Question	Answer
Due to high temperatures, transmission lines are limited to their maximum capacities. Beside RA, is transmission adequacy analyzed for critical RA-hours?	It should, and that's the main reason that we included a sixth principle for RA to properly account for transmission, both internally and with neighboring BAs. Typically RA analysis will use a simplified transmission topology that has zones or sub-areas that need to meet local capacity requirements due to transmission constraints. These can be thermal transmission limits or other (i.e. voltage stability, etc.)
What are the options under consideration for improving reliability at reduced cost and no carbon in California?	1. Increased coordination with neighboring BAs and firm transmission, 2) Increased energy storage deployment, 3) Using a more conservative load forecast for RA and reserve margin, 4) Transitioning to a reserve margin across multiple (all) hours
How to better account for the performance needs of resources (ramping, PFR, etc.) beyond EUE to serve a net load with greater variability/uncertainty?	The power system needs a full spectrum of grid services, ranging from sub-seconds (inertia & FFR) to seconds and minutes (regulation), to ramping, and slower speeds like non-spinning reserves and ultimately capacity. I don't think one type of analysis or one grid service is necessary or practical. But most or all of these services will need to be adjusted and refined with further variable renewable (VRE) and inverter-based resource (IBR) integration and fossil retirements.
If ELCC is a "quick fix," what then is the longer term fix in your opinion?	To be determined. Right now I think ELCC is a good metric for capacity accreditation (paying resources for the capacity service they bring to the system, on average), but we need something else for reliability planning. I would like to see reliability metrics directly integrated into the capacity expansion planning process, which would need to become more stochastic and evaluate many years of weather and outage patterns - and replace the planning reserve margin (PRM) altogether.
Did you consider compensation mechanisms and how that might/should change?	No. Currently this work is focused on the Resource Adequacy analysis methodologies and metrics, and has not focused on the subsequent compensation and capacity accreditation process. However, this is a logical next step that we will be discussing with partners.

What level of EV penetration does the RTS-GMLC data set incorporate? And, does that level match likely scenarios for the coming decades?	The RTS-GMLC "out of the box" does not include EVs, demand response, or load shifting - this is something we have added (or intend to add shortly) to the analysis to make sure that our First Principle on load participation is adequately evaluated.
Does the state of charge and usage pattern of storage change its ELCC? A battery that's needed to power the system overnight may not be available @peak.	Yes, absolutely. That is why this work advocates for *chronological* evaluation of the power system commitment and dispatch for resource adequacy analysis. For energy storage and demand response utilization can greatly affect ELCC and system RA metrics.
Where is the tradeoff between having the grid operator dictate solutions (T, D upgrades or certain G technology types) vs. setting a PRM and letting markets work	In general, I believe markets (and/or competitive solicitation in non-ISO regions) work to determine the solutions for resource adequacy. The grid operator should not dictate solutions, but they are important in ensuring that resources are measured fairly and accredited for the services they provide. I don't believe PRM adequately does this today.
Have you paired a chart of distributions of outage events x value of lost load against a chart of (storage/DR) resource costs to cover such outage events?	Yes, that was the last slide of the presentation, but ran out of time. The next step will be to compare different resources (or combinations of resources) ability to improve reliability as a function of total system cost (operating costs, capital costs, O&M costs, etc.)
What is meant by planning problem? Investment in infrastructure or flexibilities or power plant (especially hydro) dispatch planning?	Ultimately both the investments in infrastructure and flexibility of that infrastructure matter for planning. This presentation focused on ensuring enough resources are available given uncertainty in load, weather, and generator outages - this is for a "capacity grid service" but other grid services need to be evaluated as well.
Is this apply to hydro system power (90%) with wind generation that is highly correlated with peak-load?	In general, this work should apply to hydro-based systems as well. I think the big difference is there would need to be even more weather years evaluated, but potentially less need to focus on chronological operations. I think all of the other principles and methods apply, regardless of the resource mix.
As you go to longer-duration storage and higher shares of renewables, does that require longer chronological modeling intervals?	The chronological modeling intervals don't change, but the need for chronological modeling certainly increases and the amount of weather data that should be used also increases.

How will RA margin change with resource mix? If 50% of electricity is wind, we need bigger margin, if we have full storage, does needed reserve margin decrease?	This highlights the problem with the Planning Reserve Margin generally. It will be a constant moving target based on the resource mix and requires that planners regularly update how much each resource "counts towards the RM" using something like ELCC. Each resource's ELCC is based on the amount of capacity installed, as well as the overall resource mix for the rest of the system. This can be useful for near-term and current year analysis, but starts to break down for long-term planning.
Does the chronological effect also need to be applied to DSM resources? A commercial DR program may not have the same MW impact at 7PM as it does at 4PM?	Yes, absolutely. DSM resources should be evaluated with the same level of fidelity as generators, with information on availability, outage rates, time constraints, duration constraints, etc. For example a DR program may be limited on the number of calls per year/month/day, etc. so the utilization in one period affects subsequent ones.