The Division of Ratepayer Advocates Comments in response to
Technical Questions on Proposed Scenarios, R.12-03-014
September 7, 2012

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1a. Are any resources double counted or inappropriately left out of the analysis?

Event-Based Demand Response

Peak Time Rebate (PTR) is inappropriately left and should be included as Event-Based Demand Response (DR). The July 27, 2012 Assigned Commissioner's Ruling on Standardized Planning Assumptions (ACR), Attachment, and page (p.) 17, states:

> Event-based demand response shall be accounted for as a supply-side resource. The most recent Load Impact reports filed with the Commission should serve as the mid scenario. For PG&E [Pacific Gas and Electric Company], this should also include the pending peak time rebate program.

Energy Division (ED) Draft Scenarios also state that Event Based DR should include PG&E's PTR.[1] However, Load Impact reports filed June 1, 2012 do not include PG&E's PTR program. It is unreasonable to assume that the PTR will provide zero megawatts (MW) in 2022. Even if PG&E's implementation of PTR is delayed, it is likely to be a short-term issue since Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E) have implemented their PTR programs. DRA recommends adding 235 MW for PTR, as determined in Decision (D.) 09-03-026,[2] to PG&E's Event-Based DR mid assumption.[3]

The Event-Based DR value for PG&E should be 729 MW[4] in 2022, to accurately reflect Event-Based residential and non-residential load impacts, in addition to the aforementioned 235 MW for PTR in 2022. Making these corrections, result in a Total mid Event-Based DR for PG&E of 964 MW, instead of the current value of 665 MW in 2022.[5]

Total mid Event-Based DR value for SDG&E should be 165 MW[6] in 2022 instead of the current value of 133 MW in 2022.[7]

Making the corrections summarized above, DRA recommends that the total mid Event-Based DR value for all three investor owned utilities (IOUs) in 2022, increase from the current value of 2595 MW by 331 MW to 2926 MW.[8] (See

[1] ED Draft Scenarios, p. 13, footnote 30.

[2] While PG&E projected a 260 MW peak load reduction from default residential PTR, D.09-03-026 appears to have adopted a modestly lower figure. Per p.133 of D.09-03-026, "we adopt PTR savings through 2030 in the amount of 5,714 MWs as opposed to PG&E's forecasted amount of 6,307 MWs." This amounts to a reduction of fewer than 10% in PG&E's projected residential PTR aggregate peak load reduction over the multiyear analysis period. Applied to PG&E's single-year (2012) estimate of 260 MW, the adjustment adopted in D.09-03-026 would yield a projected peak load reduction of 235 MW for 2012.

[3] Scenario Tool, worksheet Supply Individual Assumptions, cell O7. PTR value may be adjusted down in earlier years (i.e. 2012) if the program is delayed, but it should be assumed that PTR will have the full 235 MW by 2022.

[4] PG&E Load Impact report executive summary, filed June 1, 2012, p. 17, table 6-1. 729 MW is obtained by adding Event Based Residential and Event Based Non Residential load impacts.

[5] Scenario Tool, worksheet Supply Individual Assumptions, cell O7. PTR value should be adjusted down in earlier years (i.e. 2012), but it should be assumed that PTR will have the full 235 MW by 2022.

[6] SDG&E Load Impact report executive summary, filed June 1, 2012, p. 56 (mimeo). 165 MW is obtained by subtracting 5 MW for PLS, which is Non-Event Based DR, from the Total of 170 MW. Please note that SDG&E does not provide load impacts for 2022, but it can be assumed that 2021 load impacts will be the same as 2022 load impacts.

[7] Scenario Tool, worksheet Supply Individual Assumptions, cell O9.

[8] Scenario Tool, worksheet Supply Individual Assumptions, cell O6.

Table below). DRA also recommends revising the low Event-Based DR to 2633 MW[9] and the high Event-Based DR to 3219 MW.[10]

IOU	Scenario Tool current value for mid Event Based DR in 2022	Correct value for mid Event Based DR in 2022
PG&E	665 MW	964 MW
SCE[11]	1797 MW	1797 MW
SDG&E	133 MW	165 MW
Total	2595 MW	2926

Non-Event Based Demand Response

Non-Event Based DR, as currently calculated in the ED Draft Scenarios, does not properly reflect incremental Permanent Load Shifting (PLS), Real-Time Pricing (RTP) and Time-of-Use (TOU) Pricing. The ACR, Attachment, p. 13, states:

> For demand-side demand response programs, the values embedded in the Energy Commission load forecasts will be utilized. Demand-side demand response programs that are non-event-based are included on the demand side of the assessment.

Non-Event Based DR is therefore calculated based on the Energy Commission's California Energy Demand (CED) forecast, which identifies "incremental impacts from current committed programs in these planning areas (PG&E and SCE only), which include real-time or time-of-use pricing and permanent load shifting, to add up to 69 MW in 2022."[12] The CED does not provide a breakdown of this MW value by specific IOU program and does not include any Non-Event Based DR attributed to SDG&E. DRA has not received any response from the Energy Commission regarding this number. It is unclear, and highly unlikely, that the CED includes any portion of the 53 MW for PLS, approved in the most recent 2012-2014 DR budget cycle decision for all three IOUs.[13] If the CED had accounted for this PLS value, it would have included the 5 MW approved for SDG&E, but the CED does not assign any incremental committed Non-Event Based DR to SDG&E.[14] Also, the CED does not account for any incremental uncommitted PLS for the three IOUs, which is likely to be funded in future DR decisions. DRA recommends that the Energy Division obtain the most accurate information possible from the IOUs and the Energy Commission regarding PLS, RTP, and TOU.

PG&E's Load Impact reports filed June 1, 2012 show a total of 176 MW for TOU in 2022, which is labeled as Non-Event Based DR. SCE reports 10 MW for RTP in 2020 which is labeled as Non-Event Based DR. SCE and SDG&E do not provide load impact forecasts for TOU pricing, although they have enrolled customers in TOU. It's unclear whether TOU pricing is properly accounted for in the CED. Energy Division should ensure that PLS, RTP, and TOU pricing are properly accounted for in the Planning Scenarios. DRA is willing to continue working with Energy Division and the Energy Commission to determine the correct MW numbers for these categories.

Once-Through Cooling

The Planning Scenarios assume Moss Landing Units 1 and 2 are retired in 2017, along with Moss Landing Units 6 and 7. However, Units 1 and 2, which each have a capacity of 510 MW, are relatively new units, and the 2011-2012 California Independent System Operator (CAISO) Transmission Plan assumes they will remain in operation beyond their compliance deadline dates.[15][1] While the Transmission Plan did not assume a specific date of retirement, it did assume

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[9] Scenario Tool, worksheet Supply Individual Assumptions, cell O5.

[10] Scenario Tool, worksheet Supply Individual Assumptions, cell O10.

[11] Total mid Event-Based DR value for SCE is correctly calculated in the Scenario tool.

[12] CED at pp. 33-34.

[13] D.12-04-045 at pp. 243-244.

[14] CED at p. 34, Table 1-8.

[15] CAISO 2011-2012 Transmission Plan, p. 233.

that Units 1 and 2 would be in operation through the planning horizon. DRA believes it would be reasonable to reflect the CAISO's planning assumption- specifically, that these OTC units will remain in operation through the planning horizon.

1b.Are any numbers cited in the proposed scenarios or spreadsheets inaccurate relative to the intended sources? *DRA does not* have any comment at this time, but will review final numbers for accuracy.

1c. Are there any errors in the renewable generation project data in the 33% RPS Calculator? DRA has found no errors but will continue to review the data and submit any comments by September 11, 2012.

2. Staff has assumed a resource with no current COD estimate in the Energy Commission's list of siting cases (http://www.energy.ca.gov/sitingcases/ALL_PROJECTS.XLS), but meeting other criteria, would be online by 2017. Is this a reasonable assumption? If not, please provide a year and justification. DRA does not object to this assumption.

3. If Staff could not locate a COD for an existing resource, Staff assumes a COD of 1/1/1980. Is this a reasonable assumption? If not, please provide a year and justification from a public source. DRA does not object to this assumption.

4. Is it appropriate to group renewable resources such as geothermal or biomass in with conventional generators for purposes of estimating resource retirements? Geothermal and biomass should not be considered with fossil; units when assessing retirement, because the inputs to a retirement decision include the economic effect of "returns to energy" (i.e. margin earned through energy sales to use to cover fixed costs) and this can be quite different for very-low or even zero marginal fuel cost units such as these renewables. The scenarios should reflect retirement dates for biomass and geothermal resources based on specific input from the owners of those resources. In the absence of such information, given the continuing RPS obligations, it is reasonable for all such resources to be assumed to be repowered at the end of life, for all three of the retirement scenarios. The retirement date for any remaining non-renewable resource could reflect the proposed listing for "other" units from the ACR (i.e., retire at 40 years for the mid case, repower at end of life for the low case, and retire at 25 years for the high case).

5. Is a 19% conversion from nameplate small PV capacity to peak production appropriate? If not, what data source and method publically available should be used for this calculation? A 19% conversion factor is not appropriate for peak production estimates. While DRA does not object to using 19% for the average annual capacity factor, peak production values should recognize the value of small PV output during peak times. For example, Section 6.5 of Itron's 2010 impact evaluation of the CSI program discusses this issue and indicates that peak production ratios generally exceed 40%, and can be higher than 60%, depending on the method used for estimating the ratio, the type of technology (e.g., fixed, or direction of tilt, or tracking) and the specific hours under consideration (e.g., CAISO coincident peak, or IOU non-coincident peak). The table below is from the Itron report and shows one set of ranges of possible peak impact values.

Table 6-5: Estimated PA-Specific IOU Peak Impacts

Program Administrator	Program	Peak Date and Time (PDT)	PV Systems (n)	Rated Capacity (MW)	Generation (MWh)*	Peak Hourly Capacity Factor (kWh peak hour/kW rebated)
CCSE	CSI	September 27, 2:00 to 3:00 PM	5,152	43.2	29.4	0.68
	SGIP		105	14.2	5.9	0.42
	Both		**5,257**	**57.4**	**35.3**	**0.62**
PG&E	CSI	August 25, 4:00 to 5:00 PM	21,368	218.6	119.4	0.55
	SGIP		494	80.9	37.0	0.46
	Both		**21,862**	**299.5**	**156.4**	**0.52**
SCE	CSI	September 27, 2:00 to 3:00 PM	10,015	129.7	80.3	0.62
	SGIP		291	40.8	21.9	0.54
	Both		**10,306**	**170.4**	**102.2**	**0.60**

* The uncertainty on all of these estimates is better than 90/10 confidence.

6. Please provide a prioritization of staff's proposed scenarios and portfolios, and briefly (no more than 1 page) explain the rational for this prioritization. DRA recommends the following prioritization, and may make specific recommendations about necessary changes to the Scenarios and Sensitivities in the upcoming policy comments:

1) Scenario 1 – Base Scenario: The Base Scenario is necessary to provide a middle-of-the road, reasonable assumption.
2) Scenario 3 – High Distributed Generation (DG): The Scenario 3 seems reasonable because of the Governor's prioritization of DG, and will be useful as a bookend illustrating what the grid will look like if California aggressively pursues many of its energy policies.
3) Scenario 2 – No New Demand Side Management (DSM): Scenario 2, while very unlikely, will be useful as a bookend showing what the grid will look like if California suspends many of its energy policies.
4) Sensitivity 1C – Nuclear Retirement: Sensitivity 1C is useful in showing an extreme case where no nuclear resources are pursued.
5) Sensitivity 1A – Environmental Sensitivity: Sensitivity 1A may be useful to consider the benefit in siting future renewables based on environmental concerns. However, DRA believes this sensitivity is a lower priority, and does not necessarily need to be modeled.
6) Sensitivity 1B – Nuclear Retirement: DRA does not believe that both Sensitivity 1B and 1C are necessary, and places higher priority on Sensitivity 1C, because it will show a more extreme change in policy. Sensitivity 1B seems to be more similar to the situation we are currently in, with the San Onofre plant offline.
7) Sensitivities 1D and 1E – Low and High Load Growth: DRA does not support the Low and High Load Growth sensitivities, as they are very similar to each other and to the Base Scenario. If Sensitivities 1D and 1E are pursued, their assumptions will need to be changed, which DRA will comment on in the upcoming policy comments.
8) Sensitivity 2A – Replicating Transmission Planning Process (TPP): DRA does not believe Sensitivity 2A is necessary, because of its similarity to Scenario 2 and because DRA does not see the value in replicating the TPP.