Notes from September 14, 2022, RA Reform Working Group Meeting

The CPUC Energy Division (ED) presented first (see slides). It began by discussing a further LOLE study for RA that it and its consultant ASTRAPE would prepare for submission no later than January 2023. It would involve converting LOLE modeling to the hourly RA framework under SoD. ED would provide stakeholders with more details for the LOLE study for RA including inputs and assumptions, the methodology and the process to be followed.

The starting point would be the resource portfolio for 2024. One of the inputs is the aggregated energy constraint for storage. Exceedance will be used for wind and solar. The CEC managed load will be used for the peak day of each month. There will be a test for the durability of monthly reliability. The analysis will be solved for the highest monthly load multiplier that a reliability-compliant portfolio can support. Unlike removing resources to surface LOLE, the study will increase load until LOLE appears. The test will be to see if the portfolio can meet capacity and energy needs. The process will start with the reserve margin level for September, the highest load month. Load will be added to the other months to get the same margin level.

CEC and SERVM net loads are somewhat different. The CEC load is 1-in-2 8760 hours for one year and does not reflect variability in different years. The SERVM is the worst day based on 25 different load shapes. There are 3 different portfolios: 1) 2024 expected, 2) the expected with added 10 GW of solar, and 3) the expected with 10 GW of additional storage. The differences amount to 1-3% in the winter. ASTRAPE used the NRDC tool with inputs from SERVM. It used expected available physical resources for 2024 and filled gaps with perfect capacity. The NRDC tool is 1-in-10 compliant in SERVM and loads were scaled up to see if capacity and energy shortages appeared. It found the highest PRM in each month. This approach avoided the need to calculate ELCCs for each resource. The use of expected resources means taking into account additional resources that will come online by 2024 and lead to the need to add less perfect capacity.

When asked by MRP what exceedance methodology was used, ASTRAPE said there is a tradeoff between the degree of conservatism in the exceedance choice and the PRM levels. ED said that when you pick the worst day, you are not finding a level of resources above load; you simplify by picking one spot out of the distribution rather than looking at the whole distribution. Analysis is continuing of the differences between using SERVM vs. CEC variability of net load. Bigger differences in net loads imply bigger differences in the PRM. The binding constraint is September. Applying September PRM to all months surfaces significant LOLE in many months. CEC profiles showed bigger differences between July and September than SERVM. The modeling removed all maintenance outages. The result was higher PRMs in other months than September. The analysis did not do Monte Carlo runs for portfolios.

Added load varied by month and did not include maintenance. This was in lieu of removing resources.

SERVM uses consumption profiles reconstituted with DR and BTM resources, weather-normalized. It considers the relationship among weather and electricity demand using 23 years of weather. THE whole distribution is scaled up to the CEC peak. The worst day is the worst day in all 23 years. The underlying LOLE study will be updated every year.

Gridwell pointed out that the portfolio would vary by month since RA requirements vary by month. ASTRAPE said that there would be maintenance in some months.

The portfolio baseline has been updated since July because of new in-service dates, etc. ED wants to better calibrate imports and exports, to include a high electrification scenario, and has added 2018-2020 weather years. ED used previous RA reports to come up with 4000 MW of imports for summer HE17-He22. Forced outages data came from GADS. They have stochastics on forced outages and are looking into recent forced outages in hot weather. ED is not ready to include a higher proportion of hot weather years.

Send informal comments to Donald Brooks.

SCE presented next (see slides). It said one should use an annual LOLE study to produce a single PRM. It did not use the NRDC tool. It has its own tool which it will modify and send out. The PRM is relative to the highest forecast load day of the year. SCE’s Excel model is based on a 2030 CAISO system LOLE study, not 2024. SCE recommends breaking use-limited resources into pieces to have them work better with the optimization in its spreadsheet. Its portfolio is for 2030 system-wide CAISO that meets 0.1 reliability standard.

MRP said if the load changes, it might lead to a different portfolio. SCE does not think raising the load makes sense since there is variability in load. The result in non-peak months should not be leaning on non-RA resources. An annual LOLE study has resources that vary like VERS on a monthly basis. An annual LOE study should be used as a proxy for September. It does not show the best portfolio for other months.

ED asked about differences between the SCE tool and NRDC tool in calculating the PRM. PG&E asked about next steps and suggested it would be good to test the SCE and NRDC tools together. It asked if SCE was considering updating its tool for 2024 and how the SCE tool addressed outages. SCE said stochastic load variation, renewable output variation and outages are taken into account in an LOLE study.

PG&E asked about use limitations for thermal plants. SCE said they were loosely captured in the SCE tool. It limits peakers to 12 hours. You cannot do this in the NRDC tool. SCE assumed a 6-hour limit for DR programs and 16 hours for pumped storage.

PG&E asked about updating for the 2024 LOLE study with available resources and SCE said it would clean this up and that it could update for 2024 if the data were easily available.

MRP presented next (see slides). It had questions about how to get a PRM for a monthly RA program. It also asked how to treat energy-only resources in doing a LOLE study. Should the CPUC consider a high demand case load forecast instead of the mid-mid case? The RA program does not use the concept of perfect capacity—how much capacity is needed since it is not perfect? It also asked about resource availability in all 12 months and how to address use limitations.

MRP asked if SERVM has the capability to address use limitations. ASTRAPE and ED had different perspectives and said they would discuss further.

MRP asked how to calibrate PRM for the shoulder months. SCE said PRM numbers for months other than September were not meaningful. August PRM does not tell us how much capacity is needed to meet a 1 in 10 reliability standard. It is even somewhat an approximation for September. SCE thinks you can use September figures for all months and then study whether there is leaning on non-RA resources.

MRP said the shown RA portfolio will differ from LSE portfolios and this requires an iterative calibration to achieve an annualized PRM. SCE said if an LOLE-based portfolio does not have enough energy to charge batteries, there is an issue with the LOLE study. MRP said it was unclear where batteries and state of charge are in monthly showings. SCE said this would come from the quality of work in capacity expansion models.

Regarding the issue of which load forecast to use, SCE said what is most important is load variability in the LOLE study. CAISO uses large load variability. MRP said a high electrification case would have higher peaks. SCE said one can expand the stochastic load scenarios. MRP said the current study should represent actual resources and needs to be calibrated for the monthly RA framework. It wanted to see a timeline for getting to January 2023.

There was more discussion about PRM issues.

Cal Advocates asked ED if it had considered dropping the first three years when it added 2018-2020 to the load forecast. ED said it was assuming early years are less extreme which is not necessarily true. It might be possible to de-trend to reflect future higher load years but this requires additional work.

ED said that ASTRAPE picked intentionally high load days so we would expect to need lower reserves than in other months. ASTRAPE said it depends on whether you calculate the PRM over managed load and you cannot anchor on the PRM. What matters is the portfolio and managing capacity and energy requirements. SCE asked if ED calculated the PRM based on SERVM, would compliance obligation be based on SERVM? ED said yes. ASTRAPE is measuring compliance obligation against the CEC forecast but for September it uses SERVM. MRP said we were talking about load in multiple dimensions. Load is stochastic in LOLE but not the same as the CEC forecast. PG&E said for the forecast, it understands that the worst day in SERVM is the worst day in 23 years. Given that RA is using 1-in-2, if use SERVM worst day to set the PRM, would we still use the CEC forecast to set requirements? SCE said they should be the same. There are always stochastics in an LOLE study that are different from the forecast. The forecast that matters is the one to be used for PRM and compliance. These should be on the same basis, whether 1-in-2, 1-in-5 or 1-in-10. A lower forecast will lead to a higher PRM and vice versa. You should still get the same portfolio.

ASTRAPE asked what do we carry reserves for? For worst days. We look at days where reliability is of concern. This should be the basis for portfolio reviews.

PG&E raised the issue of leaning on non-RA resources.

MRP asked how meaningful is the use of a 1-in-2 or 1-in-5 or 1-in-10 forecast.

ASTRAPE said this is upstream of the LOLE analysis. Once you take care of the forecast, it is not material to SoD accounting. SCE agrees. A portfolio to avoid EEA1 is different from a 1-in-10, which could result in an EEA1. PG&E said this issue of forecasting should be taken up in a forecasting context, not RA.

CAISO asked about transmission assumptions in LOLE modeling what deliverability assumptions. ED said it did not impose a deliverability requirement in the analysis and that it did not think this was a big issue because deliverability only affects a few hours. MRP asked if the LOLE analysis included energy-only resources and ED said no. There are few deliverability constraints per year. SCE said it doesn’t matter. There is no way to model these in this type of modeling.

MRP asked about calibration using increasing load as opposed to eliminating resources. ASTRAPE said changing the load was quick and dirty and that it generally agreed with the order of supply adjustments proposed by MRP to calibrate the PRM.

EBCE presented on TY 2024. Its focus was on how aggregating showings for different LSEs could lead to less need for additional procurement. If one LSE was short for storage but another was long, combining their showings could lead to less additional overall additional procurement. It said this made the case for transactability by combining loads and resources for multiple LSEs. CalCCA said the alternative of selling excess would not solve the problem if the resources were available 24/7, because the LSE would have to procure for the hours it is now short. CLECA raised the issue of who would aggregate the portfolios and loads. Cal Advocates asked if this was s transition issue while more batteries are being procured.