STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

WHITEPAPER REGARDING CAPACITY VALUE COMPENSATION

December 14, 2018

Introduction

In the Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Transition Order), the Public Service Commission (Commission) established a new method of compensation for distributed generators, including large on-site generation projects, remote crediting projects, and community distributed generation (CDG) projects. This new compensation method, the Value Stack, offers compensation to the owners or beneficiaries of those projects based on the actual, calculable values that those projects provide to the system when injecting power. One element of the Value Stack is Capacity Value, which reflects the value that a distributed generator provides by offsetting the need for the interconnecting distribution utility to purchase installed capacity (ICAP) in the wholesale market.

This Whitepaper discusses the experience with Capacity Value compensation over the first 12 months of Value Stack applicability and provides Department of Public Service Staff (Staff) recommendations for improving Alternative 1 and Alternative 2 Capacity Value compensation. Staff recommends that the proposed changes in this Whitepaper be taken up by the Commission simultaneously with the proposed changes in the Staff Whitepaper Regarding Future Value Stack Compensation also filed today so that all modifications to Value Stack compensation happen at the same time. In advance of Commission consideration, Staff requests stakeholder comments on these recommendations by February 25, 2019 and requests that stakeholders specifically provide input on the questions listed at the end of this Whitepaper.

Background

The VDER Transition Order recognized that utility ICAP costs were most precisely caused by the consumption that occurs during the New York Control Area (NYCA) single peak hour every summer. Thus, the most accurate way to compensate distributed generators for allowing utilities to avoid capacity costs by injecting power would be based on the quantity of injections during that NYCA peak hour. This is often referred to as the “capacity tag” approach. It is the method used to bill mandatory hourly price customers for their ICAP responsibility. It is also the method that the Commission ordered be used for compensating “dispatchable” technologies in the VDER Transition Order. In the VDER tariffs, this method is referred to as

"Alternative 3." It is mandatory for dispatchable technologies and optional for other technologies.

Because the NYCA single peak load hour is not known with certainty until after the summer cooling season is over, the Commission concluded that this would be too volatile a compensation method for intermittent technologies such as solar and wind, at least at the outset of VDER:

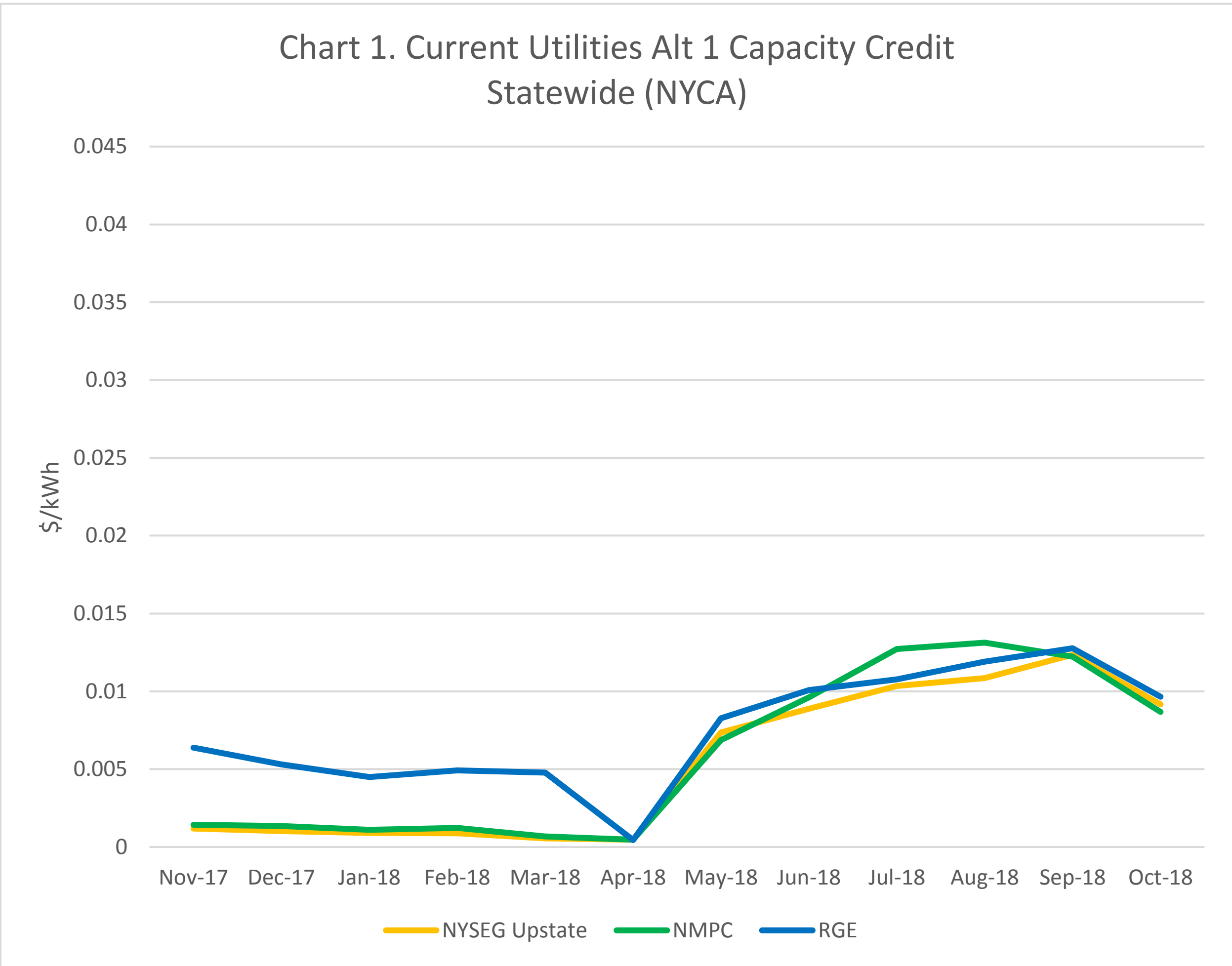
> …[C]ompensating these technologies through the capacity tag approach could provide a highly variable and uncertain revenue stream to these facilities. That, in turn, could be a serious impediment to the maturation of this nascent market, especially during Phase One of the transition from NEM. (VDER Transition Order, p.102)

Therefore, the Commission accepted two alternative compensation methods proposed by Staff. The default method, Alternative 1, was based on "the capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile" and spread that class's $/kW value into a $/kWh value with compensation at that value received for all generation during all hours of the year. A second option that intermittent resources can select, Alternative 2, instead compresses the $/kW value into a higher $/kWh value with compensation at that value received for all generation during 460 summer hours to "encourage project siting and design focused on peak summer hours." The 460 summer hours are 2:00 PM to 7:00 PM on every day from June 1 to August 31.

Discussion Regarding Alternative 1

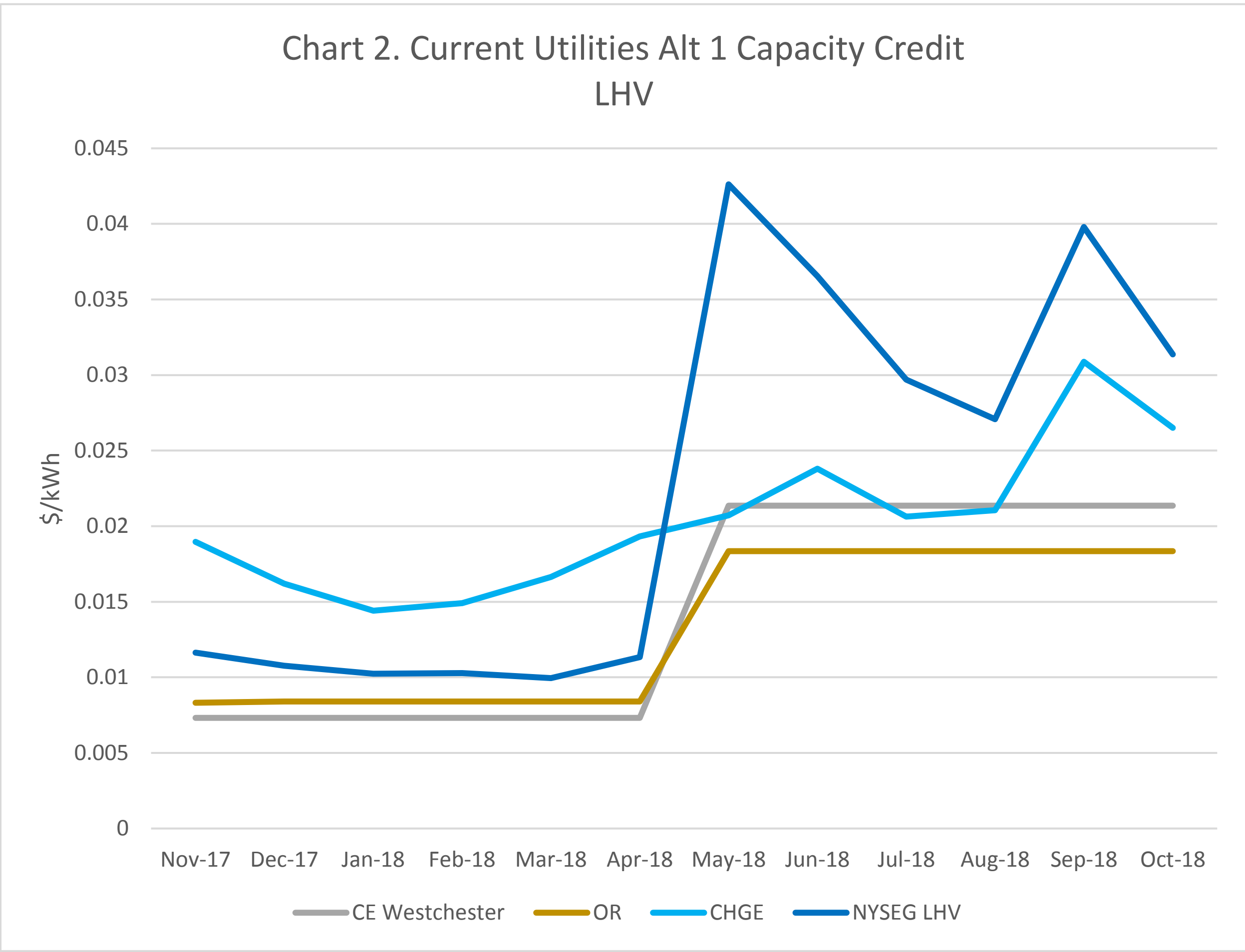
After review of proposed methods, the Commission, in its September 14, 2017 Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (VDER Implementation Order), ordered the utilities to use the "peak kW to kWh" method described in that Order for selecting the service class with the load shape most similar to the PV load shape estimates on the record. This led to each utility selecting a service class unique to its tariff, which, while similar as possible to the solar generation load shapes, may differ in ICAP cost recovery design from other utilities for various reasons. Nonetheless, the first year of capacity credits for the three utility regions in the "Rest of State (ROS)" ICAP region were fairly similar to each other, as shown in Chart 1.

The one exception to this was that RG&E's credit for November 2017 through March 2018 was noticeably higher than for National Grid or NYSEG-Upstate. RG&E explained that this difference was because it had mistakenly included the service class's annual hedge value in the credit calculation for November through March but excluded those hedge values for April and subsequent months once it discovered their inclusion. These annual hedges tend to levelize ICAP costs over the year and thus including their value provides higher than seasonal values in the winter months and lower than seasonal values in summer months. Because RG&E caught the mistake before the summer months, it claims it did not disadvantage any project.



However, this highlighted an unexpected issue to Staff. The method used for determining the service class to be used for Alternatives 1 and 2 was based solely on load shape. However, some of those service classes ICAP costs are hedged by their utilities and therefore they receive an all-in ICAP charge based on a mix of spot and hedged prices; others of those service classes are unhedged and simply are charged based on NYISO-reported ICAP prices (some monthly "spot" prices, others 6-month "strip" prices); while still others are hedged but the hedge component is assessed to customer bills as a separate rate element.

In addition to this ICAP cost hedging distinction among utilities, it is clear that, even though the same method was used to select service classes, these do not necessarily reflect consistent values across the utilities in the Lower Hudson Valley (LHV) ICAP region (Chart 2).



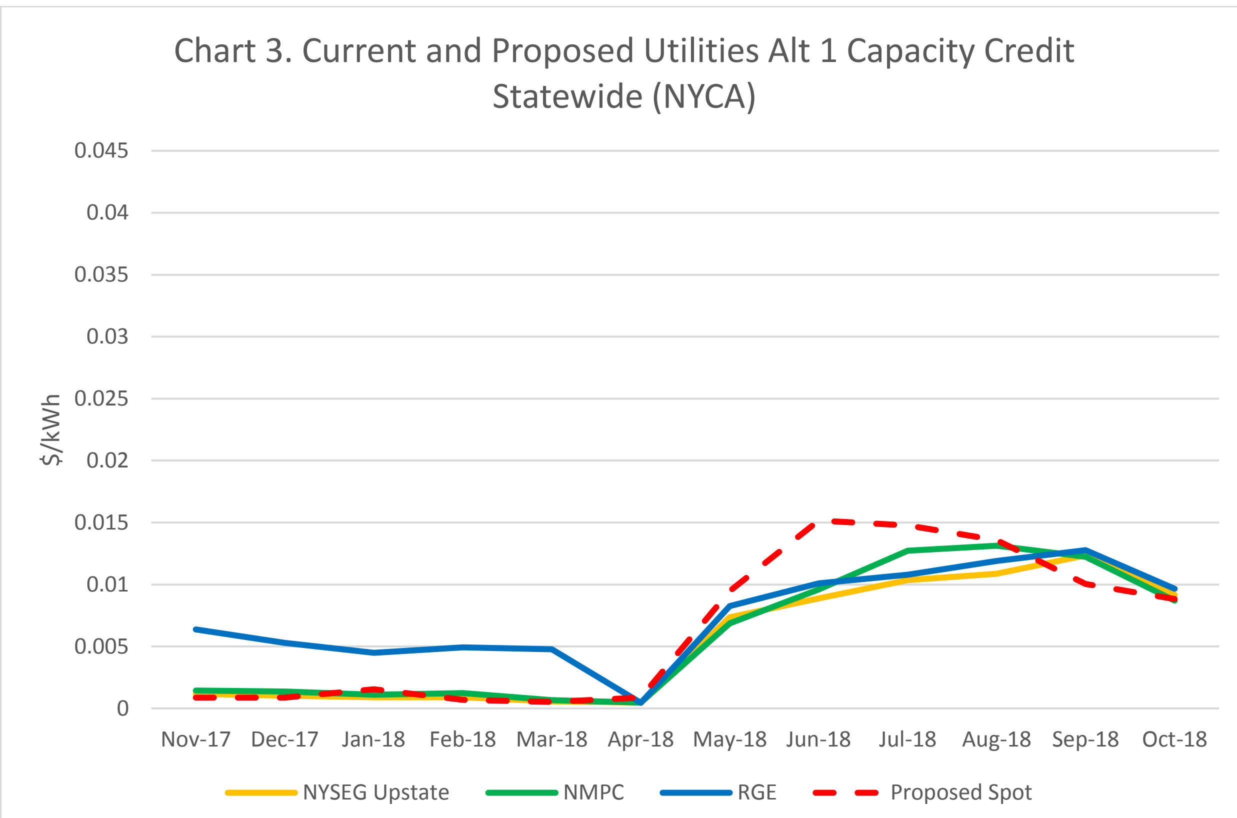
Given the various inconsistencies between utilities, Staff concludes that a new, consistent method should be used for calculating Alternative 1 and Alternative 2 Capacity Values for projects receiving Value Stack compensation.

Staff's proposed new method is to base Alternative 1 Capacity Value compensation on published NYISO monthly prices for the price element,[1] using solar photovoltaic (PV) load

---

[1] Historical ICAP values, for both the 6-month strip and monthly spot markets, are included in Appendix 1. Up-to-date price information is published by the NYISO at https://www.nyiso.com/installed-capacity-market, though in many cases the price

curves provided by the New York State Energy Research and Development Authority (NYSERDA) to estimate the likely ICAP contribution from the "fleet" of distributed intermittent generation in an ICAP region and determine the number of kWhs that value should be spread over to develop the Alternative 1 Capacity Value $/kWh credit for each month. The specific details of that calculation, and description of the specific NYSERDA load shapes proposed for each ICAP region, are described in Appendix 1. In Charts 3, 4, and 5, below, an estimate is provided of what Alternative 1 Capacity Value credit level the proposed method would have produced for each ICAP region over the first year of VDER. The method is shown based on the NYISO ICAP monthly spot price but use of the 6-month strip price may also merit consideration. The strip price would provide a more stable price and could be higher or lower than the monthly price for any given period or region. Spreadsheet files are provided in Appendix 2 with the data and calculations Staff used to produce these charts.



information is provided as the unforced capacity (UCAP) price, which must be converted to an ICAP price using the methods described in the reference materials linked on the NYISO webpage.

Chart 4. Current and Proposed Utilities Alt 1 Capacity Credit
LHV

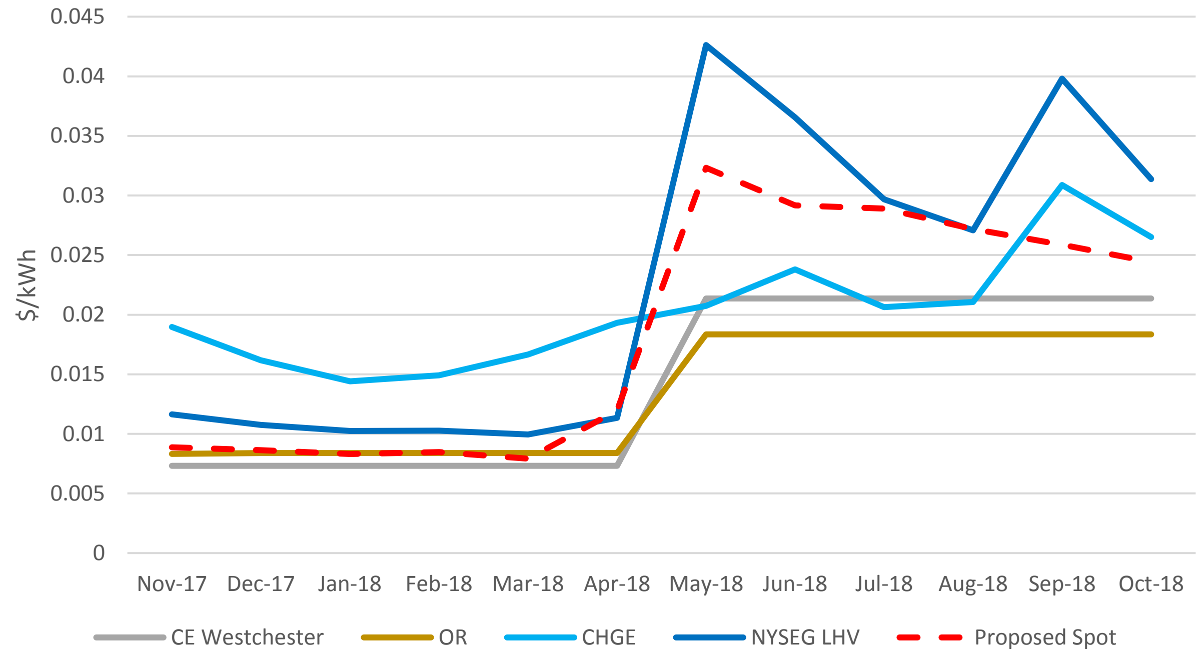
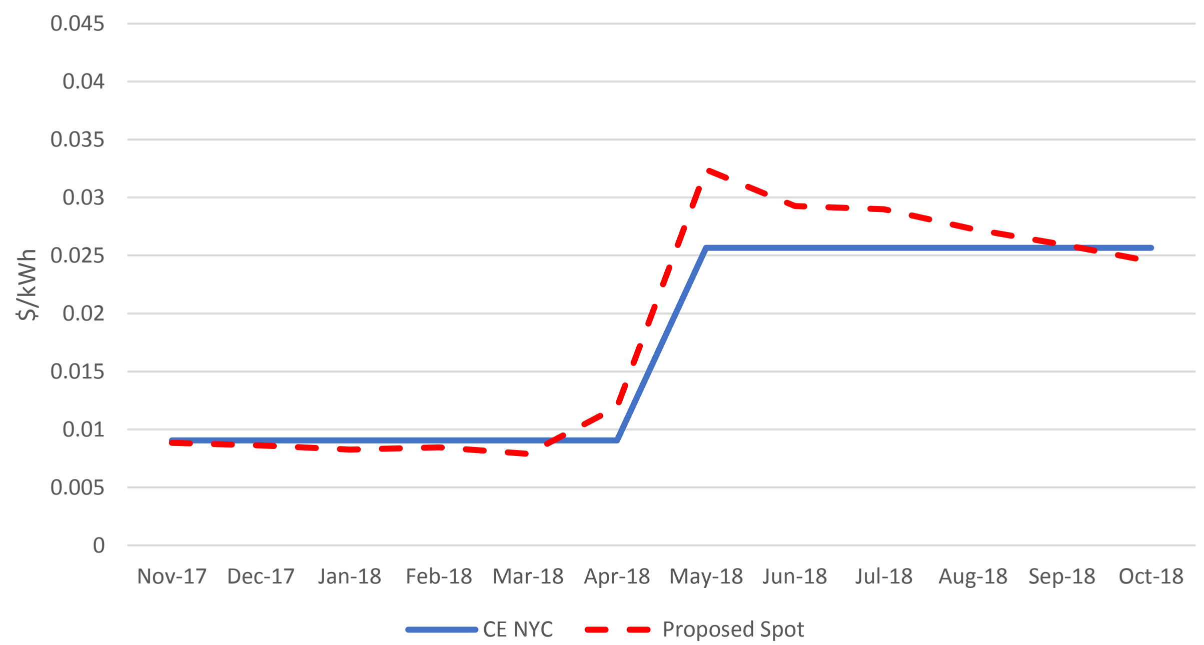


Chart 5. Current and Proposed Utility Alt 1 Credit
NYC



Staff notes that these are only example calculations and each utility would still apply their individual loss factors, so there would still be small differences among the utilities.

Discussion Regarding Alternative 2

Appendix 1 shows how the PV load shapes that Staff believes best represent solar production in New York compare to the summer hours that were most likely to be candidates for the NYCA single peak hour, year over year. The data demonstrates that the most important candidate hours in the summer occur on non-holiday weekdays,[2] from June 24 through August 31, during the hours of 1:00 PM through 6:00 PM (i.e., 1PM-2PM, 2PM-3PM, 3PM-4PM, 4PM-5PM, and 5PM-6PM). The number of those hours varies between 240 and 245 hours, depending on the year, and they present a significantly more accurate and more targeted approach than the 460 hours currently used for the Alterative 2 Capacity Value.

Staff proposes to change Alternative 2 to focus on those 240-245 hours each summer, increasing the $/kWh value accordingly such that projects should receive essentially the same or better[3] average compensation. This would increase the accuracy of the Alternative 2 price signal while still spreading compensation over enough hours to provide reasonable certainty and predictability to projects.

Thus, Staff proposes that the annual $/kW value for the fleet in each ICAP region that is derived in Appendix 1, for Alternative 1, would also be used for Alternative 2, but that $/kW-year value would be divided by the PV load shape's estimated kWh for those 240-245 summer hours to derive Alternative 2's $/kWh credit. The kWh for those hours in those load shapes is shown in Appendix 1, as are the resulting Alternative 2 $/kWh that would have resulted from Staff's proposed method with the prior year's NYISO ICAP prices.

Conclusion

The changes proposed in this Whitepaper will increase the transparency, consistency, and accuracy of Capacity Value compensation under Alternative 1 and 2. However, Staff recognizes

[2] That is, all weekdays other than July 4.

[3] Average compensation may be higher as a result of the shift from focusing on 2PM-7PM to focusing on 1PM-6PM, as solar projects are likely to have higher generation levels during 1PM-6PM period.

that projects currently in development may have signed contracts and secured financing based on current rules. For that reason, Staff is open to grandfathering projects that qualified[4] prior to the filing of this Whitepaper into the preexisting Capacity Value rules.

Staff requests stakeholder comment on the recommendations in this Whitepaper by February 25, 2019 and encourages specific attention to the questions listed below.

Questions for Stakeholder Comment

1. Did Staff select the correct load shapes? If not, what load shapes should be used?
2. If Staff's (or a similar) approach is adopted, should it rely on NYISO monthly spot prices or NYISO 6-month strip prices?
3. Should projects that have already qualified be grandfathered? If so, should they be allowed to "opt in" to a new ICAP method, recognizing that Market Transition Credit (MTC) values were based on prior ICAP estimates?
4. Is Staff's selection of critical summer ICAP hours incorrect? If so, explain why and suggest a better alternative.

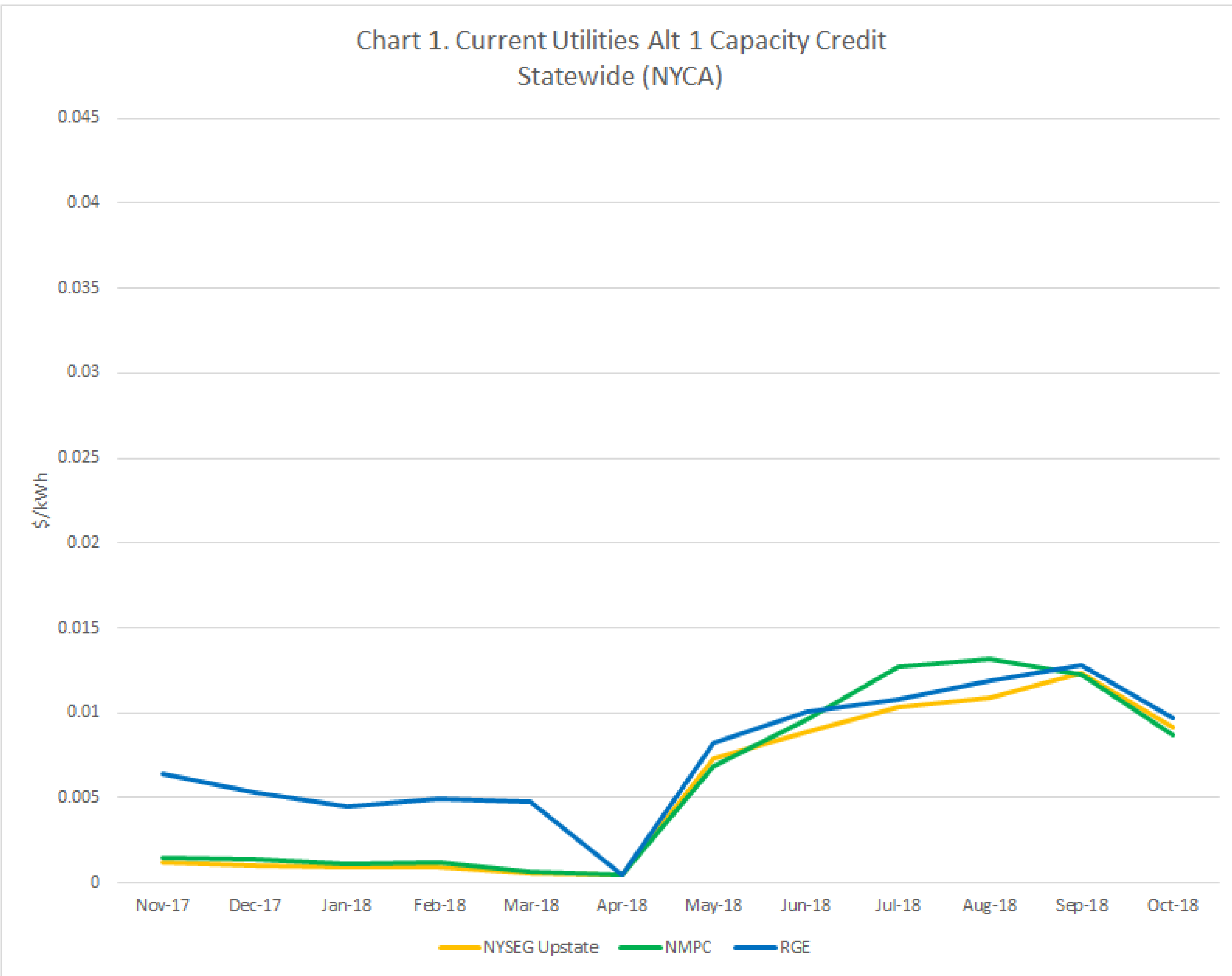
4 A project "qualifies" when it meets the standard for placement in a Tranche; that is, when it has a payment made for 25% of its interconnection costs or has its Standard Interconnection Contract executed if no such payment is required.

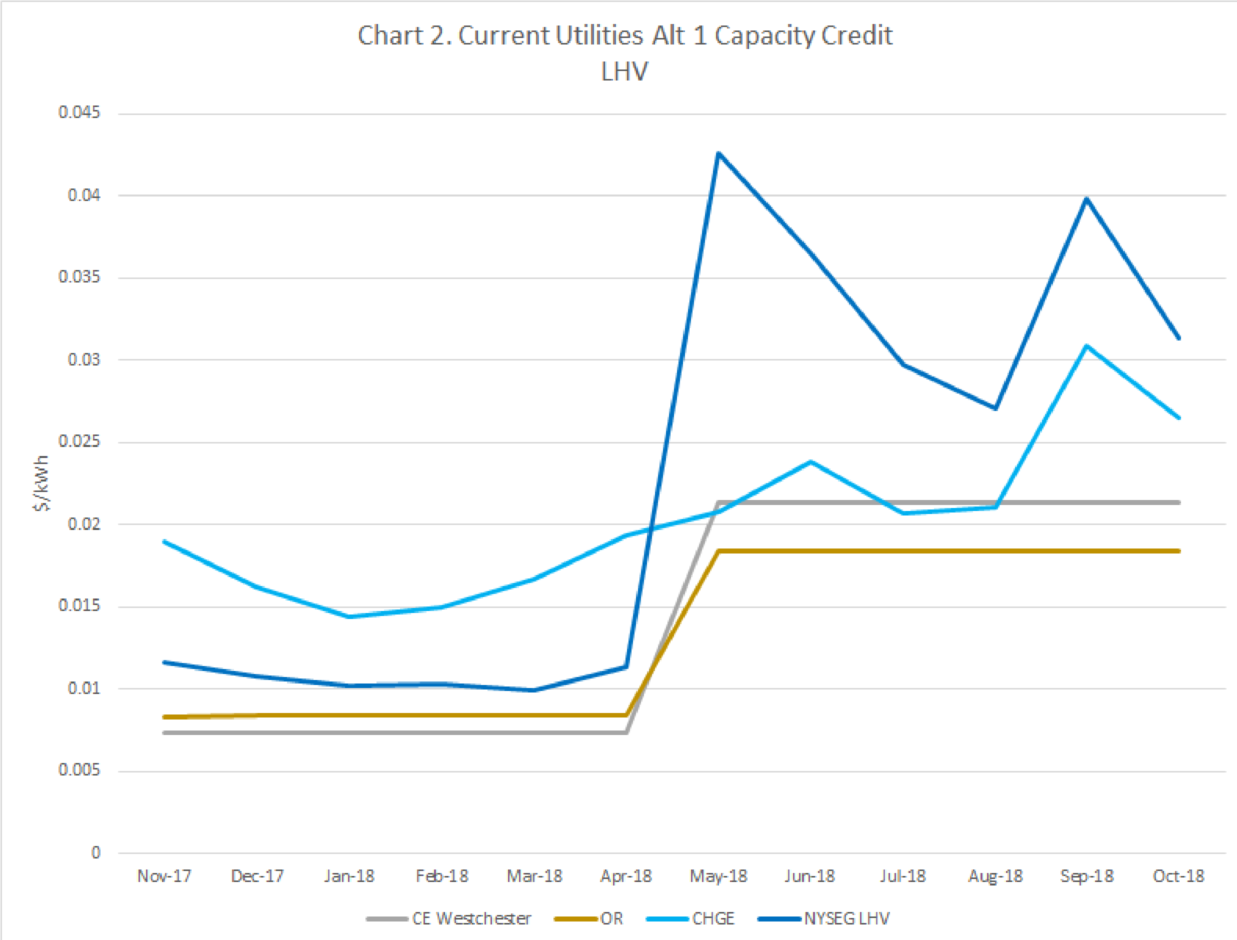
Appendix 1

Existing Utility ICAP Credits Under VDER

Table A1 and Charts 1 and 2 show the existing ICAP credits under Alternative 1 (Alt 1) for the first 12 months of the VDER tariffs.

Table A1.	VDER ICAP Alt 1											
	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
CE NYC	0.00905	0.00905	0.00905	0.00905	0.00905	0.00905	0.02566	0.02566	0.02566	0.02566	0.02566	0.02566
CE Westchester	0.00732	0.00732	0.00732	0.00732	0.00732	0.00732	0.02136	0.02136	0.02136	0.02136	0.02136	0.02136
OR	0.00832	0.0084	0.0084	0.0084	0.0084	0.0084	0.01835	0.01835	0.01835	0.01835	0.01835	0.01835
CHGE	0.01896	0.01619	0.01441	0.01492	0.01665	0.01933	0.02073	0.02381	0.02064	0.02106	0.03088	0.0265
NYSEG LHV	0.01164	0.01076	0.01024	0.01028	0.00995	0.01134	0.04262	0.03654	0.02969	0.02708	0.0398	0.03137
NYSEG Upstate	0.00119	0.00102	0.00091	0.00089	0.00055	0.00047	0.00735	0.00888	0.01034	0.01086	0.01235	0.00916
NMPC	0.00143	0.00136	0.00111	0.00123	0.00067	0.00047	0.00687	0.00961	0.01273	0.01313	0.01223	0.00869
RGE	0.00638	0.0053	0.00449	0.00493	0.00478	0.00045	0.00827	0.01008	0.01078	0.0119	0.01277	0.00965





What is most striking is that the credits vary materially for the utilities in the Lower Hudson Valley, even though these utilities purchase their wholesale capacity from the same ICAP region of the state. In Phase 1 of VDER, utilities were ordered to base their compensation on the capacity charges from the retail service class with a load shape most closely resembling that of a solar output curve. The results of that very approximate method speak for themselves in Chart 2, above. The Whitepaper proposes a method that will result in more consistent credit values across utilities in the same ICAP region. This method will also be more transparent to all stakeholders, as it derives directly from posted NYISO wholesale market prices and specified PV load curves.

<u>ICAP Regions and Representative PV Curves</u>

For the six jurisdictional utilities, there are three relevant ICAP regions: (1) the NY Control Area (NYCA); (2) the portion of NYCA that is the lower Hudson Valley and New York City (G-J Locality); and (3) Zone J, i.e., just New York City (NYC). NYCA always has the lowest ICAP prices. National Grid and RG&E may purchase all of their required ICAP from the NYCA. NYSEG may purchase all NYCA ICAP for its non-Hudson Valley load. Central Hudson and O&R must purchase a minimum portion of their load from the G-J Locality, but may purchase the remainder or their requirement from the NYCA sub-market. This is also true for the NYSEG load in the Hudson Valley, and for Con Edison's load in Westchester. For Con Edison's load in New York City, it must buy a minimum portion of its load from NYC ICAP, while the remainder may be purchased from the other regions. Note that all LSEs must purchase ICAP that sums to more than 100% of their forecasted load. The minimum percent that must be purchased from the nested submarkets (the Local Capacity Requirements or LCRs) may change once every twelve months, beginning in a summer capability period. Recent LCRs are shown in Table A-1.[5]

Table A-1. Historic LCRs

	NYC	G-J	NYCA
Winter 14/15	0.85	0.88	1.17
Summer 2015	0.83	0.91	1.17
Winter 15/16	0.83	0.91	1.17
Summer 2016	0.81	0.90	1.18
Winter 16/17	0.81	0.90	1.18
Summer 2017	0.82	0.92	1.18
Winter 17/18	0.82	0.92	1.18
Summer 2018	0.81	0.94	1.18

[5] For the purposes here, the minimum reserve requirement for the statewide area is used. However, the utilities will use the actual amounts of "excess" ICAP LSE's are required to purchase under the ICAP demand curve approach employed by the NYISO.

NYSERDA location-specific PV load curves were used to estimate the "fleet performance" of distributed PV installations in each of these ICAP regions. NYSERDA provides 108 load shapes, representing all combinations of the following specifications:

	Location	
1	Albany	
2	Binghamtom	
3	Brookhaven	
4	Buffalo	
5	Ithaca	
6	New York City	
7	Plattsburgh	
8	Rochester	
9	Syracuse	
	Type	
1	Fixed (open rack)	
2	Fixed (roof mount)	
3	1-Axis tracking	
4	2-Axis trackng	
	Orientation	
1	135° (SE)	
2	180° (S)	
3	225° (SW)	

A subset of the 108 load shapes was used to derive a representative PV load shape for each ICAP region (included in the accompanying spreadsheet workbook file). For the purposes here, the Fixed (roof mount) installation, averaged over the three orientations, for each location, were used. The cities averaged to represent each ICAP region were:

ICAP Region	Cities Averaged
NYC	New York City
G-J	Albany New York City
NYCA	Albany Binghamtom Buffalo Ithaca Plattsburgh Rochester Syracuse

I

CAP Quantity (kW) Contribution per kW Nameplate (DC) and kWh

The three representative PV load shapes were used, along with historical summer load data, to determine the likely quantity of ICAP contribution per each kW installed, and per kWh generated over a defined period, for each region.The first simple approach used was to use the date and time of the peak hour for the past 26 years (the furthest back complete data was available):

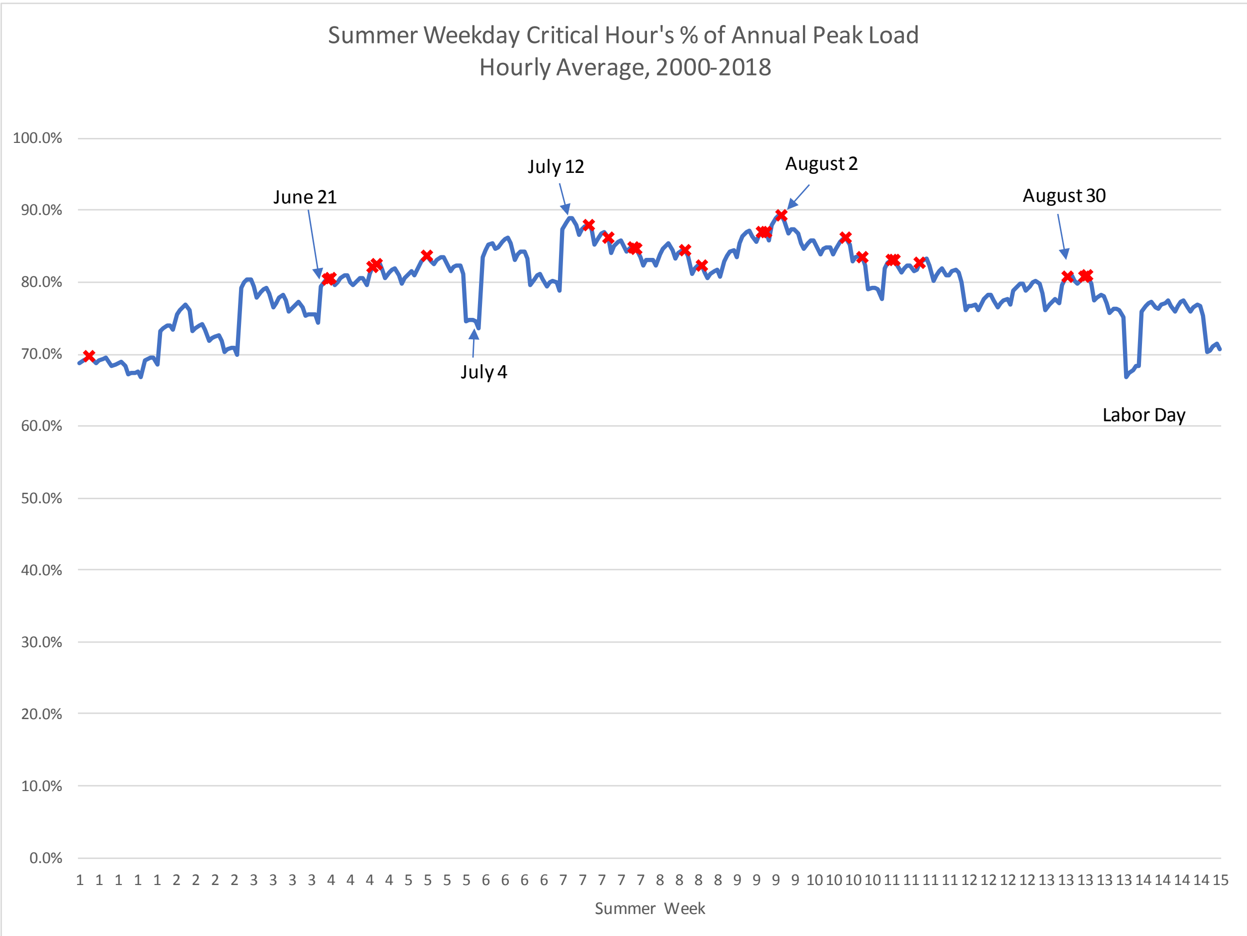
	Historical ICAP Hours (Hour Beginning)	Date
1993	14	7/8/1993
1994	14	7/21/1994
1995	15	8/4/1995
1996	16	7/18/1996
1997	14	7/15/1997
1998	16	7/22/1998
1999	13	7/6/1999
2000	16	6/26/2000
2001	14	8/9/2001
2002	16	7/29/2002
2003	16	6/26/2003
2004	16	6/9/2004
2005	16	7/26/2005
2006	13	8/2/2006
2007	16	8/8/2007
2008	16	6/9/2008
2009	15	8/17/2009
2010	16	7/6/2010
2011	15	7/22/2011
2012	16	7/17/2012
2013	16	7/19/2013
2014	15	9/2/2014
2015	16	7/29/2015
2016	16	8/11/2016
2017	17	7/19/2017
2018	16	8/29/2018

The kW output from each PV curve for each of those summer day/hour combinations was identified, and averaged, for each region:

			Representative PV Shape		
	Historical ICAP Hours (Hour Beginning)	Date	NYCA	G-J	NYC
1993	14	7/8/1993	0.349154	0.319918	0.30077
1994	14	7/21/1994	0.450792	0.342327	0.370843
1995	15	8/4/1995	0.319823	0.324682	0.379504
1996	16	7/18/1996	0.220733	0.179344	0.128908
1997	14	7/15/1997	0.488392	0.377748	0.44194
1998	16	7/22/1998	0.252646	0.230346	0.22406
1999	13	7/6/1999	0.493605	0.479743	0.39102
2000	16	6/26/2000	0.260454	0.248428	0.250127
2001	14	8/9/2001	0.448409	0.452943	0.499111
2002	16	7/29/2002	0.24014	0.224569	0.224321
2003	16	6/26/2003	0.260454	0.248428	0.250127
2004	16	6/9/2004	0.204534	0.258951	0.265485
2005	16	7/26/2005	0.25207	0.210335	0.186771
2006	13	8/2/2006	0.496625	0.322112	0.367634
2007	16	8/8/2007	0.214746	0.181025	0.168137
2008	16	6/9/2008	0.204534	0.258951	0.265485
2009	15	8/17/2009	0.324688	0.323854	0.309969
2010	16	7/6/2010	0.255131	0.228829	0.211353
2011	15	7/22/2011	0.349486	0.345373	0.33487
2012	16	7/17/2012	0.191822	0.171308	0.162783
2013	16	7/19/2013	0.199462	0.152234	0.236554
2014	15	9/2/2014	0.30114	0.289377	0.281467
2015	16	7/29/2015	0.24014	0.224569	0.224321
2016	16	8/11/2016	0.173586	0.092962	0.04231
2017	17	7/19/2017	0.111905	0.108685	0.106753
2018	16	8/29/2018	0.178683	0.159293	0.156696
		Average ICAP "Tag"	0.287814	0.259859	0.26082

While this approach does consider 26 years of the peak hour, on the other hand it only looks at 26 summer hours of the representative PV curves. which are averages for the years 2015 and 2016. This implies that these are the only relevant hours on the PV curves when considering expected PV contribution during a future year’s peak hour.

Another approach used examined the system load in all the critical summer hours as a percent of each system in the one peak hour.[6] Staff was able to obtain summer hourly system load data for the years 2000 through 2018. These data were arranged by summer week (1-17), weekday (1-5), and hour (HB13 through HB17). For each year, the system load in each of the critical hours was divided by the system load in the peak hour of that year. These percent ratios are plotted in Chart A-1.

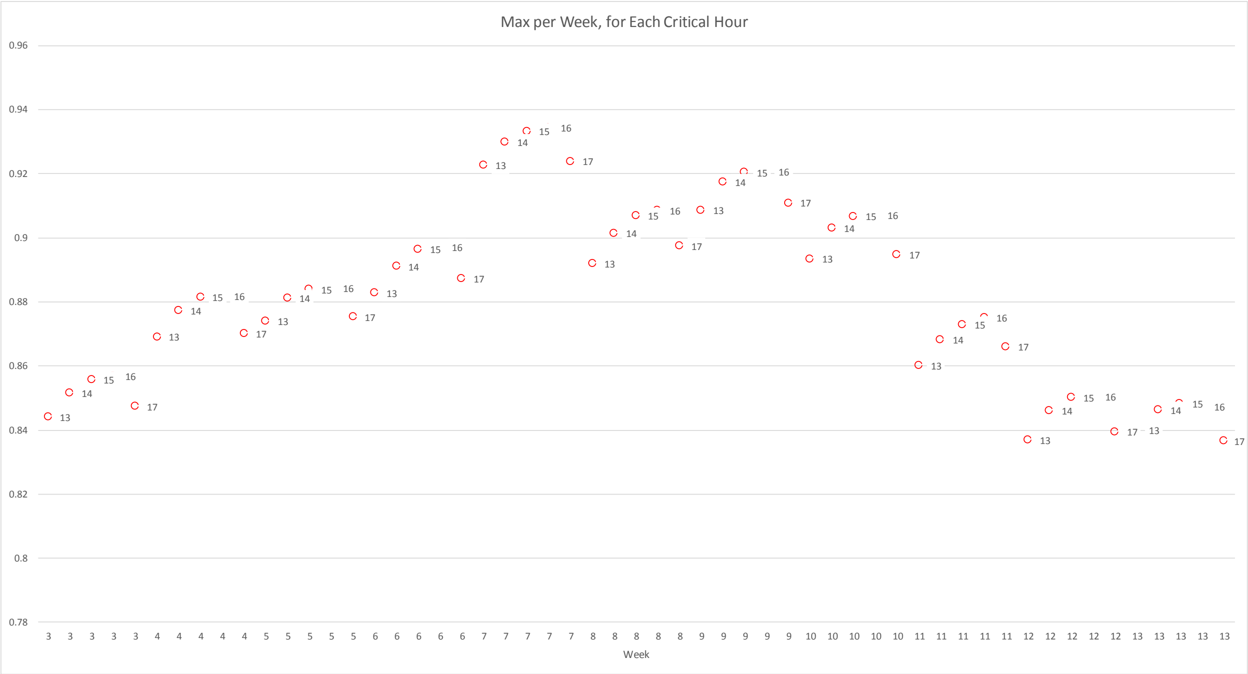


(The red x indicates a day/hour in which an actual historical peak occurred.)

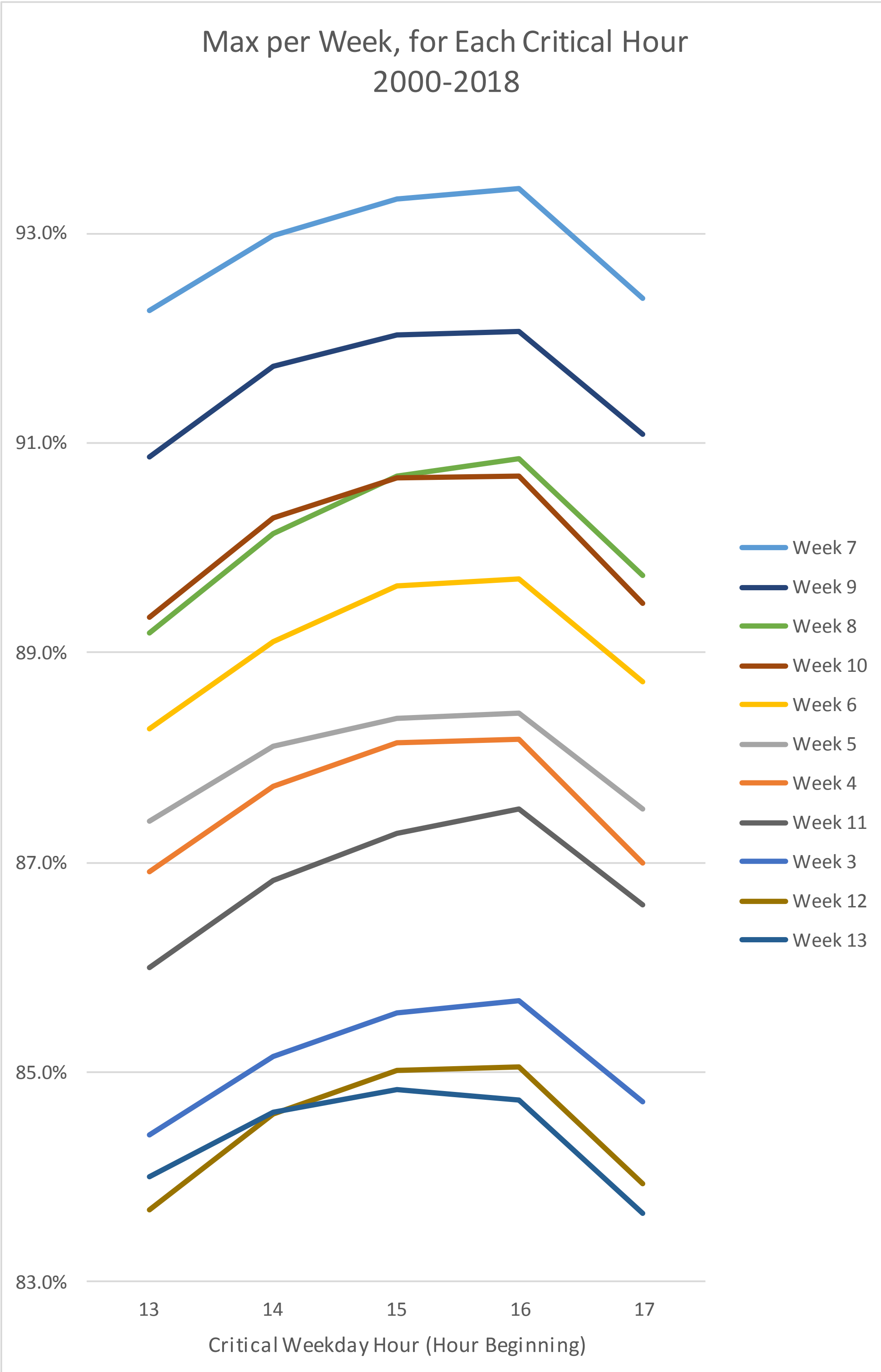
This suggested that the most likely period for an annual peak hour is that between the last week of June through the end of August.

6 A simple examination of the data confirmed that "critical hours" for system peak load were summer, non-holiday, weekday hours between hour beginning 13 (i.e. 1:00 p.m.) and hour beginning 17 (i.e. 5:00 p.m.).

This becomes even clearer if, instead of looking at hourly averages over 19 years, one looks at the maximum ratio that occurs in any given week, for each critical hour:



It is also clear that Hour Beginning 16 (i.e., the sixty minutes between 4 and 5 p.m.) is the most likely hour in which the peak will occur:



While the last two charts suggest that weeks 12 and 13 (approximately the last 2 weeks of August) might not be as critical as the others, balancing this information with that in the first chart led staff to conclude that a practical definition of critical ICAP hours for the summer are the 240 to 245 hours that occur on non-holiday, weekday hours between June 24 and August 31.

Given that definition, it is possible to look at the average output produced by the three representative PV curves. This should be a more robust estimate of the likely ICAP contribution of the fleet of distributed PV installations in each ICAP zone. Those averages are:

	For the Critical 245 Hours		
	NYCA	G-J	NYC
Avg. kW	0.29398	0.27984	0.29080
Sum kWh	72.0	68.6	71.2
Sum Hours	245.0		

Value for ICAP Under Alternatives 1 and 2

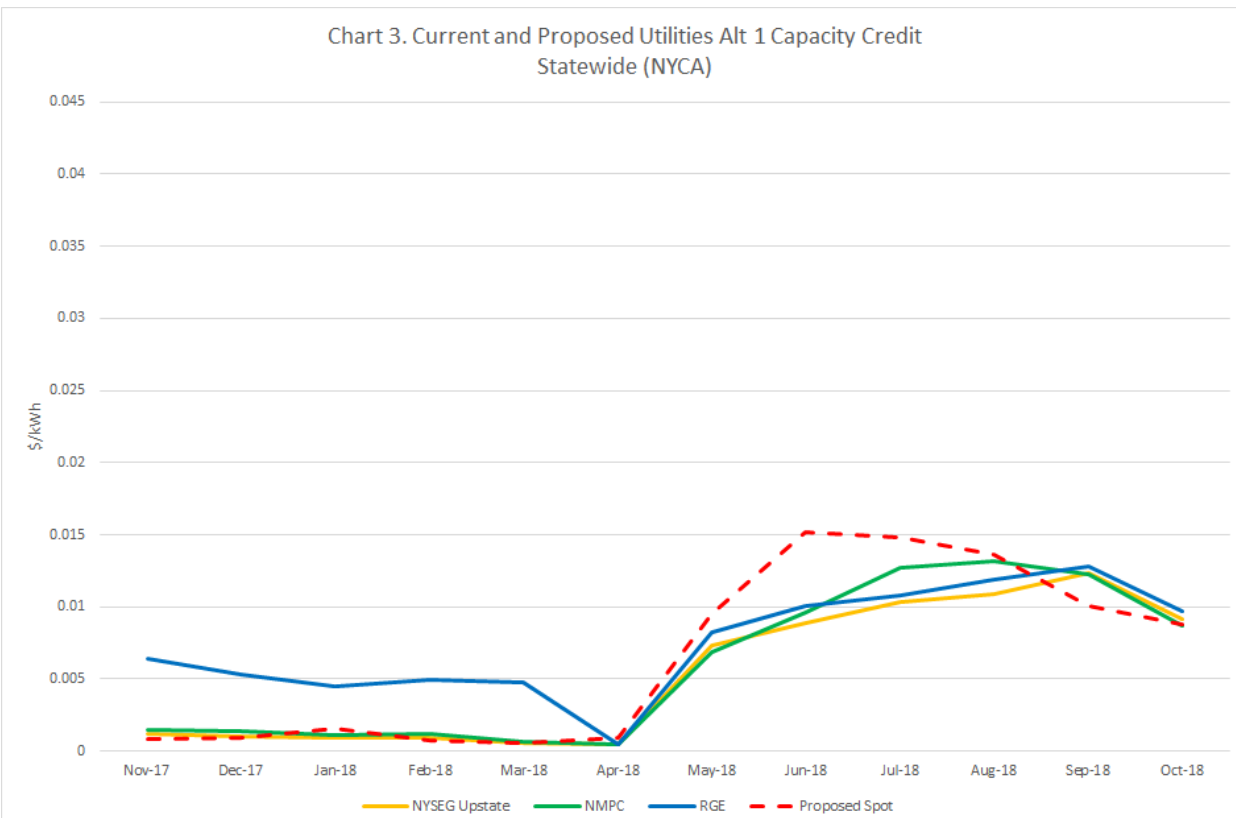
The next step in converting these estimated "fleet" ICAP quantity contribution values to $/kWh credit values is combining these with monthly NYISO ICAP prices for each region, and then applying those values to the weighted average ICAP requirement that each utility must buy from each region. That value then needs to be "grossed up" for each utility's distribution loss factor.[7]

[7] For the purposes here, an example 5% loss factor is used. However, each utility will use its specific distribution loss factor.

Alt 1. Compensation under Alternative 1 takes the $/kW-Year value provided by the representative PV curve and spreads that value over the entire year's kWhs produced by that curve. In Table A2, the $/kW Year values, annual number of kWhs, and $/kWh credits that would result are shown. Charts 3-5 show how these credits would have compared to the credits the utilities provided under the existing method.

Table A2.

	Wholesale Spot Prices $/kW-Mo			Retail Purchase Requirements** Wtd Avg Spot Prices $/kW-Mo			Average PV kWh Produced (annual kWh/12)			$/kWh Credit		
	NYCA	G-J	NYC	NYCA	G-J	NYC	NYCA	G-J	NYC	NYCA	G-J	NYC
Nov-17	$0.23	$3.26	$3.21	$0.27	$3.04	$3.00	95.3	100.8	103.8	$0.0009	$0.0089	$0.0088
Dec-17	$0.23	$3.17	$3.13	$0.27	$2.97	$2.93	95.3	100.8	103.8	$0.0009	$0.0086	$0.0086
Jan-18	$0.40	$3.00	$2.95	$0.48	$2.85	$2.81	95.3	100.8	103.8	$0.0015	$0.0083	$0.0083
Feb-18	$0.18	$3.13	$3.08	$0.22	$2.91	$2.87	95.3	100.8	103.8	$0.0007	$0.0085	$0.0084
Mar-18	$0.14	$2.93	$2.88	$0.16	$2.72	$2.68	95.3	100.8	103.8	$0.0005	$0.0079	$0.0079
Apr-18	$0.23	$4.42	$4.35	$0.27	$4.11	$4.05	95.3	100.8	103.8	$0.0009	$0.0120	$0.0119
May-18	$2.47	$11.12	$11.02	$2.92	$11.09	$11.01	95.3	100.8	103.8	$0.0095	$0.0323	$0.0324
Jun-18	$3.96	$9.60	$9.51	$4.68	$10.01	$9.94	95.3	100.8	103.8	$0.0152	$0.0292	$0.0293
Jul-18	$3.86	$9.52	$9.44	$4.56	$9.91	$9.85	95.3	100.8	103.8	$0.0148	$0.0289	$0.0290
Aug-18	$3.55	$8.98	$8.90	$4.19	$9.33	$9.26	95.3	100.8	103.8	$0.0136	$0.0272	$0.0273
Sep-18	$2.62	$8.74	$8.66	$3.10	$8.88	$8.82	95.3	100.8	103.8	$0.0100	$0.0259	$0.0259
Oct-18	$2.30	$8.29	$8.21	$2.72	$8.38	$8.32	95.3	100.8	103.8	$0.0088	$0.0244	$0.0245
		sum = $/kW-Year ==>		$23.84	$76.19	$75.54	1,143.4	1,210.0	1,245.0	<==Total Annual PV kWh per kW		



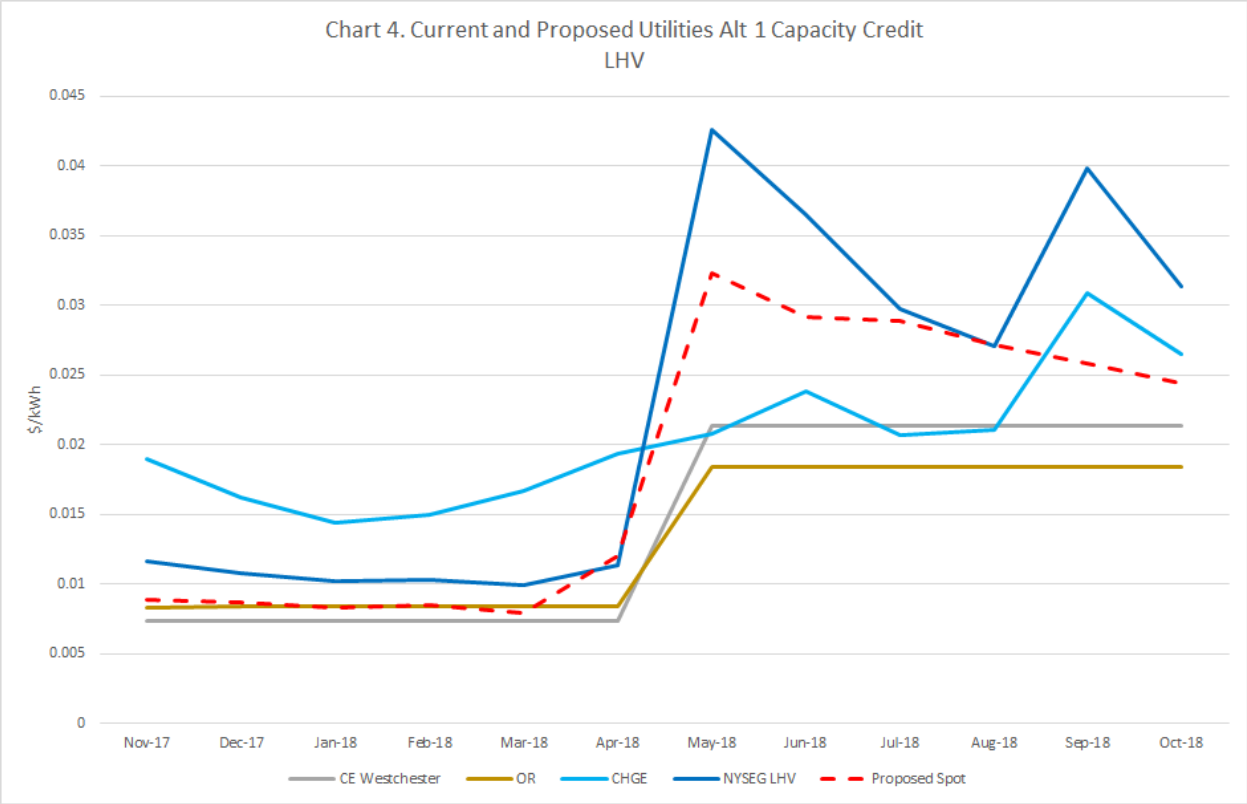


Chart 4. Current and Proposed Utilities Alt 1 Capacity Credit
LHV
$/kWh
0.045
0.04
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
CE Westchester
OR
CHGE
NYSEG LHV
Proposed Spot

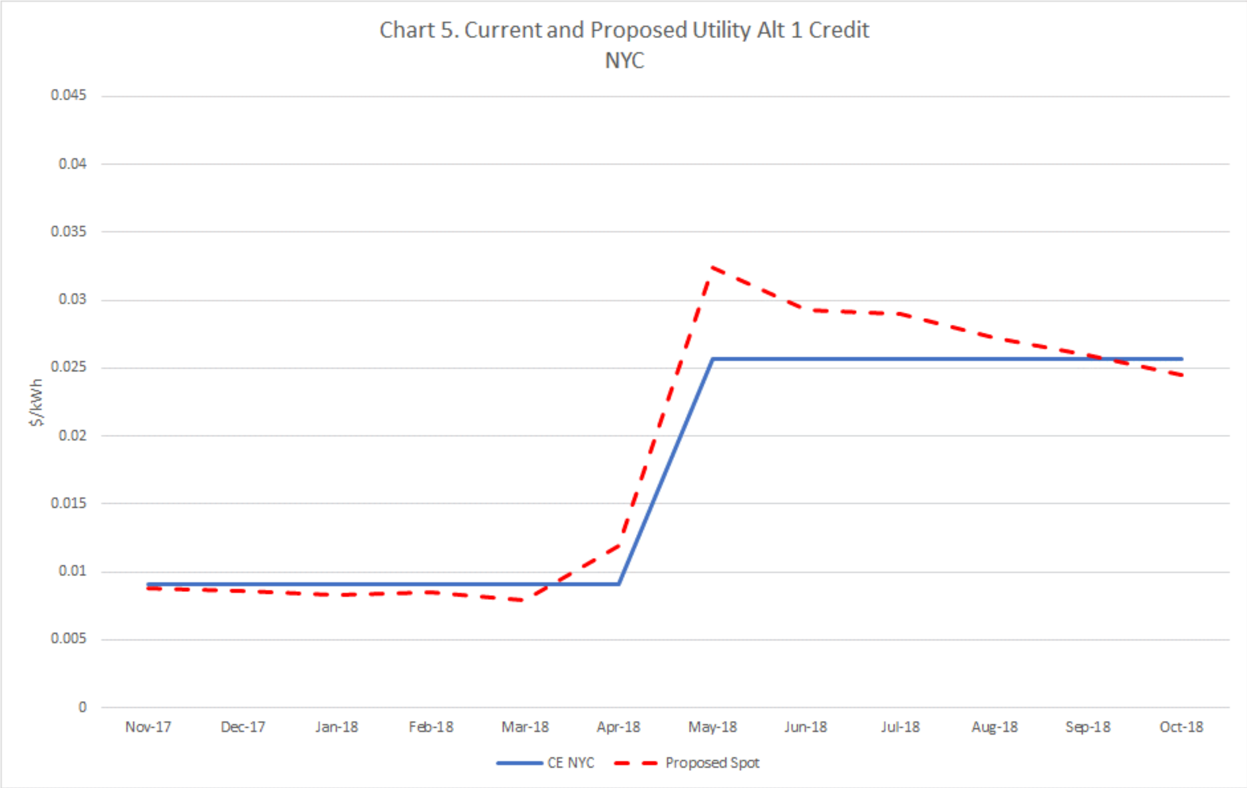


Chart 5. Current and Proposed Utility Alt 1 Credit
NYC
$/kWh
0.045
0.04
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
CE NYC
Proposed Spot

Alt 2. The intent of Alternative 2 is to take the same $/kW-Year ICAP value provided by the representative PV curve, but compress its compensation into a limited number of peak hours. It is these peak hours that provide the actual ICAP value to the system. While it is true that a given PV system that behaves exactly as the representative curve will receive the same compensation under Alt 1 or Alt 2, the purpose of Alt 2 is to provide the incentive to some projects to modify their production characteristics generate more during these valuable peak hours.

Table A3 shows the conversion of the $/kW-month reported wholesale prices, to the corresponding retail purchase requirement, to the total $/kW-year value applied to the PV capacity tag value, and finally $/kWh credit this method produces for both the existing 460-hour summer period, and the more precise 245 hour period. While Staff prefers the 245-hour period, we also show the credits values under the 460-hour method for direct comparison to the utilities' 460 credits from last summer.

Table A3.							
	Wholesale				Retail Purchase Requirements**		
	Spot Prices $/kW-Mo				Wtd Avg Spot Prices $/kW-Mo		
	NYCA	G-J	NYC		NYCA	G-J	NYC
Nov-17	$0.23	$3.26	$3.21		$0.27	$3.04	$3.00
Dec-17	$0.23	$3.17	$3.13		$0.27	$2.97	$2.93
Jan-18	$0.40	$3.00	$2.95		$0.48	$2.85	$2.81
Feb-18	$0.18	$3.13	$3.08		$0.22	$2.91	$2.87
Mar-18	$0.14	$2.93	$2.88		$0.16	$2.72	$2.68
Apr-18	$0.23	$4.42	$4.35		$0.27	$4.11	$4.05
May-18	$2.47	$11.12	$11.02		$2.92	$11.09	$11.01
Jun-18	$3.96	$9.60	$9.51		$4.68	$10.01	$9.94
Jul-18	$3.86	$9.52	$9.44		$4.56	$9.91	$9.85
Aug-18	$3.55	$8.98	$8.90		$4.19	$9.33	$9.26
Sep-18	$2.62	$8.74	$8.66		$3.10	$8.88	$8.82
Oct-18	$2.30	$8.29	$8.21		$2.72	$8.38	$8.32
					$23.84	$76.19	$75.54
				$/kW-Yr	$23.84	$76.19	$75.54
				ICAP Tag	0.31	0.29	0.31
				$/kW-Yr PV	$7.36	$22.39	$23.06
				kWh 460	96.7	88.6	89.4
				kWh 245	72.0	68.6	71.2
				$/kWh 460	$0.0761	$0.2526	$0.2579
				$/kWh 245	$0.1022	$0.3265	$0.3237

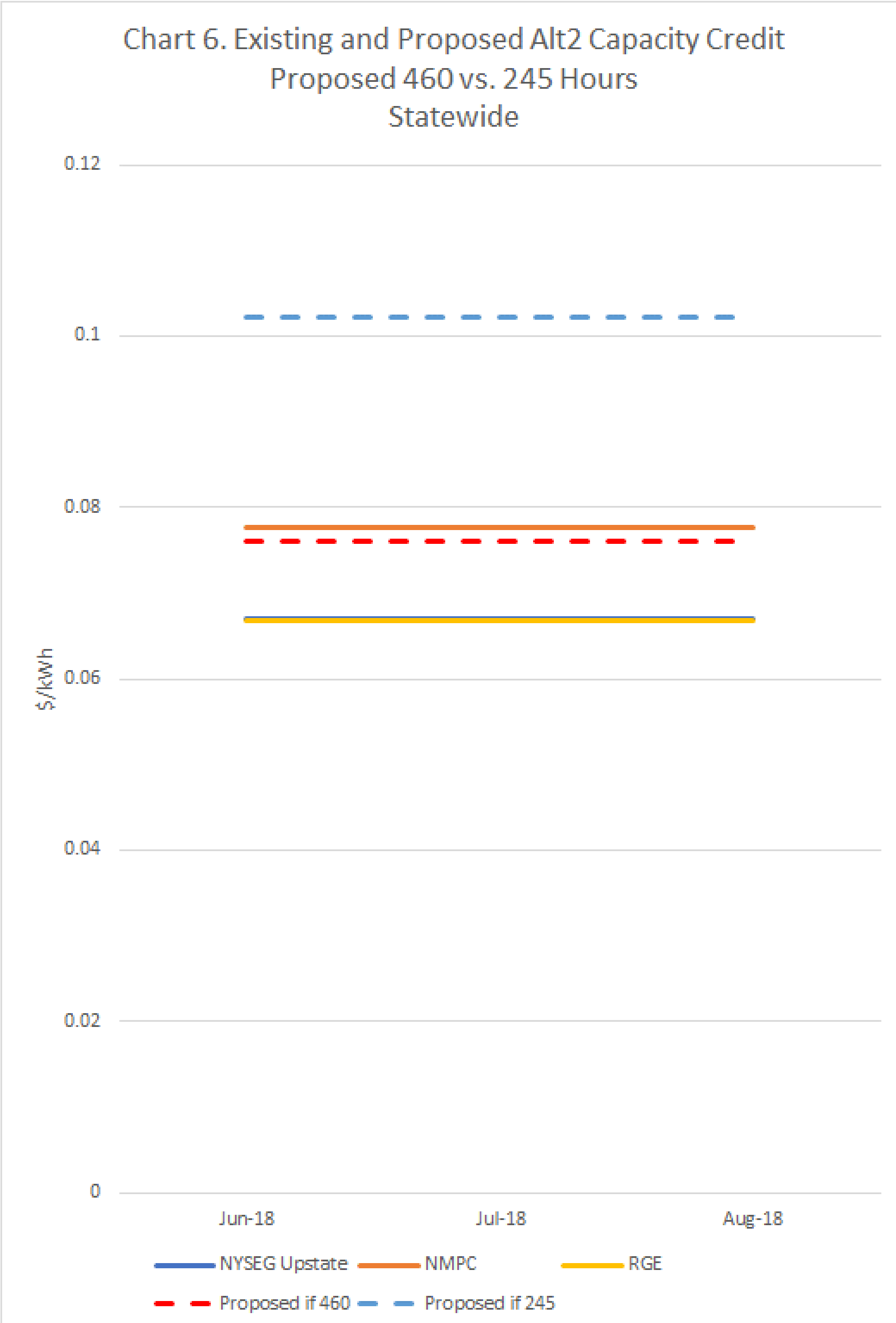


Chart 6. Existing and Proposed Alt2 Capacity Credit
Proposed 460 vs. 245 Hours
Statewide
$/kWh
0.12
0.1
0.08
0.06
0.04
0.02
0
Jun-18
Jul-18
Aug-18
NYSEG Upstate
NMPC
RGE
Proposed if 460
Proposed if 245

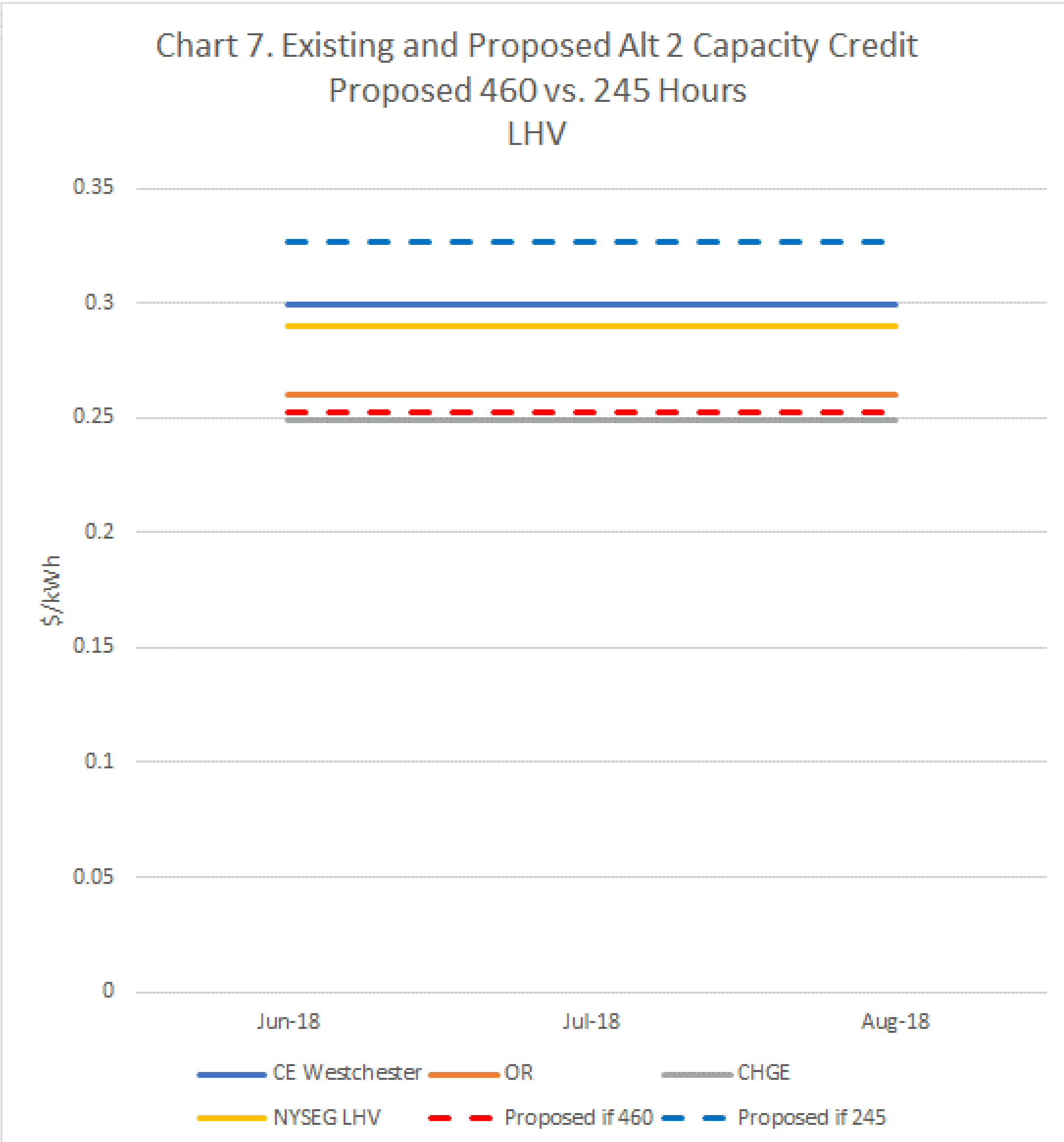
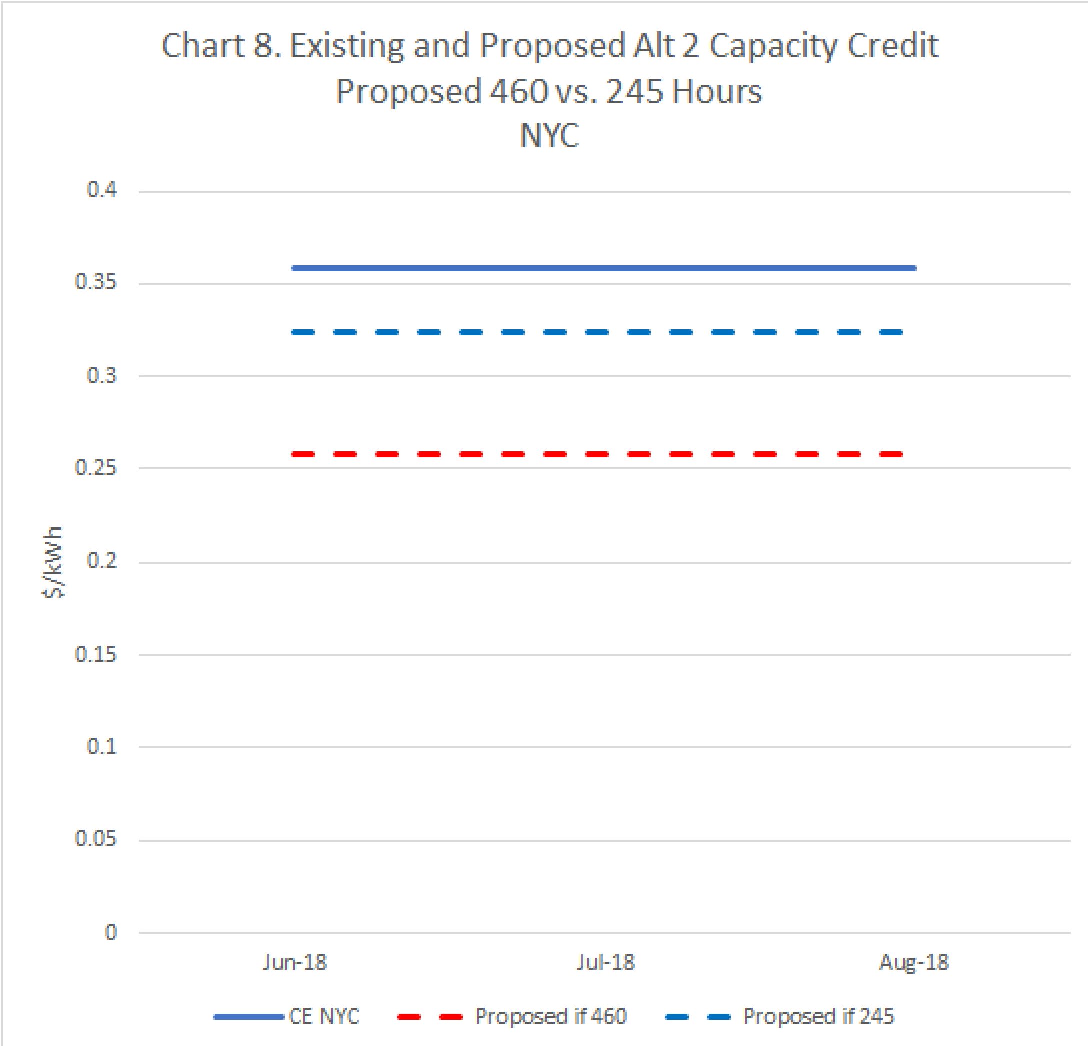


Chart 7. Existing and Proposed Alt 2 Capacity Credit
Proposed 460 vs. 245 Hours
LHV
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
$/kWh
Jun-18
Jul-18
Aug-18
CE Westchester
OR
CHGE
NYSEG LHV
Proposed if 460
Proposed if 245



The details of these calculations are provided in the accompanying spreadsheet, Appendix 2.