DR. H. EDWIN OVERCAST

Appendix A

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke Water Power

Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black & Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director of Black & Veatch Management Consulting, LLC.

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Appendix B

Marginal Cost Studies Are Not Useful In Determining Avoided Costs or Level of Intraclass Subsidy

In the Order of Notice opening this docket the Commission stated that as part of the prehearing conference and technical sessions "The performance of marginal cost of service studies by the three regulated electric distribution utilities and the *anticipated completion and filing dates for such studies*" (emphasis added) should be discussed. UES has filed a marginal cost study in its current rate case before the Commission, docket DE 16-384. That study and the supporting testimony are incorporated herein by reference.

In that order, the Commission stated that the legislative purposes of this proceeding require "ensuring costs and benefits are fairly and transparently allocated among all customers" and "a fair allocation of costs and benefits." These standards and purposes must be addressed based on any cost analysis provided in this docket. It is not possible, however, for a marginal cost study to satisfy either of these purposes.

As I explained in my direct testimony in the UES rate case, marginal cost bears no relationship to the costs that comprise the utility's revenue requirements. This means that a marginal cost study cannot ensure costs are fairly and transparently allocated among solar DG customers and full requirements customers. 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, including the resources used by full and partial requirements customers. Marginal costs only reflect cost causation for growth at the margin, and since they are forward looking, costs associated with added customers, kW capacity or kWh. The kW delivery capacity may be added mostly at the fringes of the system, and may occasionally represent an expansion of an existing facility such as a feeder or a circuit, but that does not represent the marginal cost for any more than that one location. 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 holds that 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 (followed by demand charges, while energy charges are the most elastic, particularly as those energy charges increase) 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 reached this same conclusion when he stated that the full distribution of costs “is in part along the lines that reflect true causal responsibility."[1] He further concludes 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."[2] 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."[3] It is not only that marginal cost does not equate to the revenue requirement being allocated but that marginal cost cannot reflect the causes of those sunk costs that represent the costs to be apportioned.

The marginal cost of adding load and the marginal cost of a decrement of load are not equal. The reason is actually quite simple. Adding a customer, kW capacity for delivery (the only capacity for a delivery utility like UES) or energy increases costs. The cost varies based on when and where the addition is made. It may be as little as a meter and service line or it may add capacity to the system including back to a substation. A decrement to delivery capacity or energy will not match the marginal cost of an addition simply because sunk costs by definition do not impact marginal costs and the fact that utility assets are only available in lumpy amounts and do not always result in a lower cost capacity being available to reduce costs. A simple example will illustrate this point. Data for UES shows that the class NCP across the entire system would change at most by about 2% of delivery capacity as the result of solar DG. UES installs a 10 kVa transformer as the smallest size

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[1] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150

[2] P. 158

[3] P. 158

transformer on the system. The connected load capacity on even a small home will be more than 10 kW because a typical range has at least 12 kW of connected load. If a customer uses gas for heating, water heating and cooking, the expected peak demand will be about 8 kW and would require a 10 kW transformer. The customer cannot reduce the transformer load enough to replace 10 kVa. In addition, a two percent reduction for multiple customers on the same circuit will not be large enough to reduce any components of the delivery system even if the facilities are old enough to require replacement. Thus, the marginal cost of a new delivery facility does not represent the avoided cost for the system unless the facilities are concentrated on a circuit that needs to be replaced because of load growth. In that event, there are a number of options that may result, as follows: delay the replacement of the circuit, upgrade the circuit because of DG peak loading, replace the circuit with smaller facilities or upgrade the circuit as planned. Two of these options have no avoided cost and one of those two actually has costs caused by DG. The other two options have minimal avoided costs because delaying the upgrade is the net present value (NPV) of the annual cost difference in the facilities over the life of the facilities. This number will not be as large as the marginal cost of a new addition used to estimate marginal costs. Replacing the facilities with smaller facilities is also not as large as marginal costs but is the NPV of the difference in total cost of the two options over the life of the facilities on a per kW basis. For the smaller facilities, per kW cost will be higher for the smaller facilities, and this difference is the smaller of the two cases with avoided costs. In any of these cases the marginal cost study provides no useable information related to avoided costs.

Marginal Cost in Rate Cases

Marginal cost studies have value in determining the optimum on-peak/off-peak periods for the energy component of a TOU rate as well as the energy cost differential to be reflected in rates. Marginal cost studies are useful in determining the coincident peak (CP) demand charge for a utility that has on-peak demand charges for generation capacity. (This does not apply to UES and would not apply even if UES had generation capacity because the FERC has ruled that for utilities participating in ISOs or RTOs with an active capacity market, a utility is not required to purchase QF capacity under PURPA rules since capacity prices are determined in markets. Thus, the value of DG capacity should be based on the avoided costs of a utility scale DG facility rather than the traditional avoided cost of the least capital intensive unit for the system. For a delivery-only utility, there are no marginal energy costs other than those determined in the market for default service. All of the delivery related costs are fixed and caused by capacity demand or customer access. It is instructive to note that in the marginal cost study filed in DE 16-384, the marginal customer cost is about $41 and would be the monthly customer charge for the domestic class if the study is used for pricing. It is also worth noting that there would be no kWh charges for delivery service, as that would be based on a demand charge of $6.44 (marginal cost based) or about $5.32 per kW proposed in the rate case on an embedded cost basis subject to a 100% ratchet to recover that marginal cost based revenue requirement. It is reasonable conclude that the rate guidance of the marginal cost study is sound and fully supports the use of a three part rate for UES services consisting of a customer charge and demand charge for delivery services and a kWh charge to recover default energy costs. This latter charge would be subject to a seasonal and TOU feature as well.

Conceptually, the long-run is a period where all costs become variable. The theory is based on a competitive model of the long-run in theoretical economics based on the competitive model. It is also true that in developing long-run cost curves - both marginal and average - the long-run technology is fixed and input prices are fixed. There is no question that these latter two assumptions cannot be true over time, and these assumptions impact directly the assumption that all costs are variable in the long-run for an electric utility. Since the long-run includes changes in technology and differing input prices, efficient utilities minimize revenue requirements by changing the mix of inputs as output changes, but within an environment that includes sunk costs and lumpy capital additions. As a result, the only long-run variable costs are those related to the production or purchase of energy. The reason for this is that as demand for capacity or customer access changes in the short-run, utilities make new long-term investments in response to those changes. Those costs extend the long-run for the shorter of the economic life of the new assets or the physical life of the assets. Since this is an iterative process resulting from an accumulation of short-run decisions, there is no period when any long-run costs can vary with kWh usage. So in the real world, as contrasted with the theory of long-run costs, there is really no measure of time where all costs are simultaneously variable. Thus, there is no costing rationale for translating long-run costs that are greater than the marginal demand or customer costs to be recovered in marginal energy charges. Energy charges in particular are not optimal when set on long-run marginal costs except in the event of long-run equilibrium when both short-run and long-run marginal costs are equal. Since that theoretical requirement also requires that economies of scale be fully exhausted, that occurrence cannot occur for utilities, as that would mean that short-run marginal cost would have to equal long-run average cost and short-run average costs. In simplest terms, the marginal price to recover revenue requirements would need to equal the average total cost of electricity. Interestingly for that to be true marginal cost would equal revenue requirements. Even if that were true, it would not be one set of costs because costs for delivery - marginal or average - differ based on the portions of the system used in common by different classes of customers.

The theory of marginal cost is a theory of pricing services and in no model does it relate to cost of service with the exception of long-run equilibrium in a competitive market. In all other market models with downward sloping demand curves, the rule for profit maximization is that price is set on the demand curve at the point where marginal revenue equals marginal cost. In that case it would only be an accident that that price would equal average costs that is the basis for revenue requirements.

As I have stated above, marginal cost studies cannot be used to determine intra- or inter-class subsidization because that subsidy is related to revenue requirements, not marginal costs. We do know that the marginal customer cost of $41 for domestic customers is greater than the proposed customer charge, and recovery of that excess cost in volumetric rates creates inequity and inefficient rates. Larger customers subsidize smaller customers and the largest customers pay a larger share of these costs, sending a totally incorrect price signal about the cost of using another kWh. The role of marginal cost studies in regulation is to inform pricing and to establish rates that reflect marginal costs.

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Appendix C

The Acadia Study: Value of Distributed Generation

This Appendix provides an assessment of the Value of Distributed Generation distributed at a Technical Session which was written by the Acadia Center.[1] The first element discussed in the Acadia study is the avoided energy costs. We know that avoided energy costs are based on the LMP values that may or may not be related to gas costs. Gas is not the marginal fuel for UES in all hours of the year. Further, the Acadia methodology assumes that gas is the marginal fuel and that the marginal heat rates for every year in their avoided energy cost calculation remain the same. There is no attempt to normalize unit outages or to address the addition of new, more efficient resources being added to the system. As a result, the avoided energy costs are almost certainly overstated. This is true even before considering the fact that the LMP price includes transmission losses at the load node that are subsequently double counted, with an 11% loss adjustment that is added to the avoided cost for transmission and distribution. Further, the 11% loss factor is not accurate for the simple reason that this value is purported to be the peak load marginal loss value. Since avoided losses are not solely at the peak hour and since DG increases losses when exporting power back to the grid, the actual avoided losses must be the net avoided losses and must be adjusted for load conditions when DG is operating. This would exclude all winter peak load conditions and also would exclude high load and cost hours in the summer evening. Finally,

[1] Acadia Center, “Value of Distributed Generation, Solar PV in New Hampshire, October 2015

there are no load or core losses on the system that cannot be avoided that are included in average losses. The end result is that avoided losses for distribution are based on average system losses, less no load losses, less increased losses from export power. It may also be that the avoided losses should be reduced by the effect of low power factor, where solar DG does not produce vars and those must be provided from the utility system. In sum, it is sufficient to know that the average avoided LMP for an optimally placed south-facing solar DG system is lower than the average LMP of residential load ($45.28/mWh compared to $47.04/mWh) which implies that the avoided losses should be less than the average system distribution losses after adjusting the average for no load losses. Excess generation by solar DG has an average LMP of $44.08/mWh that, when coupled with the marginal LMP for customer utility load of $47.25, illustrates the energy arbitrage for banking and further demonstrates that the avoided losses are nowhere near the 11% losses used in the Acadia study. In addition to these errors, the Acadia study departs from the “but for” standard by inflating avoided energy costs by an additional 9% for wholesale risk premium and ISO-NE costs. As a practical matter, the ISO-NE costs are not avoidable since they are recovered through a formula with a true-up provision to full revenue requirements. The wholesale risk premium is not an avoided cost because UES does not incur this cost. In short, the Acadia study uses highly inflated values to calculate the avoided energy rates and, to compound the error, uses the wrong discount rate to calculate the present value of these costs. Since energy cost under current regulation is a pass through to consumers, the appropriate discount rate would not be a societal rate but rather either the utility discount rate or even more appropriately the customer discount rate, since the levelized payment resulting from the calculation would be paid by consumers. The consumer’s energy discount rate has been estimated in a 1979 Bell Journal of Economics article at 20%.[2] With all of these errors there is no reason to believe that the single largest component of the south facing solar DG is close to the value calculated in the study.

Avoided Capacity

The value used for the FCM for all of the years beginning in 2019 is overstated by about 54%, meaning the NPV of capacity is wrong based on the estimate. This demonstrates the error potential for estimating future costs while ignoring the effects of competition and changing technologies. This value is also 170% above the least cost capacity in the auction. In either case, the capacity value is overstated by a significant amount. This value is then adjusted by the same 9% used in the energy calculation for wholesale risk premium and ISO-NE costs. As in the above case, these cost are not avoided by UES and therefore do not meet the “but for” standard. As for losses, the EIA has statewide utility losses at 5.3%.[3] Since 25-30% of losses are no load losses that do not change with load, even the marginal losses would be about 7% excluding no-load losses. Using 11% inflates the loss savings. The Acadia study also applies a reserve margin adjustment to the FCM value and thereby double counts reserve because the FCM price includes adequate reserves for the ISO-NE to maintain system reliability. The use of a social discount rate for private costs is also an error that increases the NPV of capacity costs and would be inconsistent the proper determination of utility avoided costs. The proper discount rate under the “but for” standard

[2] Individual discount rates and the purchase and utilization of energy-using durables, Jerry A . Hausman, The Bell Journal of Economics, Vol. 10, No. 1 (Spring, 1979), pp. 33-54

[3] EIA State Energy Profile, New Hampshire Table 10

would be the utility discount rate based on its marginal cost of capital and would be significantly higher and therefore lower avoided costs.

Avoided Transmission Capacity Costs

First, the value used in the study is out of date and changes each year with the transmission revenue requirements of the system owners. Further, there are no avoided costs associated with this rate because if demand is reduced and revenue does not match the costs under the formula, the true up provision applies along with interest for the balance. Thus, this cost cannot be avoided and is actually the embedded cost of transmission system from before 1997 and after 1996 as two embedded cost components. This is the equivalent to using a fully allocated cost of service study to value avoided costs. This does not meet the "but for" standard because these costs are not avoided by the utility. Consistent with other comments related to the discount rates used in the study, an incorrect value is used here as well. There is also another technical error in that the capacity value of DG is based on the Seasonal Claimed Capability under the ISO-NE process for determining that value. There is no relationship between SCC and the avoided cost of transmission. Transmission charges are billed on the monthly peak hour and the SCC will be zero for six or more months and will vary with the hour that peak occurs each of the other months. That peak could occur on a cloudy day in a shoulder month and have no solar DG available and hence no impact on this cost. As a practical matter, with no transmission facilities UES cannot avoid any transmission costs. Also, UES pays for congestion costs in the LMP price that is defined as the marginal cost of congestion at the load node. A simple review of these congestion costs shows that on average, the real time charges are negative and the day ahead average charge is about $0.36 per day. The highest congestion cost hour in the day ahead LMP calculation did not even occur at the monthly peak hour and in real time turned out to be a negative value in that hour.

Avoided Distribution Costs

This calculation is not based on any costs associated with UES. The UES distribution system has nothing to do with the top 5% of ISO-NE peak loads for the simple reason that ISO-NE peak loads are based on the total diversity of a region while the distribution peaks for substations and other delivery plant are based on the diversity of its service area. The closer one measures load to a customer, the less diversity benefits are available to moderate peaks. It is common for utilities to have more substation capacity than the system demand peak and more transformer capacity than substation capacity. Thus, the data used to determine solar avoided capacity would be an incorrect methodology. Further, there is no need to create a value based on avoided load because for UES the maximum demand on the delivery system occurs when excess deliveries occur with no diversity because of solar DG. As I have shown above, there are no distribution avoided costs in any event.

DRIPE Energy and Capacity

This value is based on something that has no impact on the utility's avoided costs because there is no payment that a utility makes for Demand Reduction Induced Price Effects (DRIPE). This concept is not based on sound economics as it relates to DG. First, under the current net metering with banking, other customers do not see the impact of lower energy costs (if any, as discussed below) since their prices increase to recover the avoided fixed costs. The result is no benefit from solar DG to customers. There is, however, another effect that is not mentioned here. The income effect for customers adopting solar DG may result in them consuming more power from the grid than they would have, absent DG. That power is also more likely to be consumed in high load hours as customers increase their comfort levels. There is some anecdotal evidence in Arizona to support this income effect concept. There is little need to discuss this element further as it cannot meet the "but for" standard of avoided costs.

Avoided CO_2 Compliance Costs

Acadia states that these costs are "the *embedded costs* associated with meeting existing and proposed greenhouse gas (GHG) emissions reduction requirements." (Emphasis added.) Since embedded costs are sunk, they cannot be avoided by definition. Only variable costs associated with emissions can be avoided and those are already included in the energy LMP. As for proposed regulations to monetize these requirements, those costs do not meet the "but for" standard and cannot be counted under the FERC definition for avoided costs.

Avoided NO_x Compliance Costs

As with the CO_2 Acadia states that the embedded costs are used. This is fundamentally the same error that is discussed above. The marginal costs associated with NO_x are also included in the LMP energy price. Adding these costs again double counts the avoided costs. Also note that the incorrect discount rate is used as well.

Net Social Cost of CO_2

The Acadia study estimates this value as an avoided cost but it is not useable in the context of avoided costs for both practical and theoretical reasons. None of these costs meet the “but for” standard and thus are not relevant to the analysis. In all likelihood, they are way overstated because they make no account for technology changes over the study period or even for the possibility that there will be no other costs internalized. Practically speaking, they are not allowed in the calculation. Theoretically, there is no basis for including them unless all of the net effects are considered. For example, 64% of all solar panels are manufactured in China, where most electricity is produce by coal and with lower emission standards than in the United States. Therefore, increasing the incentive for solar DG increases solar panel production that results in higher CO_2 emissions. The actual avoided costs should at least net out these externalities. Further, the views expressed in this discussion do not recognize the economic theory of externalities. In the seminal work on this subject, “Externality,” the authors conclude that “Pareto-equilibrium in the case of marginal externalities cannot be attained so long as marginal externalities remain, until and unless those benefitting from the change are required to pay some ‘price’ for securing the benefits.”[4] This simply means that efficient social policy must include bilateral taxes on both the utility and the consumers who benefit. Hence the approach proposed by Acadia violates fundamental economic principles of efficiency.

Net Social Cost of SO_2 and Net Social Cost of NOx

Neither of these costs meets the “but for” standard and cannot be included in the context of avoided cost payments to QFs as noted above. The use of these costs suffer from all of the

[4] “Externality”, James M. Buchanan and Wm. Craig Subblebine, Economica, N. S. 29(1962), pp. 371-384

problems discussed above related to CO_2. Further, while these are social costs in the sense of externalities, the societal discount rate used to calculate present value is not appropriate. The simple reason is that once the costs are internalized they become private costs and subject to the discount rate applicable to the electric utilities in this case.

Acadia Study Summary

As I show above, there is no evidentiary value of this study in determining the avoided costs that comply with PURPA and Federal regulations. With numerous corrections to avoid errors in discount rates, double counting use of embedded costs and so forth, such a study could be useful in the IRP process for determining the least cost options for meeting the requirements of system reliability, efficient operation and responsible conservation and environmental objectives. In my view, rooftop solar will not be the least cost option and there should be no additional incentives beyond the FERC approved avoided costs. Further, if the state as a matter of policy wants to provide other benefits to solar DG, there is nothing to prevent those benefits outside of the avoided cost payments. The FERC has made this point as well in its decisions.

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Appendix D

The Mixed Monopoly and Competition Model

The concept of a mixed monopoly and competition model is not new, as other industries have been faced with similar issues. In some cases the very existence of the monopoly model has been replaced by competition entirely, such as the case of the airlines and the trucking industry. In others, regulators have developed tools to address the mixture of competition and regulation. Two examples that come to mind are railroads and liquids pipelines. There has also been an evolution of the mixed model in the electric industry. A major force behind the analyses of these events was Dr. Alfred Kahn, who served as a Federal Regulator (the Civil Aeronautics Board), a State Regulator (Chairman of the New York Public Service Commission) and a regulatory scholar (<u>The Economics of Regulation</u> and any number of economic articles, papers and testimony).

Dr. Kahn described this model in a 1998 monograph published by The Institute of Public Utilities and Network Industries at Michigan State University. That Monograph entitled "Letting Go: Deregulating the Process of Deregulation" provides the description of the model as follows:

- It is clearly not possible to totally eliminate direct regulation of what we have traditionally considered to be the authentic public utilities. The reason, of course, has been the persistence of monopoly, particularly in the local distribution networks and also in electric transmission, which has required continuing regulation for two closely relate reasons:

- To protect captive, principally residential and small business, customers;
- To ensure fair and efficient competition between the integrated utility companies and the challengers dependent upon their access to their monopolized or partially-monopolized facilities, including safe guarding against cross-subsidization of that competition by the incumbent utilities at the expense of their monopoly customers.1

This is the fundamental concept of the mixed monopoly and competition model. Namely, certain aspects of the public utility remain a natural monopoly, in particular the facilities associated with service delivery and more as will be discussed later. Several parts of this discussion apply to this proceeding. First, regulation is needed to protect the captive residential customers who cannot (or choose not to) avail themselves of DG or net metering, recognizing that this is at least a plurality and more than likely a majority of the residential class. Second, Dr. Kahn notes that competition should be fair and efficient. As I explain in the testimony, the implications of net metering are such that the competition for the end use loads served by DG is neither fair nor efficient under the net metering, banking and volumetric rates commonly used for residential service and small commercial service customers. Third, and more importantly, I show that net metering creates cross-

[1] “Letting Go: Deregulating the Process of Deregulation”, Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 17

subsidization, not by the incumbent utility, but by the rent seeking[2] behavior of the solar DG advocates that occurs at the expense of customers who remain monopoly customers.

Typically, the argument for this rent seeking behavior is that it will have a small dollar impact on customers providing the subsidy and the industry cannot make it on its own initially (the infant industry argument). Dr. Kahn specifically recognizes this behavior by these entrants and summarizes the impact of this behavior by noting "the encouragement that preferential subsidies and protections of this kind give to would-be competitors to devote their entrepreneurial energies primarily to seeking such preferences and ensuring their perpetuation by interventions before regulatory agencies and the courts, rather than concentrating on being more efficient suppliers than the incumbents."[3] With regard to solar DG, the proliferation of roof top solar is not the least cost alternative to acquiring renewable energy resources or even solar DG, as the cost of solar is subject to economies of scale just as the utility costs benefit from scale economies. This is demonstrated by the lower market price for solar when the price is market based compared to the implied price (with subsidies) associated with net metering. Particularly given that DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year round contract for solar generation. This is just another example of how markets have both a competitive option and regulation of the remaining natural monopoly.

[2] Rent seeking is the activity of a person or firm that tries to obtain benefits for themselves through the political arena: The New Hampshire Public Service Commission in this case as well as legislatively through the PURPA amendment adding the net metering standard. Typically, the benefit consists of a subsidy for their product or service, including favorable tax treatment and measures that inhibit competitors such as inefficient regulated rates.

[3] Kahn, op. cit., page 21

One of the characteristics of true competition is that subsidies are not sustainable. Under regulation, artificial subsidies may be sustained for a longer period of time but must be addressed ultimately if utility service is to be sustainable. Where the competitive market is subsidized through regulation, the result is that there is excess and inefficient investment in the favored competitive services such as rooftop solar DG in this case. The result will not be consistent with least cost planning or even efficient operation of the monopoly portion of the market. Ultimately, the monopoly segment of the market must establish fully unbundled rates so that when a customer uses a monopoly service the customer pays for the costs that that use imposes on the monopoly. To establish unbundled rates, the cost of service must be unbundled for the services provided. Rates must be developed that signal the factors that cause cost by customer groups that have homogeneous characteristics that cause the cost. When rates reflect class cost of service on an unbundled basis and the underlying cost of service reflects the principles of cost causation and matching, subsidies will be eliminated; the price signal in the rates will incent efficient use of resources; rates will be just and reasonable; rates will not be unduly discriminatory; investment in DG will be consistent with least cost planning and efficient competitors will earn the required market return for the risk associated they take. In summary, the following elements must exist for long term stability and sustainability of the mixed market model:

1. Cost of service reflects cost causation for each class of customer.

2. Rates match cost in the rate effective period.4

3. Rates are fully unbundled such that all energy related costs are recovered in energy charges (preferably seasonal and time differentiated based on marginal cost differences), fixed capacity costs are recovered in demand charges and customer costs in customer charges that may not be the same for all customers in a class when the services they select differ.

4. Price signals should reflect marginal cost to the extent practical, while still matching costs and revenues.

5. Costs not included in test year revenue requirements such as the present value of future avoided costs or the levelized cost of future avoided energy should not be part of rates or part of valuation of assets that have no long-term, enforceable, contractual obligation for service and even with a long-term power purchase contract energy should be valued at the market as the market changes through time.

It is essential that rate classes be established based on factors that cause known differences in cost of service. These factors include voltage level of service- secondary, primary, sub-transmission and transmission or some subset of these factors based on the types of service the utility provides. Voltage level is important because it impacts energy costs (delivery losses) and capacity costs (extra equipment not used by other classes of service and the required level of capacity). Quality of service (firm or non-firm) is another dimension for

[4] The rate effective period is the first year after new rates take effect. This is simply a statement of the court mandated requirement that rates provide the utility a reasonable opportunity to earn the allowed return not only in total but that the rates match the cost of service by class of customers.

determining the classes of service. Type of service is another dimension such as full requirements or partial requirements that result in different demand characteristics for different portions of the system. Special service arrangements may impact the definition of classes. This would include customers who require redundant facilities for reliability or unusual load characteristics such as very low load factors. Finally, there may still be a need to recognize differences by traditional end use classes such as residential, commercial, industrial or size of customers within a class. The need to create multiple rate classes based on cost causation will be reduced. So the number of rate schedules in a tariff should be more manageable.

Full requirements customers are those who purchase the full bundle of services provided by the utility. Partial requirements customers are those who choose to select only some of the services provided by the regulated utility. To the extent that the selection of the services provided by the utility results in a different mix of hourly loads and more or less use of particular services provided by the unbundled utility, the partial requirements customers must be treated separately for cost recovery for rates to be just and reasonable.

There are many different categories of partial requirements customers. For example, customers who buy competitive generation services while using the utility for delivery of those services are no different with respect to delivery services than full requirements customers who use delivery services for utility generated services. By unbundling delivery service from generation services customers in the same class may make competitive choices and pay rates that are just and reasonable for delivery regardless of the source of energy and capacity for generation.

For other partial requirements customers the competitive services they purchase may change the cost characteristics for the customers. A simple example will illustrate this concept. Suppose a customer owns a run of the river hydroelectric generator that is used for supplying a portion of the customer's energy and capacity. By its nature a run of the river facility has highly variable output based on weather. During rainy periods the output is higher than dry periods when output may even be zero. For a summer peaking utility that may mean that there is no capacity at the generation peak of the utility and thus no capacity savings from the facility but only energy savings. It is likely that the facility produces its maximum output in the spring and fall so that the energy value is even less than the average energy value. As for delivery charges - transmission and distribution - the customer looks just like any other summer peaking customer for those charges as well. The potential for cross subsidy from other customers is high if costs are recovered in a simple two-part rate using average kWh charges. The subsidy is minimized if demand costs are recovered in demand charges, customer costs in customer charges and energy costs are based on seasonal time of use kWh charges.

A separate class for partial requirements customers is needed when the customers use the system differently than other customers who have the same end-use loads. Different usage patterns result from how a partial requirements customer uses the system. Simply, solar DG customers have far different load profiles than full requirements residential customers as I demonstrate in my testimony. These differing load profiles include much lower load factors, including the potential that some customers would have zero load factors and the class average load factor in the single digits. Solar DG customers provide an excellent example of a group of residential customers that use the system very differently from full requirements customers.

DR. H. EDWIN OVERCAST

Appendix E

DG Customer Load Shapes and System Impact

This Appendix contains our review of the 8760 demand data for the Residential class and the DG hourly demands for the same period (using the Concord Airport location hourly production profile). Please see the summarized results in Table 1:

Table 1 – Residential Peak Profile

Month 2015	**Hour of Peak**	**% Maximum PV Generation**	**PV Generation @ Peak (kW)***	**Class Peak (kW)**	**% Peak Reduction**
January	1/27/15 7:00 PM	0.0%	0	109,029	0.00%
February	2/15/15 7:00 PM	0.0%	0	115,318	0.00%
March	3/1/15 7:00 PM	0.0%	0	100,772	0.00%
April	4/9/15 7:00 PM	0.1%	2	80,119	0.00%
May	5/27/15 6:00 PM	7.2%	147	108,576	0.14%
June	6/23/15 8:00 PM	0.2%	4	101,928	0.00%
July	7/19/15 6:00 PM	15.3%	312	135,341	0.23%
August	8/17/15 6:00 PM	6.0%	122	129,006	0.09%
September	9/7/15 7:00 PM	0.0%	0	131,156	0.00%
October	10/18/15 6:00 PM	0.0%	0	87,778	0.00%
November	11/29/15 6:00 PM	0.0%	0	97,224	0.00%
December	12/29/15 6:00 PM	0.0%	0	103,091	0.00%
*Based on 2,029 kW of installed PV capacity (loss adjusted).					

As this table indicates, the UES residential class 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 basically not operating at time of most residential monthly peaks. Further, during the months in which PV is producing at the residential system peak, the production of the facilities is 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 .25% of peak. The data also means that there is no avoided distribution costs associated with solar DG because these changes are too small to impact the required size of distribution assets at the time of the class non-coincident peak (NCP).

The results for the analysis of the system peak are similar to those presented in Table 1 above for the Residential class. Please refer to Table 2 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, the effect upon system coincident peak reduction continues to be insignificant from any system planning perspective.

Table 2 – System Peak Profile

Month 2015	**Hour of Peak**	**% Maximum PV Generation**	**PV Generation @ Peak (kW)***	**System Peak (kW)**	**% Peak Reduction**
January	1/8/15 6:00 PM	0%	0	209,818	0.00%
February	2/2/15 6:00 PM	0%	0	206,567	0.00%
March	3/5/15 7:00 PM	0%	0	189,572	0.00%
April	4/2/15 10:00 AM	55%	1113	166,622	0.67%
May	5/27/15 3:00 PM	28%	573	233,851	0.24%
June	6/11/15 3:00 PM	72%	1476	217,670	0.68%
July	7/30/15 2:00 PM	82%	1670	268,272	0.62%
August	8/18/15 3:00 PM	94%	1925	265,389	0.73%
September	9/9/15 3:00 PM	15%	304	265,208	0.11%
October	10/28/15 6:00 PM	0%	0	170,091	0.00%
November	11/30/15 6:00 PM	0%	0	184,685	0.00%
December	12/29/15 6:00 PM	0%	0	193,496	0.00%
*Based on 2,039 kW of installed PV capacity (loss adjusted).					

I also 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 2,029 kW, loss adjusted) on the system as of December 2015; in addition, I evaluated the typical 8760 production profile of a solar DG facility in the region. The following Table 3 provides the DG monthly data used to develop a DG load profile.

Table 3 – Installed DG Solar Capacity and Customer Counts by Month

Month	Customer Count	kW AC*	Avg. Installation Size
1	130	749	5.76
2	136	788	5.80
3	139	812	5.84
4	147	885	6.02
5	159	988	6.21
6	166	1,095	6.60
7	177	1,175	6.64
8	186	1,232	6.62
9	197	1,317	6.68
10	213	1,425	6.69
11	241	1,623	6.74
12	285	1,928	6.76

*Not adjusted for losses

As this data shows, the later installations are uniformly larger than the earlier installations and raise the average size of installed DG.

Table 3 also shows that installed solar capacity more than doubled between January and December 2015. This growth rates emphasizes the need to address DER issues urgently.

My analysis of costs and load shapes assumes that all 285 customers had installed solar facilities for entire year. To make this proforma adjustment, I assumed that the full requirement load for the customers before solar installation is same as their billed kWh. Based on the actual installed capacity at the end of year, I could calculate both deliveries and excess kWh at any hour of the year as explained in detail below. Table 4 below shows a summary of my calculations.

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 4.

Table 4 – Annual Usage Profile 2015 of DG Customers

	Energy (MWh)				
Load Component	**Before Solar Installation (Calculated)**	**Notes**	**After Solar Installation (Metered)**	**Notes**	**Total**
Full Requirements (FR) Load	1,129	Metered	2,404	FR = Production + Deliveries - Surplus	3,534
Production	1,317	Based on proxy production profile Concord Airport location	1,838	Based on proxy production profile Concord Airport location	3,155
Deliveries	682	Calculated	1,419	Company metered data	2,101
Surplus	870	Calculated	853	Company metered data	1,722
Consumed at Premise	448	Production – Excess	985	Production – Excess	1,433

As this table shows, as a group, the DG customers continue to be heavy users of the delivery system with energy deliveries from the system equal to about two-thirds of the amount of energy produced by the PV system. This means that these customers are pulling almost as much energy from the grid during hours when their facilities are not producing as they are producing during daylight hours. In total, their annual full requirements load of 3.534 MWh is only slightly more than 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 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.

The data also shows that the maximum load on the delivery system occurs when the solar DG customers are using the system to deliver excess output for resale to the system. This value is based on data used to develop the solar class cost study and also to derive load shapes for DG customers. Figure 1 below compares the excess solar DG deliveries on the peak day of May 14, 2015 to the residential load shape scaled to match the DG load shape. The data shows that maximum solar output uniformly occurs in low load hours for residential customers and that solar output is zero in the highest cost load hours of the day. There are implications for this load shape related to the following:

1. Avoided distribution costs- there are none since this is the peak that delivery facilities must serve:

2. DG increases system losses as it pushes excess generation back onto the grid; and

3. DG with net metering and banking benefits from energy cost arbitrage.

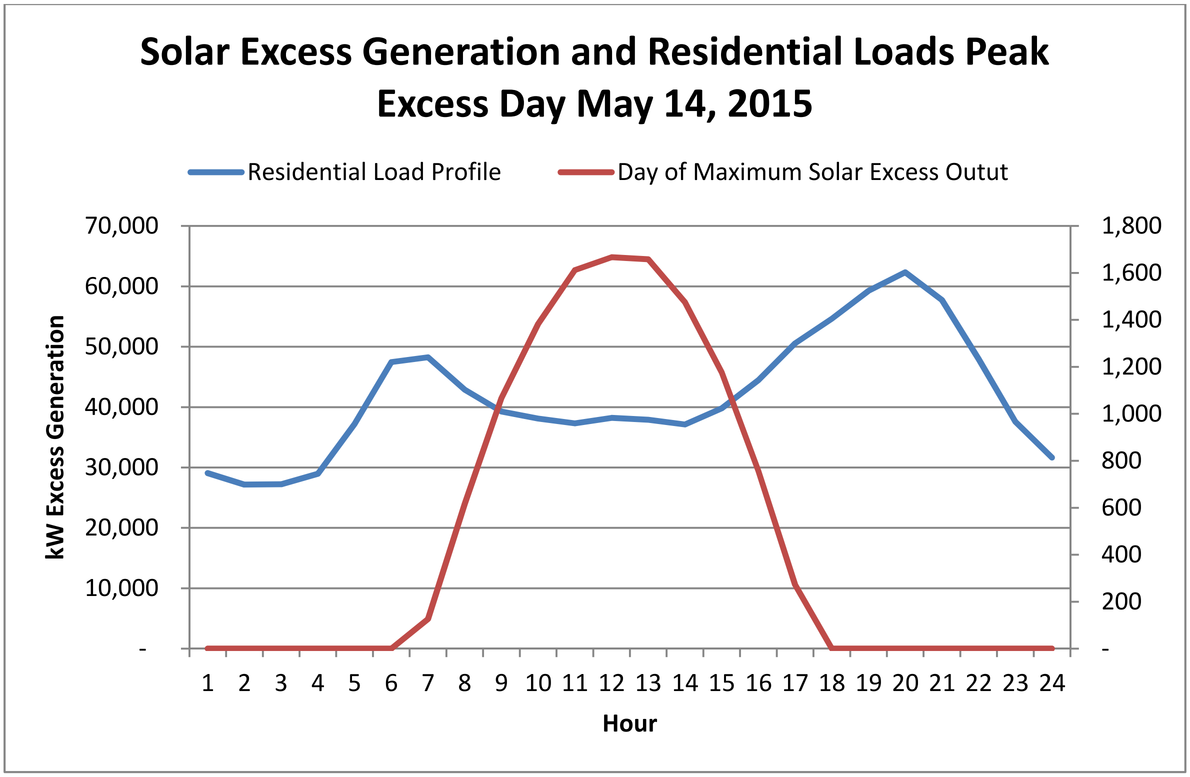

Figure 1 Solar Excess Deliveries

I have calculated the load duration curve for both DG solar and full requirements residential customers. Figure 2 below provides the load duration curves and demonstrates that these two groups of customers use the system differently and their load patterns are not the same.

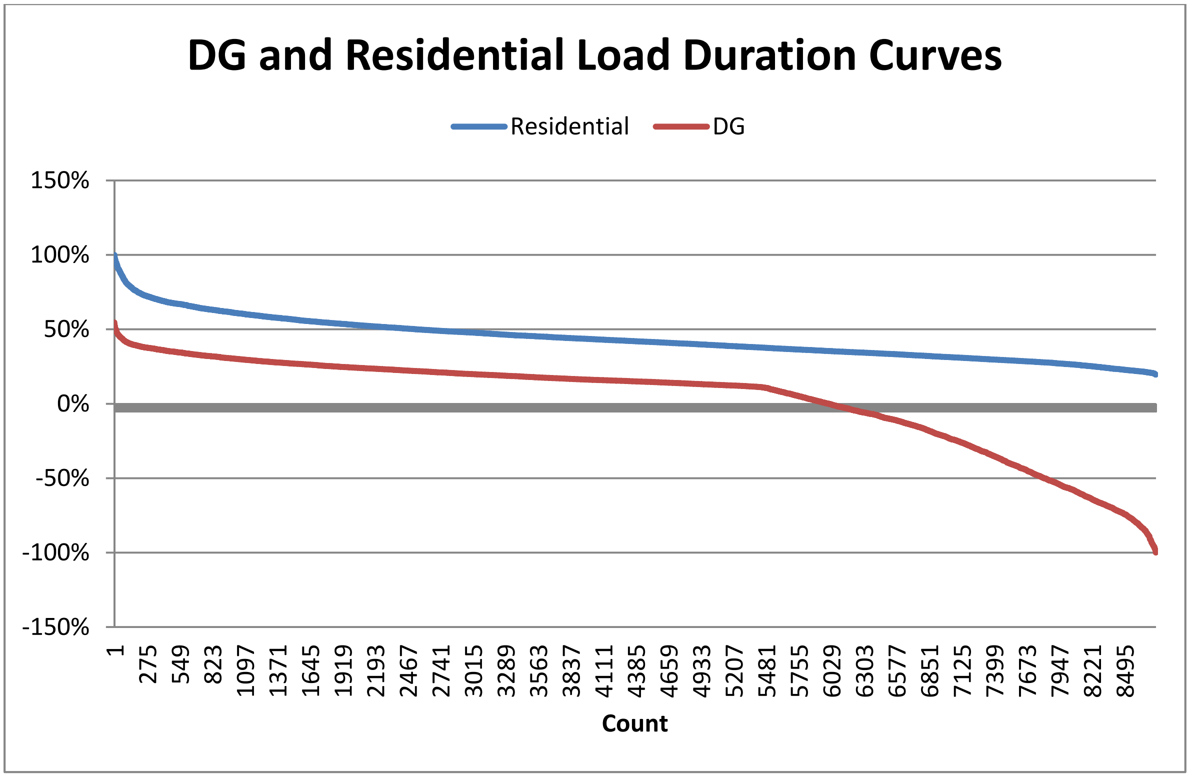

Figure 2 Load Duration Curves

In particular note that the load peak of solar DG customers is just slightly over 50% of the delivery peak. This verifies the conclusion that DG customers use the delivery system in different ways. It also illustrates why it is impossible to recover delivery system costs based on kWh charges when DG customers have zero kWh consumption as a class for over 2000 hours per year.

Figure 3 below illustrates the net load of solar DG customers on the same May 14th day. It shows how even with a small amount of DG on the system, the DG customers load creates the Duck Curve as discussed by CASIO in their planning documents. This will continue to grow as the installed DG grows on the system. At some point, if not already in aggregate, these loads will require additional spinning and operating reserves as well as fast start capability units to maintain voltage and frequency within desired operating limits.

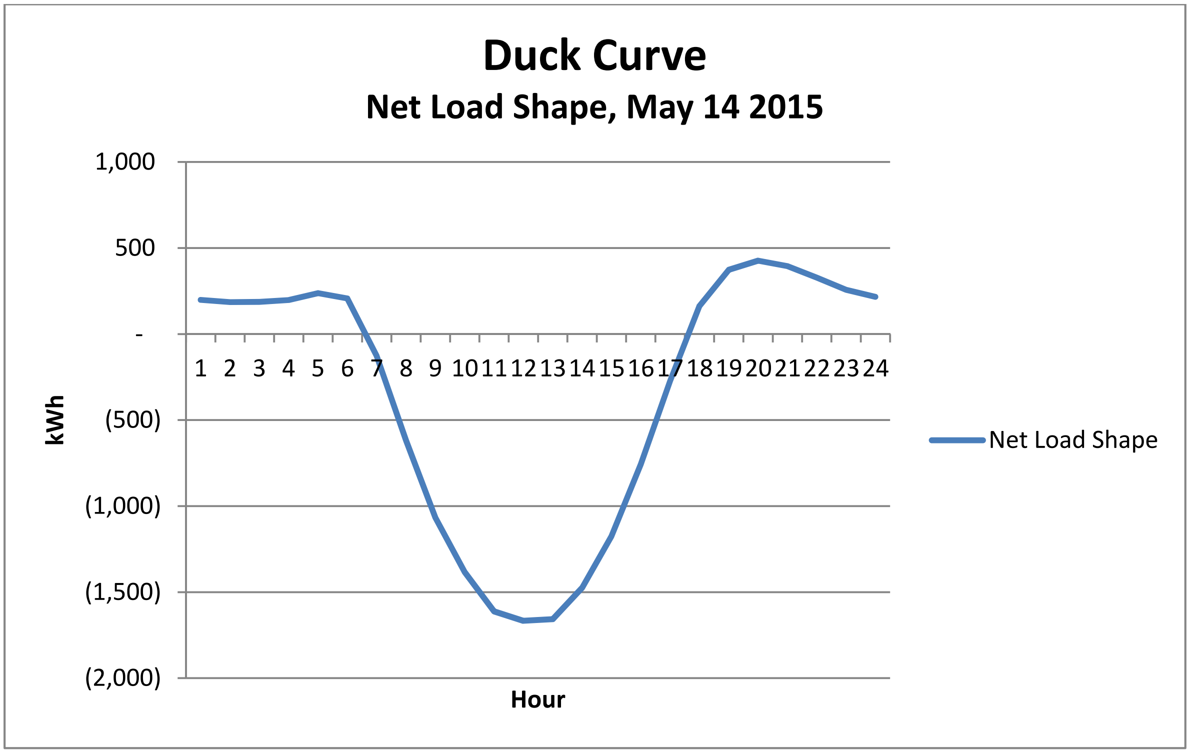

Figure 3 Duck Curve

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 and they actually cause more costs for excess deliveries than for load. This means DG adds cost to the delivery system and further confirms that there are no avoided delivery costs. 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 production peak load could be measured. Based on this data, I conclude that the current two-part rate for DG Prosumers significantly violates the matching principle of rates and creates undue subsidies for these customers that must be absorbed by non-DG customers.

Given the load differences, it is necessary to develop a separate class for these partial requirements customers. Using basic tools of rate analysis I show that a separate three part rate is the only feasible option for solar DG customers. It is instructive to compare the distribution of bills for the UES solar DG customers after installing solar DG to the counterfactual loads before DG. Figure 4 below shows how the bill frequency has changed dramatically from the full requirements monthly kWh billing to the solar DG monthly kWh billing.

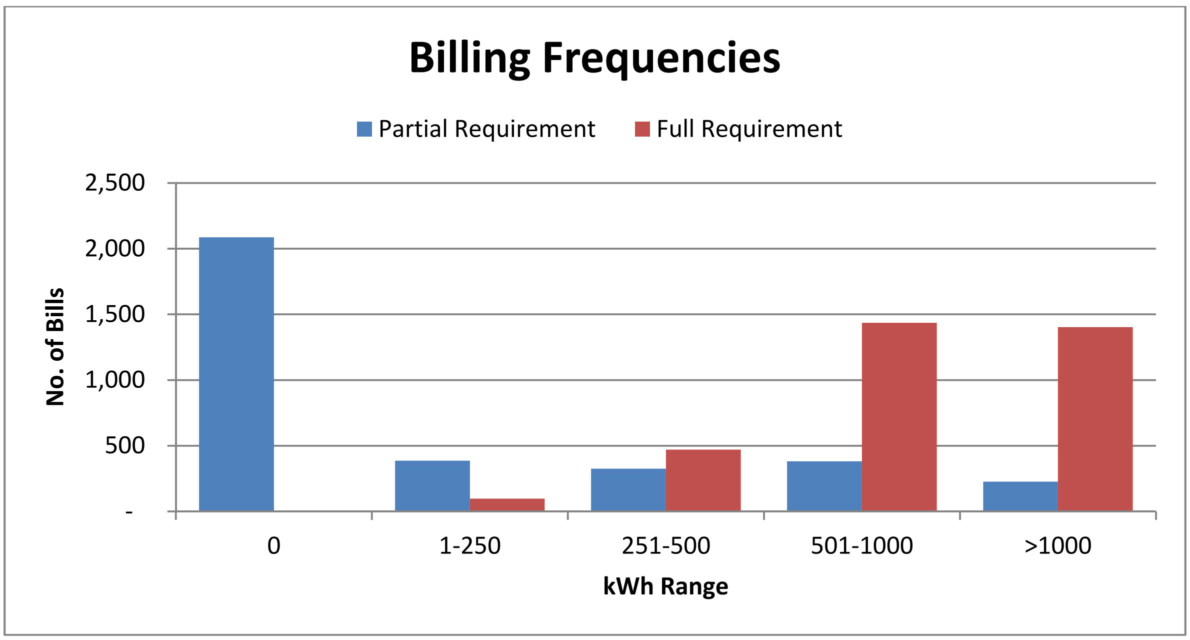

Figure 4 Comparative Bill Frequencies

Figure 4 shows that there are more bills for zero kWhs for solar DG customers that there were bills for over 1000 kWhs when these customers were full requirements customers. It is impossible for a two-part rate that recovers fixed delivery costs in kWh charges to recover the costs when these customers switch to DG and have most of their bills below 250 kWhs. The data shows that these solar DG customers actually use more of the delivery service capacity as DG customers than they did as full requirements customers. With so little energy use it would be impossible to recover the solar DG costs on the same rate as other full requirements customers. That conclusion is consistent with the cost studies above. It also means that there is not a two-part rate that can track costs for solar DG customers. Solar DG customers must not only have a separate rate class but a different rate design as UES has proposed in its rate case. The rate must have a compensatory customer charge, a demand charge that recovers fixed delivery costs and the default energy rate if served by the utility.

Using the UES solar DG class data and the load research class data used in the cost studies it is possible to analyze the class monthly load factor on the distribution system. That load factor is calculated as the class average demand for the month divided by the class NCP for the month. This NCP load factor illustrates how solar DG customers use the delivery system each month. Figure 5 below provides the monthly load factors of full requirements residential customers and the partial requirements solar DG customers.

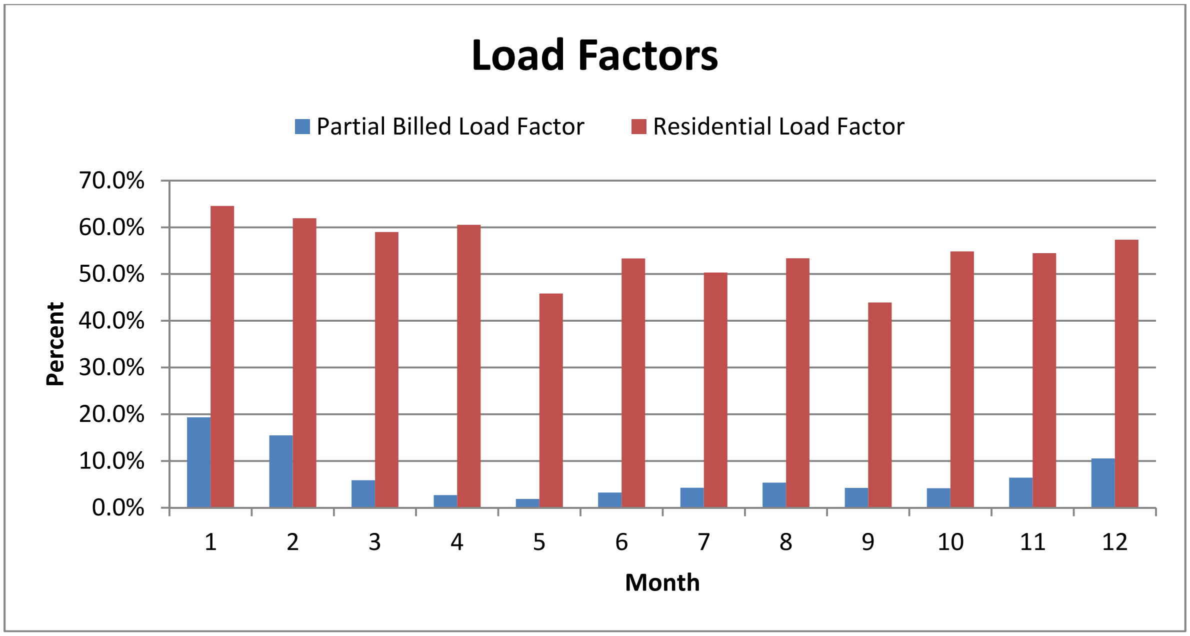

Figure 5 Comparison of Full Requirements and Partial Requirements Monthly Load Factors

As this comparison illustrates, solar DG customers have extremely low load factors in every month of the year and falling into single digits in nine of the twelve months. Residential full requirements customers have much higher monthly load factors in every month. The residential class has monthly class NCP load factors above 40% in every month and in 9 months of the year above 50%. In contrast, solar DG customers have 10 months when they do not exceed an NCP class load factor of 10% and they never exceed 20%. Given the differences in load factors for every month of the year it is impossible to conclude that solar DG customers are in any way similar to full requirements customers and therefore cannot be considered homogeneous with the full requirements customers.