Questions for Discussion with the DR Collaborative, Prepared by Matthew Tisdale

5.14.13

1.1. How are existing DR programs performing? What response has been provided in past years?

1.1.1. Commission Staff's May 1 Report on 2012 Program Performance was critical of some program performance and forecasting. Was their analysis accurate? Was it reflective of prior years?

1.2. What is the present and future technical potential for DR in California? Economic potential? Market potential?

1.2.1. Would spending time developing answers to these questions as we do for EE be good use of time?

1.3. What are the Commission's goals for DR? The EAP II committed to 5% of peak load from price responsive DR (which we are well short of). Does that goal need to be reevaluated or reinforced?

1.3.1. Would new numerical MW targets/goals be useful?

1.3.2. What about non-MW targets…would further definition of desired DR characteristics be useful?

1.3.3. Are the Commission's principles on DR clear to the IOUs, ISO, and other stakeholders? If so, what are the principles and do they need renewing? If not, how do we clarify?

1.4. The Commission has committed to integrating DR into wholesale markets. Does that commitment remain? What are the cost and benefits of this policy?

1.4.1. Can wholesale and retail DR coexist into the future? Are there reasons to continue to maintain retail DR programs for distribution and local reliability reasons? If so, which DR resources should be left in retail and which should be wholesale? What criteria drive this distinction?

*The primary reason to retain some retail DR programs that are not bid in as supply (i.e. PDR or RDRR) is simply that the benefits do not outweigh the costs at this time and may never.*

*The programs that now make sense to move to PDR/RDRR are for resources that the CAISO must procure or must use in real time to operate the system. This would include any DR that is for ancillary services or for real time energy on five minute dispatch. It also includes the pure reliability program which is now just the Base Interruptible Program (BIP) for PG&E. When BIP is moved to RDRR it will also include a lot of Demand Bidding Program (DBP) MW which can also be bid into the day-ahead energy market. Thus, when BIP moves to RDRR the CAISO will have a large part of the DR programs in their market as supply (~*

*200 MW for PG&E). In the future, the IOUs have plans to offer DR as ancillary services and five-minute energy, and pilots are planned or have been done.*

*Programs that should **not** move to PDR/RDRR are generally the day-ahead energy programs and dynamic rates (CPP/PDP/SmartRate/ PTR). Though some day-ahead DR programs are dispatchable locally, dynamic rates programs are not dispatchable on a local basis and thus could not be made into PDR. The CAISO is notified when these programs are called and is supposed to incorporate that information into their operations. They have plenty of time on a day-ahead basis to factor in the DR. There is little or no identified benefit for these to bid as PDR. The CAISO can also "call" these programs if it anticipates problems a day ahead.*

*There is significant cost to bidding as PDR, and the processes of registration and settlement are cumbersome. We should take the time to get the "bugs" of PDR/RDRR worked out over time and the costs brought down before we decide to push more DR into PDR/RDRR. Also, we want to allow innovation to take place in the DR market as new technology and players enter. This is particularly true at the retail level. Forcing all DR programs to bid in as PDR will slow innovations in DR at the retail level because of the additional integration costs.*

1.4.2. What may be the impact of the Court of Appeals ruling on the ISO's compensation scheme under its Reliability Demand Response Resource (RDRR)? How should potential Court action affect the Commission's next steps with DR?

*We cannot do RDRR until the CAISO gets the RDRR tariff approved. This may require waiting for the court decision.*

1.4.3. Should the IOUs retain dispatch control over DR resources or should that control be given to the ISO? Perhaps the ISO should have control over some, but not all? If so, which DR should they have dispatch control over?

1.5. Should the IOUs continue to offer DR products directly to their customers? Or should more/all procurement of DR go through competitive solicitations like the AMP programs?

*As long as the IOUs are LSEs and as long as they operate electric transmission and distribution systems it will be efficient for them to have some DR. This is because DR can be efficiently integrated into rate design, and into transmission and distribution planning and ops. But the IOU can and should use aggregators for much of the other DR. The role of aggregators should continue to grow.*

1.6. How is DR affecting load forecasts and procurement of supply? What feedback loops should the Commission expect between the implementation of the Padilla letter, assessments of avoided costs and cost effectiveness, and DR procurement authorizations?

1.6.1. The ISO's confidence in the dispatch, duration, and availability of DR weighs heavily on whether that DR ultimately displaces transmission and generation resources. How can the CAISO's confidence be raised? Are potential accommodations feasible and/or cost effective?

1.7. What happens to the "Sutter Problem" if we're successful in making considerable improvements to DR in California? Should perspectives on this question impact how the Commission proceeds?

1.8. Does the Commission agree with the following statement? If so, how would this principle effect upcoming decision-making?

1.8.1. "any initiative that attempts to influence the way in which customers use electricity in order to maintain electric system reliability and minimize overall electricity costs must focus on the legitimate needs of customers first, or it will fail. The needs and wishes of the ISO, the utilities, regulators or any other stakeholder group are secondary to this fundamental reality."

1.9. In recent LTPP decisions, the Commission has assumed 200 MW of DR will be available in the LA local reliability areas (LRA) during an N-2 event between now and 2021. The same assumption has been made for the San Diego LRA. What needs to happen in order for those assumptions to become reality? Are any changes needed to IOU procurement or dispatch capabilities for DR?

1.10. What improvements to the cost-effectiveness protocols are needed? Are we on schedule to have effective tools to complete an evaluation of IOU proposals for the planned 2015-2017 cycle?

1.10.1. What are the most essential improvements needed for the cost-effectiveness protocols?

*The "A" factor should be fixed to more accurately weigh the value of the top hours, dual participation must be addressed, and what costs should be included in the cost effectiveness and what should not. These are the "deficiencies" identified in the last DR cycle decision. There is a consensus on how to solve these and so it should be done quickly as it is also needed for new AMP contracts. Also, any new characteristics or qualities that the Commission would like DR programs to have (e.g., ramping) will need to be valued in the cost effectiveness methodology. Otherwise, there is the risk that the programs will not be found cost effective and will not be approved.*

1.10.2. Are the assumed avoided costs reasonable?

1.10.3. Should value of DR providing flex RA be considered? If so, what impact does this have on timing of finalizing protocols?

1.11. What rules will govern aggregation of retail customers into non-IOU programs? (Proposed Rule 24 and related issues)

1.12. Should the Commission require emergency programs (i.e., BIP, API) be available for dispatch before non-RA resources? Should dispatch order be altered more generally? Why or why not?

1.13. Is DR fully eligible for RA now? Partially eligible? Should DR be eligible for participation in forthcoming Flexible RA markets?

1.14. PG&E AMP contracts expire at the end of 2014; the next cycle begins in 2015. Does the Commission want to have these programs lapse for one year or grant additional authority? If Commission doesn't want them to lapse, how will that authority be granted? Will there be any specificity to that authority in terms of resource characteristics, contract tenure, cost-effectiveness?

*It is important for the continuation of this important resource to have an RFP this year so that customers, aggregators and PG&E can smoothly plan for this DR after 2014. Not doing so will be disruptive to the aggregators' customers and increase aggregators' costs in the next RFP.*

1.15. Does the Commission agree that we need to resolve the following issues before wholesale integration is possible? If so, how will we resolve?

1.15.1. Rule 24

1.15.2. CAISO metering and telemetry requirements

1.15.3. Financial settlements

1.15.4. Adequacy of revenues from energy-only markets to support DR business models

1.15.5. How does the relative lack of volatility in energy market prices effect the viability of wholesale DR? Is past prelude?

1.15.6. ISO timeline requirements used to facilitate financial settlements

1.15.7. Whether ISO products appropriately reflect unique nature of DR, as opposed to shoe horning DR into products more suitable to generators

1.16. Can DR focused on water service agencies deliver resources that are a good value?

1.17. How do ISO/PUC requirements for DR dispatch notice (time between notice and customer response), duration (amount of time customer maintains response), and availability (how much total time customers may be asked to respond) to other jurisdictions? Should we have the goal of being comparable or should California be more demanding?

1.18. How should the Commission consider DR that results from rate design (rather than non-rate incentives or penalties)?