# DRA

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*California Public Utilities Commission*

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November 21, 2012

CPUC Energy Division
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**Subject: The Division of Ratepayer Advocates' Protest to Southern California Edison's Advice Letter 2804-E (Update Regarding the Cost-Estimate for the California Portion of the Devers-Palo Verde No. 2 Transmission Line Project)**

## Introduction

The Division of Ratepayer Advocates (DRA) hereby submits this protest of Southern California Edison Company's (SCE) Advice Letter (AL) 2804-E, dated November 2, 2012. The AL requests Commission approval of SCE's updated cost estimate for the California portion of the Devers-Palo Verde No. 2 Transmission Line Project (DPV2 or the Project).[1] SCE submitted a proposal to increase the maximum cost, or "cost cap" for this project from the original amount of $545.3 million, approved in Decision (D.) 07-01-040,[2] to $701.3 million (in 2005 dollars). The new estimate escalated to 2012 year dollars brings the total project cost to $944.8 million. As described below, the facilities associated with the DPV2 project have undergone multiple changes and additions since the Commission approved the project in 2007. SCE states that the major contributors to the cost increases leading to the need to increase the cost cap are (1) environmental factors, and (2) project cost escalation. However, the advice letter fails to provide supporting documentation that justifies the cost increases. In order to fully evaluate SCE's proposal, DRA recommends that the Energy Division suspend AL 2804-E for further evaluation to determine if SCE's request is "just and reasonable" as required by Public Utilities Code §§

[1] In AL 2804-E, SCE also refers to the California portion of the DPV2 project as Devers-Colorado River Transmission Line Project (DCR).
[2] See D.07-01-040, Decision Granting a Certificate of Public Convenience and Necessity (CPCN) for the Devers-Palo Verde No. 2 Transmission Line Project, January 25, 2007, pp. 4-5.

451 and 454. In accordance with GO 96-B, Section 7.5.2,[3] DRA requests that the AL be suspended for 120 days.

Furthermore, the Commission should treat AL 2804-E as requiring Tier 3 treatment pursuant to General Order (GO) 96-B, because SCE's claim that the AL qualifies as a Tier 2 – or even a Tier 1 – filing is contradicted by the General Order. GO 96-B does not allow Tier 1 or 2 treatment for rate changes that do not fall within an already-approved range or that follow a formula already approved in a Commission decision. SCE's claim that it is entitled to Tier 2 treatment because of Section 5.2(7) of the Energy Industry Rules appended to GO 96-B is incorrect because that section only applies to matters eligible for Tier 1 treatment for which the utility opts to seek Tier 2 treatment. Tier 1 advice letters do not include proposals for cost increases such as the ones SCE seeks in AL 2804-E, so the Tier 1-to-Tier 2 conversion SCE cites is not permissible here. Rate increases under Tier 1 advice letters are only allowed when they are purely formulaic and already pre-determined by the Commisison,[4] and the rate increase here does not qualify.[5]

**Background**

DPV2 was submitted as a CPCN application to the CPUC on April 11, 2005, (A. 05-04-015). The Project was initially a 500 kilovolt (kV) transmission line, approximately 230 miles in length, from the existing Harquahala Generating Station switchyard in southern Arizona to SCE's existing Devers substation, located in North Palm Springs in Riverside County, California. A second 41.6-mile 500 kV transmission line would connect the Devers substation and SCE's existing Valley substation located in the unincorporated community of Romoland in Riverside County, near SCE's load centers. Decision 07-01-

[3] Section 7.5.2 provides that: "The Industry Division's notification will suspend the advice letter's effectiveness and will state the reason for the suspension and its expected duration, which will not exceed *120 days* from the end of the initial review period unless the utility agrees in writing to a longer suspension period." (Emphasis added.) Indeed, given the magnitude of the cost increase, DRA may seek a second period of suspension, as allowed by Section 7.5.2: "If the reviewing Industry Division determines that a suspended advice letter requires disposition by the Commission, and the Commission's deliberation on the resolution prepared by the Industry Division continues beyond the expiration of the suspension period, the suspension is automatically continued for a further period, and the Industry Division will so notify the utility and protestants, as above. The further period of suspension will run until the Commission acts on the resolution, but will not exceed *180 days."* (Emphasis added.)

[4] The only rate change allowed in Tier 1 is "(3) A change in a rate or charge *pursuant to an index or formula* that the Commission has approved for use in an advice letter by the Utility submitting the advice letter, not including the first time the Utility uses that index or formula. This Industry Rule does not cover a change in a methodology, such as a methodology approved by the Commission for use by a Utility for performance-based ratemaking." (Emphasis added.)

[5] SCE further confuses matters by stating it desires a Commission resolution on its AL: "The actions requested herein require more than ministerial action, and thus disposition on the merits should be by Commission resolution." (Emphasis added.) Only Tier 3 resolutions require Commission – rather than staff – action; however, DRA agrees that a Commission decision is required and that the matter should be handled under Tier 3 rules.

040 approved the Project on the basis that the DPV2 transmission line would generate significant economic benefits to California ratepayers. In addition, the Commission established a precondition for the construction of the California portion of the Project to commence after the Arizona portion of the Project was approved by the Arizona Corporation Commission (ACC).[6] Decision 07-01-040 also set the maximum cost initially determined to be reasonable and prudent for the approved DPV2 project at $545.3 million (in 2005 dollars).[7]

On June 6, 2007, the ACC denied SCE's request for a Certificate of Environmental Compatibility for the Arizona portion of the transmission line. Subsequently, SCE filed a Petition for Modification (PFM)[8] with the CPUC on May 14, 2008, requesting the Commission to authorize the construction of DPV2 facilities in only the California portion of the originally proposed DPV2 project. According to the California Independent System Operator (CAISO), the California-only portion of the Project would allow access[9] to potential new renewable and conventional gas-fired generation in the Blythe area and help California meet its renewable energy goals.[10]. The CPUC approved SCE's PFM on November 20, 2009, in Decision D.09-11-007, but conditioned the start of construction upon CAISO approval of the Project.[11]

On September 5, 2012, SCE filed a second PFM of D.07-01-040. SCE's proposed modifications consist of mitigation measures required by the Federal Aviation Administration (FAA): the installation of marker balls on certain transmission line spans and lighting on certain transmission structures. On October 30, 2012, the Commission issued a Proposed Decision (PD) approving the PFM.

## Analysis and Recommendations

As stated in SCE's AL and discussed above, "DPV2 has evolved from a transmission line intended to bring economic power from Arizona generation to California load to a project

[6] See D.07-01-040, Decision Granting a Certificate of Public Convenience and Necessity for the Devers-Palo Verde No. 2 transmission line project, January 25, 2007.
[7] See D.07-01-040, pp. 4-5.
[8] See SCE Petition for Modification filed on May 14, 2008 and supplemental information filing on June 26, 2009 (Supplemental Filing).
[9] SCE filed a Permit to Construct Application for the Colorado River Substation Expansion Project on November 3, 2010. The 500/220 kV substation would facilitate interconnections to renewable generation in the Blythe area. The CPUC approved construction of the expanded Colorado River Substation on July 14, 2011 in Decision D.11-07-011.
[10] See Notice of ex parte communication of the CAISO, June 19, 2009. The letter states that CAISO identified the need for the California portion of the Project to interconnect new generation in the Blythe area in California.
[11] See August 5, 2010 CAISO letter to the Commission: Updated Information Regarding Construction of Devers-Palo Verde No.2 Transmission Project (A.05-04-015). The letter indicated that CAISO had approved DPV2.

that will be used to bring energy from new conventional and renewable generation projects near the California/Arizona border to California load."[12] The facilities associated with DPV2 project have undergone multiple changes and additions. The AL describes changes to eight major cost categories that SCE claims occurred since the approval of the DPV2 project and associated cost: (1) Preliminary Engineering & Licensing, (2) Bulk Transmission, (3) Environmental Mitigation & Monitoring, (4) Substation, (5) Land, (6) Telecommunications, (7) Distribution, and (8) Contingency. The cost changes are calculated in 2005 dollars, for a total of $701.3 million and then escalated to 2012 dollars, resulting in a total project cost cap of $944.8 million.[13] DRA's initial review of the AL finds significant project cost increases in the cost categories of Bulk Transmission, Environmental Mitigation & Monitoring and Project Cost Escalation.[14]

SCE contends that the major contributing factors to the changed cost estimates for Bulk Transmission and Environmental Mitigation & Monitoring are direct and indirect costs to address environmental requirements.[15] The Bulk Transmission cost category increases are a result of higher than initially expected contract costs for construction. However, the Environmental Mitigation & Monitoring cost category was not part of the original cost cap approved in D.07-01-040. Although DRA agrees that several modifications to DPV2 have occurred since D.07-01-040 resulting in additional permitting and implementation of environmental compliance, mitigation and monitoring, SCE's AL fails to provide documentation to support its claim that environmental requirements have resulted in a $159.1 million increase in the cost of the Project. Some examples of documentation that are not included in the application are, contractor billing (such as requests for proposal, statements of work, proposed budgets, amendments to scope, and invoices) and SCE's construction work in progress (CWIP) filings with the Federal Energy Regulatory Commission (FERC) pursuant to Section 205 of the Federal Power Act.

With regards to SCE's project cost escalation from 2005 to 2012 dollars, Appendix A of the AL provides details regarding the cost escalation method and financing cost, including "the escalation rates used to inflate and deflate the historical Project Expenditures for the years 2005 through 2011 and forecast Project Expenditures for the years 2012 through 2014."[16] The project cost escalation from 2005 to 2012 dollars accounts for $243.5 million of the total project cost increase. DRA has concerns regarding the project cost escalation

[12] AL 2804-E, pp. 7.
[13] AL 2804-E, pp. 10.
[14] AL 2804-E, pp. 10.
[15] Direct costs include preparation of permits, requests for variances, mitigation measure monitoring and reporting, and associated environmental documentation. Indirect costs include implementation of mitigation measures during construction and associated delays and loss of flexibility to cost-effectively manage and sequence construction work.
[16] AL 2804-E, pp. A-1

method: the project escalation rate blending[17] and the escalation of costs already incurred in 2005-2011.Additional supporting documentation is needed to assess the cost escalation method and financing cost for this AL including, but are not limited to, contractor billing (such as requests for proposal, statements of work, proposed budgets, amendments to scope, and invoices) and SCE's CWIP filings with FERC for the updated costs for DPV2.

## Conclusion

In order to fully evaluate the AL and determine whether SCE's request for a cost increase for this project is "just and reasonable" as required by Public Utilities Code §§ 451 and 454, DRA requests that AL 2804-E be suspended for further evaluation. DRA intends to conduct discovery and issue data requests for additional supporting documentation for the cost increase request in this AL. The Commission should treat the AL as a Tier 3 advice letter, which requires a Commission vote on the cost increases SCE proposes.

Please address any questions about this protest to Connie Chen at 415-703-2168 and Connie.Chen@cpuc.ca.gov.

/s/ Cynthia Walker

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[17] SCE's Project Escalation methodology consist of separately escalating and deescalating the labor and nonlabor related expenditures by separate labor (based on SCE's historical, average, and forecasted hourly earnings escalation rates for transmission workers) and nonlabor (transmission capital escalation based on the Handy-Whitman Index of Public Utility Construction Cost) escalation rates.