

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Investigation to facilitate proactive development of transmission infrastructure to access renewable energy resources for California.

I. 05-09-005

**COMMENTS OF THE
CALIFORNIA WIND ENERGY ASSOCIATION
ON PRELIMINARY SCOPING MEMO**

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Pursuant to the Ordering Paragraph 7 of the Commission’s September 8, 2005, Order Instituting Investigation (“OII”), and the extension of time granted by ALJ Halligan on September 28, the California Wind Energy Association (“CalWEA”) submits comments on the range of issues identified in the Preliminary Scoping Memo included within the OII. In addition, we take this opportunity to highlight informal actions that the Commission could take now in order to facilitate the collaborative approach that it seeks with other state agencies.

I. The Commission Can Take Informal Steps Now to Facilitate Interagency Collaboration

We support the OII’s vision (p. 2) of a collaborative agency approach in this effort to facilitate the expansion of transmission capacity to access renewable energy resources. To that end, we encourage the Commission to take two steps now that will assist this investigation without prejudging any of the issues that the investigation will consider.

A. The CAISO should be encouraged to consider state RPS goals in its plans

The Commission should request of the California Independent System Operator (CAISO) that it consider the necessity of meeting the state’s renewable energy goals in its planning efforts. Under the planning process announced on August 1, the CAISO will be

preparing an annual five-year project-specific plan and a 10-year conceptual plan, identifying projects that studies indicate would enhance grid operations and provide economic and reliability benefits. The plans will account for load growth, new generation resources, and plant retirements. The plans should also account for meeting the state's RPS goals. To that end, the CAISO could integrate the work that its staff has done for the Tehachapi Collaborative Study Group (TCSG), and any similar work for the Imperial Valley Study Group, into their larger effort

The CAISO's initial plans will be available for stakeholder review in January and finalized shortly thereafter, so it is important to seek to affect the plans now, rather than after this investigation begins. While formal action may be required by the FERC to ensure that the CAISO's future planning efforts encompass state policy goals (and this investigation should consider whether the CPUC should pursue a FERC order in this regard), the Commission should encourage the CAISO to immediately incorporate the work it is already doing for the CPUC's transmission study groups into its current planning efforts.

If the CAISO can proactively consider the transmission upgrades that would most efficiently connect the largest concentrations of least-cost renewable resources, it could go a long ways toward accurately quantifying the costs and benefits of the system upgrades required to accommodate those resources. For example, a preliminary analysis by the CAISO of a Tehachapi-Midway connection recently prepared for the TCSG shows that the North-of-Path-26 congestion previously estimated by PG&E is virtually eliminated when the Tehachapi wind resource is effectively integrated into the overall network. The congestion estimated by PG&E has resulted in the application of significant transmission adders to the bids submitted to PG&E for Tehachapi wind resources. If the CAISO can estimate the costs and benefits associated with the network upgrades required to accommodate the state's largest renewable resource areas, it may reduce the need to quantify network benefits and congestion costs as anticipated in this investigation.

B. The Commission should request integration cost information from the CEC

The California Energy Commission (CEC) has a very significant research effort underway to examine the statewide system impacts of higher levels of intermittent renewables on the California grid and to recommend technical, operational and policy strategies for mitigating any impacts that may be found. While this Intermittency Analysis Project (IAP) will produce very useful information by late 2006,¹ it is not clear at this point whether the project will produce estimates of system integration costs and capacity values in the forms that are necessary for the RPS procurement and Tehachapi CPCN processes, or produce those figures in the timeframe that they are needed.

To date, the Commission has relied upon information from the CEC's "California RPS Integration Cost Analysis – Phase I" study, which was an analysis of the costs associated with existing renewables resources on the system. The decisions that this Commission must make on transmission expansions, as well as approvals of utility-selected competitive bids, will require integration cost information related to significant additional quantities of renewable resources. Ideally, the integration cost adders would relate to the quantities of renewable energy associated with the related increments of new transmission capacity.

The Commission should urge the CEC to ensure that the information it needs to advance the state's RPS goals is produced either as part of the IAP, or from a separate effort. CalWEA has encouraged the CEC to produce the information that will be needed by this Commission, but at present we are not assured that this is the case.

II. The List of Issues Should Be Expanded to Consider How the Commission Should Make Findings of Network Benefits, and Whether the Commission has the Authority to Direct a Utility's Choice on Transmission Financing

CalWEA supports the inclusion of all of the issues identified in the Preliminary Scoping Memo. In section II.B, below, we propose two additional issues for this investigation. Inclusion of these issues, if addressed effectively, will result in the Commission's ability to meet California's RPS goals without the need for major changes in

¹ We are informed that the April 2006 date initially anticipated for completion of this project has slipped to the end of 2006.

FERC's current approach to transmission cost recovery. Rather, the Commission can promote transmission upgrades that provide network benefits while tapping the state's major renewable resource areas (with costs therefore recoverable from all transmission customers), and ensure that those upgrades are financed by the transmission owner. In section II.A, we provide some context for these issues by offering some points of clarification to the discussion in the OII.

A. Points of Clarification

1. Transmission expansions can have both network and non-network characteristics

The OII's discussion of "gen-ties" and "network upgrades" connotes a black/white, either/or view of how FERC determines cost responsibility, which is inconsistent with actual practice at FERC. For example, the OII states (at p. 4):

"facilities that link a generator to the first point of interconnection with the existing grid, so-called 'sole-use' or 'gen-tie' facilities, are the sole responsibility of developers [footnote omitted] and, thus, are not eligible for cost recovery under FERC rules."

This statement is true for facilities that serve only to interconnect a generator and are devoid of network characteristics. The statement is not true for a facility that serves to interconnect a generator and has network characteristics; in this case, FERC leaves room for discretion in determining whether an upgrade is network or non-network. Indeed, the Commission has previously agreed with CalWEA that facilities located before the point of interconnection to the existing transmission grid are not necessarily gen-ties, i.e., a network upgrade can expand the boundaries of the transmission grid. (See D.04-06-013, pp. 10 and 12.)

An accurate understanding of FERC's practice in this area has important state policy implications for the proceeding at hand, which we address below. Specifically, the discretion inherent in the FERC's criteria for "network" (or "integrated") status provides this Commission with the ability to put before FERC arguments that a facility should be designated "network" when that facility has both network and non-network characteristics.

2. FERC allows transmission owners to provide up-front financing

The Commission stated (on p. 5) that “FERC policy has been to assign the up-front costs of network upgrades to developers, to be paid back by ratepayers over a five-year period.” A more accurate description is that FERC allows the utility to require the generator to pay the full cost initially. In this case, the utility would reimburse the generator, over a period beginning with the date of the upgrade's commercial operation, and ending as much as 20 years later.² The transmission owner may, however, elect to cover the upfront cost itself, as SCE opted to do with its proposed Antelope Project and which the FERC permitted.³

In addition, Public Utilities Code § 399.25(b) directs the Commission to order the utility to seek network treatment from FERC and to seek cost recovery in transmission rates (rather than require generator financing). While the state’s legal ability to direct the utility’s choice on this point has been called into question by a recent court challenge,⁴ the court decision on this issue was not dispositive.⁵ Having the utility make the proposal to FERC is

² See FERC Order 2003-B at para. 35 (“to provide a definite end date for reimbursement [to the interconnecting generator] that is not to be exceeded, we are revising *pro forma* LGIA article 11.4.1 to state that full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.”)

³ See paragraph 35 in *Southern California Edison Company*, "Order on Petition for Declaratory Order," Docket No. EL05-80-000, 112 FERC para. 61,014 (July 1, 2005).

⁴ *Southern California Edison v. Public Utilities Commission*, No. B171050 (Calif. Ct. App. Aug. 31, 2004).

⁵ It is CalWEA’s legal opinion that the court found preemption not of the statute, but of the CPUC's decision applying the statute, for the following reason: Section 399.25(b) directs the CPUC to order a utility *to file at FERC* proposing network treatment and utility financing. In contrast, the CPUC's decision implementing Section 399.25 (D. 03-07-033) required the utility *to finance* the upgrades. That is, the CPUC decision presumed to make the financing decision itself. Only FERC can determine the funding responsibility. In invalidating the CPUC’s decision, the California appeals court found that the CPUC's decision was preempted by the Federal Power Act, but the court did not address explicitly the distinction between "requiring funding" and "requiring filing." In contrast, the CPUC's Tehachapi decision (D. 04-06-010) correctly ordered the utility to seek FERC approval for the CPUC-specified preference on financial responsibility. Nevertheless, the court's decision has created doubt, within the CPUC, as to the Commission’s legal ability to direct the utility to take financial responsibility for an upgrade. The Commission should decide

important legally because if FERC finds the utility’s proposal to be consistent with the broad and flexible “just and reasonable” standard of the Federal Power Act, FERC is bound by court precedent to accept and approve the utility’s filing, even if FERC would prefer a different outcome.

B. Additional Issues for the Investigation

1. How should the Commission go about making findings of network benefits, pursuant to P.U. Code § 399.25?

This question needs to be addressed in this proceeding for several reasons. First, P.U. Code § 399.25(b)(1) requires the Commission to make findings of network benefits for facilities that facilitate achievement with the state’s renewables goals. Second, a Commission determination is essential where the transmission-owning utility would otherwise classify a facility that has dual characteristics (non-network “gen-tie” characteristics and network characteristics) as a non-network facility. This is, in fact, what occurred with Segment 3 of Southern California Edison’s Antelope Project. Though the OII states (in footnote 15) that this segment “was categorized as a gen-tie by FERC,” in fact FERC made no independent finding; it simply accepted at face value SCE’s characterization of the segment as a non-network facility. This Commission supported SCE’s characterization without having made its own determination, as required by Section 399.25(b)(1).⁶ Had the Commission explored the issue itself, it should have found that Segment 3 has network characteristics as well as gen-tie characteristics;⁷ or, had the Commission not found such benefits, it could have ordered SCE to reconfigure the proposed facility so that it provided network benefits. SCE is now studying just such a

this issue summarily on the basis of CalWEA’s instant filing; or in the alternative explore and resolve the question in this proceeding.

⁶ This Commission’s filing in support of SCE’s FERC Petition on the Antelope Project stated (at p. 16), “The CPUC agrees with SCE that ... Segment 3 does not readily fit the definition of a network upgrade, and would probably be classified as a “gen-tie” under the Commission’s existing definitions.”

⁷ Evidence of Segment 3’s network benefits was put forward at FERC by CalWEA.

reconfiguration.⁸ Making findings of network benefits is, therefore, necessary to expedite the transmission upgrades so that the state’s RPS goals may be achieved on time.

In this proceeding, the Commission should consider the process by which it should make such findings, or direct the parties to make such findings, and how such findings should be communicated to FERC (especially in the event of disagreement between the parties).

2. Does the Commission have the authority to direct the utility’s choice on up-front funding?

As discussed in Section II.A.2, above, FERC allows the transmission owner to elect whether to finance the upgrade initially or to require generators to provide initial financing. It is not clear whether this Commission has the legal ability to direct the utility’s choice. This issue warrants discussion in this investigation. The parties could be invited to make legal arguments on either side. The parties could also discuss whether any changes in FERC policy would be helpful in resolving, or are necessary to resolve, the issue. For example, FERC could revise its Order 2003 approach to remove the utility’s ability to impose upfront financing on the generator in circumstances where a state is willing to have its ratepayers bear the risk of unused capacity.

III. Modifying the Interpretation of P.U. Code § 399.25 in Decision 03-07-033

A. Merits of Modification

The OII invited comments on the merits of modifying the Commission’s existing interpretation of P.U. Code § 399.25, which requires that a transmission facility have network characteristics in order to be entitled to cost recovery in retail rates. (OII, footnote 15.)

CalWEA believes that there is substantial merit in modifying the Commission’s D. 03-07-033. Modification of D. 03-07-033 would enable the Commission to provide for retail rate cost recovery for Antelope Segment 3, which SCE has characterized as a “gen-tie”

⁸ SCE’s Gary Schoonyan stated at the September 12, 2005, Energy Action Plan meeting that SCE is studying a connection between Segment 3 and the Midway substation, which, he said, would provide the network benefits that FERC requires if transmission customers are to be charged for the facilities. CalWEA strongly supports this effort.

facility devoid of network characteristics, and potentially other upgrades that similarly accommodate multiple generators through high-voltage transmission lines. Even in the event, as indicated in footnote 8, above, that Segment 3 becomes part of a larger network facility, there may be an interim period of time in which Segment 3 is operable in advance of the complete upgrade; in this situation, interim cost recovery in retail rates may be necessary to assure SCE that its prudent costs will be fully recovered. Further, there may be instances, in relation to Tehachapi or other renewable resource areas, where it will be necessary or desirable for the transmission owner to finance a large non-network “gen-tie” facility with the costs ultimately paid for by multiple generators that utilize the facility (but which do not have the ability to finance it).

In D. 03-07-033, the Commission determined that § 399.25, including the retail rate cost recovery mechanism in § 399.25(b)(4), does not apply to gen-ties. Since Segment 3 has been deemed to be a gen-tie (and since other facilities may similarly classified), a Commission decision to allow Segment 3’s costs into retail rates could be considered inconsistent with D.03-07-033 if it is not modified. Therefore, to avoid a potential legal challenge, it would be prudent to modify D. 03-07-033 to enable retail rate cost recovery for high-voltage transmission lines that (whether they have network characteristics or not) provide access to multiple renewable energy generators in a resource area that is necessary to facilitate achievement of the state’s renewable power goals.

B. Basis for Modification

In modifying D. 03-07-033, the Commission would need to change its conclusion in that decision that § 339.25 applies only to network upgrades and not to non-network facilities. The Commission could explain that it does have jurisdiction to issue a CPCN to utilities that build high-voltage, non-network facilities to accommodate multiple generators-- a situation that was not considered when the decision was issued.

The Commission could also clarify that a finding of network benefits is not necessary for the following reason. First, § 399.25(a) sets the scope of the statute as applying to transmission facilities (under review in a CPCN or PTC proceeding) that are necessary to facilitate achievement of the RPS goals. Decision 03-07-033 already concludes that (non-

network) “gen-ties” are transmission facilities, so (assuming that the subject facilities are necessary to facilitate achievement of the RPS goals) they meet the first statutory hurdle.

Second, § 399.25(b) lists a series of things that the CPUC is required to do in relation to the facilities described in § 399.25(a), i.e., transmission facilities that are necessary to facilitate achievement of the RPS goals. Among the things that the CPUC must do are the four items described in § 399.25(b)(1)-(4). This list is not exclusive and retail rate cost recovery in § 399.25(b)(4) is not dependent upon any of the other items. Indeed, network benefits is only included as an item in § 399.25(b) to the extent that there is an evidentiary record supporting such a finding. As such, it is appropriate to read the statute as requiring the CPUC to provide for retail rate cost recovery even if there are no network benefits.

This interpretation is consistent with a plausible explanation of the purpose of § 399.25(b)(4). In particular, § 399.25 as a whole was intended to secure the construction of transmission facilities that are necessary for RPS purposes. The statute requires the CPUC to pursue before FERC cost recovery by transmission customers (“roll-in” treatment) and utility financing of these transmission facilities. If, however, FERC declines to approve recovery of the costs in transmission rates, § 399.25(b)(4) directs the CPUC to allow cost recovery in retail rates so as to allow the transmission facilities to be built. It does not matter if FERC rejected the roll-in and utility financing because the costs were not warranted by network benefits, or if FERC found that there were no network benefits. So long as the facilities are transmission facilities necessary for RPS purposes and FERC does not include the costs in transmission rates, the Commission may provide for cost recovery in retail rates.

We look forward to further discussion of these issues as the investigation proceeds.

Respectfully Submitted,

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