UNITED STATES OF AMERICA 91 FERC ¶ 61,205
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr.

California Independent System Operator Corporation — Docket No. ER00-2019-000

ORDER ACCEPTING FOR FILING AND SUSPENDING PROPOSED TARIFF REVISIONS AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued May 31, 2000)

On March 31, 2000, the California Independent System Operator Corporation (ISO) filed Amendment No. 27 to its tariff, proposing a new methodology for determining transmission Access Charges, through which the embedded costs of the transmission facilities comprising the ISO controlled grid are recovered. The filing was required by legislation restructuring the California electric industry, and later by this Commission.[1] In making this filing, one of the objectives of the ISO is to create incentives to encourage new parties to join the ISO and become Participating Transmission Owners (Participating TOs). The ISO Governing Board approved the instant Transmission Access Charge (TAC) filing after an extensive stakeholder process. In this order, we accept for filing, suspend, and set for hearing the proposed Access Charge methodology and related tariff revisions. We also hold the hearing in abeyance pending efforts at settlement and establish settlement judge procedures.

Background

The current Access Charge methodology consists of three separate zone rates based on the revenue requirement of the Participating TO. Under Amendment No. 27, this methodology will continue in effect until a new Participating TO joins the ISO. Once that occurs, the Access Charge for high voltage transmission facilities [2] will be assessed based on the combined transmission revenue requirements of all the Participating TOs in each "TAC area," which correspond to each of the three control areas that were combined to form the ISO control area. If the Los Angeles Department of Water and Power (LADWP) chooses to become a Participating TO, its control area would become a fourth TAC area.

Docket No. ER00-2019-000

The ISO proposes that, over a ten-year transition period, the high voltage Access Charge (HV Access Charge) for these TAC areas would be combined to form a single ISO grid-wide Access Charge. This would be accomplished by blending the individual TAC area high voltage transmission revenue requirements with the sum of all Participating TOs' high voltage transmission revenue requirements, with the proportion represented by the ISO grid-wide portion increasing by ten percent each year. In addition, capital investments in any new high voltage transmission facilities, or additions to existing facilities, would be included in the ISO grid-wide component of the HV Access Charge. The low voltage transmission Access Charge would continue to be a license plate rate based on Participating TO's low voltage transmission revenue requirements.

The ISO explains that, as a result of the stakeholder process, the proposed Access Charge methodology "incorporates an integrated set of provisions to balance the costs borne and benefits received by all affected stakeholder classes," [3] primarily addressing likely cost shifts between current and new Participating TOs with higher cost transmission facilities. With the advent of the new methodology, customers of current Participating TOs may pay higher transmission rates, but the amount of that increase will be mitigated by a ceiling on cost shifts in any one year during the 10-year transition period. The ISO believes that this potential for cost increases is balanced by certain benefits to the customers of existing Participating TOs, such as a lower Grid Management Charge (GMC), reduced congestion costs, and potentially lower costs for energy and ancillary services.

New Participating TOs may bear increased costs as a result of being subject to the Access Charge and the GMC. So that these increased costs will not deter the entry of new Participating TOs, the proposed methodology includes a "hold harmless" provision whereby the existing Participating TOs will compensate the new Participating TOs for any net increase in these costs for the 10 year transition period. In addition, there is a "buy-down" provision that requires new Participating TOs to use any cost-shifting benefits they receive solely to reduce their transmission plant investment, thereby lowering their transmission revenue requirements.

Other significant features of the proposal, intended to encourage new Participating TOs to join the ISO, include:

- any new Participating TO will receive firm transmission rights (FTRs) associated with the transmission facilities or entitlements it turns over to the ISO's operational control, without having to purchase them in an auction;

- establishment of a Revenue Review Panel (RRP) independent of the Commission that will have the authority to review transmission revenue requirements of entities that are not subject to FERC's jurisdiction;

- permitting the systems of new Participating TOs to qualify as Metered Subsystems [1] to facilitate their continued operation as vertically integrated utility systems while enabling them to participate in the ISO.

Notice, Interventions and Responsive Pleadings

Notice of the ISO's filing was published in the Federal Register, 65 Fed. Reg. 20,447 (2000), with motions to intervene and protests due on or before May 21, 2000. A notice of intervention was filed by the Public Utilities Commission of the State of California (California Commission). Timely motions to intervene, comments, and protests were filed by the entities listed in Appendix A. In addition, Dynegy Power Marketing, Inc. (Dynegy) and the United States Department of Energy Oakland Operations Office (DOE) filed motions to intervene out-of-time, and the California Large Energy Consumers Association (CLECA) filed an untimely motion to intervene. On May 8, 2000, the ISO filed an answer, and Southern California Edison Company (SoCal Edison) filed reply comments. On May 16, 2000, the City of Vernon (Vernon) filed an opposition to SoCal Edison's reply comments.

Positions of the Parties

Numerous parties filed comments and protests. The Utility Reform Network (TURN), on behalf of its small ratepayer constituents, supports the proposal in its entirety, describing the compromise, "as close to a 'win-win' scenario as this Commission is ever apt to see in matters of this much complexity and contentiousness." [2] Pacific Gas and Electric Company (PG&E) and SoCal Edison support the bulk of the TAC methodology with modest modifications, and the California Commission protests a single aspect of the proposal, asserting that use of an RRP is contrary to the FPA.

However, municipal utilities and other entities not subject to FERC jurisdiction (Governmental Entities, or GEs) are nearly unanimous in their opposition to the TAC filing, urging some combination of rejection, suspension, and establishment of hearing or settlement judge proceedings. Several contend that the filing is patently deficient and should be rejected on that basis alone. Specific elements of concern include the use of the RRP, the ceiling on cost increases for existing Participating TOs, the use of gross load rather than net load as the appropriate billing unit, and the fact that FTRs will be made available to GEs outside of the auction process for no longer than the ten-year transition period. Many also object to aspects of the Metered Subsystems provisions, and they seek rejection of the buy-down provision. On the other hand, Lassen Municipal Utility

District (Lassen) indicates that it is in the process of joining the ISO and that it expects to do so on or about July 1, 2000.

Sempra Energy (Sempra) opposes the proposal entirely, instead championing the use of license plate rates and criticizing bifurcation of the Access Charge into high and low voltage rates. Sempra argues that the license plate model avoids cost shifting and therefore promotes the formation of Regional Transmission Organizations (RTOs), and that Order No. 2000 [3] recognized it as an acceptable way to recover fixed transmission costs. Further, Sempra asserts that the proposal unduly discriminates in favor of GEs in order to induce their participation in the ISO.

California Department of Water Resources (DWR) and State Water Contractors object to the proposal's failure to allocate costs based on customers' contribution to peak usage (i.e., time of use rates).

Enron Energy Services, Inc. (Enron) complains that the proposal's treatment of FTRs and Metered Subsystems for new Participating TOs is superior to that for current market participants and argues that it is unfair to require customers of the original Participating TOs to pay the stranded costs of new Participating TOs, as they are not served by and do not receive any benefits from new Participating TOs. Finally, Enron observes that there must be a hearing to determine whether the benefits that the ISO has suggested will accrue to original Participating TOs will in fact arise.

In its Answer, the ISO reiterates its belief that the proposed methodology is fully consistent with the goals of Order No. 2000 and contends, with respect to the various contested issues, that the compromise package does not unduly discriminate against any class of market participants. The ISO asserts that there is no basis for rejecting the proposed Access Charge methodology, and that suspension and an evidentiary hearing would have limited value. Further, the ISO states that appointment of a Settlement Judge alone is not likely to bring the stakeholders closer to consensus without guidance from the Commission on the policy issues presented in the comments, and urges the Commission to "exercise caution before upsetting the delicate balance at which the ISO Governing Board finally arrived." [4]

Discussion

Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), the California Commission's notice of intervention and the timely, unopposed motions to intervene of the entities listed in Appendix A serve to make them parties to this proceeding. In view of the early stage of this proceeding and the absence of any undue prejudice or delay, we will grant Dynegy's and DOE's motions to intervene out-of-time and accept CLECA's untimely intervention.

Although answers to protests generally are prohibited under 18 C.F.R. § 385.213 (a)(2), we nevertheless find good cause to allow the ISO's answer in this proceeding because it provides additional information that assists us in the decision-making process. SoCal Edison's reply does not provide additional information that aids us in our disposition of this proceeding; we will, therefore, reject it. Vernon's motion in opposition thus need not be addressed.

Overview of the Transmission Access Charge Filing

At the outset, we recognize and appreciate the numerous complex issues in this proceeding as well as the significant progress produced during the stakeholder process. We share the view expressed in many of the pleadings that, while the process has been tedious, the ultimate goal of improving the existing rate design and expanding the ISO grid are worth the effort. [5] We also concur with the ISO's objectives of creating an equitable balance of costs and benefits among the various affected classes of stakeholders and the treatment of all Participating TOs on the same basis.

We are cognizant of the considerable effort undertaken by the ISO and the California stakeholders in attempting to reach a consensus here, and we endorse the two-tiered rate approach reached through the stakeholder process. We find generally that the two-tiered rate approach is reasonable. [6] This evolution in rate design away from the utility-specific zone rates to a high voltage grid-wide methodology ensures a uniform grid-wide rate. We find the ISO's proposal which includes incentives for non-Participating TOs is a very positive step toward expanding the ISO's transmission grid. We also endorse the removal of disincentives such as the self-sufficiency test for Participating TOs. [7] Numerous GEs have previously identified this provision as a barrier to joining the ISO, and as a result, this test was never implemented.

We respect the ISO's concern that the delicate balance among the stakeholder classes reflected in the TAC filing could easily be upset. Nevertheless, we find that the proposal has not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Accordingly, we will accept the proposed tariff Amendment No. 27 for filing, suspend it for a nominal period, subject to refund, and set it for hearing.

While we are setting this case for a trial-type, evidentiary hearing, we believe it would be useful to continue the negotiations among the parties with the assistance of a settlement judge. We also concur with the comments of a number of intervenors that the stakeholder process has produced a framework upon which final resolution through settlement is possible. These comments indicate that further negotiations will depend on Commission guidance on major issues of contention. In this order we provide the requested guidance on the issues that are most critical to the resolution of this proceeding. Therefore, the hearing we have ordered shall be held in abeyance, and we will appoint Chief Administrative Law Judge Wagner as a settlement judge to assist the parties in reaching a settlement.

A. The Revenue Review Panel

An important and difficult issue in this proceeding deals with the rates for non-public utility members of the ISO. The ISO proposal requires that non-public utility entities such as locally publicly owned electric utilities (GEs, short for Governmental Entities) that are new Participating TOs submit their high voltage transmission revenue requirement to the ISO. [8] To enable filings to be made on a comparable basis, the ISO will develop and post on its Home Page a procedure for uniform accounting for high voltage transmission facilities that is consistent with the FERC Uniform System of Accounts. If the revenue requirement for a new Participating TO that is not subject to this Commission's section 205-206 rate jurisdiction is submitted to the ISO and an objection is raised that cannot be resolved, the justness and reasonableness of the revenue requirement will be evaluated by a Revenue Review Panel (RRP) in accordance with standards established by FERC pursuant to the FPA and, if applicable, standards established by the ISO Governing Board. The RRP will be comprised of three individuals who have substantial experience in the establishment of unbundled transmission rates for public utilities and who do not have a financial stake in any participant in the California electricity market. Furthermore, the ISO proposes that the decision of the RRP shall be final and shall not be subject to further review.

Numerous intervenors have taken issue with the use of the RRP in determining the revenue requirement of entities that are not subject to the Commission's section 205-206 rate jurisdiction. The California Commission argues that only this Commission, subject to judicial review, can decide the justness and reasonableness of the proposed charges. For supporting precedent, the California Commission points to this Commission's ruling in Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062, (1999) (Central Hudson) where we held that the transmission services provided by the New York ISO are jurisdictional notwithstanding the fact that some non-public utility entities such as the Long Island Power Authority may elect to join the New York ISO. PG&E also argues that the ISO is required to file with the Commission all rates and charges under Section 205 of the FPA and this obligation extends to rates for transmission service using the transmission facilities of GEs. PG&E states that if the Commission were to permit the ISO to set the transmission revenue requirement for GEs, this would constitute an unlawful delegation of its statutory duty because the ISO's transmission service rates, resulting from the blending of all transmission revenue requirements (public utility and non-public utility alike), are jurisdictional.

On the other hand, a number of municipal intervenors argue the RRP should be rejected and that jurisdiction over their transmission revenue requirement has been determined by the California legislature to be with local municipal councils. They contend that control should not be wrested from these local officials, and that to do so would contravene California state law. These GEs argue that their own public processes are sufficient to ensure the reasonableness of their transmission revenue requirement. Other municipals request that if the RRP is implemented, then its determinations should be subject to the review and acceptance of this Commission. Specifically, LADWP states that the RRP could be acceptable provided that: (1) the principles and standards recognize and accommodate legitimate differences between GEs and IOUs; (2) the review process is completed prior to a GE transferring control of its facilities to the ISO; and (3) any standards and procedures developed for the RRP should not be subject to change by the ISO Governing Board without approval of this Commission.

The ISO in its Answer agrees that the proposed HV Access Charge is subject to this Commission's jurisdiction under Part 2 of the FPA. Furthermore, the ISO notes that because the HV Access Charge is based on the transmission revenue requirement of all Participating TOs, including GEs that choose to become Participating TOs, the HV Access Charge methodology must include provisions to ensure that those revenue requirements are just and reasonable. However, the ISO does not believe that requiring non-public utility Participating TOs to submit their transmission revenue requirements to the Commission under Section 205 of the FPA is the only permissible means for confirming the reasonableness of those revenue requirements. The ISO asserts that the Commission has latitude to accept different approaches to satisfy its statutory requirement and notes that the Commission on rehearing in Central Hudson, stated that:

> We note . . . that we cannot review LIPA's rates under the Section 205 just and reasonable standard, but will apply the comparability standard we use when evaluating non-jurisdictional, so-called "NJ" transmission tariffs to assure that the tariff rate is comparable to the rate LIPA charges itself and others. [[9]]

Thus, the ISO concludes that the proposed RRP represents a carefully crafted compromise solution to reconcile the opposing positions on this issue which is a critical element of the Commission's RTO initiative.

We believe that the appropriate regulatory review authority of the transmission revenue requirement of non-public utility entities who may become Participating TOs is a complex and evolving question. We do not wish to be overly prescriptive at this time but rather remain flexible to resolutions within the bounds of the FPA. Consistent with our previous discussion in this order, we instruct the parties, with the assistance of a designated settlement judge, to negotiate within the following guidance. The ISO's proposal that the RRP's findings are final and non-appealable is inconsistent with our statutory responsibilities. In Order No. 2000-A, we confirmed that we did not intend "to broaden the applicability of section 205 to non-public utilities." [10] Nevertheless, the Commission must be able to determine that the pass through of costs by the ISO to its customers are just and reasonable. We believe that such a determination can include prior review by the RRP to the extent allowed by the FPA. We also find that the current public process rate review utilized by many GEs does not supplant the FPA requirement for Commission review of rates in these circumstances.

We also note that the proposed RRP is consistent with our stated preference to utilize and implement ADR procedures where possible so as to allow for a more timely and certain regulatory finding. Consistent with that goal, we note that while the RRP process may be acceptable as a prerequisite to Commission review, we have concerns over possible regulatory lag resulting from this process and, as such, will require the parties to include stated time constraints in any review process that is agreed upon so as to ensure a timely regulatory outcome.

B. The Ten-Year Transition Period and Cap on Cost Shifts

As noted previously in this order, one of the prominent features of the ISO's proposal is the use of a ten-year transition period for the conversion of transmission revenue requirements in three separate TAC Areas to a single, HV Access Charge. The ten-year transition period is done on a straight linear basis, e.g., 10 percent of each TAC area's composite transmission revenue requirements will become part of a grid-wide rate each year of the transition period together with 100 percent of new capital additions made by all Participating TOs. This transitional grid-wide rate is added to the specific TAC area rate to produce a composite rate that will be assessed to the load of each UDC, MSS or SC in their respective TAC areas during the transition period. The ISO supports the use of this ten-year period as the basis upon which a smooth transition from disparate TAC area rates to a single grid-wide rate would occur and a means by which to mitigate cost shifting among the Participating TOs.

The ISO has also included an annual limitation or "cap" on the increase in the total payment responsibility applicable to gross loads in the service area of an original Participating TO during the proposed ten-year transition period. The annual"cap" for each of the Original Participating TOs is $32 million each for PG&E and SoCal Edison and $8 million for SDG&E.

A number of GEs request rejection of the proposed ten-year transition period arguing, among other things, that it is unnecessary and unsupported. Specifically, the City of Burbank (Burbank) argues that it is an unnecessary remedy for rate shock based on prior Commission threshold levels utilized in other areas of regulation. LADWP has proposed a compromise ten-year transition period in which 50 percent of the high voltage transmission revenue requirement of all Participating TOs would be collected through a grid-wide uniform rate and the remainder collected through the ISO's proposed TAC area mitigation proposal. Other GEs express concern over the linear approach and the potential lumpiness of the transition period depending on when entities join the ISO. Furthermore, other GEs note that the differences between the transmission costs of new and original Participating TOs could be reduced by significant planned capital additions by the original Participating TOs.

With respect to the "cap" on cost shifts during the proposed ten-year transition period, GEs have requested that the cap be rejected because the ISO has provided no support for it, and the cap numbers appear to be simply the highest numbers that the ISO could get the original Participating TOs to accept. Other GEs argue that the cap should be eliminated because it limits the benefits to the new Participating TOs and does not consider the larger package of benefits that the Original Participating TOs received including billions in stranded cost recovery.

The ISO in its Answer states that, under the circumstances that presently exist in California, it is reasonable to phase-in the HV Access Charge over a ten year period and to limit the amount of costs that could be shifted to customers of Original Participating TOs in any year during the transition period. The ISO notes that the Commission has accepted similar transition periods in the case of other independent system operators such as NEPOOL. The ISO also states that the ISO Governing Board took into account the potential for additional transmission investment and reasonably determined that mitigation of cost shifts associated with the widely divergent transmission revenue requirements of original Participating TOs and most new Participating TOs was necessary to prevent unduly abrupt cost shifts during the transition period.

We recognize that some transition period may be appropriate in order to mitigate extreme cost shifts. The ISO is correct in that we did permit a similar transition period in NEPOOL, giving considerable weight to the interests of Participants who would pay more under the composite rate in determining the appropriate transition period. [11] We also recognize that a "cap" on cost shifts to customers of the Original Participating TOs that could occur during the ten-year transition period may be appropriate. However, the current record in this proceeding has not demonstrated that a ten-year transition period and the proposed limits on the amount of cost shifts are the proper ones necessary to mitigate abrupt cost shifts. For example, CMUA has cited to evidence that at least one of the original Participating TOs is planning significant dollar amounts of capital additions over the next five years. Under the ISO proposal, these capital additions will not be phased-in but will immediately become part of the grid-wide charge. Thus, while the ISO states that the impact of significant planned capital additions was considered by the ISO Governing Board in deliberations regarding the appropriate transition period, the potential impact on cost shifts still appears in dispute.[12] Additionally, the potential benefits that would inure to the customers of the original Participating TOs from the expansion of the transmission grid should also be considered in the selection of a reasonable transition period and the proper cap on cost shifts.

Generally, the use of transition periods are to mitigate large cost shifts and rate effects. Therefore, we believe the record should include, on a broader level, information on the overall impact of changes in transmission costs on the overall cost of electricity. We note that the ISO has submitted some information in the instant filing that indicates that the cost of transmission on the monthly bill of a typical residential end-user is approximately 3.1 percent of the total cost of electricity. From a broad perspective, this is a relatively small percentage cost component. Thus, negotiated mitigation measures that are designed to prevent abrupt cost shifts should also look at the context of transmission costs relative to the total cost of electricity.

In conclusion, we reiterate that, at this juncture, we are not able to ascertain whether the ten-year transition period and the proposed $72 million annual cap provides the proper compromise of costs and benefits. Additionally, we recognize that our rulings on other issues may impact this compromise. Therefore, we instruct the parties, with the assistance of the appointed settlement judge, to further evaluate and consider all relevant costs and benefits and the proper context of such amounts in the selection of an appropriate transition period.

C. <u>TAC Areas</u>

Under the ISO's proposal, the HV Access Charge will be based on three "TAC Areas" that correspond to the three original Participating TO's control areas: a Northern Area (PG&E), a Southern Area (SDG&E), and an East Central Area (SoCal Edison). If LADWP were to join the ISO, a fourth TAC Area, the West Central Area, would be established. The ISO proposes that when the first GE joins any one of the three TAC Areas, or if LADWP were to join and establish a fourth TAC area, the beginning date of the ten-year transition period is established for all the areas. If the LADWP joins after the beginning date of the transition period for the three TAC areas, its ten-year transition period would begin as of the date it joins the ISO.

Generally, the Intervenors have not taken issue with the ISO's proposal to use three or potentially four TAC areas during the proposed ten-year transition period. However, LADWP protests the potentially different beginning date for its transition period as being unduly discriminatory and requests that all TAC areas have the same transition date.

Our review indicates that the use of a different beginning date for this fourth TAC area, depending on the date when and if LADWP were to join the ISO, could result in a transition period to a single system rate significantly beyond the proposed ten-year transition period. Without further justification we believe that this potential delay to the final transition is unsupported.

Therefore, based on the current record, we find that the fourth TAC area should have the same transition date as the other proposed TAC areas. Alternatively, the ISO must submit additional information demonstrating the need for the deferral in any subsequently negotiated HV Access Charge proposal filed with the Commission.

D. Firm Transmission Rights

Under the ISO's proposal, a new Participating TO shall receive FTRs for Inter-Zonal interface commensurate with the transmission facilities and Converted Rights that it turns over to the ISO. The new Participating TO will receive the FTRs directly without the necessity of participating in the ISO's auction during the ten-year transition period. The ISO proposal also limits the FTRs given directly to the new Participating TOs to the lesser of the ten-year transition period or the term of the existing contract. The quantity of FTRs that the new Participating TO receives for their transmission capacity will be determined when a Transmission Control Agreement between the ISO and the new Participating TO is executed.

A number of Intervenors request that the ISO provide more details on its plan for FTR conversion and a definition of the term "commensurate." Similarly, a number of Intervenors protest the limitation on FTRs to ten years for those Existing Rights' contracts whose term is greater than ten years and argue that the FTRs must last for the life of the facility in the case of ownership, or the full term of the existing contract in the case of entitlement. Intervenors also raise concerns over the level of firmness and the scheduling priority of Existing Rights over Inter-Zonal Interfaces. In addition, Enron argues that it is unjust and unreasonable and discriminatory to implement FTRs for new Participating TOs in a manner that is far superior to that granted current market participants.

In its Answer, the ISO states that after the ten-year transition period, all Participating TOs will be treated the same for their owned transmission facilities and converted rights: they will receive FTR auction revenues and will be able to purchase FTRs in the ISO auction or purchase them in secondary market transactions. Thus, after the transition period, new participating TOs will receive auction revenues that reflect the market-determined value of the capacity of its transmission facilities and Converted Rights.

Generally, we find that the ISO's proposed treatment of FTRs is reasonable. As explained by the ISO, the proposal to exempt new Participating TOs from the auction process during the transition period is a feature that has been offered as an inducement to encourage participation in the ISO. The proposal will afford the new Participating TOs protection against potential cost increases during the transition period.

With respect to the ISO's proposal that the FTRs be limited to the lesser of the ten-year transition period or the life of the contract if its term is less than ten years, we find that this proposal is also reasonable. The holders of contract rights that become new Participating TOs must recognize that this election will fundamentally change their current status, and consistent with that change, the new Participating TOs should have to participate in the auction process for the purchase of FTRs in the same manner as the original Participating TOs after the transition period.

We also agree with Intervenors that more information is needed regarding various aspects of the ISO proposed treatment of FTRs. Therefore, the appointment of a settlement judge should help with the informational process and the subsequent negotiations regarding specific issues that may arise from the details of the ISO proposed treatment of FTRs.

E. Phantom Congestion

______The ISO states that one of the benefits (in terms of cost savings) of new Participating TOs is the reduction of what it terms "Phantom Congestion." This term, as explained by the ISO, relates to the scheduling timelines afforded to current GEs under Existing Rights contracts which are different and not entirely compatible with the day-ahead and hour-ahead schedules that the ISO operates under. Because the Existing Rights contracts allow scheduling changes after the ISO scheduling deadlines, available transmission capacity remains unutilized. According to the ISO, an after-the-fact review of actual data from December 1998 to November 1999 indicates that in many days the congestion on contract paths was less than anticipated because the holders of Existing Rights did not fully utilize those rights, but that information was not available in real-time to the ISO to allow the market to respond. Thus, the ISO states that, if there were immediate conversion of Existing Rights to FTRs for new Participating TOs, this "Phantom Congestion" would be eliminated.

A number of GEs argue that: (1) "Phantom Congestion" is a valuable scheduling right of the GEs; (2) the ISO is at fault for failing to develop software to accommodate these rights nor recognize the operational realities of full service utilities; and (3) the requirement that Existing Rights be converted to FTRs to alleviate the purported

"Phantom Congestion" is a step backwards inasmuch as the ISO currently allows a five year conversion period during which time a party to an Existing Contract can become a new Participating TO and continue to exercise their contract rights. Additionally, some GEs have suggested that the appropriate place to deal with this issue may be the stakeholder process now under way in the ISO congestion management program.

We do not agree with the position taken by the GEs. Software that perpetuates the non-conforming schedules will not fix this problem of "Phantom Congestion". We believe that this approach simply suggests an iterative scheduling process that will not allow sufficient time for the market to respond and will leave the ISO with insufficient time to manage the grid reliably. Furthermore, while GEs contend that their scheduling flexibility is a valuable asset, it results in overall market inefficiencies due to scheduling time lines that do not conform to the time lines of the overall markets. It is difficult to justify the scheduling flexibility advantage in light of the congestion these rights cause the ISO. Therefore, "Phantom Congestion" is a market inefficiency that must be addressed and rectified as quickly as possible. In the event this issue is not resolved in the overall negotiations, we will address it in a separate proceeding.

F. <u>The "Buy-Down" Provision</u>

The ISO has proposed a Transition Mechanism under which savings, defined as a "TAC Benefit," received by new Participating TOs for joining the ISO are computed.[13] As explained by the ISO, a new Participating TO annually compares what it would have paid for transmission if had not joined the ISO versus its assessment for transmission by the ISO. Similarly, a new Participating TO annually compares what it would have paid in GMCs if it had not joined the ISO versus its assessment for GMC by the ISO. The net savings or TAC Benefit from these two components is computed (if the costs are actually greater than savings, then the hold harmless cap is invoked for a new Participating TO during the transition period). The new Participating TO's investment in high voltage transmission facilities will be reduced by the TAC Benefit. Specifically, according to the ISO, the new Participating TO may use the amount of the TAC Benefit to retire debt supporting the transmission facilities or to establish a fund to service that debt. Accordingly, each year during the transition period a new participating TO is required to amortize or "write-off" investment in high voltage transmission facilities equal to the savings realized through the TAC Benefits. [14]

A number of Intervenors have protested this "buy-down" provision. Vernon argues that, because the crediting provision prospectively reduces the revenue requirement, it provides a return of capital without a return on capital. Vernon also presents a present value analysis which it believes reflects an accurate understanding of how the buy-down proposal is to be implemented. Southern Cities believe that the buy-down provision constitutes discriminatory and inappropriate interference in the financial autonomy of a new Participating TO and is fundamentally unfair to its end-use customers. Southern Cities also argue that the limitation on reflecting benefits to their customers will require them to pay rates based on the full cost of the transmission facilities but no longer receive the full benefit of those facilities. The Northern California Power Agency (NCPA) argues that the credit back provision is neither internally consistent, justified, nor rational, and that it constitutes a regulatory taking in that the return on investment is diverted for purposes of reducing the cost of transmission in the future. NCPA notes that it shares with PG&E entitlements in the California-Oregon Transmission Project (COTP) and this credit requirement would result in a different, and thus discriminatory, rate treatment for owners of the same line. CMUA asserts that the ISO presumes that a true source of funds exists from which to amortize the new Participating TO's transmission investment and, in reality, that no such source exists.

We believe that the "buy down" provision is unsupported and potentially discriminatory, and it is therefore rejected. While we recognize that the ISO has included this provision as a mechanism by which to attempt to equalize the cost of the facilities of the original Participating TOs with that of the new Participating TOs through a converging of the varying transmission revenue requirements over the proposed ten-year transition period, it has not demonstrated that this provision is reasonable. There is general agreement by all parties that there will be benefits that will inure to all users of the ISO grid if new GEs were to join the ISO. We agree. Also, we agree with the GEs' comments that the higher cost transmission facilities of the GEs is a vintage problem and that any concerns over the return of or on capital related to the facilities of a new Participating TO should be examined in the forum where the revenue requirement of the new Participating TO is reviewed. The approved depreciation rates or the proxy capital recovery factor utilized as the bases for the recovery of investment in the HV facilities of the new Participating TOs should be utilized as the basis for the amortization of those facilities, and no further buy down of the investment base is necessary or appropriate. This procedure should protect against any discriminatory treatment of facilities that are jointly owned by an original Participating TO and a new Participating TO regarding the depreciation of those facilities, whereas the ISO's "buy down" proposal could result in an accelerated book amortization of the new Participating TOs' portion of jointly owned transmission facilities but allow a less accelerated depreciation of the facility by the original Participating TOs.

Moreover, we also believe that the "buy-down" proposal is fundamentally inconsistent with the goals of Order No. 2000 and will discourage participation in ISOs. There may be a perception created that newer and thus higher cost transmission investment should be devalued. Thus, we believe that, while a transition mechanism may be appropriate, it should not include a "buy-down" provision.

G. Use of Gross Loads with Limited Exclusion

The ISO's proposal provides that the HV Access Charge and the transition charge are payable on each MWh of energy withdrawn from the ISO controlled grid. The Utility Distribution Companies (UDCs), Metered Subsystem Operators (MSS) or Scheduling Coordinators (SCs) will pay the ISO the HV Access Charge based on the amount of gross load. The proposed HV Access Charge methodology recognizes an exception for loads that are served by an existing Generator Unit that is a qualifying small power producer or qualifying cogeneration facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA) and has either: (1) secured Standby Service from an existing Participating TO and will continue to do so and thus, is already bearing a portion of the costs of the ISO grid through the charges for Standby Service; or (2) is configured to be curtailed concurrently with the outage of the Generating Unit, and thus, is not relying on the ISO grid for the receipt of either operating reserves or energy. Such loads would be netted out and not be subject to ISO charges.

Calpine Corporation and a number of GEs have protested the proposed use of gross load as the appropriate billing units. These intervenors argue that behind the meter generation serves load that does not actually utilize the ISO grid and, therefore, should not be subject to ISO charges. A number of GEs also argue that the exception to gross load for QFs results in undue preference and discrimination. The Energy Producers and Users Coalition and Cogeneration Association of California argue that the ISO proposal properly excludes existing loads that are met by the internal generation of QFs but fails to exclude new, non-grandfathered QF loads. As such, they assert that the ISO proposal violates both the FPA and PURPA in that it discriminates against new standby service customers.

The ISO in its Answer notes that the transmission service made available under the ISO Tariff is the equivalent of network integration service under the Commission's pro forma tariff, and that the Commission has repeatedly determined that the use of gross load is appropriate for network service. With respect to the exception for QF load currently paying standby service, the ISO argues this exception appropriately recognizes that payment, and for QF-served loads that are not eligible for the exemption, they can exclude transmission costs in the calculation of standby service charges to recognize that the load is now bearing a portion of those costs through the HV Access Charge. The ISO concludes that the creation of this exemption does not require the creation of far broader exemptions that would allow other transmission customers to escape paying for the cost of the transmission system.

Our review indicates that the continued use of gross load as the billing units as proposed by the ISO is appropriate. In Order No. 888 we addressed similar concerns regarding loads that were "behind the meter," and we see no change in circumstances to warrant a different result here. [15] With respect to the exceptions for existing QF and cogeneration facilities, we generally agree with the ISO's criteria used to support its proposal. However, the record should be further developed to demonstrate that the criteria are applied in a non-discriminatory manner in order to avoid possible future claims of discrimination.

H. Metered Subsystems

The ISO's proposal also includes provisions that would enable the systems of new Participating TOs to qualify as Metered Subsystems (MSS). The ISO states that allowing new Participating TOs to qualify as MSS would facilitate their continued operation as vertically integrated utility systems while also providing an alternative way to participate in the ISO's markets and to use the ISO controlled grid for transactions with their surplus resources. The ISO states that limiting the availability of MSS status to entities that elect to become Participating TOs is consistent with the intent of the concept as a means of encouraging participation in the ISO by publicly owned entities that chose to remain vertically integrated.

A number of Intervenors have taken issue with various aspects of the ISO's proposed MSS. Some Intervenors argue that the eligibility for the MSS should not be limited to entities that become Participating TOs while other Intervenors challenge the provision requiring the operator of a MSS to comply with all applicable provisions of the ISO tariff. Intervenors also raise specific concerns over the operation and implementation of the ISO's proposal. Enron contends, among other things, that all generating entities that interface with the ISO controlled grid should be entitled to implement MSS, and not just existing municipal utilities or irrigation districts.

The ISO in its Answer responds to the various operational and implementation concerns and arguments requiring MSS members to become Participating TOs. The ISO also responded to Enron's protest by stating, in part, that by seeking to do away with limits on MSS, Enron is trying to revise radically the ISO's scheduling procedures, the structure of the ISO's markets, and the manner in which the ISO receives information about the status of generating units in its control area and where necessary, issues dispatch instructions to them.

Some comments on this issue indicate that the ISO and GEs appear to have made progress on this issue, and the parties should continue negotiations with the settlement judge. We note that the issue of the availability of MSS status being limited to those entities that elect to become Participating TOs is before the Commission in Docket No. ER98-3760-000, et al., and will therefore be decided in that proceeding. For the purposes of this proceeding, the parties should narrow their negotiations to the stated purpose of the MSS (i.e., accommodating vertically integrated systems in the ISO framework).

Docket No. ER00-2019-000

Remaining Issues

While we have addressed and given guidance on the major issues that have been presented by the ISO's proposal, there remain other issues. Some of these issues appear to be specific concerns that with additional information and clarification are resolvable. Additionally, several parties raise issues that are unique to their particular situation, e.g., time-of-use rates for parties with water interests. In order to afford the parties and the settlement judge flexibility in reaching an overall settlement, we will not address these additional issues at this time. However, we strongly urge the parties and the settlement judge to use a consensus approach and focus their efforts on those issues whose resolution is necessary for GEs to become new participating TOs in the ISO grid.

The Commission orders:

(A) The ISO's proposed tariff revisions are hereby accepted for filing, and suspended for a nominal period, subject to refund, to become effective on June 1, 2000, as requested.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held concerning the justness and reasonableness of the ISO's proposed tariff revisions. However, this hearing will be held in abeyance while the parties attempt to settle, as discussed in Paragraphs (C)-(E) below.

(C) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (1999), the Chief Administrative Law Judge is hereby designated as the settlement judge in this proceeding. To the extent consistent with this order, the designated settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene an initial settlement conference as soon as practicable.

(D) Within 120 days of the date of this order, the settlement judge shall issue a report to the Commission. The settlement judge shall issue a report at least every 60 days thereafter, appraising the Commission of the parties' progress toward settlement.

(E) If the settlement discussions fail, a presiding administrative law judge, to be selected by the Chief Administrative Law Judge, shall convene a prehearing conference in this proceeding, to be held within approximately fifteen (15) days of the date of the settlement judge's report to the Commission, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E. Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, to rule on all motions (except motions to dismiss), and to preside over the hearing in this proceeding, as provided in the Commission's Rules of Practice and Procedure.

(F) The ISO is hereby informed that the rate schedule designations will be supplied in a future order. Consistent with our prior orders, the ISO is hereby directed to promptly post the proposed tariff sheets as revised in this order on the Western Energy Network.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.

APPENDIX A
Timely Interventions

California Department of Water Resources (DWR)
California Electricity Oversight Board
California Manufacturers and Technology Association
California Municipal Utilities Association (CMUA)
California Power Exchange Corporation
Calpine Corporation (Calpine)
Cities of Anaheim, Azusa, Banning, Colton and Riverside (Southern Cities)
Cities of Redding, Santa Clara and Palo Alto and the M-S-R Public Power Agency (Cities/M-S-R)
City of Burbank (Burbank)
City of Roseville
City and County of San Francisco
City of Vernon (Vernon)
Cogeneration Association of California and Energy Producers and Users Coalition
Duke Energy Trading & Marketing, L.L.C.

Docket No. ER00-2019-000
Enron Energy Services, Inc.
Glendale Water and Power Department (Glendale)
Independent Energy Producers Association
Lassen Municipal Utility District (Lassen)
Los Angeles Department of Water and Power (LADWP)
Metropolitan Water District of Southern California (Metropolitan)
Modesto Irrigation District (Modesto)
Northern California Power Agency (NCPA)
Pacific Gas and Electric Company (PG&E)
Sacramento Municipal Utility District (SMUD)
Sempra Energy
Southern California Edison Company (SoCal Edison)
Southern Energy California, L.L.C.
Southern Energy Delta, L.L.C.
Southern Energy Potrero, L.L.C.
State Water Contractors
Transmission Agency of Northern California (TANC)
Trinity Public Utility District
Turlock Irrigation District (Turlock)
Utility Reform Network, The (TURN)
Western Area Power Administration (WAPA)
Williams Energy & Marketing Company

---

[1]Section 9600(a)(2)(A) of California's A.B. 1890 required the ISO to recommend a new rate methodology within two years after commencement of operations. See Pacific Gas & Electric Company, et al., 77 FERC ¶ 61,204 at 61,827 (1996).

[2]High voltage transmission facilities are those transmission facilities in the ISO controlled grid that operate at 200 kV and above.

[3]Transmittal Letter at 7.

[1]The ISO defines a MSS as a geographically contiguous system of a new Participating TO, located within a single zone which has been operating for a number of years prior to the ISO Operations Date subsumed within the ISO Control Area and encompassed by ISO certified revenue quality meters at each interface point with ISO grid and ISO certified revenue quality meters on all generating units internal to the system which is operated in accordance with a MSS agreement.

[2]TURN at 3-4.

[3]Regional Transmission Organizations, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), (Order No. 2000), reh'g denied, Order No. 2000-A, 65 Fed. Reg. 12,088, 90 FERC ¶ 61,201 (2000), FERC Stats. & Regs. ¶ 31,092.

[4]ISO Answer at 12.

[5]For example, the Los Angeles Department of Water and Power (LADWP) controls approximately 25 percent of the transmission import capacity into the state of California.

[6]As such, we reject Sempra's arguments against a "postage stamp" HV Access Charge and the bifurcation of the ISO-operated transmission facilities into low and high voltage components.

[7]Under the self-sufficiency test, a Participating TO is required to have generating and transmission resources greater than or equal to its monthly peak demand plus resources necessary to meet other WSCC reliability criteria.

[8]See Section 7.1.1 and Section 9 of Appendix F, Schedule 3 of the ISO Tariff. For Participating TOs that are public utilities under the FPA, they will make the appropriate filings at FERC to establish their transmission revenue requirements for the applicable HV Access Charge and to obtain approval of any changes thereto. Also, for Federal power marketing agencies whose transmission facilities are under ISO control, they shall develop their High Voltage transmission revenue requirement pursuant to applicable federal laws and regulations, including filing with FERC.

[9]88 FERC ¶ 61,138 at 61,403 (1999).

[10]Order No. 2000-A at 31,372.

[11]See New England Power Pool and Massachusetts Municipal Wholesale Electric Company, 83 FERC ¶ 61,045 at 61,237-41 (1998), reh'g pending.

[12]However, we do recognize that the amount of new capital additions may be impacted by both the timing and number of new Participating TOs joining the ISO.

[13]See Appendix F, Schedule 3, Sections 1.2(b) and 6.1(b).

[14]The ISO clarifies in its Answer that the new Participating TOs retain complete discretion regarding the financing of their transmission facilities. However, for ratemaking purposes, over the ten-year transition period, the new Participating TO's transmission revenue requirement will be calculated to reflect a reduction to net plant balances by the amount of "savings" realized by each new Participating as though the Participating TO applied the cost-shift benefits to reduce its investment in high voltage

transmission facilities, regardless of whether or not it does so. The ISO thus concludes in its Answer that the "buy down" mechanism does not interfere with the financing discretion of new Participating TOs or deprive them of any cost recovery or returns to which they are entitled on their investments in high voltage transmission facilities.

[15]See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 at 31,735-36 (1996) (Order No. 888), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 62 Fed. Reg. 64,688, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), appeal docketed, Transmission Access Policy Study Group, et al. v. FERC, Nos. 97-1715 et al. (D.C. Cir.).