STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design	**Matter 17-01277** **Case 15-E-0751**

Comments on the Joint Utility *Mass Market Bill Impact Analysis* and E3 *NEM Successor Rate Design Analysis*

Clean Energy Parties: Solar Energy Industries Association, Coalition for Community Solar Access, the Natural Resources Defense Council, the New York Solar Energy Industries Association, the Pace Energy and Climate Center, and Vote Solar

Dated: October 19, 2018

The Clean Energy Parties (CEP) appreciate the opportunity to comment on the two analyses presented at the October 10, 2018 workgroup meeting. These analyses, the Joint Utility's "Presentation on Mass Market Bill Impacts" (JU Analysis) and E3's "NEM Successor Rate Design Analysis" (E3 Analysis), represented the next steps in the Rate Design Workgroup process towards understanding how the various rate design proposals might impact different customers and different customer types. We recognize that this type of analysis has previously not been performed across the various utilities, and that efforts were made by the utilities to present their results in a consistent manner. We also acknowledge that performing and compiling the results was not a trivial task. That said, CEP has some methodological concerns about these analyses. We have also discovered at least one serious error and caution that the results of these analyses be viewed in the broader context of New York policy.

The results of our review indicate the representative customers from the JU analysis may not represent the larger population of customers or even subgroups of customers within specific stratum. This calls into doubt the results of the subsequent analyses on bill impacts, cost shift, and project economics. We outline the methodological flaws in these comments, but again request that the JU provide the customer level load research data, accompanied by a narrative of how the restrictiveness of the samples were tested to ensure applicability to the larger population of customers.

CEP disputes that the E3 Analysis demonstrates that a "cost shift" exists. As was clearly identified in the report and presentation, the values do not include the full "E" value associated with renewable generation, grossly underestimating the value. Further, it does not include externalized benefits such as economic development, health improvements, resilience benefits, and others. So while the specific parameters of this analysis may have calculated a mathematical shortfall in revenue collected through rates, the E3 analysis is not – nor does it claim to be – a comprehensive analysis that must be performed to determine if a "social cost shift" exists.

Assuming that the E3 Analysis is updated with corrected utility input, it will remain a more narrowly focused analysis. The results can be instructive, but they must be viewed within the proper context. A mathematical cost shift produced by this model is only part of the information that policy makers need to determine how to proceed.

JU Analysis

As presented at the October 10, 2018 meeting, the JU Analysis proceeded in the following manner:

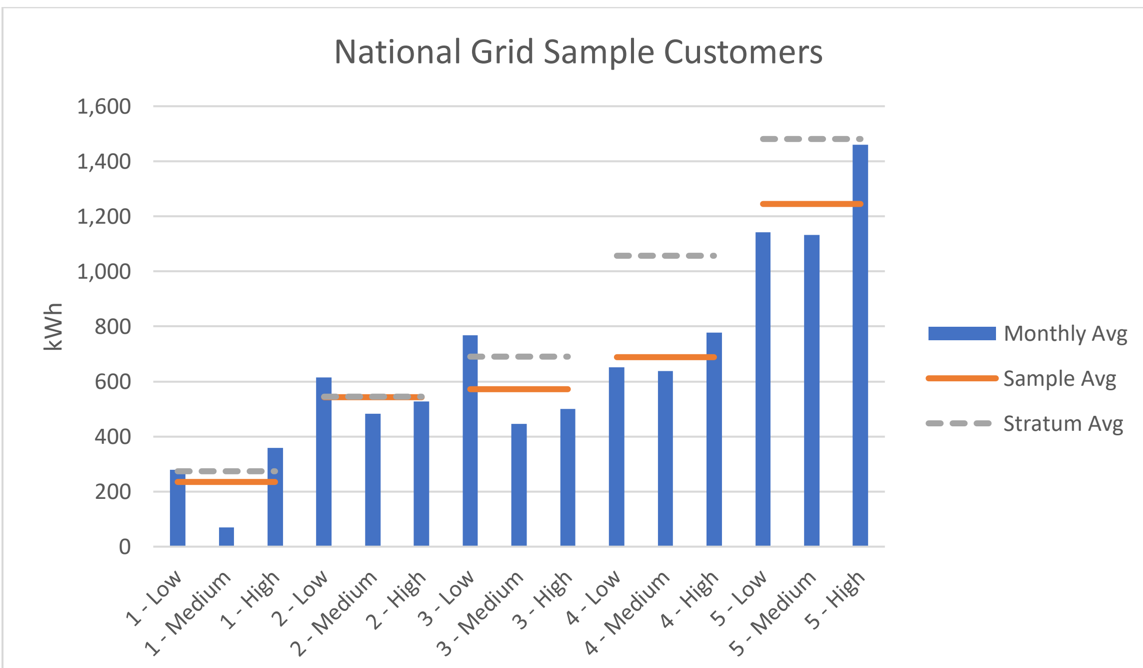
1. Each utility, using its internal or purchased load research data, segmented its customers into different strata.
2. For all customers in a stratum, the average monthly load factor was calculated and customers were rank-ordered by this metric.
3. A single, exemplar customer was selected for each stratum that most closely matched the 25th, 50th, and 75th percentile of the average monthly load factor distribution
4. Solar systems were sized to offset 70% and 100% of annual load of these customers, and hourly PV generation was determined for these systems from NYSERDA data.
5. Each individual customer's hourly load was modeled under each of the four rate designs and two sensitivities, in addition to the current rates, with no solar system.
6. Each individual customer's hourly usage was overlayed with PV generation data to produce a "net load" for both a 70% and 100% system. This net load was then re-analyzed under each combination of rates.

This methodology suffers from several problems that cast doubt on the representativeness of the analysis. Most of these issues come down to the decision to use rank-ordered monthly average load factors as a major criterion and to select only a single customer from each stratum/load factor for subsequent analysis. As a result of this decision, it is unclear whether the individual customer that was analyzed is truly representative of customers in the stratum, and whether the average of these customers can be relied upon as being representative of the full class. It is also unclear whether the strata are truly representative of the population. The Joint Utilities did not provide any additional detail or narrative around how these samples were tested for representativeness. These issues were subsequently propagated into E3's analysis.

The Selected Customers are Not Representative of their Strata

It bears repeating that CEP has been raising this issue for months and has repeatedly asked for, and has been repeatedly denied access to, the underlying load research data to perform this analysis on our own. While the four JU that utilize internal load research data did provide 8,760 strata data on October 12, 2018, and this information can be useful to better understand how rates impact specific customers, it remains insufficient to develop a complete understanding of the distributional impacts of the proposed rate designs.

A good example of this dilemma is found in the customers that were selected by National Grid (NG). The figure below reproduces the monthly average usage from the 15 sample customers, along with the sample averages by stratum (orange) and the full strata average (grey). As is shown, while the specific customer selected might come close to the 25th, 50th, and 75th percentile in average load factor, they do not share this distribution in terms of overall usage.



The customer for Stratum 1 / Medium has a miniscule monthly average usage of 69 kWh. This is so small as to require only a 0.66 kW system – 2 panels – to offset the customer's entire load. Clearly, this is not a viable solar candidate, and yet it is used to represent the median load factor customer for the stratum that holds nearly 40% of National Grid's customers. Another obvious issue is found in Stratum 4. Here, the sampled customers have an annual usage that is 35% lower than the full Stratum 4, with the closest customer "only" 26% lower.

The average customer usage is clearly asymmetric. Of the 15 customers, only 4 exceed the full stratum value, and on average exceed it by 14%. Meanwhile, the other 11 customers fall short of their stratum averages by 28% - twice as large of a discrepancy. In fact, two of the three Stratum 3 customers have a lower annual usage than any of the Stratum 2 customers, despite this grouping supposedly being comprised of larger customers. At the same time, the largest Stratum 3 customer uses more energy than all of the Stratum 4 customers, despite the full Stratum 4 average usage being 53% higher than the full Stratum 3 average.

National Grid's Analysis Contains a Major Error, while Others Have Smaller Inconsistencies

When performing this analysis, CEP uncovered a serious data error related to the calculation of the average monthly load factor in NG' model. CEP calculated each month's load factor and was planning to compare it to the average monthly load factor. In doing so, CEP discovered that in many cases, NG had transposed the average monthly load factor between multiple low, medium, or high customers, resulting in a mis-assignment of the customer for subsequent analysis.[1]

For example, while the average of the monthly load factors for Stratum 1 – Low is 10.2% (the same value that NG calculates), the Medium and High load factors are transposed. The average of the monthly load factor values for the Medium customer is 19.3%, while NG reports 16.5%, but the average of the monthly load factor values for the High customer is 16.5%, while NG reports 19.3%. The table below shows all the values, and only three of the 15 are correct, highlighted in green below:

	Reported LF			Calculated LF		
Stratum	**Low**	**Med**	**High**	**Low**	**Med**	**High**
1	10.2%	16.5%	19.3%	10.2%	19.3%	16.5%
2	14.3%	19.7%	23.9%	23.9%	14.3%	19.7%
3	14.9%	17.6%	22.7%	22.7%	14.9%	17.6%
4	17.5%	20.9%	25.0%	17.5%	25.0%	20.9%
5	22.4%	24.2%	29.3%	24.2%	22.4%	29.3%

[1] This error does not change the previous analysis related to the kWh of usage in each stratum, although it would impact the order of the low, med, and high bars within a strata.

This error is damaging to NG's analysis, as all of the subsequent results that presented results based on low, medium, and high load factors, as well as E3's summary that utilized NG's data as is, are corrupt. CEP has not performed a thorough analysis of the remainder of NG's workpapers, but the presentation of the results, and the incorporation of NG's values into the E3 Analysis is broken.

CEP attempted to determine if other utilities' analyses were similarly burdened. This task was complicated as utilities utilized different methodologies to calculate their figures, and what follows is not a comprehensive review of each utility's model.

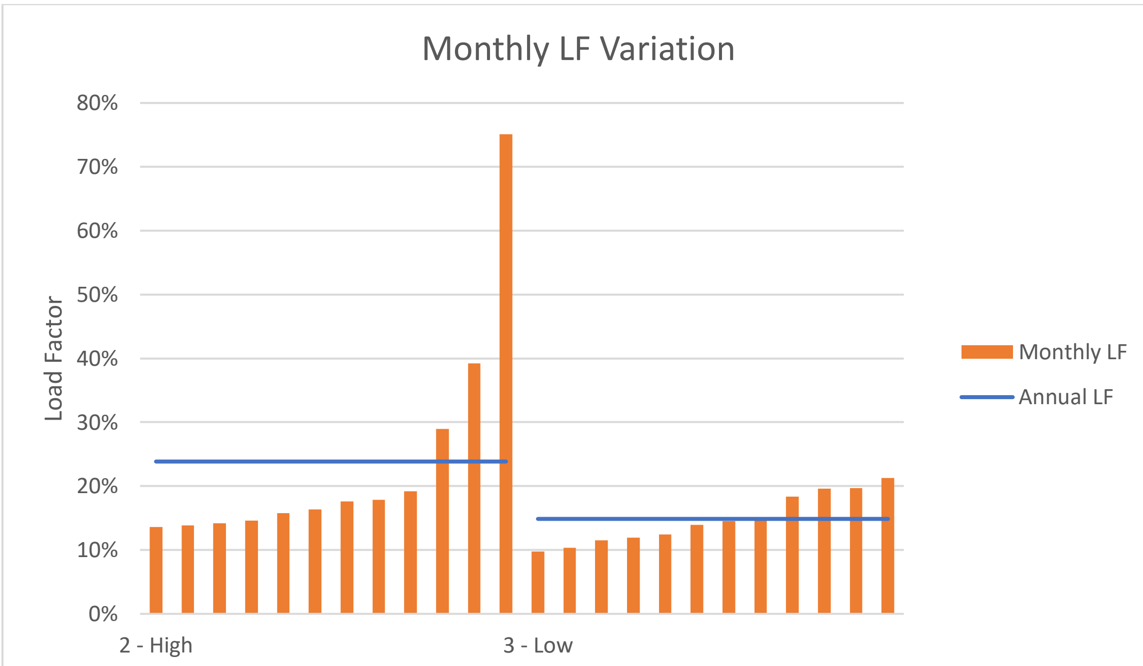
NYSEG and RG&E appear to have used one base customer per strata, and then manipulated either the kWh or kW data to produce the low, medium, and high load factor customers. This is evident in its worksheet. For instance, all three Strata 1 customers have identical annual usage, but the load factors vary. Further, the ratio of peak demand values between the low, medium, and high load factor customers are the same across different strata, even as the total kWh change. It does not appear that NYSEG and RG&E based their analysis on 15 unique customers as some other utilities did. This further exacerbates the representativeness of the sample issue

An analysis of O&R's and Con Edison's workpapers show inconsistencies between the average annual load factors presented on the main summary and the average of the monthly load factors derived from the data sheets. The differences are relatively small, and do not appear to have the same transposition issue as NG. Further, the average of the monthly load factors do consistently increase as one steps from low, medium, and high categories, even if they do not match the summary value. However, the reason for this inconsistency is unclear.

The Average of Monthly Load Factors Masks Important Information

Returning to NG's workpapers, and after correcting the load factors to properly align the low, medium, and high categories, another methodological issue surfaces. The decision to select customers based on the average of monthly load factors masks the large variation that individual customers may have between months. Further, this approach does not distinguish high or low values in summer or winter months, when the impact on the grid – and hence cost to serve the customer – varies dramatically.

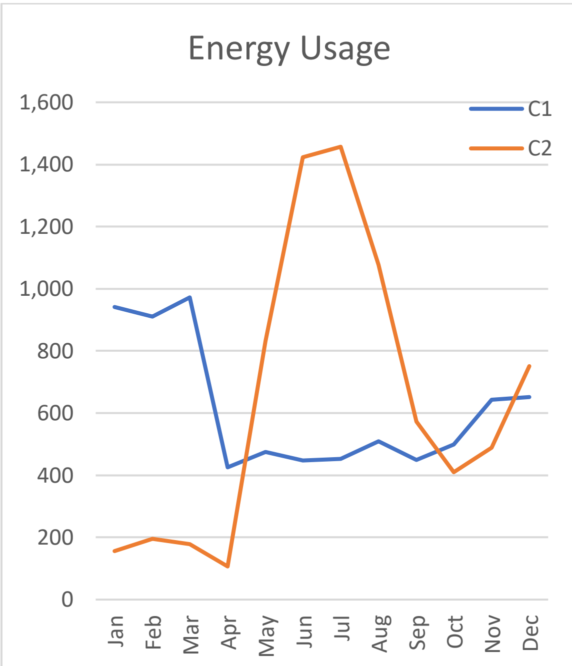
The chart below shows the corrected Strata 2 – High LF and Strata 3 – Low LF customer. While the average value for the high load factor customer is 60% higher (23.9% vs. 14.9%), it become quickly evident that this result was produced from just a few months' of unusually high readings that do not reflect the typical usage of the customer. If one were to exclude the three highest months from each average, the high load factor customer is only 21% higher (15.9% vs. 13.1%), a much more modest difference.

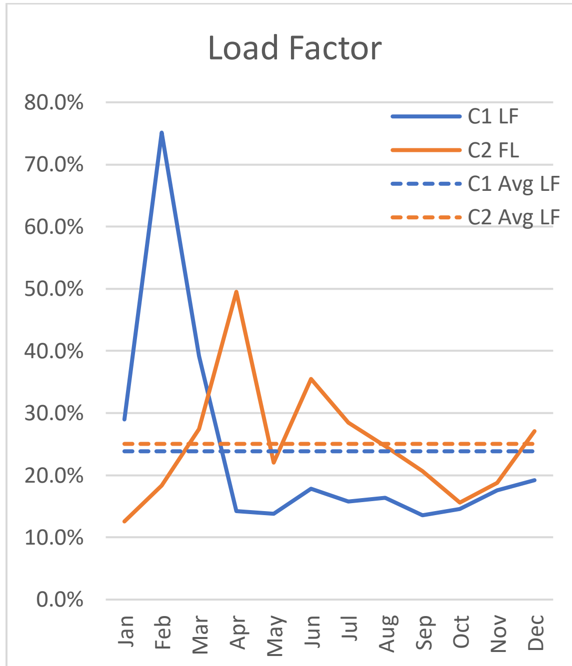


We performed a more detailed analysis for two customers in NG sample. Although these two customers were selected from different strata, the total annual energy and load factors are within 5% of each other. This is substantially less variation than between customers within a stratum in NG's sample. Using these key metrics, the customers might appear to be quite similar, despite their assignment to different strata.

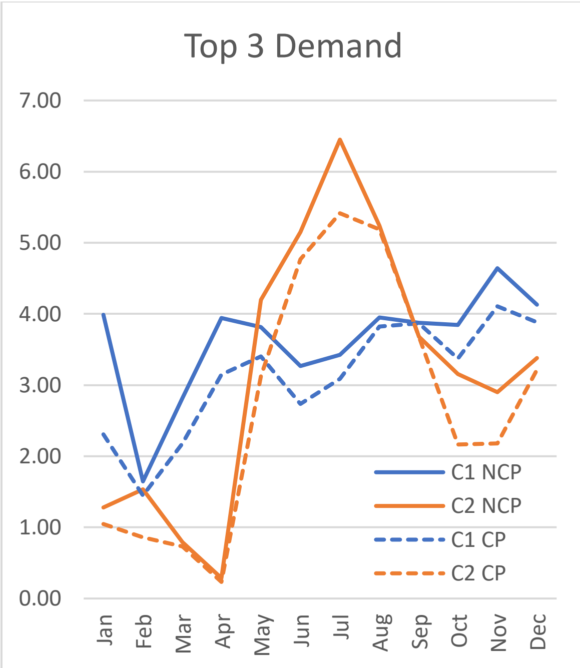
	Customer 1	**Customer 2**
Strata	2	4
LF Category	High	High
Annual Usage	7,378	7,646
Avg. LF	23.9%	25.0%

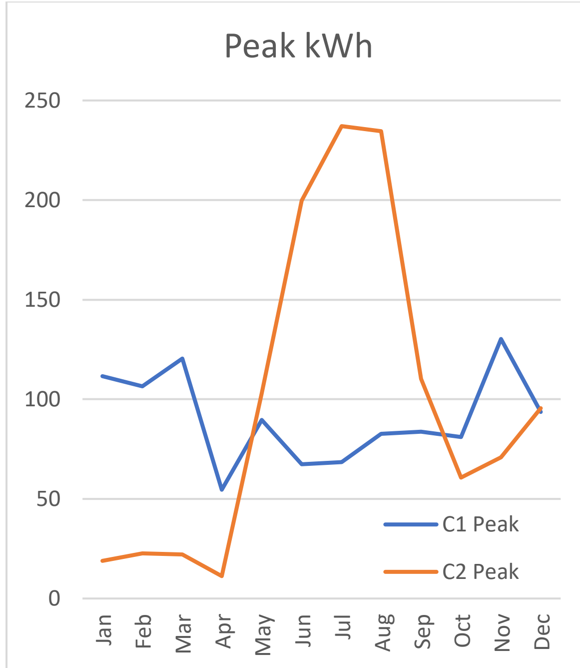
A closer look at the underlying data reveals a substantial variation in the usage of the two customers. Customer 1 appears to be an electric heat customer with no air conditioning, while Customer 2 appears to have natural gas or oil heat and air conditioning. The load factors vary substantially month to month, even as the annual average is very similar. Customer 1 has several months of high load factors in the winter months, but relatively low load factors in other months.





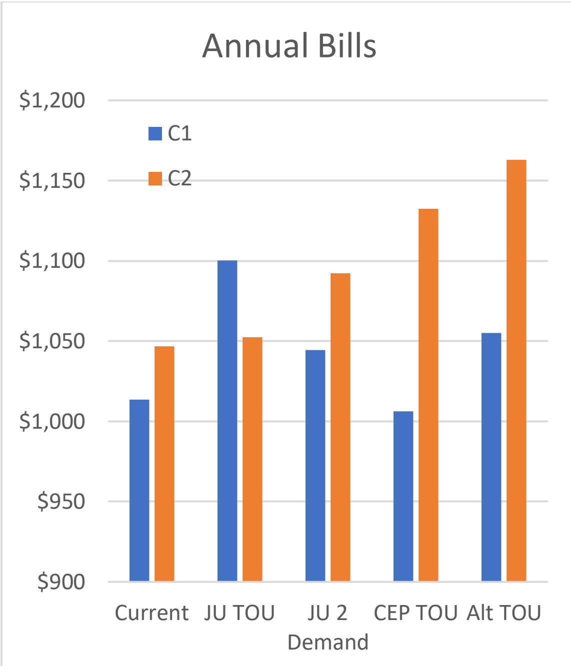
There are also differences in the peak demand and on-peak energy usage of the customers. When using the JU's methodology of the top 3 non-coincident peak (NCP) and coincident peak (CP), we find that Customer 2 puts more load on the system during peak hours in the summer. This is consistent with the higher overall usage in the summer likely due to air conditioning. We also find that Customer 2 uses considerably more on-peak kWh than Customer 1. These are expected results based on the monthly usage profile.

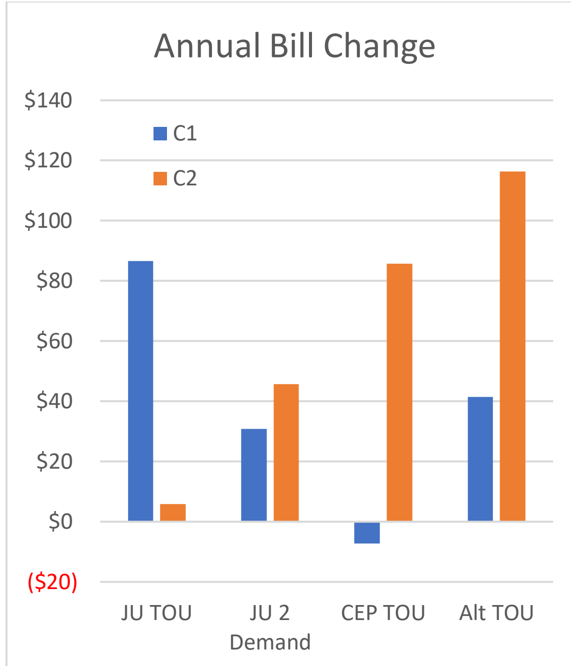




While these two customers are both "high" load factor customers based on the average of the monthly values, it is evident that they place very different burdens on the system. NG's rate design establishes a peak period between 1 and 6 PM weekdays, and has higher rates in the summer than in the winter. The CEP rate for NG has a summer peak period between 2 and 6 PM and a winter peak period between 2 and 8 PM. Customer 2 uses more energy and has a higher on-peak demand in the summer months. Given the peak hours that NG selected, one would think this should result in higher bills for Customer 2 relative to Customer 1. However, this is not consistently the case.

Customer 2 does pay about 3% more than Customer 1 under the current rates. But under the JU TOU demand rate, Customer 1 would see their bill increase by nearly $90, while Customer 2 would only see a $6 increase, despite Customer 2's much higher on-peak system usage. This is almost the exact opposite result from the CEP proposal, where Customer 1 would reduce their bill slightly, while Customer 2's summer usage results in a higher bill.





The point of this analysis is not just to show how these two customers would be individually impacted by the various rates (although this result is instructive), but rather to show that "similar" customers based on the JU's sorting and selection methodology can face dramatically different bill impacts depending on their actual detailed usage. Without access to the underlying data, it is impossible for CEP to know whether these two individual customers truly represent their strata. Had the JU selected a customer one entry up or down on the sorted list, it is possible that the entire outcome of their analysis would change.

E3 Analysis

As explained in the October 10 meeting, E3 utilized data from the JU Analysis and calculated the weighted average bill savings and avoided cost for each utility, the "cost shift" and rate impacts for non-participants, and a projected economics on a use-case basis. These analyses were performed for the existing rates as well as each of the four rate designs and two sensitivities discussed previously. The methodology appears to focus on the first-year impacts rather than a discounted NPV of revenue and cost streams.

The analysis also calculates DRV on a ten-hour basis, as opposed to the proposed 460-hour basis. While the 460-hour update has not yet been formally approved, it is CEP's expectation that it will be in the future. It is difficult to determine from the analysis how large of an impact this will be on the avoided DRV value for these customers, but by using just 10 hours from a handful of customers, once again calls the representativeness of the selected customers into question.

Given the major issues that CEP uncovered in NG's analysis, CEP does not consider the E3 results for NG to be accurate or useful in this proceeding. Additionally, both CHG&E and RG&E submitted revised bill impact analysis in the past week that were not incorporated into E3's analysis. Although it appears the scope of these revisions were contained to just one or two rate designs for these utilities, it further muddles the presentation of the overall results.

E3 Analysis is Not a Comprehensive "Social Cost Shift" Analysis

E3 incorporated the JU Analysis data on a per utility, per strata basis and averaged the savings from an effective 85% solar customer (a 50/50 split between the 70%/100% levels). It then used these data to create a load-weighted average for each utility, excluding any customers who used fewer than 150 kWh per month as they were unlikely to be prime on-premise solar customers. Based on this average customer, the bill savings from customers were calculated for each rate and sensitivity. E3 also calculated a "cost shift" value, representing the amount per 10 MW of solar that was undercollected from solar customers as compared to the average revenue from the class. Finally, E3 calculated a simple payback period using capital costs from NYSERDA, a 2020 ITC value, and first year savings from the system.

A Lack of Workpapers Prevents Transparency

E3 did not provide detailed workpapers of its analysis, providing only the hardcoded values behind the charts in its presentation. This made an analysis of its methodology impossible. CEP asked for, and E3 provided, additional results at the strata level, along with results for 70% and 100% PV customers. But key steps, such as how customers under 150 kWh per month were treated, and how the weighted averages were constructed, remain unknown.

The lack of transparency is problematic. In its presentation, E3 indicated that "load profiles with less than 150 kWh/month were excluded as unlikely candidates for solar adoption". While CEP does not disagree that customers this small are unlikely to adopt roof-top solar, they very well could adopt community solar. However, since community solar rates are not in scope for this exercise, this issue is less of a concern.

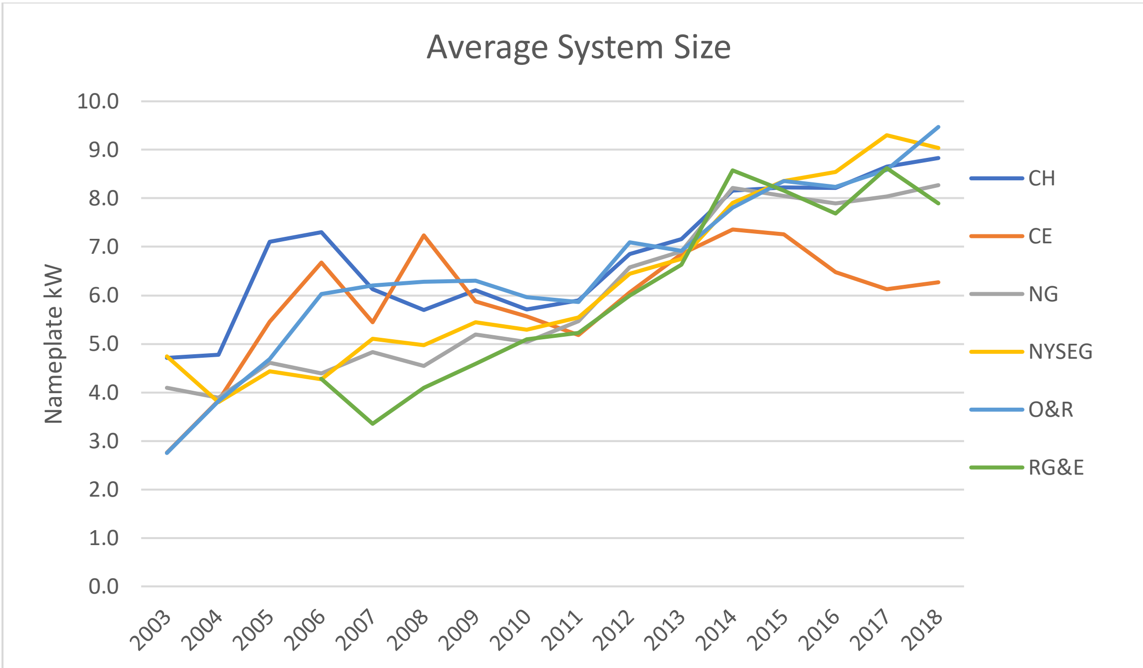
That said, the specific manner in which E3 excluded these customers could have an impact on the calculation of the weighted average. If E3 excluded the individual customers in the stratum that were under this threshold, and calculated the strata average with the remaining two, it will produce one result. If they instead removed any customers from under 150 kWh from the customer count of the strata, it will produce a different result. E3's workpapers are insufficient to determine which method was taken.

It is also unclear how the weighted average was calculated. E3 indicated that "bill savings are calculated as the load-weighted average of the savings in each stratum (with equal weight given to each load factor and each PV size)". If weighted by the stratum load, this could produce a result with larger-than-appropriate aggregate PV system size, overstating the size of the size of savings relative to usage. If weighted by customer count within each stratum, the final aggregate PV system size will be closer to what is needed to match the consumption of the average customer, leading to more appropriate results. The lack of detailed workpapers makes it impossible to determine which of these methodologies were followed.

Projected Installed System Sizes Do Not Reflect Market System Installs

Embedded in E3's methodology is the assumption that the PV system size that were used to calculate the "cost shift" are in fact the types of systems that will be installed in the market. However, this is not the case.

Data from NYSERDA's NY-SUN contains data on almost 85,000 residential PV systems installed since 2000. CEP analyzed this data set to determine trends in PV installations and to compare actual system sizes to modeled system sizes. As seen below, the trend in all utilities except for Con Edison is towards larger systems. In 2011, the average system was between 5 and 6 kW for all utilities. By 2018, with the exception of Con Edison, this figure had increased significantly to between 8 and 9.5 kW.



The average system size is not the only metric that recently changed. In the past five years, the median size has increased from 6.8 kW in 2013 to 7.9 kW in 2018. The share of the market that is comprised of systems under 3 kW remains very small, ranging from 1.7% of installs in O&R to 5.7% of installs in CE, with the other utilities coming in between 2.5% and 4% of installs. However, based on the strata averages provided by the utilities, 43% of customers across all utilities would require a system below 3 kW to cover either 70% or 100% of their load.

Based on this data, there exists a mismatch between the types of systems that the JU Analysis and E3 Analysis assume and what is actually being installed in the market. The practical effect of this is that the E3 Analysis overweights the contribution that small systems have in its aggregated figures.

Subject to the representativeness issues that were raised earlier, it appears that under the JU demand rates, smaller customers save relatively less on their bill from installing solar than do large customers. In the JU presentation, Strata 1 customers reduced their bill by between 10% and 35% on the demand tariffs with 100% solar, while Strata 5 customers reduced their bills by between 45% and 60%. By overweighting the Strata 1 customers, the reported "cost shift" of the

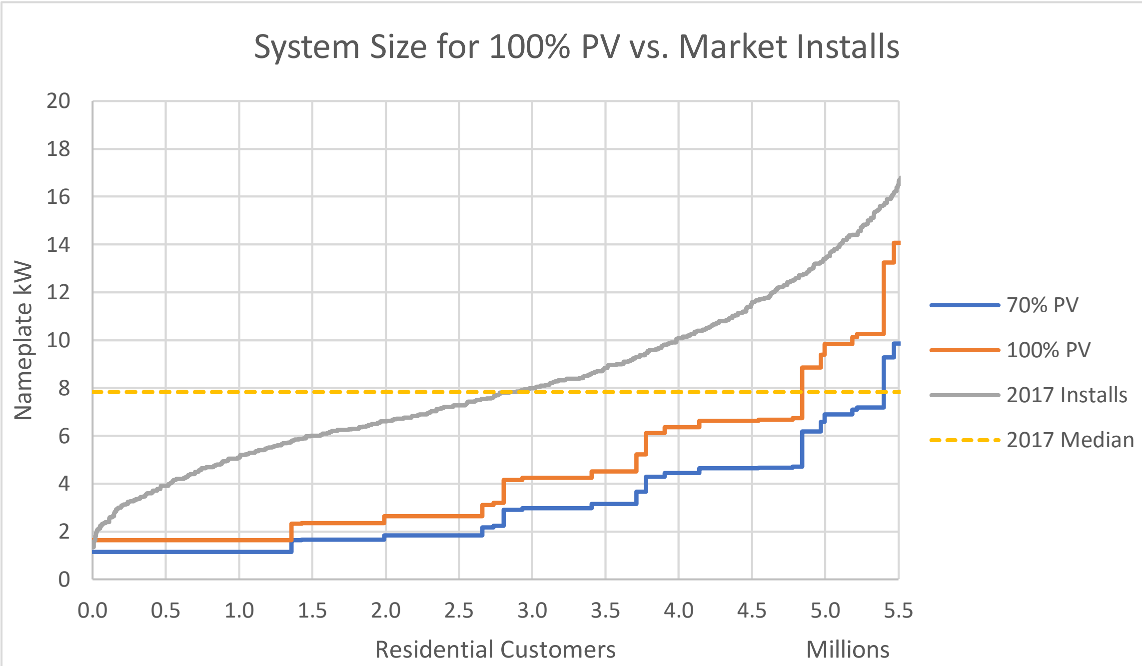
JU demand rates is likely lower than it would be based on market installs as fewer small customers would install solar, leading to more large customers with higher bill savings.

For the volumetric TOU rates, there is a similar outcome, but the scale of the change is different. Under the CEP rate, Strata 1 customers reduce their bill between 45% and 55%, while Strata 5 customers reduce their bill around 75%. Without more transparency on how E3 performed its analysis, it is not possible at this time to fully understand how this issue would affect the results of the various tariffs.

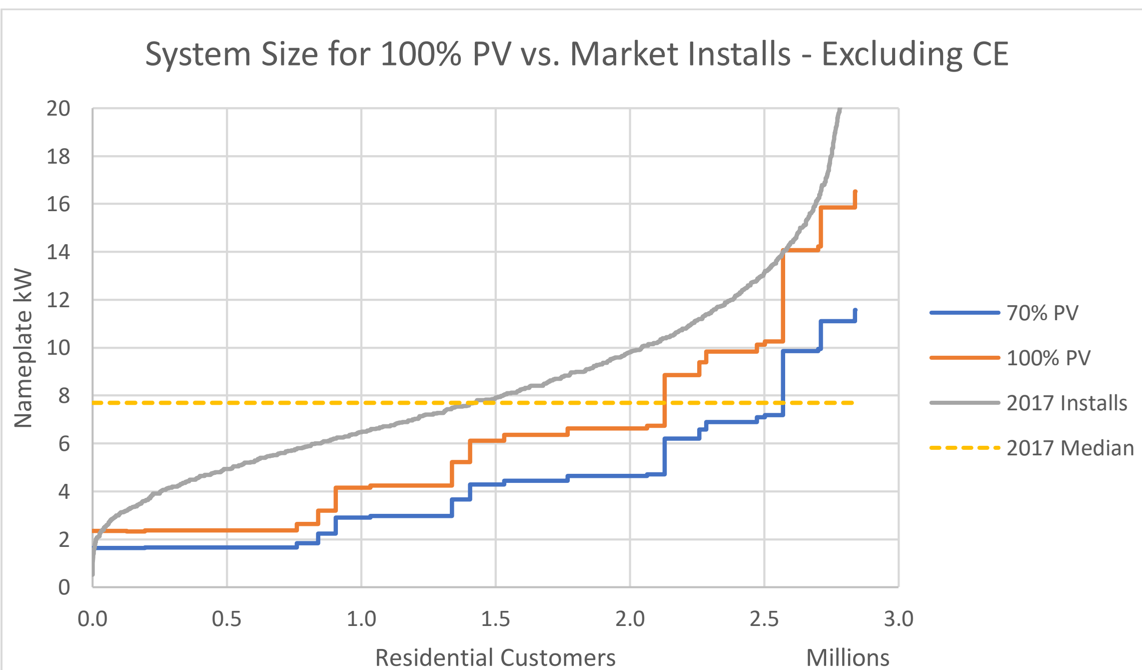
Customers Requiring Small Systems are At Risk of Losing Access to Onsite Solar

The predicament of small customers is clear. Under the JU demand charge rate designs, the savings that accrue to small customers is simply too low to justify installing onsite solar. However, these same customers make up the bulk of residential accounts in the utilities' territories. There is already a challenge to cost-effectively install small PV systems under the current rate designs, as evidenced by the dearth of small system installs. Adding in additional challenges associated with rate designs that disproportionately affects small customers is an unneeded headwind.

The figure below shows the usage profile of the entire class of residential customers, along with the PV system size that would be needed to meet 70% and 100% of their annual load. Note that because the data here is based on strata averages, there is a step effect that would not be evident in a chart with each individual customer usage, but the general shape should be quite similar. Overlaid on this is the actual distribution of market installs, scaled to the number of customers. At each point in the actual install curve distribution, the market is delivering systems larger than can be used by the corresponding customer.



This issue is influenced by Con Edison's territory, where there is a disproportionate quantity of small customers. However, even after excluding Con Edison from the data set, the issue clearly remains.



Conclusion

The errors in NG's should be rectified and its results reposted. Con Edison and O&R should determine why the average of the monthly load factors on their detail pages do not match the values on the summary page and provide an explanation. NYSEG and RG&E should provide more details on how they produce the kW and kWh values for their strata customers as their methodology appears to diverge from the other utilities.

E3 should provide additional workpapers and increase the transparency of its analysis. At a minimum, it must rerun its analysis with the corrected workpapers from the JU. It should also provide more information on how the 150 kWh cutoff was managed and how the weighted averages were calculated from the utility data.

The solar industry, environmental advocates, and many New York public officials have embraced a policy goal of having enough distributed solar in New York state to serve 1 million households, just five years from now. The NYSERDA database currently has about 90,000 entries. To attain a more-than-ten-fold increase in the number of solar systems, dramatic efforts will be required across all areas of policy. Although rate design is only one such mechanism, it is a critical policy lever.

Despite all the issues that CEP identified with the JU and E3 Analyses, they do highlight the specific challenge that small customers face in installing onsite solar. CEP does not believe that an entire swath of the market should be left on the sideline, unable to cost-effectively install onsite solar systems due to biased demand-based rate designs. And while other policy support for small systems might be possible, these are subject to budget constraints in a way that rate design is not.