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1-08-14
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 13-12-010 (Filed December 19, 2013)

THE OFFICE OF RATEPAYER ADVOCATES' COMMENTS ON ASSUMPTIONS AND SCENARIOS FOR THE CPUC's 2014 LONG TERM PROCUREMENT PLAN PROCEEDING AND THE CAISO'S 2014-2015 TRANSMISSION PLANNING PROCESS

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January 8, 2014

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I. INTRODUCTION

Pursuant to Administrative Law Judge (ALJ) Gamson's email ruling on December 19, 2013, the Office of Ratepayer Advocates (ORA) submits the following comments and responses to questions posed in ALJ Gamson's email. The questions and comments relate to the December 18, 2013 Workshop on "Planning Assumptions and Scenarios for use in the California Public Utilities Commission (CPUC) 2014 Long Term Procurement Plan (LTPP) Proceeding and the California Independent System Operator (CAISO) 2014-2015 Transmission Planning Process (TPP)." The Energy Division distributed "Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-2015 Transmission Planning Process (Planning Assumptions)" prior to the workshop, with some assumptions updated on December 26, 2013.[1]

II. DISCUSSION

1. Is the current range of scenarios sufficient to cover current policy issues facing the CPUC?

The range of scenarios presented is sufficient and encompasses a variety of possible futures for 2024; however, ORA recommends that the Commission focus finite modeling resources on three scenarios and two additional sensitivities to model for the 2014 LTPP. ORA recommends the Commission adopt the following three scenarios for use in the Operating Flexibility modeling:

- Trajectory Scenario (base case)
- High Load Scenario
- Expanded Preferred Resources Scenario

The Trajectory Scenario or base case should be considered the highest priority for the Operational Flexibility modeling. This scenario is most likely to reflect the future policy and procurement directives of the State's energy agencies in the near future. The High Load scenario will incorporate increased demand to reveal any potential strain on system resources. It is also important to include a scenario with increased levels of preferred resources, beyond the amount

[1] The Planning Assumptions are available at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm under 2014 LTPP, December 26, 2013 documents.

mandated in various preferred resource proceedings. Modeling additional preferred resources above what is mandated is consistent with the Loading Order to procure energy efficiency, demand response, and renewable resources before conventional gas-fired generation. In addition, the Expanded Preferred Resource Scenario is consistent with Southern California Edison Company's plan to account for additional demand side management programs and the potential for increased preferred resources in local areas.[2] These resources may materialize through procurement authorized as part of Tracks 1 and 4 of Rulemaking (R.)12-03-014 (the 2012 LTPP). ORA therefore recommends that the Commission adopt the "High" level of Additional Achievable Energy Efficiency (AA-EE) forecast for the Expanded Preferred Resource Scenario. In addition to these three scenarios, ORA recommends the Commission model two sensitivities to the Trajectory Scenario:

- Early retirement of Diablo Canyon (see ORA's comments on question 5);
- Implementation of a 40% Renewable Portfolio Standard

2. Are there any technical errors in the proposed scenarios, scenario tool, or RPS Calculator? For any identified errors, please be very specific in your comments including the location of the error and the correct value, including the source for the revised value. If appropriate, please provide a revised spreadsheet showing any corrected values. Some example questions to consider in identifying factual errors are:

a) Are any resources counted twice or inappropriately left out of the analysis?

ORA does not have any comments on this question at this time but reserves the right to respond to other parties' comments in reply.

b) Are any numbers cited in the proposed scenarios or spreadsheets inaccurate relative to the intended sources?

[2] *See e.g.,* Opening Brief Of Southern California Edison Company on Track 4 Issues, filed November 25, 2013 in R.12-03-014, at pp. 24-26.

Demand Response

It appears that Southern California Edison's (SCE) SDP-Commercial numbers in the scenario tool are calculated based on SCE's SDP-C March 27th, 2013, report.[3] ORA recommends updating the numbers for SCE's SDP-C program to reflect changes made in a report issued on May 29th, 2013.[4] The May 2013 report updated the March report's 2022 forecast for the 1-in-2 weather year, August peak, from 44 megawatts (MW) to 76 MW.

Energy Storage

The storage discussion of the Planning Assumptions errs by saying that: "According to D.13-10-040, the maximum size of storage projects that count towards the target is 50 MW but there is no overall cap."[5] In fact, the 50 MW limit only applies to pumped hydro, and not to other storage technologies.[6]

The Planning Assumptions mistakenly state that some resource types such as Concentrating Solar with storage would count toward the 2020 target if the resource comes online by 2020.[7] In fact, any storage system will count toward the 2020 target if it is installed and operational after January 1, 2010 and no later than December 31, 2024.[8]

c) Are there any errors in the renewable generation project data in the 33% RPS Calculator?

ORA understands that the 250 MW mandate pursuant to the Senate Bill (SB)1122 Bioenergy Feed-in Tariff currently being designed in R.11-05-005 (the RPS proceeding) is included in the planning assumptions via the Renewable Net Short Calculation (line 12), but only Renewable Auction Mechanism (RAM) and Renewable Market Adjusting Tariff (ReMAT) projects that are currently under development are included. ORA recommends assuming full compliance with these mandatory programs. The utilities' procurement targets for these

[3] 2012 Impact Evaluation of Southern California Edison's Commercial Summer Discount Plan (SDP-C), March 27, 2013, Table 6-2, p. 6-5.

[4] Revised 2012 Impact Evaluation of Southern California Edison's Commercial Summer Discount Plan (SDP-C), May 29, 2013, Table 6-2.

[5] Planning Assumptions, p. 13.

[6] Decision (D.)13-10-040, pp. 36-37, Appendix A, p. 3.

[7] Planning Assumptions, p. 13.

[8] D.13-10-040, Appendix A, p. 3.

programs are established by statute and Commission regulations. It is reasonable to assume that the utilities will comply with their obligations.

To project compliance with the SB1122 Bioenergy Feed-in Tariff, staff took the mandated capacity of the program – 250 MW – and assumed a capacity factor to achieve a gigawatt hour (GWh) projection of its annual output. A similar calculation can be performed for the three technology categories of the ReMAT. For the RAM, assumptions may not be as clear-cut but for forecasting purposes, ORA recommends the use of an average capacity factor of the projects resulting from the three RAM auctions that have already achieved executed and approved PPAs (and whose output is already included in the RPS Calculator).

3. Should Diablo Canyon be assumed online or retired in the Trajectory case?

ORA recommends that the Trajectory Scenario not assume the retirement of Diablo Canyon when its license expires in 2024 (Unit 1) and 2025 (Unit 2) (see ORA's response to question 1 for a list of scenarios and sensitivities ORA supports). However, the retirement of Diablo Canyon in 2024/2025 should be studied as a sensitivity to the Trajectory Scenario. The quantitative modeling results of any given scenario run from the system need analysis are not likely to provide the "right" answers to questions of need. However, the differences seen between scenario results will shed light on the drivers behind resource need. Understanding these drivers will help the CPUC to make informed policy decisions concerning where to allocate resource procurement dollars. The key benefit to modeling multiple scenarios is discerning how the results differ when different sets of input assumptions are used and using modeling results to illuminate what factors drive need by reviewing comparative differences across scenarios.

4. Is the treatment of energy storage for capacity value reasonable?

Section 4.2.4 of the December 26, 2013 Planning Assumptions states that the 700 MW transmission-connected storage target in 2020 will be the default assumption in the planning studies.[9] ORA agrees with modeling 700 MW of transmission-connected storage as a supply-side resource. It is reasonable to construe the planning assumption inclusion of 700 MW "to be modeled in all planning studies" as including full capacity credit for transmission-connected

[9] Planning Assumptions, p. 13.

storage resource, or full resource adequacy accreditation, for any system study; and full representation (i.e., 700 MW) as a supply/capacity resource at specific transmission busses in any local study.

However, ORA does not agree with the proposed capacity treatment for the 425 MW of distribution-connected storage and the 200 MW of customer-side storage. Section 4.1.8 of the Planning Assumptions states that the 625 MW storage target from distribution connected storage and customer side storage will "not count as capacity in power flow studies."[10] The proposed energy storage planning assumption concludes that since "there is no expectation that distribution and customer sited storage will be deployed and operated in a manner that provides capacity value at times of system stress, nor is there any information about where these resources will be deployed"[11] then the 625 MW storage target should not count as capacity in power flow studies.

While the distribution and customer-connected storage may not be able to provide effective system or local capacity at 100% of the installed peak output,[12] it is unreasonable to assume 0% for its contribution to system capacity, especially for the aggregate of storage resources being modeled for the future LTPP year 2024. While some fraction of the targeted resources – especially those coming online in the earlier years – may not have full dispatchability, controllability, or multi-hour / deep cycle energy storage capacity,[13] some fraction of those resources will have these attributes; and later-year procurements are more likely than earlier-year procurements to exhibit the attributes required to be considered a capacity resource (assuming continued commercial improvement in the technical aspects of storage resources). It is not the connection point (i.e., transmission, distribution, or customer) of the storage resource that determines the extent to which it will contribute to meeting capacity or resource adequacy obligations, but the MW/MWh ratio (peak MW output to MWh energy

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[10] Planning Assumptions, p. 11

[11] Planning Assumptions, p. 11.

[12] For example, not all small-scale resources will be able to be aggregated for controllability purposes, or be controlled in a manner sufficient to capture otherwise-available temporal and spatial diversity benefits.

[13] The extent of a resource's multi-hour or deep-cycle storage capability, in combination with its controllability would be the key attributes that allow it to contribute to capacity requirements.

storage) and the controllability of the resource (individual or aggregate).[14] Until the capacity benefits of the distribution-connected and customer-connected energy storage increments pursuant to D.13-10-040 are captured by the California Energy Commission's (CEC) demand-side modeling (which they are not for purposes of the 2014 LTPP, which will use the 2013 IEPR forecast), they must be captured as modifications to either the supply or demand-side LTPP modeling, reflected in the 2014 LTPP scoping memo.

The first of the Commission's three stated procurement policy purposes--"[t]he optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments"[15] illustrates that effective contribution to reliability *is* to be expected from the procurement process. Regardless of skepticism of some stakeholders about the ability of storage resources to deliver, the Commission's policy assumes that distribution and customer-connected storage will exhibit system-wide and local capacity attributes such that *at least some portion* of the total installed amount (625 MW) should be afforded capacity credit. Thus, ORA does not agree that the entire 625 MW storage target for distribution and customer-connected resources should be assigned zero value capacity in power flow studies. As indicated in Table 1 of D.13-10-040, both distribution and transmission-connected resources are expected to provide reliability-enhancing functionality; and ORA interprets customer-sited storage that assists with "Bill [management]Mgt"[16] to imply that customers will be installing storage that lowers peak load, or is available during hours in which energy prices are high – which generally means during peak load hours. There is nothing in Table 1 to suggest that none of the storage attributes of distribution or customer resources would be available during stressful grid periods.

Additional studies and analysis could identify a portion of the 625 MW that could count toward local capacity requirements (LCR), allowing the utilities to save ratepayers money by acquiring less capacity. The storage in local areas could also be counted in power flow studies to

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[14] For example, the aggregation of many thousands of small-scale storage resources (at customer or distribution connection levels) such as electric vehicle batteries, if predictably-controlled, can have just as effective a capacity effect on the system as a single, larger-scale transmission-connected resource such as would be seen at a centralized solar thermal plant.

[15] D.13-10-040, Appendix A, Energy Storage Procurement Framework and Design Program, page 1.

[16] D.13-10-040, Table 1, p. 14.

assess the transmission lines' ability to meet needs. If need is reduced by storage MWs, then transmission lines would transport fewer MWs, potentially avoiding or delaying the need for construction of some new generation and transmission facilities. The report to be filed with the procurement application on March 1, 2014[17] will contain MW and MWh information that will be of critical importance in determining the extent to which capacity accreditation can be assigned to any given (individual, or aggregate) storage resource. If the Commission is not prepared to assign a non-zero capacity value at this time to storage installed at the distribution or customer level, then it should wait until those applications are received before finalizing this aspect of the LTPP 2014 assumptions for storage resources.

5. For existing resources that do not have announced retirement dates, Staff may assume a resource retires based on facility age. Facility age is calculated from Commercial Online Date, but the COD may not be available for some resources. If no COD is available, is it reasonable to assume the resource does not retire within the planning horizon? If not, please provide an alternate methodology and justification from a public data source as needed.

Yes, it is reasonable to assume the resource does not retire within a planning horizon if no COD data is available. ORA notes that information from the plant owner or other relevant site information are possible sources for a proxy COD.

6. How should the capacity value of energy storage, demand response, and demand side resources (PV, CHP) be allocated to small geographic regions and/or busbars and how should the capacity value be adjusted to account for locational and operational characteristics uncertainty?

Energy storage, demand response, CHP and small PV resources can reasonably be assumed to be distributed across the entirety of an IOU service territory for the purposes of operational flexibility modeling with large aggregated regions, such as is seen with the Plexos modeling structure (used for Track 2 operational flexibility modeling in the 2012 LTPP process).

For local reliability studies for future years (2024), in the absence of more granular

[17] D.13-10-040, Ordering Paragraph 3, p. 77.

geographic forecasting,[18] the aggregate capacity values for each of these resources can be allocated first to "climate zone" level granularity within each IOU service territory, based on climate zone peak load share.[19] While this represents only a rough measure of allocative accuracy, in the absence of more granular forecasting it is reasonable to assume peak load as the gauge for resource distribution. The CAISO's local studies can then assume this "climate zone peak load share" level of capacity available across the set of transmission busses that fall within the climate zone. CAISO or the IOUs would need to create a mapping of transmission busses to climate zones in order to complete the final analytical step, determining how the climate-zone MW would affect local reliability assuming "best" and "worst" electrical bus locations within each climate zone, similar to the CAISO methodology reported on in the 2011/12 Transmission Plan for OTC Retirement reliability assessment (Section 3.3 and 3.4). ORA offers this starting point to ensure that the capacity value of distributed resources is not excluded from the modeling process solely because of electrical location uncertainty in future years.

The above allocation method would address locational characteristic uncertainty (until Joint Agencies' staff can refine forecasting techniques to more granular levels). Operational characteristic uncertainty can be addressed either deterministically or stochastically. A deterministic approach could essentially use the same methods as were in place for the 2012 LTPP for assessing the NQC values for these resources. ORA recommends this approach for the 2014 LTPP. As more information is obtained on DR and storage resource characteristics, future LTPPs can modify, if necessary, the capacity value ascribed to these resources. Peak period impact factors can continue to be used for PV and CHP resources to assess their capacity value. Distribution-connected and customer-connected storage can be assigned an NQC based on some fraction of the installed peak capacity of the resource, while 100% of the transmission-connected storage capacity can be assumed available at peak times in local studies.

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[18] ORA understands that more granular information will be available in future integrated energy policy report (IEPR) forecast cycles. *See* CEC 2013 Integrated Energy Policy Report December 2013, CEC-100-2013-001-LCF, December 2013 (2013 IEPR Report), p. 91, available at http://www.energy.ca.gov/2013_energypolicy ("As mentioned, future IEPR forecasts will be disaggregated at some level to better support planning efforts. That exact level of granularity will be determined by the joint energy agencies and the availability of data to support granular models.")

[19] 2013 IEPR Report, Table 9, p. 92.

Any consideration of using a stochastic approach to quantitatively represent capacity values for these resources must be sufficiently supported. It is not clear to ORA that stochastic methods are ready to be used for capacity valuation in this round of LTPP analyses.

In general ORA recommends that the capacity values for all resources be allocated based on (1) "technical/ economic potential" as informed by specific studies for each resource; (2) any necessary studies regarding grid impacts of specific resources; and (3) IOUs' distribution planning processes.[20] That is, regions and/or busbars of high technical/economic potential, minimal/no system impacts, and significant distribution deferral benefits should be allocated a higher proportion of capacity value than regions and/or busbars with a less optimal mix of those conditions.

Demand Response

For demand response (DR), the 2012 LTPP decision on Track 2 assumptions and scenarios, Appendix B[21] describes the previously adopted methodology for assessing local capacity values for DR. No additional adjustments are needed for locational aspects of these resources for system-level modeling beyond the splits between the IOU service territories. No additional adjustments are needed for "operational characteristics uncertainty" because the process by which DR resource levels used in the 2012 LTPP modeling were computed (based on load impacts) accounts for these effects. The Track 4 assumptions for the SONGS area addressed local impacts of DR resources in the SCE and San Diego Gas & Electric territories. For any 2014 LTPP local area assessments, a similar methodology would need to be applied to the PG&E territory to determine appropriate aggregate-bus level impacts.

Energy efficiency

For system –level impacts used in operational flexibility modeling, the 2013 CED forecast includes embedded energy efficiency by service territory (each of the three IOUs) and by climate zone. The AAEE impacts are disaggregated by service territory only. For the 2014 LTPP system-level modeling, the case-specific AAEE can be directly applied to the service

[20] AB 327 (2013) requires the IOUs to file distribution resource plans "to identify optimal locations for the deployment of distributed resources." While AB 327 sets a deadline of July 1, 2015, ORA has advocated that the Commission focus more immediately on maximizing the system benefits of customer-side DG systems. See, e.g., ORA's December 13, 2013 comments in R.12-11-005.

[21] D.12-12-010, Appendix B.

territory peak load forecasts (e.g., mid-case AAEE for the base case; and high-case AAEE for the preferred resources scenario). No additional locational or operational adjustments are required for system level modeling for the 2014 LTPP.

For local impacts, the 2012 LTPP decision on Track 2 assumptions and scenarios, Appendix A[22] described the previously adopted methodology for assessing locational capacity values for EE. A similar methodology can be used for the 2014 LTPP. The availability of climate-zone level peak forecast information that helps to provide better locational distribution of the peak load forecast can also be used to allocate the AAEE impacts for the managed net demand forecast, using a climate-zone-load-share factor to assign the AAEE across the zones. Additional bus-level allocations will still be required, as was required in the 2012 LTPP, for final managed net demand allocation across the modeled buses in the local studies for the 2014 LTPP.

Lastly, ORA notes that the decision to use low-mid AAEE in the local studies (based on information in the 2013 IEPR Final Report) coupled with the mid-case baseline forecast may be overly conservative as it fully ignores any of the beneficial capacity effects associated with the AAEE peak reduction difference seen between the mid-case AAEE and the low-mid case AAEE. This difference, equal to roughly 1,600 MW in 2022 and rising to roughly 2,000 MW by 2024 [CAISO-wide] in the 1-in-10 net electricity peak demand forecast[23] is substantial. Even if locational specificity is not available at this point, some portion of the ~1,600 MW (2022) or ~2,000 MW (2024) benefit can be expected to accrue if the mid-case AAEE is established as the baseline case, and should either be considered in the local modeling, or recognized as a targetable resource[24] available to meet at least a portion of the capacity needs that may arise from modeling the more conservative forecast for local needs. ORA notes that roughly 54% of the AAEE savings difference (between mid AAEE and low-mid AAEE) arise from either

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[22] D.12-12-010, Appendix A.

[23] See Form 1.5d – Statewide – the "Total CAISO Noncoincident Peak" values for 2022 and 2024 for the two different Net Electricity Peak Demand cases provided, Low Mid AAEE Savings, and Mid AAEE Savings, for the Mid Demand Baseline forecast.

[24] Available by systematic, program-design-based targeting of EE opportunities (i.e., the peak reduction "Program Measures" seen in Table 28 of the 2013 CED) in critical local areas, as a policy choice to address local system needs.

building or appliance standards[25] and thus can be presumed to accrue across the entire service territories of the utilities, especially over the long-term (out to 2022, or 2024).

Small photovoltaics (PV)

PV's technical potential was last analyzed in the March 2012 *Technical Potential of Local Distributed PV – Preliminary Analysis* produced by Energy and Environmental Economics, Inc.[26] Energy Division staff is in the process of conducting a second study with a number of improvements to the methodology and assumptions used in the Preliminary Analysis. One important modification, which leads to significantly higher estimates of PV technical potential, is to reflect recent updates to Rule 21, including a supplemental maximum capacity screen of 100% of minimum daytime load, in addition to the fast track maximum capacity screen of 15% of peak load.[27] ORA supports Energy Division's approach with respect to using the most accurate and timely data to inform its analysis of technical potential, and further supports the timely production of updated results so that they can be publicly vetted and adopted in time to be of use for 2014 LTPP planning purposes.

Grid impacts were last analyzed in the CEC study on transmission and distribution impacts of distributed PV.[28] That study included specific findings regarding the types and locations of feeders that can integrate higher levels of DG without significant system upgrades, which should further inform the Commission's development of standard planning assumptions for the 2014 LTPP.

In general, small PV's capacity value should be adjusted to account for operational uncertainty based on its lack of dispatchability. That is, its capacity should be less valuable relative to dispatchable resources. However, if for any of the scenarios the Commission

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[25] See Table 28 ("Combined IOU AAEE Savings by Type, 2024), page 91, in Volume 1 of the California Energy Demand 2014-2024 Final Forecast. 2,462 minus 1,493 = 969 MW (Standards). The "Total" difference is 4,841 minus 3,063 = 1,778 MW. 969/1778 = 54%.

[26] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

[27] Jan. 31, 2013 Renewable DG Technical Potential Workshop presentation: http://www.cpuc.ca.gov/NR/rdonlyres/5F2B76C0-043D-46CA-8C41 1F67E3116999/0/Jan31_CPUC_RenewableDGTechnicalPotentialWorkshopSlides.pdf, Slide 34.

[28] Distributed Generation Integration Cost Study: Analytical Framework, Prepared for the California Energy Commission by Navigant Consulting, Inc., November 2013 (CEC Report No. CEC-200-2013-007), http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007.pdf

considers different technologies that would enable small PV to be considered dispatchable, then it may not be reasonable to adjust its capacity value downward in such a scenario. For example, storage supported small PV could increase operational certainty and dispatchability.

Additionally, if the Commission determines that for any or all local areas and/or at the system level, west-or southwest-facing systems provide a higher capacity value than south-facing systems, and if an alternative compensation mechanism that would encourage west- or southwest-facing systems is envisioned, then the capacity value of small PV should be adjusted upward to reflect a higher capacity value under such circumstances.[29]

Energy Storage

As discussed above, ORA assumes that transmission-connected storage resource will be afforded full capacity credit, or full resource adequacy accreditation, for any system study; and will be fully represented (i.e., 700 MW) at specific transmission busses in any local study. No further operational or locational adjustments are necessary for this 700 MW.

The remaining 625 MW (1325-700) is not counted towards local capacity requirement (LCR) needs in the proposed 2014 scenarios. As explained in response to Question 4, while all of the 625 MW may not be credited as a capacity resource, some fraction should be credited in the local area depending in part on how the March 1, 2014 Applications[30] indicate intended procurement within LCR regions.

7. ***Decision (D.) 13-10-040) established storage goals for each of three categories – transmission, distribution, and customer-side of the meter, but does not specify the function(s) to be provided. Should storage modeling be focused on deep multi-hour cycling to support operational flexibility or rapid cycling for ancillary services? How should the production profile of each category of storage identified in the CPUC Storage Target Decision be modeled – as a fixed profile or as a dispatchable resource?***

The intended production profile of storage resources is unknown at this time. In particular, the extent to which installed MW storage resources will be coupled to "deep multi-hour cycling" or lower quantities of MWh-per-MW installed capacity is unknown. Only after

[29] AB 327 (2013, Perea) directs the Commission to develop a new standard contract or tariff for customer-side DG by December 31, 2015.

[30] D.13-10-040, Ordering Paragraph 3, p. 77.

March 1, 2014, when the investor-owned utility (IOU) Applications are filed, will it be possible to gauge what the production profiles could be.

Very limited energy storage resources might appropriately be modeled as providing "regulation" ancillary services (thereby freeing up capacity - otherwise needed for regulation - for other uses), but other storage resources may exhibit sufficient energy storage capacity (per installed MW) that LTPP modeling should assume a form of economic dispatch for the energy output of those resources. That form could be either a fixed or dispatchable profile depending on how much is known about the expected pattern of charge/discharge.

Until the IOU applications are received and at least high-level information is available on the MW/MWh characteristics of the resources, it is not possible to suggest the best way for those resources' production profiles to be modeled. In the absence of such information, the modeling should at least capture at a high level the expected effect of the presence of storage capacity. This could be done by assigning limited energy capability to the resources, and allowing them to be dispatched economically, ensuring that they would be used during the highest priced hours (i.e., shortage hours) while subject to a crucial modeling constraint on their total hours of operation during any sequence of "high stress" (e.g., peak hours, late afternoon/early evening extreme summer peak day) periods. Such operational characteristics should be captured in both the real-time dispatch and the forward-looking unit commitment portion of the modeling.

8. Should incremental small PV and small [combined heat and power] CHP on the customer side of the meter be modeled as demand-side load reduction or supply side generation? How should the production profile of each resource type be modeled? Should the same modeling convention be used in all 2014 LTPP and 2014-15 TPP studies or may specific studies make this decision in a manner best suited to the topic being studied?

Incremental small distributed resources like PV and CHP should generally be modeled on the demand-side to fully capture the transmission and distribution loss-avoidance effects (i.e. benefits) that accrue to resources located close to the point of load. Placing small PV and CHP resources on the supply side of the energy accounting ledger can be acceptable as long as these loss effects are considered. The modeling convention can be different between LTPP and TPP studies as long as the technical attributes are fully retained.

If, for any of the scenarios, different technologies that would enable small PV to be considered more like a supply-side resource (e.g., PV coupled with storage and/or advanced inverter functionalities that enable small PV systems to provide grid-balancing services) are considered, then it may be reasonable to model small PV as a supply-side resource for those scenarios, as long as loss-effect concerns noted above are considered.

9. Is the forecast of incremental small PV (beyond what is embedded within the IEPR forecast) on the demand side reasonable? If not, please provide an alternate forecast and justification from a public data source as needed.

The predictive models developed by the CEC are useful tools; however the results are in large part driven by long-term forecasts of retail rates and PV costs. Retail rates are uncertain especially for residential customers. PV costs have been trending down. To the extent further analysis of the long-term changes to retail rates (including different rate structures) and changes to PV cost trends results in different forecasts (of those retail rates, and of those PV costs), then the CPUC should work with CEC staff to re-run its predictive models based on those alternative forecasts.

10. Is the forecast of incremental CHP on the demand side and the supply side reasonable for the scenarios that include those forecasts? If not, please provide an alternate forecast and justification from a public data source as needed.

ORA does not have any comments on this question at this time but reserves the right to respond to other parties' comments in reply.

III. CONCLUSION

ORA respectfully requests that the Commission incorporate these recommendations into 2014 resource planning assumptions.

Respectfully submitted,

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January 8, 2014