since energy charges are not adequate for reflecting cost causation (virtually all economists agree that this is the correct objective for rates) it is necessary to understand all of the components that cause costs to be different. It is a fundamental proposition that costs are caused by customers, demand and energy. In fact, all cost studies use these three elements to classify costs. To match pricing with cost causation would require at least three parts: a customer charge, a demand charge and an energy charge. Customers cause distribution demand costs based on non-coincident peak demands, not on the coincident peak demand. It is common for utilities to have a greater investment in substation capacity than generation capacity and in more transformer capacity than substation capacity. The reason is simple. There is more load diversity at the system peak load then there is as the loads move closer to customers. In fact, it is not at all uncommon that substation peaks occur at different times and in some cases even different seasons from the system peak. It is even unusual for more than a few substations to peak coincident with the system peak. As with substations, feeder circuits also peak at different times than the substation that serves the feeder. To correctly reflect the matching and cost causation principles, I recommend using maximum customer demand, whenever it occurs, to recover distribution costs. This will solve the subsidy problem for delivery service and do so without any prolonged delay. It will also be easily implemented and result in a lower per unit charge that will be easier to phase in with a lower impact on bills.

Q. HOW WOULD A DISTRIBUTION DEMAND CHARGE BE DETERMINED?

A. First, it will be necessary to set the time interval over which demand is measured. 15 minute intervals are more stable over time so customers do not see large swings in their demand measurements. Second, the 15-minute intervals are also more reflective of cost causation since transformers and circuits have longer life if they do not experience overload conditions with any frequency. Third, the shorter interval results in a lower per unit demand charge to recover the distribution related costs. While the same dollars are recovered regardless of the demand interval, the shorter interval benefits both customers and the utility through stable and more predictable charges on a monthly basis. Customers also benefit because a one-time peak does not significantly change the bill. Ideally, this demand charge would be based on a contract demand rather than a measured demand in the future, since this would reflect the sizing of the local facilities installed to serve the customer and would actually be a separate facilities charge. Some utilities have used this approach for demand billed customers. This charge should be properly based on a 100% ratchet to further minimize the charge and reflect cost causation because these costs are a function of the customer's maximum demand whenever it occurs. That is because for distribution demand there is no time dimension. Once the interval is determined and the charge is based on maximum demand whenever it occurs, subject to a 100% ratchet, the kW charge would send the appropriate price signal and would be economically efficient.

Q. WHAT IS THE BASIS FOR BILLING THE DEMAND CHARGE BASED ON A 15-MINUTE INTERVAL WITH NO RATCHET?

A. First, the most common demand billing measures are 15 or 30 minute intervals. The 15-minute interval is most representative of the maximum load on the distribution system and has the advantage of a lower charge than longer measurement periods. This reduces the impact of non-recurring maximum demands on the customer. The absence of a ratchet is part of a gradual proposal. The local distribution facilities are a function of that single customer demand that the utility planned to meet when it installed facilities to serve the customer. We might even call that design day maximum demand. Ideally, the charge would be subject to a 100% ratchet on the highest billing demand in any month, as noted above. Rather, the introduction of a demand charge is a new concept and this proposal allows the customer to begin understanding the concept of demand and how it relates to the customer's bill, as an initial step to rates that will be ultimately more efficient and more cost based. Thus, there is no proposed ratchet associated with the DER rate initially. Ultimately, the use of a ratchet or contract demand should be the basis for the distribution system demand charge.

Q. SINCE UNITIL ENERGY IS A DISTRIBUTION ONLY UTILITY, HOW ARE ITS OTHER RATE COMPONENTS PRICED?

A. These other costs are pass-through costs and should be billed on the same basis Unitil Energy is billed.

Q. WHAT LEVEL OF DEMAND CHARGE DO YOU PROPOSE AND HOW DID YOU CALCULATE IT?

A. I propose a monthly demand charge of $5.32/kW to be billed on each customer's peak 15 minute integrated monthly demand. I simply converted the proposed domestic energy charge rate of $0.03786/kWh to a demand charge based on the sum of twelve monthly customer maximum demands for Domestic class. The customer will continue to be billed Default Service costs on an energy basis. The billing demands will be collected from the Company's AMI system. The calculation of the demand charge is presented in Schedule HEO-6.

Q. IS IT REASONABLE TO EXPECT THAT CUSTOMERS CAN AND WILL RESPOND TO MORE COMPLEX PRICE SIGNALS?

A. Yes. In terms of complex price signals the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost-based TOU rates were introduced for large customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs. Production and transmission demand charges are partially related to system peak hours as discussed above.

Q. IS THERE EVIDENCE THAT RESIDENTIAL CUSTOMERS CAN RESPOND TO MANDATORY DEMAND CHARGES?

A. Yes. In 2009, a rural electric cooperative in Kansas introduced a mandatory demand charge for recovery of fixed power supply costs based on the peak demand period used by the supplier. The customers of Butler REC have responded, as evidenced by the two documents provided in Schedule HEO-7. Those documents demonstrate both the educational material and the savings that have resulted from the mandatory rate for residential customers. In addition, the Salt River Project recently introduced a rate schedule (E-27, effective billing cycle April 2015) that is mandatory for Residential customers with new PV. The demand rate is applied to each customer's highest peak monthly demand using 30-minute interval data. A recent article published by

AzCentral.com on March 28, 2016 reports that based on SRP's preliminary analysis, some customers are experiencing lower bills due to their ability to limit peak demands.[22] In addition, two utilities in Nevada (Nevada Power and Sierra Pacific Power Company) have recently instituted demand charges for solar customers. Demand charges for solar customers have been proposed by companies in several other jurisdictions and those decisions are pending.[23] In addition, one of the largest electric cooperatives in the country, Cobb EMC, has introduced mandatory demand rates for solar DG and all new residential customers, as has a municipal utility in Florida: Lakeland Electric, for its DG customers. Thus, the trend is not limited to IOUs.

Q. DO YOU BELIEVE THE COMPANY'S CURRENT NON-BYBASSABLE CHARGES SHOULD BE CONSIDERED FOR THE PURPOSE OF DETERMINING DISPLACED ENERGY REVENUES?

A. Yes. As explained by Company Witness Meissner, under the Company's existing net metering provisions, all energy that is produced by PV facilities avoids paying the current energy based charges. These include both the Distribution Charge and the set of five separate non-bypassable charges (External Delivery Charge, Stranded Cost Charge, Storm Recovery Adjustment Factor, System Benefits Charge, and Electricity Consumption Tax). These costs should be borne in full by solar DG customers based on their total electric consumption, although UES is not proposing this change in the current filing. Under a separate rate schedule this can be accomplished by adding

[22] Ryan Randazzo, The Republic/azcentral.com; "SRP Data Shows Some Solar Customers Save Money With Demand Rates," March 28, 2016.
[23] "The 50 States of Solar – 2015 Policy Review," NC Clean Energy, Meister Consultants Group, February 2016.

monthly generation to load as the appropriate billing determinate. Alternatively, the charges may be converted to a capacity charge per kW of installed capacity and billed for kWh used and a capacity charge for DG capacity. UES believes that it is appropriate to change the non-bypassable provisions at the time that the Commission reviews these charges.

Q. DOES ANY ECONOMIC RATIONALE EXIST FOR NOT INCLUDING THESE CHARGES IN THE COMPANY'S DETERMINATION OF DISPLACED ENERGY REVENUES?

A. No. This treatment violates the matching principle of rate theory. As is the case with distribution system costs, none of the costs collected by these charges is avoided by the Company due to the presence of PV facilities on its system, with the exception of some of the costs collected by the Stranded Cost Charge which may have some relationship to past production obligations. In fact, the only verifiable avoided costs related to the presence of PV on the system is avoided fuel costs related to the production of PV solar energy, and those costs are treated outside of the Company's delivery rate schedule. For this reason, I believe that these costs must be reflected in the Company's displaced revenue calculation to truly capture the level of fixed cost recovery erosion that is related to solar PV. In addition, I recommend for ease of rate administration that if the Commission decides to adopt the Company's proposed three-part demand rate, that these non-bypassable charges, to the extent possible, be consolidated and also set on a demand basis. This treatment will avoid creating additional intra-class subsidies between DG and non-DG customers.

XVI. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides support for two different cost studies: an embedded cost of service study and a marginal cost of service study. I recommend the use of the embedded cost of service study to allocate the Company's revenue requirement and for determining its unit costs for rate design purposes. I also recommend that the marginal cost study be used to inform rate design. I make that recommendation based on either cost study because both domestic and outdoor lighting customers should receive a larger percentage increase of the proposed revenue requirement. I also conclude that rate designs for delivery service, to the extent possible, recover the total revenue requirement in fixed charges since no delivery costs vary with energy consumption. I conclude that the Company's partial requirements customers should all be served under separate rate schedules that reflect cost causation. As an initial step, and to provide for a gradual transition to unbundled rates, the Commission should approve a mandatory rate for all new DG customers while temporarily grandfathering existing customers under the Company's existing net metering provision.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission accept the embedded cost of service study as filed, including the use of the minimum system concept, to classify distribution plant Account Nos. 364-368 between customer and demand related costs. I recommend that the Commission adopt the proposed marginal cost methodology that is properly based on future costs. I recommend that the Commission approve the Company's proposed rate designs, including the new LED lighting rates and program. I recommend that the Commission approve the new DG rate as mandatory for all new DG customers. I recommend that any reduction in the proposed revenue requirements be used to reduce energy charges for customers' not on demand rates and to reduce demand charges for all other customers. I recommend that the Commission order the Company to develop a plan to phase in three-part rates for all customers not currently billed with a demand charge. Finally, I recommend that the Commission order the Company to develop a transition plan to move existing DG customers to the DG rate schedule.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.