

**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.

Investigation 05-09-005
(Filed September 8, 2005)

**OPENING BRIEF OF THE
CALIFORNIA WIND ENERGY ASSOCIATION
ON TRANSMISSION COST RECOVERY ISSUES**

Scott Hempling
Law Offices of Scott Hempling, P.C.
417 St. Lawrence Drive
Silver Spring, MD 20901
Telephone: (301) 681-4669
shempling@hemplinglaw.com

Attorneys for the California Wind
Energy Association

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The California Wind Energy Association (“CalWEA”) respectfully submits this opening brief on transmission cost recovery issues in response to Assigned Commissioner Grueneich’s ruling of December 21, 2005, setting forth the scope and schedule for this proceeding (“Ruling”). We address the questions posed in the Ruling regarding cost recovery and those raised in a preliminary scoping memo, also referenced in the Ruling.

The Commission's careful questions share a common premise: that the success of the renewables mandate depends on effective methods of financing the necessary transmission. To be effective, a financing method must have four features:

Predictability: Those who put up money initially must know when they will be reimbursed, and those who must pay ultimately must know how much and when.

Economic efficiency: First, different financing sources carry different costs; the goal is to minimize total cost. Second, cost responsibility produces investment prudence; decisions on timing and location will be efficient if they are constrained by cost consideration.

Fairness: The costs must be borne by the beneficiaries; mismatches between benefits and burden cause inefficiency and are politically unsustainable.

Lawfulness: The methods must comply with state and federal statutes, and with constitutional protections of utility investment.

CalWEA here offers ideas which have these four features. In designing these ideas, CalWEA reviewed prior Commission decisions under state law, and prior Commission interpretations of federal law. In both cases, CalWEA has found that modification of the Commission's conclusions is permissible under present statutes, and necessary to achieve the

stated objectives.

Successful financing methods require a full understanding of the interaction among state law, federal law, type of facility and type of financing method. To achieve that understanding, CalWEA has organized its comments into four parts.

Part I is an overview, explaining cost recovery options and their jurisdictional paths.

Part II turns to cost recovery from retail ratepayers, under Public Utilities Code Section 399.25(b)(4).¹ We discuss eligibility, evidentiary requirements, timing and cost allocation.

Part III discusses the notion of obtaining cost recovery for non-network upgrades from transmission customers, through the tariff of the California Independent System Operator (CA ISO).

Part IV discusses steps the Commission can take to maximize the probability that renewables-inspired upgrades will carry renewable power.

I. Overview: The Cost Recovery Options and Their Jurisdictional Paths

To ensure sufficient and timely funding of transmission projects, the Commission must determine who should bear the cost, or the risk of under-recoupment of costs. There are three possible categories of cost-bearers: transmission ratepayers, retail ratepayers, or interconnecting generators. (The utility never has ultimate cost responsibility, except in cases of imprudence.) Who should bear costs, and when, depends on the type and timing of benefits associated with the facility at issue. This Part I addresses four scenarios most likely to arise:

- a. network upgrade,
- b. upgrade that is non-network today, but which will become part of a network facility later,
- c. non-network upgrade with transmission benefits beyond the generator, and
- d. non-network upgrade with no transmission benefits beyond the generator, but where absence of generator coordination will add cost to RPS compliance.

This Part I will address the extent of backstop assistance appropriate for different scenarios. Part II will address the Commission's statutory authority to award backstop

treatment.²

A. Network Upgrade

1. Background on FERC treatment of upgrade costs

By "network upgrade," we mean a facility which will satisfy FERC's criteria, set forth in FERC's *Mansfield* decision.³ The costs of a network upgrade are recoverable from all transmission customers through general transmission rates. This cost recovery begins when the upgrade commences commercial operation. At that time, the costs enter the utility's transmission

¹ All statutory references are to the Public Utilities Code.

² Appendix A summarizes key terminology relating to jurisdiction.

³ In *Mansfield Municipal Electric Department v. New England Power Co.*, 97 FERC 61,134 (2001), *affirming* 94 FERC If 63,023 (initial decision), the Commission adopted a five-point test for determining whether facilities are part of the integrated transmission network:

1. Whether the facilities are radial, or whether they loop back into the transmission system;
2. Whether energy flows only in one direction, from the transmission system to the customer over the facilities, or in both directions, from the transmission system to the customer, and from the customer to the transmission system;
3. Whether the transmission provider is able to provide transmission service to itself or other transmission customers . . . over the facilities in question;
4. Whether the facilities provide benefits to the transmission grid in terms of capability or reliability, and whether the facilities can be relied on for coordinated operation of the grid; and[,]
5. Whether an outage on the facilities would affect the transmission system

And in *Northeast Texas Electric Cooperative, et al.*, 108 FERC para. 61,084 (July 29, 2004), *aff'g* 100 FERC para. 63,033 (2002) (Initial Decision), the Commission stated:

"On the question of how to determine whether a facility is a network facility, the Commission has stated that a showing of any degree of integration is sufficient."

Id. at para. 48 (*citing*, at n.66, *American Electric Power Service Corp.*, Opinion No. 311, 44 FERC 61,206 at 61,748, *reh'g denied*, Opinion No. 311-A (1988), *reh'g denied*, Opinion No. 311-B, 46 FERC 61,382 (1989)).

revenue requirement. This treatment is known as "roll-in."

There is an exception to this approach if the facility, albeit network, would not have been built but for the interconnecting generator's request. In that instance, FERC allows the transmission owner to require the generator to pay the costs of construction as they are incurred, prior to commercial operation. Then when the upgrade enters the transmission revenue requirement on commercial operation, the generator is reimbursed through credits on its transmission bills. FERC also allows the utility to relieve the generator of the obligation to bear the costs initially; under this latter approach, the utility bears the costs (as discussed in the first paragraph of this subsection); then recovers them from ratepayers on commercial operation.⁴

FERC's approach involves several uncertainties for the utility. These uncertainties, and the option of alleviating them through the backstop of Section 399.25(b)(4), are discussed next.

2. Uncertainties at FERC and their relief through the backstop

FERC does not allow upgrade costs to enter the transmission owner's revenue requirement prior to commencement of commercial operations. The utility will be incurring many costs prior to commercial operation; not only construction costs, but design and study costs also. Delays in project construction cause delays in commercial operation, creating uncertainty for the utility as to when cost recovery can begin. The Commission can allow recovery of these costs, if prudently incurred, from retail ratepayers through the backstop.⁵ This

⁴ In the past, CalWEA has recommended that the CPUC order the utility to relieve the generator of the initial financing obligation. The utility has responded that such a CPUC order is preempted by the Federal Power Act. SCE in particular has argued that the appellate court decision found such preemption. CalWEA understands the decision differently. In the order invalidated by the court, the CPUC purported to order the interconnection contract to be changed in favor of the generator. Such an order is preempted, because only FERC may determine interconnection terms. CalWEA's recommendation was different: that the CPUC order the utility to file at FERC a proposed contract amendment relieving the generator, with the final decision resting in FERC's exclusive hands.

⁵ As we explain in the statutory interpretation section, Part II below, the Commission can use the backstop because the transmission costs are, as of that time, "not approved for recovery in transmission rates" by the FERC. There is, therefore, no need for the CPUC to wait for FERC to reject a particular upgrade as "non-network." Although there is a distinction between FERC jurisdictional transmission customers and state-jurisdictional ratepayers, the overlap is large; large enough that the CPUC should not delay the implementation of projects that could be funded through the backstop, just to await an uncertain FERC outcome.

initial financing by the retail ratepayers would be reimbursed by the interconnecting generators when the original costs are placed in the FERC-jurisdictional transmission revenue requirement, collected by the utility and then credited to its retail customers.

Another uncertainty arises where the project is built in advance of, and in reasonable anticipation of, future generator appearance; there is risk that sufficient generators will not appear to fill the capacity or even to make continued construction worthwhile. In both these situations, there is risk that the utility will not recover its full investment through FERC-jurisdictional transmission rates; either because the usage is too low to cover the cost, or because the utility has to abandon the project and be subject to FERC's traditional disallowance of 50% of abandoned plant costs. (FERC has said it will waive its abandoned plant rule under certain trunk-line circumstances, but the availability of this waiver is still a matter of case-by-case FERC decision.)

The CPUC can eliminate the utility's cost uncertainty by making the backstop available in advance of utility expenditures and for all prudent costs, including but not limited to preliminary environmental, siting and transmission studies as well as transmission construction costs.

Having retail ratepayers bear the cost of prudent surplus breaks no new regulatory ground. The electric industry is capital intensive, with economies of scale in transmission (and often generation) favoring large assets. With a statutory obligation to serve, utilities under these circumstances have had no choice but to build ahead of need, with load growing in. Where such advance construction is prudent, i.e., it minimizes total cost, the cost is a ratepayer obligation -- and therefore appropriate for the backstop. In this instance, where there are statewide benefits associated with achieving the RPS mandates (and the absence of any other entity to cover the cost associated with the non-appearing generators), it is permissible under the statute for ratepayers to cover the costs, if "prudently incurred."

As to types of costs eligible for backstop recovery, Subsection 399.25(b)(4) allows "recovery [of] ... any increase in transmission cost" from retail ratepayers. "Any increase" can include either upfront financing (followed by reimbursement by the generator) or permanent cost responsibility (no reimbursement by the generator). Within these two categories, the ratepayer assistance can be for the full cost or for some fraction. Many options fit within the phrase "recovery [of] ... any increase in transmission cost."

B. Upgrade that is Non-Network Today, but Which Will Become Part of a Network Facility Later

Consider a facility which, viewed in isolation from other, to-be-constructed facilities that are part of a larger plan envisioned by the state, does not satisfy FERC's "network" criteria, but will in the future. (FERC precedent does not recognize network benefits until they are present.⁶)

If this non-network facility is necessary to facilitate renewables compliance, its construction should go forward regardless of the absence of FERC-jurisdictional cost recovery. The retail ratepayers of the utility should pay through the backstop. Generators, as they come on line, would pay their usage-share of the facilities' annualized costs; the Commission would reduce the retail ratepayer-funded backstop accordingly. When FERC finds that due to subsequent additions, the facility has become "network," the full cost will enter transmission rates; then the Commission can eliminate the backstop. Cost responsibility thus shifts from the retail ratepayers to transmission customers (which would include the interconnecting generators or their customers). (As an alternative to generators gradually taking on cost responsibility, the state could have retail ratepayers cover the cost until FERC makes its network finding. Under either approach, interconnection agreements would need to reflect this treatment.)

C. Non-Network Upgrade with Transmission Benefits Beyond the Generator

Consider a transmission facility which produces transmission benefits beyond the interconnecting generators, but which will not satisfy FERC's requirements for network status. Examples of benefits would be improved reliability or economics on some parts of the transmission system, sufficient to warrant retail ratepayer involvement, but not sufficient to justify "network" status. If the Commission believes that the facility otherwise satisfies Section 399.25(b)(4), that is, it is necessary to facilitate renewables compliance, and the costs are prudently incurred, the Commission should allow retail rate recovery through the backstop. This retail ratepayer assistance would occur from the outset, to assist in initial financing, and continue for the life of the facility.

⁶ The proposed Antelope Segment 3, as described by SCE in its FERC petition, fits this description under several configuration scenarios developed by the Tehachapi Collaborative Study Group.

There is a question as to what share of the total cost should be borne by ratepayers and what share by the generators. Here the Commission can exercise judgment. Just because a facility is necessary to facility compliance does not mean a generator should have no cost responsibility. To the extent the line is a gen-tie of a type typically part of the generator's cost, the generator should bear the cost. But when the line has benefits to entities other than the generator, some sharing between ratepayers and generators is appropriate. The Commission should articulate clear cost-sharing principles in advance to reduce litigation later.

To the extent the Commission requires some cost-share of this facility to be borne by generators, there will be issues about how to allocate costs within the generator class. Since this issue arises also in the next category, we will address it there.

D. Non-Network Upgrade with No Transmission Benefits Beyond the Generator, but Where Absence of Generator Coordination Will Add Cost to RPS Compliance

Consider a non-network upgrade that, unlike the non-network upgrade in the prior category, provides no transmission grid benefits in terms of reliability or economics.

Where the upgrade benefits only a few generators, the utility should enter into its customary interconnection contract, allocating the costs according to their load shares.

But where the upgrade will involve a large number of generators, the situation is more complicated. If the facility's route, schedule and cost remain undecided, generators will not yet have committed to generation projects, let alone transmission capacity. But the Commission might conclude, after reviewing data on the amount and cost of renewable energy from a region, that sufficient generation capacity will materialize to make the transmission project economical. From that finding, and given the need to begin construction, there is only one feasible source of financing this non-network facility -- the retail ratepayers.⁷

Under this hypothetical, rational generators are unlikely to take accept responsibility for the entire line, or any portion of the line larger than its pro rata share. Where the Commission has found that the line is economically sized and configured, the Commission can find that the line is necessary to facilitate RPS compliance, because absent ratepayer-funded construction,

⁷ The retail ratepayers are the only feasible source because (a) the generators have not appeared, (b) the facility is non-network and therefore cannot be charged to transmission customers, and (c) there are no grounds for requiring the utility to bear the economic risk.

suboptimal arrangements would emerge, increasing total RPS costs. The Commission therefore can use the backstop for initial financing. The utility later can allocate the facility costs among the generators as they interconnect, pursuant to interconnection contracts, collect the costs to date, reimburse the ratepayers, and replace prospective backstop financing with the generators' contributions.

While the Commission could address this type of facility case-by-case, articulation of criteria for backstop qualification will cut down on hearing room time -- an ardent desire of those lacking ratepayer-funded litigation budgets.

II. Cost Recovery Through the Section 399.25 Backstop: Eligibility, Evidentiary Requirements, Timing and Cost Allocation

In this Part II, we apply the statutory language to the scenarios described in Part I, to show where the Commission has authority to have ratepayers bear the cost through the backstop of Section 399.25(b)(4).

A. Boundaries on Eligibility

1. The Section 399.25(b)(4) backstop is not limited to facilities requiring CPUC siting approval

D. 03-07-033 stated (at p, 17, footnote omitted) that Section 399.25

"applies to network transmission upgrades as defined above--and not to gen-ties. As discussed below, Sec. 399.25 applies to applications for transmission line construction/upgrades subject to this Commission's siting jurisdiction. Gen-ties are considered part of the cost of the generation project and are sited by the CEC."

The CPUC there found that Section 399.25(a), in referencing the CPCN process, creates the context for all of Section 399.25. From that premise, the Commission reasoned that the backstop described in subsection (b), which refers to "a transmission facility described in subdivision (a)," is available to a transmission facility only if it is a network facility, and then only if it satisfies both of these criteria:

1. the facility is "necessary to facilitate achievement of the renewable power goals" and

2. the facility is the subject of an application for a CPUC-granted "certificate".

The Commission's interpretation is not compelled by the statutory language. As a matter of surface verbal logic, the phrase in subsection (b)(4) could refer to a facility which satisfies only the first of these two phrases, or both of them. But a close look at the structure of subsection (a) and subsection (b) shows that the better interpretation is that the subsection (b) backstop can apply even if only the "necessary to facilitate" phrase is satisfied. Subsection (a) and subsection (b) deal with independent subjects: subsection (a) deals with the criteria for obtaining a certificate; subsection (b) deals with methods of cost recovery. Nothing about the structural relationship between subsections (a) and (b) limits the cost recovery options in subsection (b) to the certificate scenarios addressed in subsection (a). What is common to both subsections (a) and (b) is the "necessary to facilitate" principle. Nothing in the language of subsection (a) indicates that its purpose is to establish the context for the entire Section 399.25. Just because subsection (a) precedes subsection (b) does not mean that subsection (a) establishes boundaries that confine subsection (b).

Independently of verbal logic and structural logic, there is economic and policy logic (which the Commission should impute to the Legislature). By excluding from subsection (b) transmission facilities that are necessary to facilitate but which do not come to the CPUC for siting approval, the Commission creates an unexplained distinction. Siting processes are unrelated to cost recovery processes. Regardless of whether a facility is small or large, network or non-network, gen-tie or other, cost recovery assurance is the transmission investor's prerequisite. And any one of these types of facilities can be equally critical to achievement of the renewable mandates. Certainly the Legislature anticipated what the Commission knows: that a facility that might not have network characteristics could be large, expensive, needing of cost recovery assurance, but go through a separate siting process. It would not make sense for the Legislature to have declared that of several facilities equally necessary to achievement of the renewables mandate, some receive cost recovery assurance and others don't, merely due to the happenstance of their status under pre-existing certificate processes.

2. **The Section 399.25(b)(4) backstop is not limited to facilities providing network benefits**

The language of the backstop provision does not confine the backstop to “network” facilities. The structure of all of subsection (b) confirms that that "network" benefits are not a prerequisite for backstop assistance. Subsection (b) lists four actions required of, or available to, the CPUC. The list implies no interdependence among the four; no loss of clarity is suffered from reading paragraph (4) separately from paragraphs (1), (2) and (3). For example, CPUC actions relating to network benefits are required only if there is an evidentiary record supporting network benefits. Because network benefits are not mentioned in subsection (b)(4), the backstop is available even without network benefits.

This reading is consistent with the reason for a backstop. Subsections (b)(1)-(3) require the CPUC to pursue before FERC the utility financing and rolling-in of these transmission facilities. Under FERC policy, such a result requires a FERC finding of network benefits. The backstop then becomes available if there is no FERC finding (as explained in Part II.C below, the CPUC need not wait for a FERC rejection of network status). The backstop thus is available, necessarily, where there are not network benefits, as defined by FERC. So long as (a) the facilities are transmission facilities necessary to facilitate RPS achievement, and (b) FERC does not include the costs in transmission rates, the Commission has the authority to apply the backstop.

3. Even if traditional gen-ties fall outside Section 399.25(b)(4), a trunk-line facility performing both gen-tie and "transmission" functions deserves the backstop

In D. 03-07-033, the Commission appears to have reasoned that if a facility is a gen-tie, it falls outside the CPUC's siting jurisdiction; because it falls outside the CPUC's siting jurisdiction it is not eligible for the backstop. At Part II.A.1 above, we explained the need to correct the Commission's jurisdictional reasoning. But assuming *arguendo* that the jurisdictional distinction does exist, the Commission should revise its understanding of gen-ties to reflect the possibility that a facility can play two roles.

A facility can be a gen-tie, i.e., carrying power from the generator to the ISO transmission grid, yet also provide system benefits by increasing reliability and improving the economics of the transmission network as a whole. Consider this reasoning: Enactment of the state RPS statute created a statewide demand for renewables. That statewide demand for renewables is now adding to the statewide demand for transmission. The placement of injection

and removal points will affect the total cost of compliance. Each gen-tie, by injecting power at a particular point, reduces the need for injection at some other point. Each gen-tie therefore affects total transmission cost. For major gen-ties designed not to interconnect a particular project, but to access an entire region of renewables essential for RPS compliance, the Commission should view such facility not as a mere gen-tie but as “trunk line” that minimizes the costs of RPS compliance by using economies of scale to reduce interconnection costs.

Consider another example: the situation discussed in Section I.C above in which the “gen-tie” provides improved reliability or economics on some part of the transmission system, sufficient to warrant retail ratepayer involvement, but not sufficient to justify "network" status.

To view every interconnection-related facility as either “generation” or “transmission” oversimplifies today’s industry. The Commission should revise its network/gen-tie distinction by recognizing the possible special contributions of these trunk-line facilities. They might not be "network" under FERC's definition, but they can fall within the term "transmission" as used in Section 399.25(b)(4). That is sufficient to trigger the backstop.

B. Evidentiary Requirements

- 1. If the Commission does make gen-ties backstop-eligible, it should apply Section 399.25(b)(4)'s "prudently incurred" requirement to distinguish between gen-ties that deserve ratepayer support and gen-ties that do not.**

The preceding subsection explained that the backstop is available to "transmission" facilities, both network and non-network. The Commission may not grant backstop status to every gen-tie, however. The backstop is not a subsidy for generators seeking to avoid reasonable cost responsibility. The Commission needs a dividing line between eligible and ineligible gen-ties.

That dividing line exists in the statutory phrase, "prudently incurred." It is not prudent for a utility to give away service to some, charging the cost to others. Applying that principle here: for an interconnection to a particular generator, benefiting only that generator, it is not prudent for a utility to foot the bill and have ratepayers pay.

On the other side of the dividing line would be a gen-tie that does not merely interconnect, but which also provides benefits to customers because its size and location will

allow grid access for many generators needed for the RPS mandate. Because of its large size relative to any one project, the line would not be built without a utility's initial financing. In this situation, it is prudent for the utility to provide backstop cost support initially. The ratepayers take the risk of surplus capacity in the line, on the grounds that even with this risk, the line is the most economical and feasible means of achieving least-cost, best fit compliance with the RPS mandate. The backstop allows initial financing by the ratepayers, but does not preclude the Commission from authorizing or directing the utility to recover proportionate payments from each generator as it interconnects, and returning those payments to the retail ratepayers.

A third situation, which would justify permanent cost responsibility being shared by interconnecting generators and ratepayers, would be where the gen-tie also provides reliability benefits insufficient for roll-in. And there may be other situations where a gen-tie provides sub-network reliability benefits as well as trunk-line economy benefits. In each situation, the Commission will use judgment in determining what share of the cost would be "prudently incurred" by the utility, and whether ratepayer cost responsibility should be on a temporary or permanent, full or partial basis.

2. The Commission should clarify the evidence required to satisfy the "necessary to facilitate" standard

The "necessary to facilitate" phrase in Section 399.25(a) establishes a transmission facility eligibility screen for two purposes: for obtaining a certificate authorizing construction under subsection (a), and for obtaining the cost recovery under subsection (b). The legislative purpose is to promote the construction of transmission facilities that will enable achievement of the state's renewable power goals. If the provision does not serve this purpose, it has no practical meaning.

The Commission has discretion to determine what type of evidence will satisfy the "necessary to facilitate" standard. This evidence must be sufficient to distinguish necessary from non-necessary facilities, but should not perpetuate the chicken/egg problem that the statute was designed to overcome. Rather, the statute should serve specifically to remedy the situation in which renewable generation facilities cannot be built due to a lack of transmission capacity. This purpose would be defeated were the Commission to require, to satisfy the "necessary to facilitate" standard, evidence of generation facilities far along the development path.

We discuss below how the Commission can use the “necessary to facilitate” standard to promote construction of needed infrastructure and avoid perpetuating the chicken/egg problem. We indicate the changes in past Commission decisions that are necessary to achieve this end.

a. Necessary vs. non-necessary

The statutory standard is "necessary to facilitate achievement of the renewable power goals established in Article 16 (commencing with Section 399.11)." Included within the renewable power goals provisions is the Legislature's "least-cost, best-fit" standard (P.U. Code Sec. 399.14(a)(2)(B)). "Necessary to facilitate" therefore means that without the facility at issue, the transmission-owning utility (and perhaps other retail providers) would be unable to facilitate achievement of its numerical requirements on a least-cost, best fit basis. That is, without the facility, the utility might meet its numerical requirements, but not on a least-cost, best-fit basis.

Examples of evidence that would distinguish a necessary facility from a non-necessary facility would be of the type set forth in the Commission’s June 7, 2005, Scoping Memo for SCE’s CPCN Application 04-12-007 (Antelope-Pardee 500 kV Transmission Project):

1. Sufficient magnitude and concentration of renewable resources, as compared to the state’s overall renewable resource goals;
2. “Developability” of the renewable resource area, e.g., presence of factors conducive to project development (such as compatible land use designations, military clearance regarding possible interference issues, low population density, etc.), and lack of factors that will hinder project development – such as incompatible land use designations, environmental or cultural sensitivities, high population density, etc.). (This factor was not included in the June 7, 2005 scoping memo.)
3. Results of each of the utilities’ RPS solicitations to date (including bilateral proposals), showing the number, total megawatts, and average price of offers from the resource area in question as compared to all offers received;
4. The number of short-listed bidders and signed contracts from the resource area in question for each utility;
5. The number of transmission cost studies requested of each utility as part of the RPS process;
6. The amount of resources from the area in question included in each utilities’ RPS compliance plan, and (if available) from the plans of other retail sellers;

7. The number of requests for System Impact Studies/Facilities Studies (SIS/FS) submitted to the CAISO by developers in the resource area in question, including number of projects and project size, as compared to number of requests by developers in other renewable resource areas;
8. Number of SIS/FS studies completed by the CAISO (or transmission owner), including number of projects and project size, as compared to number of requests by developers in other renewable resource areas;
9. Evidence (from the CAISO or other sources) of executed contracts with any non-utility RPS-obligated retail seller or municipal utility;
10. Signed interconnection agreements between projects in the resource area in question and the CA ISO/transmission-owning utilities.

b. Avoiding the chicken/egg problem

Although the Commission should seek the type of evidence listed above, a chicken/egg problem would arise, defeating the purpose of the statute, if the Commission were to require evidence that specific projects are far along on the development path. For example:

Executed Contracts: A developer cannot reliably price power from a project that cannot be built for several years due to lack of transmission capacity. Equipment orders cannot be placed until the in-operation date for transmission capacity is reasonably certain. If equipment orders cannot be placed, equipment prices—which can be significantly affected by currency exchange rates, primary resource costs, and supply/demand issues—cannot be predicted with certainty. Compounding the problem is uncertainty in future federal tax benefits. On the other side of the table, the purchasing utility is unlikely to sign a bid whose price is uncertain. If a bid is accepted, it will likely allow either party to cancel the contract without penalty; for that reason, even signed agreements are not likely to constitute “hard evidence” that a project will be built.

Signed Interconnection Agreements: For the same reasons, it is difficult for developers to get into the queue and pay for the associated studies, and even more difficult to sign interconnection agreements, without having a power purchase agreement and without knowing when and where transmission capacity will be available. Developers generally do not have significant working capital until a PPA is in place, and must focus their resources on projects that they are reasonably certain are going to materialize.⁸

Therefore, while the evidence listed above should be reviewed, and is probative of the “necessary to facilitate” question, the Commission should not expect to see substantial evidence of projects with executed contracts and signed interconnection agreements, especially early in

⁸ The history of transmission projects in this state does not inspire investor confidence.

the facility permitting stage (see “Triggers,” below). Rather, the Commission must be prepared to make a judgment that there is reasonable assurance that the resource area will be developed if transmission capacity is provided.

c. Triggers

In the Ruling soliciting this brief, the Commission asked “What triggers should be developed for the staged permitting and construction of large-scale projects that might be necessary to ensure the success of the RPS program?” The same pieces of evidence described above should be considered in all stages of the cost-recovery approval and CPCN/PTC approval process; less evidence should be required, however, to approve cost-recovery for early-stage planning and permitting costs. As the engineering and environmental studies needed to prepare CPCN and PTC applications and Proponent’s Environmental Assessments are finalized, developers will gain greater confidence that the transmission capacity will be built, and will be more likely to prepare bids and enter the interconnection queue. Once these studies are completed, therefore, the Commission can expect to see greater development activity, and greater weight of evidence when it comes time to approve each stage of transmission facility construction.⁹

d. Needed changes in commission policy

In its initial interpretation of P.U.C. Sec. 399.25, the Commission agreed with the joint ruling of two administrative law judges:

If the facility is an integral part of a renewables project approved pursuant to the RPS procurement process (i.e., a winning renewables bid), we believe that creates a prima facie finding that the transmission project will facilitate the achievement of the renewable power goals set forth in Article 16 of SB 1078. ...

(CPUC D.03-07-033 at p. 15) (emphasis added). The decision did allow that “affirmative steps” such as assessments of major environmental issues and land acquisition needs could be taken without winning renewables bids. In the case of the Tehachapi wind resource area, these steps led the Commission to order the filing by SCE of two CPCN applications. In the June 6, 2005,

⁹ This pattern has been borne out in the case of the Antelope transmission projects; hundreds of megawatts of wind capacity have entered the transmission queue in this resource area in the year since SCE filed its CPCN application in December of 2004. We expect more

scoping memo for one of these applications, A.04-12-007, Assigned Commissioner Grueneich set forth a set of criteria for making the “necessary to facilitate” determination, as discussed above. The scoping memo did not indicate what would constitute sufficient evidence for making the determination, although it stated, “...to make such a finding, we must, at a minimum, consider the results of the RPS process to date.” (A.04-12-007 at p. 7).

We believe this idea of “consider[ing] the results” is the appropriate course. But it is at odds with the Commission’s initial decision, which suggests that a winning renewables bid is required. The Commission should revisit this decision to make it more consonant with the criteria set forth in the Assigned Commissioner’s ruling in A.04-12-007, as discussed above.

e. Conclusion

The Commission should avoid reading the “necessary” language to require certainty. The Commission should be looking for an array of evidence, without setting particular thresholds regarding actual project developments. The array of evidence must, taken as a whole, demonstrate that, without the transmission facility, achievement of the state’s RPS goals would be unlikely to occur.

3. Making findings regarding network benefits

The CA ISO, CEC and CPUC recently announced a new collaborative planning process in which the CA ISO will consider the state’s energy policy goals as set forth in the CEC’s Integrated Energy Policy Report and the CPUC’s procurement program.¹⁰ Under this process, the ISO would analyze Participating Transmission Owners’ (PTO) assessments of long-term transmission needs in light of statewide policy goals, including the RPS. Thus, transmission planning will consider the need to reach procurement goals for renewables along with reliability and economic criteria.

It should be possible to use this planning process to support findings of network benefits pursuant to Section 399.25. The ISO appears to be in the position of assessing whether transmission projects that would advance RPS goals -- by providing expanded access to

projects to enter the queue on completion of the required studies.

¹⁰ See “Assigned Commissioner’s Ruling Regarding Next Steps in Procurement Planning,” Appendix B on Transmission Planning Collaboration, in CPUC R.04-04-003, December 2, 2005.

renewable resource areas – would also provide economic and reliability benefits to the network at large. The ISO process can identify cases in which more detailed studies are needed, such that a study group (such as the Tehachapi Collaborative Study Group) should be formed (or continued). The ISO could classify RPS-related upgrades into the four categories discussed in Part I: (i) network upgrades; (ii) upgrades that are non-network today, but which will become part of a network facility later; (iii) non-network upgrades with transmission benefits beyond the generator; and (iv) non-network upgrades with no transmission benefits beyond the generator, where absence of generator coordination will add costs to RPS compliance.

The Commission should work with the CA ISO on the criteria to be used to avoid the need for the Commission to revisit the CA ISO's decisions. Indeed, P.U. Code Sec. 399.25 subsection (b)(1) envisions the CPUC taking an active role in determinations of network benefit, requiring the CPUC to “make findings, when supported by evidence, that transmission facilities necessary to achieving the RPS goals provide benefit to the transmission network” In so doing, the Commission should recognize that the FERC's rules for determining whether an upgrade is "integrated" with the network are general and subjective.¹¹ FERC has stated that "[o]n the question of how to determine whether a facility is a network facility, ... a showing of *any degree of integration* is sufficient"¹² (emphasis added). Although FERC has exclusive jurisdiction to determine who bears an upgrade cost, the California Legislature has directed the CPUC to try to influence the FERC outcome in favor of a network finding in an effort to promote renewables. Under Section 399.25(b), the CPUC can order a utility to propose "network" treatment to FERC and argue at FERC directly for network treatment. We hope the CPUC's collaboration with the ISO will produce agreement among all parties regarding the classification of facilities in favor of network determinations whenever the evidence can support it.

C. Timing of Backstop Availability

¹¹ FERC applies five factors, the “*Mansfield* factors,” in making its determinations. See *Mansfield Municipal Electric Department v. New England Power Co.*, 97 F.E.R.C. para. 61,134 at p.61,613-15 (2001).

¹² *Northeast Texas Electric Cooperative*, 108 FERC para. 61,084 (July 29, 2004) (emphasis added), *aff'g* 100 FERC para. 63,033 (2002) (Initial Decision).

In two prior decisions, the Commission has stated or implied that Section 399.25(b)(4) precludes backstop implementation until FERC "declines to authorize" cost recovery:

1. In D.04-06-010 (June 9, 2004), Conclusion of Law 4 states: "The Commission has authority under sec. 399.25 (b)(4) to authorize rate recovery of transmission projects to meet RPS goals if FERC *declines to authorize* such recovery" (emphasis added).
2. In D.03-07-033 (July 10, 2003), the Commission refers to " the Legislative requirement in sec. 399.25(b)(4) that we allow recovery of the utilities' costs of these transmission facilities in our retail rates, if FERC *does not approve* full recovery ..."

These statements conflict with the statutory text (in fact they conflict with each other). Section 399.25(b)(4) makes the backstop treatment available for facilities "that *are not approved* for recovery in transmission rates by the" FERC (emphasis added). This language does not require a specific FERC rejection before the CPUC awards backstop treatment. The phrase "are not approved" is in the present tense. The phrase "are not approved" does not equal "have been disapproved." There is no need to await a specific FERC denial. If, at the time of the backstop, the facilities lack FERC cost recovery approval (i.e., "are not approved" for cost recovery), the statutory test is met.

Text conflict aside, the Commission's reading has a logical defect. It assumes the Legislature intended cost recovery certainty in California to depend on the pace and organization of a busy federal docket. Cost recovery for new transmission facilities in California will not be timely if the state must await a FERC denial of cost recovery before using the Section 399.25(b)(4) backstop.

Even if the Commission's reading is consistent with the statutory language, so too is the reading offered here. With two interpretations thus available, the Commission has discretion to choose. It should choose the one that best advances the statutory purpose: achieving the RPS goals. Those goals are met with more certainty when the backstop's timing depends on Commission decisions rather than FERC decisions.

There will be circumstances in which seeking a specific FERC approval (for purposes of getting the denial presently required by the CPUC's interpretation of "are not approved") will be futile and unnecessary. Where FERC policy is clear that certain types of facilities are ineligible for cost recovery (e.g., non-network RPS "trunk lines" of the type described by SCE in its

petition to FERC in FERC Docket No. EL05-80-000), then a FERC filing will be useless. In this instance at least, the Commission should move forward with the backstop permitted by the "are not approved" language, not only because at that time the facilities "are not approved" but also because they "will never be approved."

Once released from its prior timing constraint, the Commission can proceed to employ the backstop. The Commission can issue a decision approving a project, in advance of cost incurrence, identifying all steps associated with a particular project and stating that all prudent costs associated with such project will be recoverable in the next rate case. These costs should include all costs necessitated by construction, including the preliminary environmental siting and transmission studies that are necessary to plan for and permit the facility. These items all fit into the Section 399.25(b)(4) category of "transmission costs ... resulting from the construction of the transmission facilities..." The cost-recovery approval should be done in two stages: pre-construction costs and construction costs, as approval of pre-construction costs requires a lower threshold of evidence, discussed in section II.B.2.c, above.

D. Cost Allocation Between Utilities

Several regions have renewables capability sufficient to satisfy the RPS needs of more than one utility, as well as Energy Service Providers (ESPs). Absent cost allocation, the costs will fall on the constructing utility (to be covered via the 399.25 backstop as discussed above) while benefits will flow to other retailers. At what point should these other retail sellers share in the cost?

If the Commission knew in advance which retail seller will use what portion of the upgrade, advance allocation of cost could ensue. Absent that information, allocation attempts will produce disagreement. Disagreement produces delay. The Commission is no stranger to inter-utility disputes and their resource consumption. Consider the protracted wrangling among all three large electric utilities in A.00-11-038 over the allocation of Department of Water Resource (DWR) contract costs. Or, more recently, Edison's ill-fated attempt in A.05-06-003 to spread the costs of "reliability-related generation" in southern California.

The Commission can avoid this agony by assigning initial cost responsibility to the ratepayers of the utility that develops, builds, and owns the new transmission. Then, as evidence

emerges that another utility or ESP will use, and benefit from, the upgrade on a long-term basis – for example, a long-term RPS contract to purchase renewable generation requiring access to the new lines – that entity should bear a cost share equal to its line usage share.

Such a policy follows long-established practices. In the early 1990s, PG&E undertook a major expansion of its mainline gas pipeline facilities, with a primary focus on moving additional Canadian gas supplies to southern California. In the certification decision for that expansion, the Commission allocated to PG&E the primary cost responsibility for the new line. Edison and SDG&E both contracted with PG&E for portions of the capacity of the expansion, and thus paid for the new line to the extent that their customers benefited from using it.¹³ The Commission has used similar models for electric transmission lines, with the California IOUs building and owning new transmission lines on which a portion of the capacity and the costs are allocated long-term to other entities.¹⁴ In this regard, CalWEA concurs with PG&E's "Top 6" filing that the CAISO needs to develop a system of long-term Congestion Revenue Rights (CRRs) to ensure that an IOU that contracts for long-term renewable generation located in another CAISO zone will have the ability to ensure, long-term, its rights to move that power to its own service territory.

Establishing such a policy now avoids debates later, debates that would delay the infrastructure on which RPS compliance depends. It also achieves fairness by matching cost responsibility with usage.

III. Cost Recovery Through the CA ISO Tariff

The Commission requested "a discussion of ... an amendment to the CA ISO tariff to place non-network, high voltage, transmission gen-tie lines needed to accommodate renewable resources under the CA ISO's operational control and making them eligible for cost recovery under the CA ISO's transmission access charge (TAC)."

This question misperceives FERC precedent. Regardless of who has operational control, FERC will allow a transmission facility's costs in general transmission rates only if the facility

¹³ See D. 90-12-119 in A. 89-04-033.

¹⁴ CalWEA recalls that Edison built its Devers – Palo Verde No.1 transmission line in the 1980s with a portion of the capacity and cost contracted to the Los Angeles Department of

provides network benefits. Under CA ISO's present tariff, CA ISO cannot take control of transmission that is not network transmission. It is theoretically possible to change CA ISO's tariff to give CA ISO control over non-network transmission. But that transfer of operational control, by itself, does not change the non-network status of the facility. FERC will not (and under the Federal Power Act, cannot) assign costs to customers unless there is benefit to those customers. A non-network facility by definition does not benefit all transmission customers.

It is possible that a facility presently non-network and controlled by a utility, will provide network benefits when transferred to the CA ISO, due to operational treatment that only the CA ISO can provide. If this possibility applies to a renewables-inspired facility, then the Commission should order utilities to effect the transfer, if the Commission wants the costs spread throughout all transmission customers rather than borne only by retail ratepayers under the backstop. But if the transfer of control does not convert the facility's benefits from non-network to network, the transfer will not achieve the Commission's cost-shifting objective.

Nor does it matter to the network vs. non-network determination that CA ISO is an independent entity. In the SCE decision, the FERC majority rejected SCE's submittal not because SCE is a non-independent transmission provider, but because the submittal disclaimed any network benefits. The majority's brief explanation of its rejection said nothing about independent vs. non-independent status.

It is true that in Order 2003, FERC authorized independent entities to vary from the standard interconnection contract. FERC's reason was that independent entities have no incentive to discriminate. *See* Order 2003 at para. 822 ("RTO or ISO should be treated differently because an independent RTO or ISO does not raise the same level of concern regarding undue discrimination."). The discrimination of concern to FERC was discrimination by a generation-owning transmission provider against independent generators. This relaxation has nothing to do with the distinction between network and non-network facilities.

In short, since the independent/non-independent distinction had no effect on the majority's decision (nor should it have, because roll-in depends on network benefits, not on who controls the line), it is necessary for CA ISO, if it does seek roll-in status for any facility, to make the network benefits clear. The "just and reasonable" requirement that transmission

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customers bear costs only to the extent those costs benefit the network is rooted in the Federal Power Act's "just and reasonable" requirement. The flexibility granted by Order 2003 to independent entities cannot violate that standard.

Finally, there is no legal way for FERC to create a special category of facilities which do not have network benefits, but which are necessary to California's renewables goals, and then order rolled-in cost treatment for them. FERC has no statutory authority under the Federal Power Act to deviate from just and reasonable ratemaking (which standard requires that cost-bearers be benefit-recipients), for the benefit of renewables. That a separate federal statute, PURPA, promotes renewables is irrelevant to the Federal Power Act. When we talk of benefits to the ratepayer, we are talking about the ratepayer buying the service at issue -- here, transmission service. It makes no difference to the transmission ratepayer -- in her role as transmission ratepayer -- that the state is attracting more generation or increasing the diversity of that generation. Those concerns are not Federal Power Act concerns.

IV. The Commission Should Require Utilities to Act Under the CA ISO Tariff to Maximize the Probability that Renewables-Inspired Upgrades Will Carry Renewable Power

Because the California utilities have transferred control to CA ISO, access to their transmission facilities, including new facilities induced by the renewables mandate, is subject to CA ISO tariffs and FERC rules, all under the nondiscriminatory principles articulated in FERC Order No. 888 and implemented under the CA ISO's tariff. There is no guarantee that, merely because a California utility builds and owns particular transmission facilities, the utility will have use of those facilities to transmit power for its own load. Nor does the CA ISO process guarantee that merely because a particular utility contracts to purchase power from renewable generators, such utility will obtain transmission service in an amount necessary to transport that power to its retail load -- even if, as is anticipated in this proceeding, the utility designs and builds transmission facilities specifically for the purpose of connecting with renewable generators. Rather, once the utility builds transmission facilities and turns them over to CA ISO, those facilities become part of the multi-utility transmission network operated by CA ISO and subject to CA ISO's open access rules, which are, in turn, subject to the jurisdiction of the

Federal Energy Regulatory Commission (FERC). The building utility obtains no specific right to use the proposed transmission facilities.

Renewables project developers therefore have a responsibility to establish a position in the FERC-regulated CA ISO interconnection queue. SCE recently has required developers on its RPS short-list to establish and maintain a queue position. CalWEA supports Edison's recent Advice Letter 1950-E that proposes to allow Edison to fund the interconnection studies required to move RPS short-list projects forward. Without knowing when and where transmission will be available, developers do not know which of their potential projects will be developed first, and therefore where they should focus their resources.¹⁵ Edison's support in AL 1950-E is a constructive means to solve this "chicken-and-egg" problem.

The Commission should be concerned, however, that transmission upgrades intended to access renewable resource areas are actually used for their intended purpose. The Commission's options in this regard are limited by the FERC's open access requirements. Other states have taken action to increase the chance that new lines intended by their owner for renewable generation are used for that purpose. For example, the Minnesota Commission required Xcel Energy, as a condition of certificates for new transmission to serve the wind-rich Buffalo Ridge region, to sign PPAs with a minimum of 625 MW of new wind resources in that area.¹⁶ This condition enabled Xcel to ensure that the Midwest ISO would provide the new wind facilities with transmission access as network facilities. CalWEA recognizes that ordering the California IOUs to sign PPAs with resources in certain areas would run counter to the structure of the California RPS program, which is based on competitive solicitations open to renewables of all types, and in any part of the state. If California wishes to use a market-based mechanism for renewables procurement, instead of a resource planning approach, the state needs to streamline the market-based RPS procurement process, and ensure that utilities sign PPAs for their 2010 RPS requirements as early as possible, and that the utilities continue to assist short-listed

¹⁵ For example, in the Tehachapi area, several developers have potential projects in many different locations; which projects get built first will depend on the ultimate transmission configuration and development schedule.

¹⁶ See Minnesota PUC Decision No. 03-0025, issued March 11, 2003 in Docket No. E-002/CN-01-1958.

developers to obtain and maintain transmission access via the established FERC-regulated procedures.

CONCLUSION

In conclusion, we urge the Commission to issue a clear decision on these cost recovery issues as soon as possible, as transmission availability is the critical missing element to realizing the state's renewable energy goals.

Respectfully submitted,

Scott Hempling
Law Offices of Scott Hempling, P.C.
Attorneys for the California Wind
Energy Association

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Appendix on Terminology and Jurisdiction

"Transmission" -- A facility can be transmission or non-transmission. The boundary is determined by FERC's 7-factor test announced in FERC Order No. 888.

"Network" -- If the facility is transmission, it can be, under FERC's policies, network or non-network. Categorization is determined by the five factors announced by FERC in Mansfield.

"Distribution" -- If the facility is non-transmission:

1. its treatment falls outside of section 399.25.
2. it is, under the Federal Power Act's designations, local distribution or non-local distribution. Under the Federal Power Act, local distribution is state-jurisdictional and non-local distribution is FERC-jurisdictional.

"Rolled-in pricing" -- Rolled-in pricing is the act of placing the cost of a transmission upgrade into transmission cost of service, to be borne by all transmission ratepayers. Rolled-in pricing is the opposite of "assign the upgrade cost to the generator." In D.03-07-033, the CPUC described this usage as SCE's usage, but that description is incorrect. Parties use the term "roll-in" to mean "all transmission customers bear the cost." Contrary to the CPUC's usage in D.03-07-033, "rolled-in pricing" does not refer to the distinction between initial financing and permanent cost responsibility.