UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interconnection Queuing Practices	)	Docket Nos. AD08-2-000
	)	
Midwest Independent Transmission System Operator, Inc.	)	ER07-1375-000
	)	
Southwest Power Pool	)	ER07-1311-000
	)	
PacifiCorp	)	OA07-54-000
	)	
United States Department of Energy Bonneville Power Administration	)	NJ08-2-000
	)	
PJM Interconnection, L.L.C.	)	ER08-280-000
	)	
California Independent System Operator Corporation	)	ER08-140-000

POST-TECHNICAL CONFERENCE COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION, AUSRA, INC., ABENGOA SOLAR, INC. AND BRIGHTSOURCE ENERGY ON INTERCONNECTION QUEUING PRACTICES

Pursuant to the Commission's Notice Inviting Comments dated December 17, 2007, in the captioned proceedings, the California Wind Energy Association ("CalWEA"), Ausra, Inc. ("Ausra"), Abengoa Solar, Inc. ("Abengoa Solar") and BrightSource Energy ("BSE" and, together with CalWEA, Abengoa Solar and Ausra, the "Wind and Solar Parties") hereby submit their comments on the issues raised at the Commission's technical conference on December 11, 2007, to address interconnection queuing practices. The Commission's notice states that the purpose of the technical conference was to discuss possible methods to address the current challenges of queue management while still honoring the open and non-discriminatory access goals of Order No. 2003. The Wind and Solar Parties' comments and attached "white paper" address these issues.

I. SUMMARY

As set forth below, the Wind and Solar Parties share the Commission's goals of reforming the generation interconnection process to alleviate the queue backlogs and, more fundamentally, to achieve the timely construction of interconnection facilities and transmission system upgrades to accommodate new generating resources in an open and non-discriminatory manner. Meeting this objective is all the more essential in view of the growing proliferation of state renewable portfolio standards ("RPS") across the country, and the need to harmonize the construction of new facilities with state and federal siting requirements.

The basic problem is this: the current sequential generator interconnection study process duplicates system transmission planning, resulting in a complex and repetitive procedure. While a first-in-time approach is one means of fairly awarding transmission rights, there is also a downside. Generation developers may be allocated significant cost responsibility for network upgrades identified through interconnection studies (upgrades that ultimately may not be required once the comprehensive transmission planning process is complete). These projects may, therefore, choose to withdraw their service request and re-enter the queue at a lower position. When this occurs, transmission providers must restudy the system impacts of lower-queued projects and potentially reallocate transmission upgrade cost responsibility. This leads to excessive delays and uncertainty for project developers, investors and power purchasers.

The Commission, however, need not sacrifice basic fairness in favor of efficiency to alleviate the significant queue backlogs currently plaguing portions of the country. Rather, as summarized here and discussed in more detail below and in the white paper attached to these comments, the Commission can meet its public interest obligation under the Federal Power Act ("FPA") and alleviate the queue backlogs while preserving basic fairness for all interconnecting

generating resources by granting flexibility to permit transmission providers, on a case-by-case basis, to adopt the following essential reforms:

- Permit limited waivers of existing queue rules to allow retroactive studies in geographical (*i.e.*, electrically-related) clusters. This approach is an essential first-step to alleviate existing queue backlogs.

- Clusters of generating projects should be studied using a streamlined process to evaluate generators' transmission cost responsibility, and to provide the basis for an "earnest money" deposit to permit the generator to remain in the queue and proceed to the interconnection agreement stage. This streamlined approach would determine generator transmission cost responsibility within months of entering the queue, rather than potentially years later under the current approach.

- The generator's transmission cost responsibility would be fixed, and would not change based on the decisions of other generators in the queue. This would eliminate the need for re-studies when queue changes occur, and thereby eliminate the cycle that has caused the delay and uncertainty in the first place.

- Detailed design of the actual transmission facilities needed to interconnect new generators should be performed in the larger regional transmission expansion planning ("RTEP") process, as reformed by the Commission's recent Order No. 890 directives. That process should consider interconnection of generators with signed interconnection agreements, along with system reliability needs and potential economic opportunities, and then design optimal facilities to meet all these needs in total.

The foregoing approach would:

- Allow real projects to commit to an interconnection agreement with reasonable cost and timing certainty;

- Establish meaningful financial obligations for developers seeking to interconnect to the transmission grid as a means of weeding out speculative projects with no real commercial prospects;

- Integrate transmission planning for interconnecting generators with the RTEP process to produce transmission expansion plans that simultaneously meet multiple needs;

- Devise transmission expansion plans that proactively plan for transmission build-out in anticipation of future supply needs, as well as those needed to meet state RPS goals, including coordination of transmission planning with state and federal agencies with transmission siting responsibility;

- Eliminate the need for participant funding for network upgrades;

- Clear the existing backlogged queue within a year by developing firm transmission cost responsibility figures that projects must accept to stay in the queue; and

- Establish firm timelines (*e.g.*, four to six months) to complete future interconnection studies.

Clearly, resolving interconnection queue backlogs and reforming the interconnection process involves technical issues, which we address in detail in the white paper attached as Attachment A.

II. PERSONS TO BE SERVED

In addition to the undersigned counsel for the Wind and Solar Parties, persons who should receive communications in connection with these comments include the following:

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III. COMMENTS

1. The Typical Interconnection Study Process Under Order No. 2003 Results In Unworkable Delays And Uncertainty In The Face Of The Proliferation Of Generation Interconnection Requests To Meet New State Renewable Portfolio Standards.

As the Commission is well aware, under the current Order No. 2003 large generator interconnection process ("LGIP"),[1] transmission providers generally study generation interconnection requests sequentially in the order they are received, determine the impacts of new generation on the transmission system, assess the new facilities needed to mitigate those impacts, assign cost responsibility for those system upgrades to the generators and, if the generators agree to bear the up-front construction costs, enter into interconnection agreements with them. This approach has the virtue of simplicity and fairness that first in time should be first in line.

Applying this principle to the interconnection process, however, can have decidedly undesirable results when it causes the line to stop moving and prevents new projects from being built. This harms developers and consumers, and undermines the Commission's goal to achieve competitive wholesale power markets.[2] It is not the first-in-time approach alone that brings the interconnection study process to a standstill. Rather, it is the first-in-time approach in conjunction with an unduly complex cost-allocation method that can allocate disproportionate cost responsibility for grid transmission upgrades to a single interconnecting generator, even

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1 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

2 *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 1154 (2006) ("In order for wholesale prices to remain just and reasonable, sufficient resources must be available."), *order granting in part and denying in part requests for clarification and reh'g*, 119 FERC ¶ 61,076 (2007).

though the upgrades ultimately benefit all system customers and the costs ordinarily will be rolled into system transmission rates.

The up-front funding responsibility imposed on generators through this process may vary widely. The existing system may be able to accommodate an interconnection request for Generator 1 with minimal upgrades and up-front funding responsibility, but require substantial upgrades to accommodate Generator 2, even if the second generator proposes less net capacity than Generator 1. Once the upgrade is built (or assumed to have been built in the transmission provider's system model) the next generator in the queue, Generator 3, can take advantage of any excess capacity provided by upgrades constructed to accommodate Generator 2, and thereby have lessened (perhaps significantly lessened) up-front funding exposure for additional system upgrades. These circumstances provide a powerful incentive for any generator facing substantial up-front transmission expansion funding costs to withdraw its request and re-enter the queue at a lower position. When that happens, the transmission provider is forced to re-study lower-queued projects and reallocate transmission upgrade costs, and the cycle of queue reshuffling invariably repeats, with little or no movement in the overall interconnection queue. Worse, this can cause substantial delays in actual transmission construction to permit new generation to serve the growing demands for energy.

These circumstances rightly led Commissioner Wellinghoff and many participants at the Commission's technical conference to express the view that the interconnection queuing process is broken in many parts of the country, leading to indefinite delays in the interconnection of new and badly needed generating facilities to the interstate power grid. For example, the Midwest Independent Transmission System Operator, Inc. ("MISO") estimates that, using current study methods, it would take until 2050 to clear its *existing* generation interconnection

queue that represents over 70,000 MW of proposed capacity.[3] The California Independent System Operator Corporation ("CAISO") notes that it has pending requests to interconnect nearly 60,000 MW of new generating capacity.[4] The majority of these interconnection requests reflect a proliferation of renewable energy projects proposed in large part to satisfy new demands for clean energy sources pursuant to state RPS requirements. Approximately one-third of the requests are from proposed conventional fossil generating plants.

It is abundantly clear from the comments of the MISO, CAISO and others that there are two major sources for the delays: the large increase in new interconnection requests, and the existing rules for managing and studying the transmission system impacts of these requests. As Mr. Joshua Bar-Lev summarized in his comments, delays and uncertainty resulting from the existing interconnection study process severely hampers the ability of generation project developers to meet contractual commitments under purchase power agreements, frustrating the needs of investors, lenders, power purchasers and state and federal renewable resource requirements.[5]

Clearly, reforms to the current process are urgently needed. The Wind and Solar Parties are sensitive to the concerns expressed by several commissioners at the conference that basic fairness should not be sacrificed solely to achieve more efficiency in queuing practices. We are also aware of the Commission's desire to accomplish reforms within the existing framework of Order No. 2003 as much as possible. Mindful of these concerns, the Wind and

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[3] Prepared Remarks of Clair J. Moeller, Vice President of Transmission Asset Management, Midwest Independent Transmission System Operator, Inc., at 1 (submitted Dec. 11, 2007).

[4] Prepared Statement of the California Independent System Operator Corporation for Technical Conference on Generator Queuing Practices, at 2 (submitted Dec. 13, 2007).

[5] *See* Joshua Bar-Lev, Vice President, Regulatory Affairs, BrightSource Energy, Interconnection Issues Facing Utility-Scale Solar Projects, at 3 (submitted Dec. 11, 2007).

Solar Parties have diligently worked with their consultants to develop a proposed solution to the interconnection queuing dilemma that could be implemented on a case-by-case basis. The proposed solution is detailed in the white paper attached as Attachment A to these comments and is summarized in the next two sections. The solution both solves the interconnection queuing bottlenecks in the short-term, and prevents the problems from recurring in the long-term.

2. The Commission Must Promote Solutions That Resolve The Transmission Interconnection Queue Bottleneck In Both The Short- And The Long-Term.

Clearly, the significant queue backlogs that now exist in the CAISO, MISO and elsewhere require concerted action to prevent gridlock from bringing generation development to a near halt. That result is in no one's interest. Thus, an essential first step to clearing the queues is for the Commission to signal its receptiveness to one-time retroactive waivers of queuing rules on a case-by-case basis to allow transmission providers to conduct cluster studies of existing interconnection requests.[6]

Such retroactive studies would be grouped in geographically and electrically related areas as determined by transmission providers in their reasonable discretion. Clusters would be studied using streamlined study procedures intended to identify the needed transmission upgrades and transmission cost responsibility for individual generators in each grouping. This approach would differ from the current study process, which conducts a more detailed analysis for the purpose of defining the exact network upgrades and generator cost responsibility using extensive sequential studies, even though experience has shown in the context of regional markets that little, if any, network transmission upgrades identified in this

[6] Order No. 2003 contemplates such flexibility. *See* Order No. 2003 at P 147 ("we will afford an RTO or ISO the flexibility to propose queues and queuing rules designed to meet its regional needs").

fashion have actually been built. The current process thus sacrifices the common good in a futile and time-consuming pursuit of perfection.

The Commission adopted the retroactive cluster study approach that allowed the CAISO to address a major queue bottleneck stemming from requests to interconnect new wind generating resources in the Tehachapi Wind Resource Area of California.[7] In that case, the Commission found good cause to grant the CAISO the requested waiver from queuing rules to permit a 33-month cluster study of some 4,350 MW of proposed wind generating resources in the queue, finding no adverse consequences and clear customer benefits.

The Commission also found the cluster study process was fair to all generation developers — both renewable and traditional generation alike — because it eliminated duplicative and redundant incremental system impact studies and, therefore, would lower costs to both generation developers and transmission owners. Conversely, even under the serial study and restudy approach, generation developers have no inherent cost certainty (in fact the opposite is true), so that the cluster study approach does not violate fairness principles.

The Commission has, in closely analogous circumstances, found an "aggregate study" approach appropriate for analyzing projects that should be considered together from a system impact perspective. In particular, the Commission has found it reasonable for a transmission provider to study such projects together, to streamline the process and permit customers to share in the cost allocation of necessary upgrades.[8] This approach helps minimize the incentive for queue reshuffling and inefficient restudies when higher queued projects

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7 *California Independent System Operator*, 118 FERC ¶ 61,226, *order granting clarification*, 120 FERC ¶ 61,180 (2007).

8 *Southwest Power Pool, Inc.*, 110 FERC ¶ 61,028 (2005).

withdraw because they are allocated a perceived disproportionate share of transmission upgrade costs.

In the final analysis, the Commission's willingness to entertain a waiver from the queuing rules in the Tehachapi situation led to a swift review and resolution of the queue bottleneck in a manner that was fair to all generators in the queue. A similar approach would be equally effective in other circumstances.

Although the Commission deemed the CAISO's request at the time to be a "one-time" waiver, thus suggesting that future waivers would not be forthcoming, such a result would not be appropriate given the practical realities of the current queue backlogs. As the CAISO testified at the technical conference, generation in the interconnection queue has substantially increased in the year since it filed the Tehachapi waiver request, which was not foreseeable at the time. In any event, coupled with more meaningful reforms to the LGIP study process, as discussed in the next section, it should become far less likely that queue backlogs will recur.

3. A True Long-Term Solution Harmonizes The Interconnection Study Process With The Regional Transmission Expansion Planning Process.

It is not sufficient simply to conduct retroactive cluster studies of the existing generation queues, sign interconnection agreements with willing generators and move on without reforming the underlying study process. Queue backlogs will simply recur for all of the same reasons that they have occurred in the first place. Instead, the Commission should be receptive to a more fundamental reform to the interconnection study process to break the logjam once and for all.

To begin with, the current LGIP interconnection study process needlessly duplicates the RTEP process, where network transmission upgrades needed for economic or reliability purposes are identified. LGIP studies seek to emulate the RTEP process by

performing detailed transmission planning analyses for each interconnection request precisely to identify the local and network transmission upgrades necessary to accommodate the incremental capacity associated with a particular project. The analytic models begin with a base case that includes existing transmission facilities, and those assumed to be constructed to satisfy needs associated with higher-queued projects.

The problem with this approach is three-fold. First, if higher-queued projects withdraw, lower-queued projects must be restudied because system impacts and cost responsibility can change. Second, the study process does not take into account other system needs stemming from reliability issues and economic opportunities that could be addressed simultaneously. Third, ***network transmission facilities are rarely built as a result of the LGIP studies***. Often, generators limit their output or accept "work-around" solutions rather than undertake the identified upgrade. Thus, the existing LGIP study process ultimately produces what is, at best, an approximation of actual network upgrades for each generator. That the process seeks to do so with great precision does not change the basic fact that the results are only estimates. Moreover, the fact that the entire analysis can be upset by the decision of a single generator to withdraw once it receives its cost estimate makes the exercise wasteful and inefficient.

As described in the attached white paper, a more efficient approach would use a streamlined generator interconnection study process focused on determining a fair value for each generating project's transmission financial commitment, which would be reflective of the transmission upgrade cost associated with that generator.[9] To accomplish this, transmission

[9] Use of estimates to determine a generator's up-front cost responsibility for network upgrades is appropriate given that the generator's payment is "essentially a loan from the Interconnection Customer to the Transmission Provider" that is repaid over the period set forth in the transmission

providers would open periodic queue windows — say every four to six months — to identify projects for analysis.[10] Geographically (electrically) related projects submitting interconnection requests during the cluster window would be studied together (although projects could opt-out and elect to be studied individually if they so choose).[11] All projects that do not opt-out of the cluster would be studied as part of their "locational clusters" to determine feasibility and approximate cost responsibility at their desired level of deliverability.[12]

Once this study process is complete, each project would decide whether to proceed to the individual interconnection facilities study analysis to determine the remaining cost responsibilities for projected transmission interconnections.[13] After the facilities studies are complete, each project would have the option to enter into an interconnection agreement with a binding commitment to provide an earnest money deposit based on its transmission cost responsibility. Projects with signed interconnection agreements would then be studied in the RTEP process to determine actual network transmission upgrades. The transmission provider should be required by its tariff to complete the entire study process before the time for opening the next queue window (*i.e.*, four to six months).

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provider's tariff, not to exceed 20 years. Order No. 2003-C at P 9 n.9. (We note that the CAISO's tariff provides for a five-year repayment period.)

[10] The Commission's rules allow cluster studies during six-month windows. Order No. 2003 at P 153. The main difference with the Wind and Solar Parties' proposal is the shift in emphasis on detailed system planning to the RTEP to eliminate needless duplication of study efforts.

[11] As explained in Order No. 2003, electrically isolated projects would be studied separately. Order No. 2003 at P 156.

[12] *Id*. ("allocation of cost responsibility for system upgrades and jointly used facilities is more readily managed by studying requests in clusters"). In addition, projects must provide large enough up-front payments, based on the size of the project and its choice to be studied as part of a cluster or individually, to cover the study costs and discourage speculative queue hording.

[13] This would entail payment of an additional fee based on the size of the project, which would also be structured to weed out speculative projects.

In addition, although Order No. 2003 did not mandate that grid interconnection facilities must be completed by a date certain,[14] ultimately the timely completion of transmission upgrades allows interconnecting generators to meet their deliverability obligations to power purchasers. For example, generators committing to firm on-line dates or planning to participate in capacity markets based on deliverability commitments require on-time installation of grid facilities. The Commission has ample tools outside of Order No. 2003 to provide transmission providers with the proper motivation to meet these commitments, such as incentive rates for on-time upgrades, and rate disincentives for materially late projects when the delay was within the transmission provider's control.[15] The Commission should use those tools to encourage transmission providers to achieve on-time construction of grid upgrades.

4. The Commission Should Also Use The Order No. 890 Compliance Process To Ensure That Transmission Providers Meet Their Obligations Under Schedule K To Coordinate The Regional Transmission Expansion Planning Process With Utilities, As Well As State And Federal Agencies, Affecting Transmission Facilities To Accommodate New Generating Resources.

The Commission has mandates from Congress to use its powers to facilitate the planning and expansion of transmission facilities, to coordinate the transmission siting and development of transmission needed to accommodate renewable energy projects on federal lands, and to ensure new transmission construction in constrained areas when state approval processes bog down.

In particular, new Section 217 of the FPA directs the Commission to use its authority "in a manner that facilitates the planning and expansion of transmission facilities to

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[14] Order No. 2003 at P 351.

[15] The Commission recently awarded rate incentives to Southern California Edison Company under Order No. 679 in connection with its plan to construct network transmission upgrades to integrate wind generating resources in the Tehachapi region. *Southern California Edison Company*, 121 FERC ¶ 61,168 (2007).

meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities . . . ."[16] Further, Section 368 of the Energy Policy Act of 2005 ("EPAct 2005") requires the Commission to coordinate with the Department of Energy ("DOE"), Bureau of Land Management ("BLM") and other agencies to designate transmission corridors on federal lands.[17]

Finally, as the Commission is well aware, Section 1221 of EPAct 2005 also gives it "back-stop" siting authority to authorize new transmission construction on non-federal lands in constrained National Interest Electric Transmission Corridors designated by DOE when states fail to grant necessary siting authority for new transmission projects within a year.[18] Section 1221 was enacted because our nation lacks adequate transmission infrastructure to provide reliable service and deliver electric energy to all markets at a reasonable cost.[19] Thus, Section 1221 complements Section 368 of EPAct 2005 and FPA Section 217, and provides a means to link transmission corridors on federal lands with new transmission on non-federal lands in a seamless manner.[20]

The Commission should make full use of the Order No. 890 open transmission planning and coordination requirements to implement these congressional mandates. Regional transmission expansion planning coordination is one of Order No. 890's nine core reform

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16 ENERGY POLICY ACT OF 2005, Pub. L. No. 109-58, § 1233, 119 Stat. 594, 958 (2005) (codified at 16 U.S.C. § 824q).

17 EPAct § 368.

18 *Id*. § 1221.

19 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 421 (noting the "decline in transmission investment relative to load growth in the ten years since Order No. 888 was issued"), *order on reh'g and clarification*, Order No. 890-A, 121 FERC ¶ 61,297 (2007).

20 Indeed, as the Commission pointed out in Order No. 890, a more transparent and open regional transmission planning process will facilitate the planning and expansion of transmission facilities, "as well as support the DOE's responsibilities under EPAct 2005 section 1221 to study transmission congestion and issue reports designating National Interest Electric Transmission Corridors . . . ." Order No. 890 at P 425.

principles that the Commission directed all transmission providers to incorporate into their open access transmission tariffs.[21] The Commission directed transmission providers to "coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and use consistent data, and (2) identify system enhancements that could relieve congestion or integrate new resources . . . ."[22] The Commission envisioned that regional coordination would include "transmission providers, customers, affected state authorities, and other stakeholders . . . ."[23] This directive is consistent with, and indeed required by, the statutory requirements of EPAct 2005 and the FPA.

The Commission's focus on the need to ensure that the regional planning process incorporates an assessment of system enhancements that could relieve congestion or integrate new generating resources is particularly probative of the issues before the Commission in the technical conference at issue here. As discussed above, numerous commenters called attention to breakdowns in the current LGIP process that are frustrating generation developers' ability to integrate proposed new generating resources with the transmission grid. It is, therefore, both necessary and appropriate for the Commission to be mindful of the record developed in this proceeding as it evaluates the Order No. 890 compliance filings of transmission providers in other dockets.

In short, any Order No. 890 compliance filing that does not fully address the need for regional transmission expansion planning coordination by identifying system enhancements

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21 Order No. 890 at P 523.

22 *Id*.

23 *Id*. at P 527. In the West, where transmission planning is conducted through the Western Electric Coordinating Council, as well as various sub-regional groupings, the Commission expressed the view that the sub-regional approach is workable as long as there is adequate coordination among the sub-regions.

"that could relieve congestion or integrate new resources" is necessarily deficient because it fails to promote the policy goals set forth in FPA Section 217 and EPAct 2005 Sections 368 and 1221.

Moreover, as outlined above, reforming the LGIP study process to remove inefficiencies and alleviate queue bottlenecks is an important means to achieve Order No. 890's goals to promote transmission expansion and integration of new resources through the regional planning process. Given that all transmission is ultimately identified and built through transmission provider RTEP procedures, the Commission should pay particularly close attention to how the LGIP process of each transmission provider achieves Order No. 890's core goals.

Finally, the regional transmission organization and independent system operator transmission planning and expansion processes previously approved by the Commission that do not meet these basic elements are not "consistent with or superior to" the open access transmission tariff as modified by Order No. 890.[24] For these reasons, it is imperative that the Commission make full use of the Order No. 890 compliance process to scrutinize transmission provider Schedule K filings to ensure that they meet the foregoing regional planning objectives.

Ensuring that transmission provider Schedule K filings adequately consider all regional transmission expansion initiatives as outlined above is also necessary to achieve a comprehensive solution to generator interconnection bottlenecks that are the focus of the technical conference. Federal and state initiatives to identify target renewable resource development areas are playing a significant role in both the development of renewable energy resources, and the demands these resources place on the need to expand the existing transmission infrastructure. For example, the BLM is encouraging the development of solar energy development zones on federal lands, and states like California have established a renewable

[24] *Id*. at P 439.

energy transmission initiative to further RPS targets. The transmission needed to accommodate these initiatives ultimately must be identified and constructed pursuant to transmission provider RTEP planning procedures. Thus, transmission provider regional coordination plans identified in Schedule K filings must take into consideration these targeted renewable energy development initiatives.

CONCLUSION

For the foregoing reasons, the Wind and Solar Parties respectfully urge the Commission to give careful consideration to the interconnection study reform proposal set forth in detail in the attached white paper. In particular, the Wind and Solar Parties respectfully request that the Commission signal its willingness to entertain interconnection study reform proposals on a case-by-case basis that would: (1) allow for retroactive cluster studies of existing transmission interconnection queues, and (2) provide for streamlined locational clustered interconnection study procedures geared toward determining a fair and firm estimate of each generating project's up-front cost responsibility. Finally, it is essential that the Commission scrutinize transmission provider Schedule K filings to ensure that they give adequate consideration to (and address in meaningful detail) their plans to coordinate the transmission planning process with federal and state initiatives to promote renewable energy development zones, which ultimately will place significant demands on both the generation interconnection study process, and the need to upgrade the interstate transmission grid.

Respectfully submitted,

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ATTACHMENT A

LGIP REFORM

WHITE PAPER

A Reform Proposal for the CAISO Generation Interconnection Study Process[1]

January 10, 2008

1.0 Summary

This whitepaper presents a proposed framework for comprehensive reform of the California Independent System Operator's (CAISO's) generation interconnection study process, which is subject to FERC rules governing Large Generator Interconnection Procedures, or LGIP. This proposal would:

- Allow real projects to commit to an Interconnection Agreement with reasonable cost and timing certainty, as opposed to imposing obligations simply for the purpose of weeding projects out;[2]
- Eliminate the need to do re-studies when queue changes occur;
- Integrate transmission planning for interconnecting generators with the Regional Transmission Expansion Planning (RTEP) process to produce transmission expansion plans that simultaneously meet multiple needs;
- Devise transmission expansion plans that proactively plan for transmission build-out in anticipation of future supply needs, as well as those needed to meet with state Renewable Resource Standard (RPS) goals, including coordination of transmission planning with state and federal agencies with transmission siting responsibility;
- Take into account the state's Renewable Energy Transmission Initiative (RETI) goals for development of Competitive Renewable Energy Zones (CREZ);
- Eliminate the need for participant funding of network upgrades;
- Likely clear the existing backlogged queue within a year by developing firm transmission cost responsibility figures that projects must accept to stay in the queue; and
- Establish firm timelines (*e.g.*, 4 to 6 months) to complete future interconnection studies.

The fundamental distinguishing feature of this reform proposal is that it requires the planning for all transmission system upgrades, whether the upgrade is needed to resolve projected transmission reliability concerns, capture potential economic opportunities, or interconnect new generation projects that have signed their Interconnection Agreements (IAs) and posted financial security, to be performed as part of a centrally managed Regional Transmission Expansion Planning (RTEP) process. This feature of the proposal ensures that only optimally planned and engineered transmission expansions that simultaneously address all

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[1] This proposal was developed by Dariush Shirmohammadi, a consultant to Oak Creek Energy Systems, and Hal Romanowitz, President of Oak Creek Energy Systems.

[2] A weeding-out approach that does not provide cost and timing certainty would simply favor the most well-financed companies.

transmission grid needs and opportunities will materialize. In this fashion alone, the proposed solution would be a significant improvement over the current piecemeal transmission expansions that are planned through sequential generation interconnection study processes and independently from those planned through RTEP. At the same time, planning for the transmission needs of interconnecting projects that have signed IAs and posted financial security will require that the RTEP addresses such project interconnections with the same level of commitment that it applies to planning for solving a projected network reliability problem.

Transferring the planning for the upgrades needed to interconnect projects to RTEP eliminates the need for the complex, repetitive and inconclusive studies that are currently conducted for new projects. Instead, the LGIP process can be significantly streamlined to principally focus on determining the transmission cost responsibility of the new projects in the queue. This Streamlined Generation Interconnection Study (STRGIS) process is the second major component of this reform proposal.

The STRGIS process would not only allow interconnection studies to be completed expeditiously, through simpler study processes and the use of extensive clustering, but also would offer other useful features to the CAISO, its Participating Transmission Owners (PTOs), and the Project Developers (PDs), e.g., STRGIS:

- Allows PDs to select a deliverability level for their project based on their own commercial interest, consistent with the CAISO tariff requirements, with transmission cost responsibility reflecting the selected deliverability level;
- Fixes PD transmission-cost responsibility, i.e., it would <u>not</u> change due to activities of other generators in the queue;
- Determines a PD's transmission-cost responsibility within months after project application submission;
- Allows specific projects to be studied individually, at the option of the PD, after the cluster studies are complete;
- Addresses the special needs and features of the Competitive Renewable Energy Zones (CREZs) being developed as part of various state's Renewable Energy Transmission Initiative (RETI); and
- Clear the existing severely backlogged CAISO generation queue in a short period of time (~12 months).

Most rule changes to implement these proposed reforms can be achieved through CAISO business practice, rather than tariff amendments. However, a few provisions of the tariff would need to be modified, to:

- Enable retroactive clustering on a one-time basis to clear the historic queue backlog.
- Allow for integration of generation projects that have signed their IAs and posted their financial commitments by treating interconnection of such projects as "need."

2.0 Background

About 80,000 MW of generation, approximately half renewable-energy fueled, are currently in the CAISO queue. A little more than 4,000 MWs have obtained signed Interconnection Agreements (IAs), and most of those projects entered the queue before 2004.[3] The total capacity in the queue totals over 150% of CAISO's entire peak load, so clearly most of these projects will not materialize in the near future.

The current LGIP process is effectively designed to emulate, for each individual project, the full transmission planning process, in parallel to and separate from the Regional Transmission Expansion Planning process. Because studies for each individual project relate to other projects in the queue, the LGIP process has become very complex and iterative, and it can produce an infinite cycle of recalibrated transmission studies projects. Furthermore, the transmission cost responsibilities calculated for a generator through this "iterative" process can readily change based on behavior of other generators in the queue, making project financing a major challenge.

To break this cycle, the CAISO must simplify the determination of cost responsibility, and to plan for actual upgrades only for those projects that sign IAs. The planned upgrades should be synchronized and combined with the joint regional transmission planning processes that the CAISO conducts with its Participating Transmission Owners (PTOs) and neighboring planning authorities, so that the most efficient overall solutions are selected for development – i.e., solutions that address system reliability needs, economic opportunities, and interconnecting projects together.

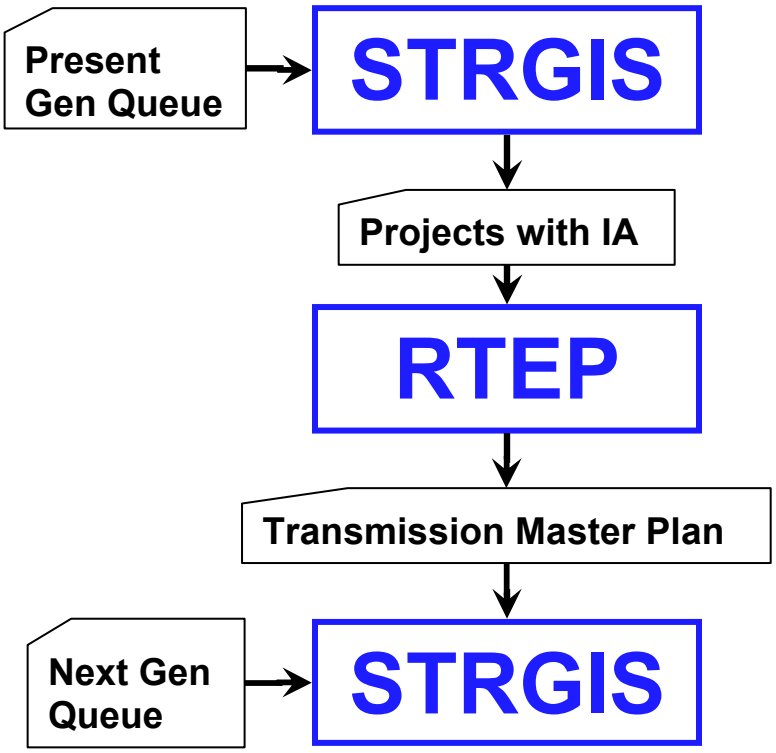
3.0 Proposed Solution

This reform proposal transfers all decisions about actual transmission upgrades -- to address projected reliability concerns, to capture potential economic opportunities, or to interconnect new generation projects -- to a centrally managed Regional Transmission Expansion Planning (RTEP) process. Once transmission planning for actual project interconnection facilities is transferred to RTEP, the interconnection studies need no longer be burdened with the current degree of complexity and attempted precision from which it presently suffers.

Instead, the LGIP process would be transformed into a Streamlined Generation Interconnection Study (STRGIS) process. It would principally focus on determining a fair estimate of each interconnecting project's "Transmission Financial Commitment" (TFC) - the project's level of transmission cost responsibility. Hence, one RTEP cycle and one or more STRGIS cycles would run sequentially to address all transmission system expansion needs, including requirements for interconnection projects. Figure 3.1, below, generally presents the overall process.

[3] Statistics as of September 28, 2007.

Figure 3.1 – Illustration of the Reformed Interconnection Study Process



The STRGIS process contains three main components:

1. Interconnection Queue Management
2. Project Interconnection Study
3. Transmission Financial Commitment

The main features of each of these components are discussed below. In addition we explain how the application of the proposed reform will immediately clear the current CAISO interconnection queue.

3.1 Interconnection Queue Management

Queue management refers to the process of accepting Interconnection Requests (IRs) from Project Developers (PDs) and processing them for subsequent studies. Under our reform proposal, the CAISO would manage the interconnection queue using the following simple procedures:

A. **Queue Window Designation and Selection of Interconnection Point(s):** On a periodic basis, say every four to six months, the CAISO would open a queue window for all PDs to submit their IRs. During this time period, the CAISO would work with PDs on the selection of the interconnection point(s) for their projects to the CAISO

Controlled Grid. A PD may select more than a single point of interconnection to be studied. The additional interconnection points would be alternate to the primary point. Alternatively, a PD may select a pair of interconnection points for an interconnecting project (or select to interconnect to the middle of an existing line) if the size of its project is large.[4] A PD would be allowed to select additional pairs of dual interconnection points.

If no suitable interconnection point(s) exists near the project location and the project location cannot be moved due to fuel availability constraints (the case for most renewable energy projects), CAISO could identify a new Interconnection Grid Substation (IGS) near the interconnecting project as an alternative interconnection point.[5]

Every interconnecting project will be required to deposit an application fee commensurate with its size and the decision to be studied as part of a cluster or individually at the time that the IR is submitted: larger projects or projects that wish to be studied individually (not as part of a cluster) would pay more. This application fee is intended to cover the entire cost of performing the system studies needed to determine the projects' deliverability cost responsibility – it does not cover the cost of performing Facility Studies (FAS). Unless the project is moved from a cluster study to individual study, see below, the application fee is final and would not be adjusted after the actual studies begin. The following table proposes an application fee schedule:

Project Size	Studied as Part of a LOC	Studied Individually
Smaller than 100 MW	$50,000	$150,000
100MW to 500MW	$75,000	$225,000
500MW and larger	$100,000	$300,000

B. **Locational Clustering:** Once the cluster window is closed, the CAISO would group generators, based on their interconnection points, into electrically-related Locational Clusters (LOCs) to be studied together. CAISO would choose each LOC, based on the shared transmission needs of the generators in that LOC and using the engineering judgment of its planning engineers. The LOCs, including the rationale for their selection, would be presented to all PDs after a queue window is closed.

A PD may opt out of its LOC and request to be studied individually, at which time the project must pay an added application fee to cover the cost of the project-specific studies. In addition to application fee implications, the request to be studied individually will have certain ramifications for the project that are presented further below.

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4 Selection to interconnect to two interconnection points is intended to allow compliance with CAISO's current planning guidelines related to Special Protection Schemes (SPS).

5 Please note that we will discuss the IGS rate treatment later in this whitepaper.

C. **LOC Study Prioritization:** The CAISO would prioritize LOC studies based on the queue date of the earliest project in that LOC.[6] If the MW size of a LOC is too large to be readily studied, the LOC could be divided into two or more Sub-LOCs based on the same criteria used for selecting a LOC until the size of projects to be studied within an Sub-LOC becomes manageable.

   Projects opting for individual studies would also be prioritized based on the same criteria used for prioritizing studies of LOCs. However, these projects would only be studied after the interconnection studies of all LOCs are completed. This point is discussed further below.

D. **Facility Studies:** Once the clustered or individual system studies for a project are complete and the PD is informed of the deliverability cost responsibility for that project, the PD can choose to commence a Facilities Study (FAS) for that project prior to signing the Interconnection Agreement. The ISO would commit to completing the FAS by a certain date. A project that chooses to enter into the FAS stage would pay the FAS fee. The FAS fee will depend on the size of the project - higher for larger projects. The FAS fee is intended to cover the true cost of performing the FAS; hence, a project may have to post added funds during the FAS or receive refund after the FAS is complete. These variations are expected to be small. The following table proposes a FAS fee schedule:

Project Size	FAS Fee
Smaller than 100 MW	$300,000
100MW to 500MW	$400,000
500MW and larger	$500,000

E. **Process Timeline:** As discussed in the next section, queue windows would present firm timelines for the CAISO to complete aggregate studies of each cluster. The CAISO will be required by its tariff to complete all interconnection studies in the four-to-six month window for each queue.

3.2 Interconnection Study Process

Once the LOCs have been finalized, CAISO can start the actual interconnection study process. The additional facilities identified in the study process, including network transmission expansions, if any, would be solely for the purpose of identifying the transmission cost responsibility, and the associated TFCs, for the interconnecting projects –

[6] Alternately, other criteria such as average queue date or weighted average queue date or average Commercial Operation Date (COD) for the projects in the LOC could be used for such prioritization. In any case, it must be noted that, due to the study methodology in STRGIS, such a selection is not expected to have any material impact on the final outcome of the studies, i.e., determination of Transmission Financial Commitment.

they would not necessarily be the actual facilities built, which, as noted above, would be identified in the RTEP.

Thus, the interconnection study results need not be excessively precise, and the study process can be significantly streamlined, as follows:

A. **Select Study Basecase:** This is done by selecting the latest WECC transmission basecase developed through the most recent RTEP or the most recently completed STRGIS whichever is more recent.

B. **Study a LOC:** LOCs are studied starting with the highest queued LOC (see Section 3.1 (C) for the definition of study prioritization). Each study LOC is modeled by including all the projects associated with that LOC connected at their relevant interconnection points.

C. **Determine Transmission System Upgrades:** These are network upgrades necessary to allow the generators in the Study LOC to achieve their selected deliverability levels. This study process should be at the level of detail used in the CAISO Feasibility Study.[7] Once the upgrades are determined, CAISO would calculate the cost per MW of capacity for each upgraded facility.[8]

D. **Determine Deliverability Cost Responsibility at the Selected Deliverability Level ("DCRSDL"):** For each generator project in the study LOC, DCRSDL is calculated simply based on projected usage of the upgraded facilities - determined by the flow caused by the project at the selected deliverability level)[9] and per MW capacity cost of such upgraded facilities, as determined in Section 3.2(C). [10]

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[7] Given the scope of the generation study process, performing these studies in any greater level of detail is not warranted.

[8] This would be done for both serial facilities, such as transmission lines and transformers, as well as shunt facilities such as capacitor banks, except that in the case of a shunt component, the MW capacity would be determined based on the added MW transfer capacity it brings about.

[9] Our proposed reform allows a PD to select the level of deliverability for its individual projects solely based on its own commercial considerations. The CAISO would perform two advisory studies for all the projects in the Study LOC to help PDs make a more educated selection of their deliverability level. The first of the two advisory studies would identify the transmission upgrades and the associated project cost responsibilities for a scenario in which all generators in the Study LOC would deliver at their full rating using the methodology described in 3.2 (D). The second advisory study would inform the PDs of the approximate deliverability level for their individual projects in the Study LOC which would result in NO added transmission upgrades. These two figures would be purely of an advisory nature intended to be used as one of potentially many factors in a PD's selection of the deliverability level for its project(s).

[10] The process would start by first determining the MW flow caused by the generator when operating at its selected deliverability level on each identified transmission upgrade (added facility). This determination would be performed by multiplying together three factors: the MW value of the selected deliverability level of a generator; the Generation Shift Factor ("GSF") of the generator on the upgraded facility; and the per-unit cost of the transmission upgrade. In the case of an added shunt facility, the cost responsibility for a project is determined based on a simple pro-rata cost sharing basis. The DCRSDL for a generator is

Note 1: This methodology would determine the cost responsibility of the generators in a Study LOC based on their subscribed use of the transmission upgrades and the per-unit cost of such upgrades and is not intended to allocate the entire cost of the identified upgrades to the generators in the Study LOC on a pro-rata basis.

Note 2: If a generator in the Study LOC causes a counterflow on a transmission upgrade for that LOC, it would be assigned a credit for the counterflow based on the per-unit cost of the upgrade.[11]

Note 3: If a generator in the Study LOC causes dominant flow on a transmission upgrade for a higher queued LOC (studied before the current LOC), it will bear added transmission cost responsibility based on the flow on that specific upgrade and per-unit cost of that upgrade.[12] On the other hand, if a generator in the Study LOC causes counterflow on a transmission upgrade for a higher queued LOC, it will receive credit on its DCRSDL based on the per-unit cost of the impacted upgrade.

Note 4: A generator's DCRSDL, determined in this fashion, will be a fixed number and will not change due to the subsequent behavior of any other generator(s) in the queue, whether in the same LOC or otherwise. At this stage, the only option that a PD would have to avoid the TFC stemming from DCRSDL would be to withdraw the project from the current queue.[13]

Note 5: If the PD chooses to have a higher deliverability level for a project with signed IA, it can submit another application for the same project for the desired deliverability increment in the next queue window and will have to go through the entire interconnection study process before the deliverability increment is approved by the CAISO. A PD also may opt to increase its deliverability level after its generator has gone into full operation using this process.

Note 6: Regardless of the selected level of deliverability, a generator may still interconnect up to its full capacity at the point of interconnection and operate subject to the CAISO congestion management protocols. However, the project would be deemed deliverable only up to the selected level of deliverability for RA capacity eligibility.[14]

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then calculated by summing the cost responsibility values for individual upgrades over all transmission upgrades. Generation Shift Factor (or Load Distribution Factor) is a well-known concept in power engineering and refers to the sensitivity of the MW change on the flow of a studied facility due to 1 MW change in the value of the studied generator. Generation Shift Factors are readily determined by most computational tools currently used for transmission planning studies.

11 At no time will the DNCRSDL for a project be negative.

12 Dominant flow happens if the generator increases the flow on the upgrade in the study scenario.

13 The PD may choose to submit an interconnection request for a withdrawn project in later queue windows.

14 Other factors beyond transmission upgrades, such as historical performance of a class of generators, may further limit the RA capacity eligibility of the project. This added restriction

E. **Study the Next Lower-Queued LOC:** Once the DCRSDL of all the generators in the Study LOC are known, the CAISO would move to the next-queued LOC and repeat steps B through D for that Study LOC. All the previously studied, higher-queued LOCs will be folded into the study basecase based on the selected levels of deliverability and the identified transmission upgrades.

F. **Study Individual Projects.** As noted before, a PD may elect to have its project be studied individually with the knowledge that such a project would only be studied after the study of all the LOCs are completed. The study process for a specific single generator would be identical to that of a LOC. Hence, steps B through D are repeated for individual generators until all generators in the current queue are processed.

G. **Perform Facilities Study:** Once the deliverability cost responsibilities of all generators in the queue are known, individual PDs are asked whether they wish to enter into the Facilities Study (FAS) stage of the interconnection study process. The FAS, similar to today's LGIP process, is principally intended to determine the extent and cost of interconnection facilities to the first point(s) of interconnection and other local network reliability upgrades necessary to interconnect the generator at the full generator capacity rating. However, before entering the FAS stage, the PD is fully aware of its DCRSDL and the corresponding Transmission Financial Commitment, allowing it to decide whether it wishes to enter into the FAS and pay the non-trivial FAS Fee.

   Once the FAS stage is complete, all the local network reliability upgrade costs will be added to the DCRSDL. The total cost is the project's Transmission Cost Responsibility for the Selected Deliverability Level ("TCRSDL"). CAISO will also determine the project's interconnection facilities costs, which will be stated separately and treated differently from the TCRSDL.

H. **Sign Interconnection Agreement:** At the end of the FAS, CAISO would translate the TCRSDL into a Transmission Financial Commitment ("TFC"), which would have to be posted by the PD using a suitable financial instrument, such as a Letter of Credit ("LC"), if it wished to enter into an IA. As will be noted in Section 3.3 (B), the posting of financial commitments would be on a graduated monthly basis. The PD would have the option to sign the Interconnection Agreement for its project or withdraw the project from the queue. Another financial commitment equal to the interconnection facilities cost of the project should be posted separately by the PD that wishes to enter into IA. As will be noted in Section 3.3, these two financial commitments would be treated differently by the CAISO.

   The project Commercial Operation Date ("COD") would be included, based on CAISO determination of a reasonable date for completion of the transmission upgrades that are necessary to make the generator deliverable at the selected deliverability level.

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is especially applicable for wind generators, which may be deemed deliverable based, for example, on the historical performance of existing wind generators at the time of system peak load condition in their general geographic location.

The CAISO would be obligated to plan, through the RTEP, for the transmission upgrades necessary to make the project deliverable on its COD.[15]

I. **Process Timeline:** Firm timelines to accompany each step of the interconnection study process outlined above are a critical element of the overall plan and will ensure that there is no "backsliding" once the existing backlogged queue is cleared. The overall study process culminating in an executed IA must be completed within the four-to-six month window for each queue, and this will be reflected in the CAISO OATT. The following table proposes a breakdown for a 6-month timeline to perform the studies.[16]

Date Range	STRGIS Activity
During the queue open window	• CAISO opens the queue window and invites IR applications. • PDs submit their IR applications, including the level of deliverability for their individual project(s). • CAISO identifies deficiencies in project applications and works with PDs to resolve them. • CAISO and each PD meet to identify primary (and alternative) interconnection point(s) for the PD's project(s). • CAISO identifies the relevant basecase(s) and study scenarios in coordination with PDs.
Days 1-30	• CAISO prepares the basecase(s). • CAISO places projects in LOCs. • CAISO informs PDs of the selected LOC for their project. • PDs choose to remain in LOCs or be studied individually.
Days 31-90	• CAISO performs the feasibility level studies and determines the DCRSDL for all projects.
Days 91-120	• CAISO meets with PDs to inform them of all their DCRSDL. • PDs decide whether they enter into FAS or drop out from this round of studies.
Days 121-150	• CAISO performs the FAS and determines TCRSDL, TFC and the interconnection facility costs for all projects.

[15] The necessary transmission upgrades could be delayed due to unforeseen events, such as complications in securing environmental permits or construction delays. To the extent that a PD can mitigate the underlying cause for such a delay, it should be allowed to intervene to eliminate the delay. Regardless of the cause, under these circumstances the generator would be allowed to interconnect to the grid at its capacity rating and start operation subject to the CAISO's congestion management protocols until the RTEP-determined transmission expansions that make the generator deliverable are completed.

[16] This timeline assumes that the CAISO will not perform the deliverability selection advisory studies for PDs.

Date Range	STRGIS Activity
Days 151-180	• CAISO informs PDs of all their financial commitments. • PD chooses to enter into IA knowing its financial commitments or drops out. • PD works with CAISO and PTO to select a reasonable COD. • CAISO, PTO and PD sign the IA. • PD posts the first installment of the TFC for all of its projects with signed IA.

3.3 Transmission Financial Commitment Management

The management of the TFC would generally be similar to the current process. The proposed general steps for managing a PD's Transmission Financial Commitment are as follows:

A. The TFC for a project will be calculated based on the project's network Transmission Cost Responsibility for the Selected Deliverability Level (TCRSDL) for a project is identified:

   TFC **=** 100% of TCRSDL (up to $1M) **+** 50% of TCRSDL (beyond $1M but less than $10M) **+** 25% of TCRSDL (beyond $10M)

   The TFC for a project, however, would be capped at $10,000/MW. The aforementioned formula and the cap are intended to mitigate the "approximate" nature of the transmission cost calculation when these costs become very large.[17]

   As noted in Sections 3.2 (G) and 3.2 (H), the TFC calculated here is related to the project's transmission network upgrades. The project's interconnection facility costs would be treated separately as noted in Section 3.3 (D) below.

B. The PD would post the TFC for a project in monthly installments. The posting period would start with the signing date of the IA and end with the start of the Regional Transmission Expansion Planning process that is intended to determine the actual transmission upgrades for that project (additional details on the RTEP process modifications are proposed in Section 4). The monthly deposits would be graduated, increasing as the project approaches the RTEP process.

   Furthermore, the TFC for a project would be tied to the project and not a specific PD. Hence, if a project is transferred from one PD to another, the TFC (posted and pending) is also transferred with the project.

[17] For example, the TFC for a 750MW project with TCDSDL of $12M would be $6M (= 1 + 9*.5 + 2*.25). However, for a 500MW project with the same TCRSDL of $12M, the TFC would be capped at $5M.

C. All network upgrades determined as part of the RTEP would be directly rate-based into the CAISO TAC, similar to the rate treatment of such facilities today. However, the portion of the PD financial posting that covers network upgrades (TCRSDL) would be released to the PD when the project goes into operation - not over 5 years. If the project withdraws at any time between signing the IA and the COD, all amounts posted towards network upgrades would be forfeited and used toward pay-down of the overall CAISO TAC.

D. Financial commitments for interconnection facilities are separately posted and will be used, to the extent necessary, in building the interconnection facilities which will be passed on to the interconnection transmission developer.[18] A PD may be required to post additional financial commitments for interconnection facilities or may receive refunds from its original deposit if the actual interconnection costs related to its project change.

3.3.1 Interconnection Grid Substation Rate Treatment

As noted earlier, the CAISO may select a new substation -- the Interconnection Grid Substation (IGS) -- as the alternative point to study interconnection of one or more projects to the CAISO controlled grid that are too far from the closest existing substation with interconnection capacity. Once the STRGIS is complete, one of the following scenarios may occur:

a. If the IGS would be connected to at least two separate transmission network substations via multiple lines, the IGS and all facilities interconnecting it to the rest of the grid will be part of the network. The CAISO would account for this condition in its TFC administration.

b. If the IGS would be connected to only one substation in the transmission network, the IGS and all the radial facilities interconnecting it to the network would be considered interconnection facilities. The CAISO would account for this condition as part of its TFC administration for the project(s). The exception applies when after completion of the RTEP, the IGS is used to interconnect multiple projects owned by multiple PDs to the system. Under these circumstances, the IGS and all radial facilities interconnecting it to the network would be subject to the CAISO's "Locationally Constrained Resource Interconnection Facility or LCRIF" tariff.[19]

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[18] The local PTO would normally play the role of interconnection facility developer. As with the current rules, interconnection facility payments may be passed on to third party transmission developers in certain circumstances.

[19] Special rate treatment may be considered for such radial facilities if, after the completion of the RTEP, the IGS is used to interconnect project(s) owned by one or more PDs that mitigate previously identified network reliability concerns or mitigate previously identified local market power conditions.

3.4 Clearing of the Current CAISO Queue

Once properly applied, the STRGIS process presented above can and should clear the current interconnection queue within 12 months. For this purpose, the CAISO should seek permission on a one-time basis to study the current interconnection queue by retroactively clustering the queued projects.

The components of the timeline for prospective study of the queue, as presented in Section 3.2 (I), will be applicable here as well, except that all date ranges should be doubled given the size of the existing queue.

Finally, it should be noted that certain transitional issues need to be addressed for those projects in the current CAISO queue. It may be appropriate under certain circumstances to allow projects to remain under the old rules (e.g., projects that have completed their Facilities Study and are ready to sign an interconnection agreement, and possibly projects that have completed a System Impact Study). It also may be appropriate to include projects under the new program but grant relief from the new, higher FAS fees (e.g., if they have already paid for a System Impact Study - which will no longer be required). We have not attempted to resolve such transitional issues in this whitepaper, but expect that stakeholder involvement and flexibility will be required to appropriately address them.

4.0 Reform of the Regional Transmission Expansion Planning Process

In the past two years, the CAISO has been going through various proceedings to establish its Regional Transmission Expansion Planning (RTEP) process for the CAISO controlled transmission system, which will culminate in its compliance filing in response to FERC Order 890. The CAISO RTEP must be modified based on the following general principles in order to improve the overall process of regional transmission planning for the CAISO footprint:

A. **Needs identification:** Allow all affected and interested parties, including PTOs, generation owners and developers, LSEs, neighboring TOs and sub-regional planning groups and the CAISO, to identify and present transmission needs and opportunities as part of an open season process: **First Open Season**. The goal of this process would solely be to focus on needs and opportunities, and **not** projects or solutions. The CAISO would then work with all parties to perform the necessary analyses to confirm and prioritize transmission needs and opportunities.

B. **Solutions to address confirmed needs/opportunities:** Allow all affected and interested parties, through a **Second Open Season** process, to propose solutions (including transmission projects) to address all the verified transmission needs and opportunities. The CAISO would then work with all such parties to screen and consider such solutions as part of a "Master Transmission Plan" that would be developed, through its open and non-discriminatory transmission planning process, to resolve the needs and capture the opportunities identified through the First Open Season process.

C. **Transmission Master Plan development and implementation:** CAISO would use agreed-upon criteria to select the least-cost/best-fit Transmission Master Plan. The CAISO OATT (Schedule K) would include coordination with interconnected utilities,

PTOs and state and federal agencies with transmission siting authority (particularly, with the California Public Utilities Commission, and the federal Department of Energy and Bureau of Land Management) in the development and deployment of the Transmission Master Plan. The PTOs would have the opportunity to construct the transmission projects selected in their service territories, consistent with their right of first refusal. All other eligible transmission developers could offer to build ISO-selected projects that the PTOs decline.

The aforementioned general reforms will also facilitate the implementation of the generation interconnection study process reforms as proposed in this whitepaper. In addition, we see the need for the following added CAISO RTEP reforms for such a purpose:

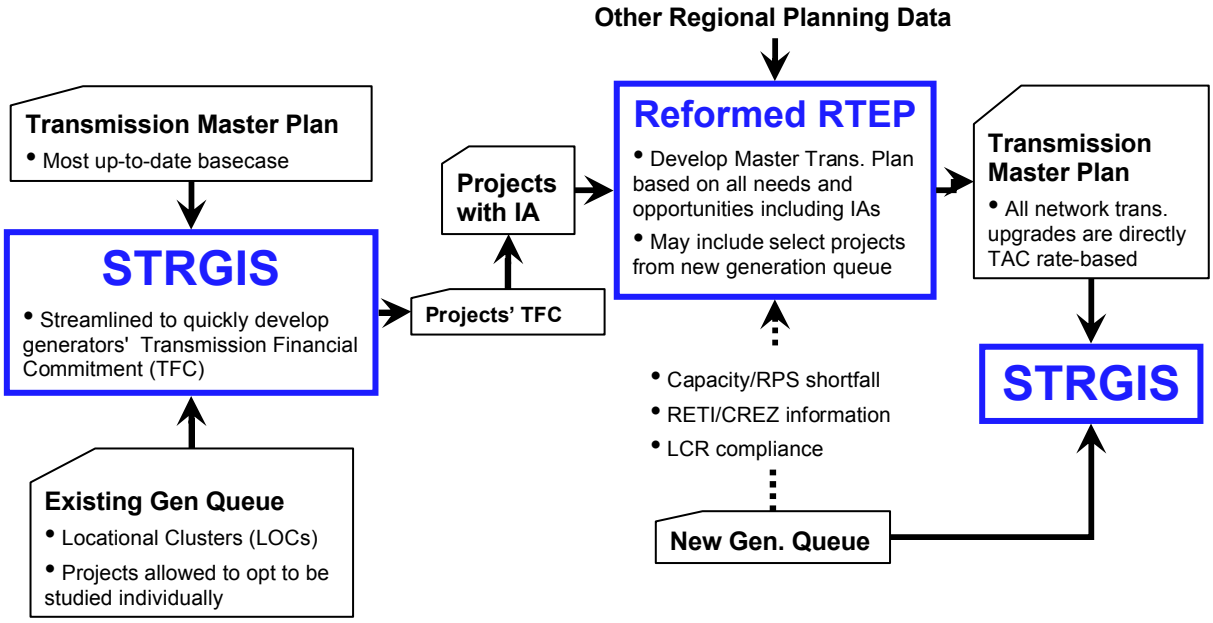
- The deliverability needs for generators that have signed Interconnection Agreements (IAs) and posted financial security should be included as NEEDS in the first open season process referenced in Item A above.

- The Transmission Master Plan as envisioned in Item B above should include the network and other transmission upgrades to address the interconnection needs of all the generation projects with signed IAs; those upgrades will be determined considering those needs and all other transmission-system reliability and economic needs and opportunities.

  We believe that PTOs and potentially third party transmission developers should be provided with rate recovery incentives (such as higher rate-of-return) for completing the network transmission upgrades needed for integrating generation projects by the date specified in the IA. At the same time, these same entities should be penalized through rate disincentives (*e.g.*, lower rate-of-return) if they do not complete their projects by the date specified in the IA.

When performing studies to determine the Transmission Master Plan as envisioned in Item B above, the CAISO should account for new resources that may not have signed IAs but should be added in order to account for projected additional resource needs for meeting reliability as well as RPS needs. We recommend that the CAISO, when selecting resources to be added into the transmission basecase, use generators in the latest queue that have not been yet processed. If the resources in the queue are insufficient to fully plan for PTO obligations, then other indicators of possible future capacity may be used.

Figure 4.1 demonstrates the interaction between the proposed streamlined LGIP process and the proposed RTEP.



Finally, while the scope of RTEP in our discussion is limited to CAISO and its PTOs, we realize that these entities will be coordinating their RTEP activities through the WECC process.

5.0 Concluding Remarks

We are proposing a long-term solution for interconnection queue management by the CAISO that can also solve the immediate and critical problems that all stakeholders are facing now and is fully consistent with all FERC open access tariffs and orders. The timing of the proposal coincides with FERC Order 890 Compliance proceedings, and it can be addressed as a longer-term Regional Transmission Planning tariff in the Order 890 compliance proceedings.

Appendix A. Preliminary Stakeholder Assessment

The Table A.1 below is intended to present the principle attributes of the proposed reforms along with an expected reaction by three main classes of the stakeholders, namely, CAISO and its Participating Transmission Owners (PTOs), California Public Utilities Commission (CPUC) and TAC Ratepayers (including the LSEs); and Project Developers (e.g., IPPs).

Table A.1 - Principle Attributes of the Proposed Reforms and Expected Stakeholder Reaction

Proposed Reform's Major Attribute	CAISO and PTOs	CPUC & TAC Ratepayers	Project Developers
1. All transmission upgrades necessary for interconnecting generators with signed IAs are planned centrally through the RTEP, not through piecemeal expansions through serial generation interconnection studies. All network transmission upgrades will be directly rate-based.	Allows CAISO and PTOs to plan for transmission expansions that simultaneously and optimally address all transmission system needs and opportunities, thus reducing the overall transmission system cost.	Reduces the overall transmission expansion costs through better expansion plans and financing.	Streamlines generation interconnection study process, helping IPPs with their interconnection study timeline.
2. The generation interconnection process will be significantly streamlined, allowing rapid processing of interconnection requests through a simple and non-iterative study process of Locational Clusters and individual generators.	Significantly simplifies the work associated with generation interconnection studies.	Allows transmission cost responsibilities for new generation projects to be known early and readily useable in LSE resource procurement processes.	Informed PDs of their transmission cost responsibilities (and TFC) very early in the process, so they can arrange financing and make proper commercial go/no-go decisions.
3. Generator transmission cost responsibilities for network transmission facilities will be translated into a refundable Transmission Financial Commitment (TFC), released after the generator comes on-line.	Significantly simplifies the TAC ratemaking process and transmission expansion financing.	See assessment for Attribute 1.	Significantly simplifies the financing process for project developers.
4. Project Developers (PDs) can select their deliverability	Requires CAISO & PTOs to consider generator	Prevents overbuilding of	Allows PDs to select their deliverability level

Proposed Reform's Major Attribute	CAISO and PTOs	CPUC & TAC Ratepayers	Project Developers
level. Regardless of that deliverability level, the generator may interconnect to the grid up to its full rating, subject to congestion management protocols for its entire capacity rating.	deliverability levels in the RTEP. CAISO operational protocols would handle congestion management of generators interconnecting beyond their deliverability level.	transmission-system based on full generator ratings and thus leads to savings for all ratepayers.	based on commercial considerations, rather than "arbitrary" decisions by third party.
5. PDs can increase their selected deliverability level later, even after the project is on-line, by submitting a new Interconnection Request (IR) for the incremental deliverability amount in subsequent generation queue cycles.	Adds to the projects to be studied in the subsequent interconnection study processes and RTEP. However, the streamlined study process should make the effort manageable.	See assessment for Attribute 4.	See assessment for Attribute 1.
6. PDs can select to be studied as part of a cluster (Location Cluster or LOC) or individually with the understanding that LOCs will be processed before individual projects.	The individual study option increases the interconnection study process workload. However, the streamlined study process should make the added effort manageable.	N/A	Allows PDs to make their own commercial decision regarding this feature.
7. The streamlined generation interconnection study process forces those "less strongly committed" projects in the queue to quickly drop off allowing "more strongly committed" projects to expeditiously move through the queue.	Allows CAISO/PTOs to focus interconnection study and subsequent transmission planning efforts on highly committed projects.	Helps prevent overbuilding of the transmission system.	Enables committed projects to interconnect on an expedited basis.

Appendix B: Acronyms

CAISO	California Independent System Operator
CREZ	Competitive Renewable Energy Zone
DCRSDL	Delivery Cost Responsibility at the Selected Deliverability Level
FAS	Facility Study
IA	Interconnection Agreement
IGS	Interconnection Grid Substation
LGIP	Large Generator Interconnection Protocols and Procedures
LOC	Locational Cluster
PTO	Participating Transmission Owner
RETI	Renewable Energy Transmission Initiative
RTEP	Regional Transmission Expansion Plan(nig)
STRGIS	Streamlined Generation Interconnection Study
TCRSDL	Transmission Cost Responsibility at Selected Deliverability Level
TFC	Transmission Financial Commitment