Notes from 8-23-22 RA Reform Workshop

ED started the day. (See slides.). It discussed the MCC buckets, starting with their history. Its focus was on DR and imported RA. For DR, the ED proposed to update its calculation for the cap on the DR MCC bucket using its existing methodology. DR counting would still be restricted to the AAH in support of this calculation. The cap on DR would increase from 8.3% to 8.5% using the status quo, to 9.7% using gross load and restricted to the AAH, and 13.9% using net load. MRP asked whether these percentages would be applied to load or load plus PRM and ED said load plus PRM. MRP expressed concern that a higher percentage would lead to an even higher amount of DR when grossed up by the PRM. ED said it would consider this. CLECA asked if a DR program that was dispatched outside the AAH could then not be used in the stack for RA under SOD. ED said its focus had been on daily use limitations and the 24 hour/month maximum dispatch and that it would address daily implications for SOD later. CEDMC asked about continuing to require DR to be available in the AAH. ED replied that this is an open issue. However, someone else in ED said that the AAH are the times of greatest system stress and that allowing DR to be shown as RA for other hours might lead to a need to increase the 24 hour/month maximum limitation. CEDMC said in SOD, if hourly needs are met, some customers could provide load drop outside the AAH and that this option should be kept open.

ED then presented its proposal for non-resource specific imports. It wants to ensure availability across the entire month. 4 hours/day during AAH, 6 days/week is roughly 100 hours/month. It could be self-scheduled or bid between $0 and negative $150 per MWh.

Then followed a discussion about how to treat supply side DR vs. load modifying DR. Calpine expressed a concern that if DR is dispatched for 4 hours it might not be able to cover a later hour need such as HE 21, especially if it is limited to 24 hours/month. ED said it would apply the MCC bucket cap to each slice.

CESA presented next (see slides). Its focus was LDES and multi-day reliability. It reviewed the parameters for storage under SOD. It said storage with duration up to 10 hours is likely to fit well into SOD but that storage with longer duration or with operational timeframes greater than 24 hours will have issues. CESA said the key source of the complexity for longer duration resources will be the charging sufficiency requirement because assets with durations in excess of 10 hours may not complete a full charge/discharge cycle in 24 hours. It proposed a seasonal charging scheme to allow excess energy taken in one season or showing period to be used to charge in another season or showing period using carryover accounting. This does create an issue of how to show such resources in each month and how to represent them in off-peak months. Vistra asked the definition of LDES. CESA said if the duration is over 10 hours. Vistra asked about those resources with a 10- to 24-hour duration. CESA responded that if an asset’s duration is 10 hours, the operational timeframe could be 24 hours and vice versa depending on charging efficiency and that there is no gap between 10 and 24 hours. Vistra said for seasonal charging one should add the duration of the storage timeframe as the time required for holding the charge. PCE said it wants to meet load 100% with renewables and its goal is to take summer excess and use it in the winter. How can this be guaranteed contractually and demonstrated to the CPUC? CESA said the resource will still be dispatched economically by the CAISO and that the seasonal charging scheme is meant for accounting purposes, not operations.

IEPA said it seems artificial to require showing for LDES outside the 24-hour SOD; you could track saved and used energy, not charging and discharging.

CESA said multi-day reliability is considered in the IRP where there are multi-day low solar, etc. scenarios that are addressed and that procurement of relevant resources can be done in RA. You need to create tools to capture value and encourage contracting to provide reliability across several days.

On slide 10 CESA suggested considering a minimum requirement for MCC buckets rather than a maximum requirement and asked if this should be done on an LSE-specific basis or across all LSEs like in the past? PCE thinks multi-day might be handled by the LOLE study and resulting PRM. They said MCC buckets assume need to serve 24-hour load with 24-hour resources but this will not be true in the future because 24 hour loads can be met with a combination of resources rather than only firm resources. MCC buckets then could create an artificial constraint. CESA is also thinking about that. Vistra does not like minimum duration for MCC bucket because it is too rigid and the market should determine what durations are needed.

SCE presented next (see slides). SCE started with its overall philosophy for resource counting under SOD and additional details on how it views hybrid resources under SOD. SCE presented a table of types of “hybrid” resources and the applicable RA counting rule and excess capacity verification rule for the resource types. It said excess capacity to charge a battery must be deliverable to be in an LSE showing. It only considers a resource a hybrid if fully paired and if it can be verified at the resource level. Vistra said CAISO has its own definition of co-located, hybrid, etc.

SCE next addressed MCC buckets. It says SOD incorporates many limitations but there is a need to take into account non-daily limits like imports and DR. Current MCC buckets only apply to peak hour. SOD eliminates much of these limits except weekly availability and monthly hour limit. SCE indicated there is a need to create a bridge during the 2024 test year from the current RA construct to SOD. SCE suggests counting storage in bucket 4 in 2024 as long as it passes the SOD capacity sufficiency test. Some LSEs are long on storage and want bucket 4 treatment. SCE proposes to retain all other MCC bucket rules without the daily limitations.

ED asked if this is related to the test year or bridging the gap. SCE said the test year. ED asked for the monthly and hourly limits if there would be data to verify? SCE said QC and monthly hourly limits could be used to help derive them. MCC buckets are based on peak. If you keep them, you might want to have a shaped requirement rather than the same for all hours.

CESA will add to SCE hybrid table. SCE’s presentation on MCC buckets only refers to 2024. Does SCE have a position for 2025? SCE said it is still developing this and considering interactions with LOLE studies.

CAISO presented next on deliverability (see slides). It said deliverability is required to count for RA. CAISO’s definition of hybrid is one resource ID. For the CPUC it could be 2 resource IDs. The CAISO explained that it tests deliverability during peak load conditions and indicated that peak load is when deliverability is highest. The CAISO stated that any energy only (EO) resource that is crossing the transmission system should not be RA (for either the RA requirement or charging requirement). The CAISO then went through the pros and cons of allowing an EO resource to charge a battery if it is at the same point of interconnection. If the CPUC allowed energy only (EO) onsite resources to charge storage, this would create different treatment for other LRAs. Right now, there are only 3 EO co-located resources so this is not a problem for resources in the queue. They can choose how to split deliverability before COD. Also, most resources are not lacking deliverability.

CESA asked about deliverability studies. CAISO is reviewing. CESA said the issue is what is storage doing or assumed to be doing in studies may not match actual operations and may be too limiting of what storage is doing in its own deliverability studies. CAISO responded that it has an open stakeholder process to address such issues. Also, if a resource is in a high local load condition, it cannot export its power in a constrained area. CESA said this assumes the flow patterns are the same in both cases. This is too simple and broad. If a resource can meet local resource needs but not those far away, it should have a specific deliverability consideration.

CalWEA asked the CAISO to consider that if a resource can meet local needs (rather than all load), then it can be deliverable (e.g., if LA basin resource can meet LA basin load but not Sacramento load). CAISO is reviewing.

CalCCA asked if EO resources feed storage, does that count for RA? Is the solution to the concern simply that EO renewables not being able to sell to the grid? CAISO replied that EO resources cannot charge across the grid. Does the CPUC count the battery for RA? EBCE said if storage is paired with EO generation, it seems as if storage resources would increase load by charging. CAISO said this is true if it doesn’t cross the transmission system. CAISO does not have point to point transmission service.

CAISO continued to address hydro with daily or monthly limits. Under SOD, need to consider having hourly values. There are QC rules for hydro to be applied with monthly showing but the CPUC left open the future QC for hydro. Reservoir levels at maximum output are lower. Some can’t both charge batteries and also meet load requirements. We don’t have a solution. CAISO suggested looking at a “time period” approach for historical usage or investigate what the PNW does.

ED said currently MCC buckets are not capturing this concern about hydro and whether it is a daily or monthly limitation. ED also asked for more data on this concern. SCE said we might be overcounting off-peak hydro but there would be no impact on reliability if it is incorporated properly in LOLE studies.

CalWEA next presented a few updated slides on its ENLR approach.

NRDC next presented some slides on the challenges with using a single exceedance level for wind and solar for all hours in one month much less for multiple months. There is an error between worst day and using exceedance based on history. It is worse for wind and especially New Mexico wind. Both the exceedance values and the worst day are based on historical weather years. SCE said the most interesting difference is between hourly counting for RA and hourly counting in LOLE. NRDC said we can learn a lot from the LOLE analysis to figure out the impacts and that it thinks weather correlation is important.

MRP asked what the LOLE study is using for the various hourly profiles. NRDC responded that it can make adjustments if a decision is made to use UCAP, etc. Need for durability of results in profiles so don’t have to keep changing the PRM; more precision would help.

NRDC questions the merit of tying QC back to exceedance. MRP asked where NRDC and PG&E differ. NRDC said that the decision calls out the use of peak day and exceedance.

ACP presented on capturing the reliability value of wind resources to the system and how to capture geographic variability (see slides) and their consequences for contracting. It said there was a lot of concern around the use of exceedance for wind and proposed 1) to identify the top 5 peak load days in each month historically, 2) review wind and solar performance on those days and 3) average data across all years to get a peak load profile, stopping at PG&E step 3. One could build on ED’s LOLE for IRP and create synthetic profiles for wind resources. The CPUC prefers historical data but they don’t exist. ACP thinks there is a need to refine the determination of worst day. SCE asked how one would benchmark using annual marginal ELCC. ACP said it did a straight average for all hours and all AAH.

CESA asked if ACP’s analysis is comparable to a 50% exceedance with a limited sample size. The presenter clarified that its analysis was an average production versus 50th percentile which yields different results.

CalWEA said PG&E has a small sample size and cautioned that small sample size leads to more variability. ACP said it might increase it to make it more robust. ACP compared average monthly wind ELCC to exceedance using annual average data but the two outputs have every different shapes. Exceedance overestimates in summer and underestimates in winter compared to ELCC. CLECA asked why CPUC ELCC is the reference point when it is a function of resource elimination to surface LOLEs in the IRP. ACP said ELCC captures diversity benefit. SCE said exceedance results are quite high for summer months and maybe a better comparison would be single peak hour exceedance value vs. current ELCC. ACP said it looked at 4-9 pm and the results did not change much. It said exceedance does not capture diversity value and provides no incentive for diversification and that exceedance levels are arbitrary and not tied to PRM or LOLE. SCE disagreed and asked who is supposed to have responsibility for diversification. SOD matches load and resources. It should capture at the LSE level what is needed to match load. It is not arbitrary. The sum of LSE resources must meet need in each hour. ACP said this would result in uncoordinated procurement of resources. SCE replied that the signals for new resource procurement are in the IRP, not RA. IEPA said it had raised the issue that each LSE has an incentive to meet its own load, but each LSE will saturate its own load profile independent of system level aggregate load profile.

PG&E presented next. It gave a recap of resource counting and said its conclusions differed from NRDC and ACP. It noted that the modeled data from the IRP had profiles that are fairly different from the CAISO actual data. It prefers to use the CAISO actual data (adjusted for economic curtailment if possible) and is concerned about the IRP data. Reliability risk in non-summer months is not clear (e.g., multiple cloudy days). There is an issue of distribution across the month and across each hour as the capacity value is not consistent. Also, the Inflation Reduction Act may affect storage charging if it reduces renewable charging requirements. NRDC said in the use of LOLE analysis for worst day you can try to avoid the resource removal to surface LOLE and try to find another way. SEIA said regarding PG&E’s slide showing 70% exceedance, it is enforcing the requirement that all hours with high LOLE have to be green (i.e., less solar is counted at the exceedance level that expected) which introduces a level of conservatism. SEIA thinks reds (more solar is counted than expected) and greens to have to average to zero but making them have to be negative is too conservative.

PG&E said it was open to further discussion and that it was indeed trying to be conservative. Perhaps the results could be tested in the PRM/LOLE analysis. There is also the issue of the use of PCAP, UCAP, ICAP, etc.

MRP asked if the capacity factors were averages. PG&E said it would check. Re surfacing LOLE, MRP said there could be LOLE events in shoulder months. It believes that in non-summer months, the grid can lean on non-RA capacity but not in summer.

SWPG asked if PG&E would recommend 70% exceedance across all technologies. PG&E replied that it could be varied; it is an open question; but this would add complexity. SWPG asked how often the exceedance value would be recalibrated. PG&E replied right now ELCC is recalibrated every two years. However, if out-of-state wind regions are more deliverable, it would be OK to use a different exceedance value.

CAISO asked if, given the variance in solar output across some months with steep slopes, how would PG&E calculate the exceedance value. PG&E said it had used an average.