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Andrew McAllister, Lead Commissioner
Robert B. Weisenmiller, Chair
California Energy Commission
1516 Ninth Street
Sacramento, California 95814-5512

RE: Docket No. 15-IEPR-07, Southern California Electricity Infrastructure Assessment: AES Southland Development's Comments on IEPR Commissioner Workshop on Southern California Electricity Reliability

Dear Commissioner McAllister and Chair Weisenmiller:

The following comments are submitted by AES Southland Development, LLC ("AES") pursuant to the *Notice of IEPR Commissioner Workshop on Southern California Electricity Reliability* dated August 4, 2015.

AES attended the recent Integrated Energy Policy Report ("IEPR") workshop on Southern California Electricity Reliability ("Workshop") held on August 17, 2015. The Commission received a number of thought-provoking presentations at the Workshop, including presentations from the California Independent System Operator ("CAISO")[1], and from Commission Staff members Michael Jaske and Lana Wong entitled, *Projection Tool to Support Contingency Mitigation Decisions*[2] and *Options for Developing Contingency Mitigation Measures.*[3] AES provides the following comments on several important points that emerge from these presentations.

1. **OTC Retirements Pose A Serious Challenge to Adequately Managing Southern California Reliability Needs.**

As noted in the CAISO's presentation, the closure of the San Onofre Nuclear Generating Station ("SONGS") has "created reliability issues in Southern California and presents certain Los Angeles and San Diego load pockets with limited options" to manage those reliability issues.

[1] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205749_20150817T080939_Southern_California_Reliability.ppt
[2] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205726_20150813T151855_Prejection_Tool_to_Support_Contingency_Mitigation_Decisions_by.pptx
[3] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205727_20150813T151857_Projection_Tool_to_Support_Contingency_Mitigation_Decisions_by.pptx

(CAISO Presentation, Slide 2) Further, "[m]anaging the retirement of once-through cooled resources presents additional challenges." (CAISO Presentation, Slide 4.) CAISO staff noted that the challenge of managing the retirement of once-through cooling ("OTC") facilities, though planned, represented a more serious challenge in certain respects than the unexpected closure of SONGS. AES agrees with these analyses and conclusions and encourages the Commission to include these important conclusions in the next IEPR.

2. Through 2020, Electrical Reliability in the Los Angeles Basin, Particularly the Western LA Basin Subarea, Is At Risk if Forecasted Savings from Energy Efficiency Do Not Materialize.

Also of note in the CAISO's presentation is that current supplies are adequate to meet reliability needs in the Los Angeles Basin and San Diego load pockets through 2020 only if additional achievable energy efficiency ("AAEE") savings occur as forecasted. (CAISO Presentation, slide 5.) The Western LA Basin has the potential to be the most impacted area if AAEE savings do not "materialize as needed", particularly when combined with Southern California Edison's current procurement shortfall of 608 megawatts from the 2,500 megawatts approved for procurement by the California Public Utilities Commission ("CPUC"). (CAISO Presentation, slide 5.) As a provider of energy storage solutions and other renewable resources, AES supports the collective efforts of the agencies to advance AAEE. On the same track, and not as an alternative to AAEE, the IEPR should recognize the potential reliability issues if AAEE savings do not occur as forecasted. While continuing to promote AAEE, the next iteration of the IEPR should recognize the potential reliability impacts for the Los Angeles Basin, in general, and the Western LA Basin, in particular, if the forecasted savings do not materialize.

3. Post-2020, Electrical Reliability in the Los Angeles Basin Is At Risk From Local Capacity Resource Shortfalls.

The CAISO's presentation stated that "local capacity resource shortfalls may occur beginning in 2021" as a result of the OTC retirements. The warning of resource shortfalls beginning after OTC retirements in 2020 is echoed in the Commission Staff Report, *Assessing Local Reliability in Southern California Using a Local Capacity Annual Assessment Tool (*"LCAAT Staff Report").[4] The LCAAT Staff Report illustrates critical reliability concerns arising in Southern California post-2020. For example, the LCAAT Staff Report states:

> The resources that have been authorized by the CPUC just barely cover the minimum required, and when these are placed on the same accounting basis as used for resource adequacy, a small shortfall occurs in the combined L.A. Basin/San Diego subarea affected by the SONGS outage. This small deficit grows slowly each year and reaches 238 MW by summer 2024. (LCAAT Staff Report, p. 11.)

[4] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205700_20150812T141329_GasFired_Generating_Plant_as_Mitigation_for_Contingencies_Threa.pdf

Further, while Commission Staff's presentation acknowledges a potential surplus in a best-case scenario, the baseline scenario illustrates a deficit in the West LA subarea of 77 megawatts, with a potential deficit of up to 1,496 megawatts. (*Projection Tool to Support Contingency Mitigation Decisions*, slide 35.) Commission Staff concluded its presentation by stating that the Local Capacity Annual Assessment Tool "reveals 2021-2024 deficits for all areas involving LA Basin." (*Projection Tool to Support Contingency Mitigation Decisions*, slide 38.)

Given both the CAISO's and Commission Staff's presentations demonstrating likely local capacity resource shortfalls commencing post-2020, it is important to start planning for the development of resources to fill such shortfalls, particularly given the lengthy development and permitting processes for natural gas-fired generation resources. The IEPR should incorporate these important planning issues in the next iteration.

4. <u>Ensuring Electrical Reliability Post-2020 May Require Extension of OTC Retirement Dates and/or Development and Licensing of "On-the-Shelf" Generating Units.</u>

The Commission Staff Report, *Gas-Fired Generating Plants as Mitigation for Contingencies Threatening Southern California Electric Reliability*[5] ("Mitigation Staff Report") identifies a number of potential mitigation measures to "ensure electric service reliability" if "resource expectations do not match requirements," including "lesser savings from preferred resource development, delays or termination of planned generation additions, or delays or poorer performance than planned of ISO-approved transmission system upgrades." (Mitigation Staff Report, pp. i, 1.) Other contingencies that should be planned for include higher than forecasted demand growth in the LA Basin and subareas. (See, *Projection Tool to Support Contingency Mitigation Decisions*, slide 22.)

One short-term mitigation measure identified is "once-through-cooling (OTC) compliance date deferral for selected facilities." (Mitigation Staff Report, p. 3.) Such mitigation measures will require careful coordination with all resource agencies such as the Commission, the CAISO and the State Water Resources Control Board to accomplish.

A "longer-term generator mitigation measure" was also proposed in the Mitigation Staff Report, which would encourage development and permitting of "conventional power plant proposals", where the proposals are "taken as far through the permitting and procurement processes as possible, but then held in reserve to receive final approval and begin construction only if triggered." (Mitigation Staff Report, pp. 1-2.) The Mitigation Staff Report presents three options for developing and permitting projects to be available "on-the-shelf":

- Option 1: Investor owned utility ("IOU") chooses a project developer who initiates the process with specific project designed by the developer.
- Option 2: IOU initiates project development.
- Option 3: Rely upon a pool of already permitted projects without a power purchase agreement. (Mitigation Staff Report, p. 5.)

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[5] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205700_20150812T141329_GasFired_Generating_Plant_as_Mitigation_for_Contingencies_Threa.pdf

Under current policies and permitting procedures, the period from the initial conception of a project, through licensing, engineering and construction, to commercial operation is a minimum of five to seven years. Developing and licensing projects on a contingency basis – to have one or more projects "on-the-shelf" and ready to be financed and built under certain circumstances will minimize the time between "triggering" and operation to ensure that needed facilities can be in service quickly in response to an identified reliability issue. Having multiple licensed projects "on the shelf" also has the following additional benefits:

- It shortens the time for bringing a project on line by up to three years, if there is an immediate need for additional generation;
- It increases competition in procurement bidding, and reduces market power that would occur if there are fewer bidders; and
- It provides greater assurance that the necessary capacity will be available, if one or more of the backup projects subsequently prove to be infeasible.

5. **<u>Of the Three Potential Options for a Longer-Term Generator Mitigation Measure Presented in the Mitigation Staff Report, Option 3 Is the Best Option to Timely Address Reliability Issues at the Lowest Cost and Least Risk to Ratepayers.</u>**

AES supports the long-term mitigation measure of encouraging development and permitting of "on-the-shelf" gas-fired generation plants in concept, but notes that adding new generating resources in California is particularly challenging. Of the three options identified in the Mitigation Staff Report, Option 3 should be the preferred option for the reasons set forth below.

A. **<u>Option 3 Provides the Quickest Path From the Triggering Event to the Project Becoming Operational.</u>**

Option 3 provides the quickest path from the triggering event to the project becoming operational. The Mitigation Staff Report estimates this period to be 41-54 months, compared to 81-102 months for Option 1 and 83-103 months for Option 2. (Mitigation Staff Report, p. 13.) Option 3 compares even more favorably to the other options, because the Stage 1 estimates for Options 1 and 2 appear to be overly optimistic. For example, it is assumed that data adequacy, review and approval of an application for certification ("AFC") will require only eight months. (Mitigation Staff Report, pp. 15-16.) None of the projects licensed by the CEC in the past 10 years have been processed that quickly.

In AES' experience, the time period for a project to be deemed data adequate can be anywhere from about two months to over nine months. Thereafter, the average processing time for an AFC is fourteen months. Thus, we believe that is more realistic to assume a range of 12 to 24 months for data adequacy and processing of AFC, and even these time periods will require extraordinary effort by the Commission to accomplish. We also believe that the Mitigation Staff Report does not adequately account for the time required pre-AFC filing. The lead time between initial due diligence on a project site and the filing of an AFC is more typically in the two to three year range.

It is encouraging that the CEC Staff believes that the six-month emergency permitting regulations the Energy Commission had as a result of the legislation during the 2000 – 2001 electricity crisis contains screening criteria that could help to expedite the Energy Commission's existing AFC process compared to the typical application. Unfortunately, even those projects that met all of the screening criteria have been processed in time periods that far exceed eight months.

It is also assumed that reconsideration and judicial review will be completed in two months. (Mitigation Staff Report, pp. 16-17.) While two months is a reasonable period for the Commission to resolve any requests for reconsideration of a decision, a Petition for Writ of Review to the California Supreme Court is likely to require three to six months to resolve, assuming the writ is denied. The timelines in the IEPR should be revised to account for these additional timeframes.

B. "On-the-Shelf" Projects from Private Developers Provide the Lowest Cost and Least Risk to Ratepayers.

Option 3 is likely to provide the lowest cost and lowest risk to ratepayers. We agree with the paper's conclusions that "Option 1 is a greater departure from the usual speculative process in which a power plant developer fronts the costs of permitting and expects to recover these costs once a project is constructed and becomes operational. In the setting of a contingent generator option, with only a limited prospect that the plant is ever constructed, these upfront costs may be so large that some special subsidy is needed to make Option 1 viable." (Mitigation Staff Report, p. 13.) Moreover, Option 1 presents great risks to ratepayers, because if a project is selected in a RFO there is no guarantee that it will be licensed, or that it will be licensed without substantial unanticipated delays.

The Mitigation Staff Report speculates that the costs for Option 2 might be slighter lower than Option 1, but does not address the Option 2 costs relative to Option 3. As with Option 1, Option 2 poses a significant risk that a project to be developed by the IOU may not ultimately be licensed, or that the licensing takes substantially longer than anticipated. Moreover, under Option 2 ratepayers will bear all of the costs incurred by the IOU if the project fails during the development and licensing stages or the construction is never triggered, unlike Option 3 projects where these risks are borne by the developer, not ratepayers. Even when the plant is operational, if it fails during its useful life, the IOU will expect to recover from ratepayers the full cost of the project, whereas under Option 3, the developers generally bear the risk of performance.

The paper also speculates that IOUs might have some advantage in negotiating costs. We disagree. Large, global developers such as AES have the same – if not better – access to competitive prices for generation equipment than IOUs. AES signs worldwide contracts for technology types with vendors. California IOUs and the quantity they would be acquiring for these possible shortfalls are unlikely to command any better deals for this equipment compared to private companies. The IEPR should reflect these facts.

C. **<u>"On-the-Shelf" Projects from Private Developers Provide Greater Flexibility to Respond to Resource Adequacy Needs.</u>**

Option 3 provides greater flexibility of project design and location, particularly if a number of projects are licensed and on the shelf. The Mitigation Staff Report suggests that the design and location of Options 1 and 2 projects are much wider than would be the case for Option 3, which depends upon a small set of projects already permitted — thus fixed by location and difficult to revise generating technology. However, there is no reason to assume that only a "small set" of projects will be permitted and on the shelf.

By licensing a number of project sites, the Commission can maximize flexibility. In addition, the Commission can improve flexibility by licensing projects with alternative configurations and technologies. For example, rather than simply license a project with a single defined configuration, the Commission should encourage flexibility by licensing additional capacity or configurations on sites that will accommodate such configurations.

The idea that Options 1 and 2 will provide greater flexibility assumes that there will be a wide variety of options when an event is triggered under Option 1 and 2. However, under Option 1 the time between the announcement of bids and the submission of bids is only five months- which is not nearly enough time for a developer to secure site control for a project and all laterals, design a project, and prepare a viable cost estimate. This process normally takes two to three years. Moreover, depending on timing, the prospective developer may not be able to conduct "spring surveys" until the following springtime survey window opens. The Staff Report also assumes that after a contract is awarded from a Request-for-Offers ("RFO") process that the developer will examine the site and begin surveys. However, because these steps are essential to project viability, they should occur before a bid is submitted, rather than after an RFO is awarded. In summary, it is doubtful under Options 1 or 2 that developers or the IOU will be able to identify and secure options from a wide range of sites in the short time frames assumed in the paper.

D. **Option 3 Preserves the Competitive Market for Generation Development.**

Since the creation of competitive markets in California, private developers have brought more than 20,000 megawatts of all types of electricity generation online in California. Since Assembly Bill 1890, which brought about the divestiture of utility owned generating assets, utility ownership of generation (other than nuclear or hydro) has been strongly discouraged. Given the inefficiencies of a system where utilities were guaranteed return on investment and where captive ratepayers often were burdened with the risk of and costs of underperforming assets regardless of the outcome of project, California has determined that private developers have a greater incentive to lower costs through competition than utilities would under a cost-of-service regulatory regime. That same logic has been re-enforced over the years in a range of circumstances, where California regulators have severely restricted utility ownership of electric generation.

Option 2 is inconsistent with the basic tenet of the California regulatory system that favors the use of competitive markets and risk-based capital for asset development, as opposed to ratepayer funding. Allowing utilities to own and rate-base generation would only hinder competition and discourage cost-effective investment that could meet the same need in a faster time-frame under Option 3. Option 2, which would allow utilities to re-enter the power production sector in regions where they were ordered to divest, would be a very costly mistake. The best way to meet the challenge of uncertainty in Southern California load pockets is Option 3, and not to backtrack on the progress California has made in promoting competitive markets.

6. The Commission May Also Wish to Examine the Use of Contingency Contracts for Gas-Fired Generation Proposals.

The Mitigation Staff Report examines three potential options in which natural-gas fired generation proposals can mitigate potential reliability issues in Southern California. Another potential option, which is discussed briefly in the "Background" section of the Mitigation Report, is for the use of contingency (option) contracts by IOUs. (Mitigation Staff Report, p. 4.) As stated in CPUC Decision 14-03-004, such an option would allow the development of a power plant, "including the necessary pre-development work to site, permit, and construct a specified [gas-fired resource]." (D. 14-03-004, p. 102.) Construction of the power plant would not begin until authorized, based upon an identified need and approval by the CPUC. (See, D. 14-03-004, p. 103.) AES recommends further consideration of this option. As with Option 3, a contingency contract option is much better from a policy perspective as it retains the competitive marketplace for generation development. A contingency contract option is also beneficial from a practical aspect, as it results in the shortest period between the triggering event and the construction and operation of a power plant to meet an identified need because not only would the siting, development and licensing have been completed, but the PPA will also have already received CPUC approval.

RECOMMENDATIONS

AES supports further consideration and evaluation of the "on-the-shelf" contingency measure described as Option 3 in the Mitigation Staff Report. To ensure that there will be future projects "on-the-shelf", if and when they are needed, there are number of steps that can be taken, including the implementation of policies and procedures by the Commission to ensure timely processing of applications for generation projects to address the following:

- Avoid potential delays in project reviews by other agencies, such as the Preliminary and Final Determination of Compliance processes conducted by air districts, and when necessary, proceed expeditiously on parallel tracks with Commission review rather than proceeding in serial fashion;
- Ensure timely completion of Commission Staff Analysis;
- Require timely participation by Intervenors;
- Allow the licensing of multiple or alternative configurations for projects to avoid the additional time needed to process amendments to project descriptions;
- Recognize the value of projects that are "on the shelf" and ready to go, even if the projects do not have a power purchase agreement; and
- Re-evaluate the threshold criteria for data adequacy, and avoid requirements that are overly prescriptive.

Where they are barriers to timely review, the Commission needs to address them expeditiously.

CONCLUSION

AES thanks the Commission for the opportunity to submit these comments. AES is available to discuss or answer any questions the Commission may have and will continue to engage in this important topic going forward.

Kindest regards,

Julie Gill
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AES – US West