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ISSUE #	ISSUE, INTERVENOR & CITE	PROCEEDING (where applicable)
231.	Section 3.1.2 if the UDC Agreement erroneously refers to " Other Tax-Exempt Bonds" while the text does not mention other tax-exempt bonds. **Turlock's 11/21/97 comments in Docket Nos. EC96-19-008 and ER96-1663-009 at 4**.	ER98-899-000, et al.
232.	Section 3.4 of the UDC Agreement should specify that it does not override the Existing Operating Agreement. **TID 11/21 at 4**.	ER98-899-000, et al.
233.	The Schedules to the UDC Agreement appear unnecessarily broad (e.g., advance scheduling and approval of maintenance are not currently required under Turlock's Existing Agreement with PG&E). **TID 11/21/97 at 5**.	ER98-899-000, et al.
234.	The UDC Agreement should not empower the ISO to override Local Regulatory Authorities (e.g., Section 5.1, on installation of equipment). **TID 11/21/97 at 6**.	ER98-899-000, et al.
235.	Liability and Indemnification should be bilateral (UDC Agreement § 9.1; similar issue in other *pro forma* agreements). **TID 11/21/97 at 6-7**.	ER98-899-000, et al.
236.	Section 5.1 of the PGA should not include suspension of trading rights as a sanction. **TID 11/21/91 at 8-9**.	ER98-992-000, et al.
269.	Tariff Amendment No. 9. Firm Transmission Rights (FTRs) could further reduce participation in the Schedule Adjustment Bid (SAB) market. The thinning of the SAB market would reduce the efficiency of the transmission auction process. **PX protest filed 7/20/98 at 4-5**.	ER98-3594-000
270.	Tariff Amendment No. 9. FTRs encourage gaming related to intentional over-scheduling of transmission. FTR holders could game the system by over-scheduling to create paper congestion in the day-ahead market while avoiding any penalties for deviations in real time. **PX protest filed 7/20/98 at 5-7**.	ER98-3594-000
271.	Tariff Amendment No. 9. The movement of significant portions of FTRs to the secondary market could reduce price transparency. The lack of transparency will make market decisions less efficient and will impede the ability of the ISO to monitor market abuses. **PX protest filed 7/20/98 at 7-8**.	ER98-3594-000
272.	Tariff Amendment No. 9. The ISO must ensure that its FTR scheduling procedures do not allow FTR holders to receive scheduling priority for non-FTR deliveries. An FTR holder may obtain priority access to transmission above and beyond its FTR capacity. **PX protest filed 7/20/98 at 8-9**.	ER98-3594-000
390.	The ISO Staff has issued a recent policy where Market Participants will be required to use ISO EMS data instead of the data in their PGA Schedule 1, without resolving numerous issues associated with this decision. **Edison - Operational experience**.	

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391.	ISO policies result in inappropriate delays in Ancillary Service certifications. ISO Staff is taking the position that changes to Schedule 1 to the PGA will be effective only after: 1) verified by the ISO, 2) approved by the FERC, and 3) ISO databases (Master Files) are updated. This process can take several months, which financially impacts Market Participants. Edison's position is that changes to PGA Schedule 1 should be made effective upon ISO certification, and revoked if the FERC later determines that the ISO certification was inadequate. There is nothing in the PGA which prevents the ISO from using this approach. Edison is concerned with the time it takes the ISO to update its Master File and the impact of this delay on the Ancillary Service certification process. The substantial time lag associated with updating the ISO's network model and databases with revised data is unacceptable. If the ISO takes the position that EMS data will be used to populate the ISO Master File, then the ISO should be required to permit on-demand testing, if requested from Market Participants, and make immediate changes to databases. **Edison - Operational experience**.	
392.	Pricing methodology for system isolation conditions – The ISO has not addressed Edison's concern when system isolation occurs requiring Edison generators to carry local load. Currently the ISO treats this deviation as uninstructed deviation paid at the hourly ex-post price which may be unjust and unfair. Generators should be held neutral for imbalances caused by system isolation conditions. **Edison -operational experience.**	
393.	Capability to handle Physical Scheduling Plants. This item appears on the Phase 2 Work Priority listing, but should be moved to become a higher priority item. It remains an issue that Edison wants to pursue. **Edison - Operational experience.**	
416.	Section 2.5.22.2(d) - How does the ISO dispatch in merit order? To what extent can the ISO deviate or skip merit order? Are criteria necessary to limit deviations? **PG&E**.	
426.	ISO has stated effort to review backlogged disputes only if filed on time and not resolved to SC's satisfaction. ISO policy needs to be reviewed, possibly with list of issues regarding backlogged settlements and stakeholder agreement on appropriate methodology to resolve items related to past disputes. **PG&E**.	
428.	Significant changes occur between Preliminary and Final statements issued by the ISO. The ISO currently does not provide an explanation or a process for resolution of differences between the two statements. **PG&E.**	
429.	There have consistently been discrepancies between ISO and PG&E final schedules. The PX points out that the ISO returns hour-ahead schedules containing large quantities of hours during which no PX trade occurred. The PX concludes that this is the result of a " broken" inter-SC trade where the ISO is using the PX to balance their overall supply and demand schedules. **PG&E**.	
430.	The ISO does not provide a copy of real time dispatch orders. This produces difficulty in reconciling RTE and IE statements. The reasons include: 1) differences in time between dispatch when dispatch is ordered and when dispatch orders are received, resulting in different BEEP prices (ISO uses time dispatch instruction is ordered, PG&E has only time dispatch order was received), and 2) the manual procedures (phone calls and faxes) used by the ISO to send dispatch instructions results in discrepancies between the ISO and PG&E logs of dispatch instructions. **PG&E**	

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547.	ISO Tariff provisions and ISO directives should govern over any other inconsistent transmission provisions and directives. **EC96-19-029 & ER96-1663-030, Comments and Protest of DWR, p. 9 filed 08/05/1998; EC96-19, et al., Comments of DWR, p. 34, filed 09/02/1997**. Existing contract rights holders should be assured unbundled, open access restructuring will provide transmission service that is "seamless" and not more difficult or costly to obtain and use. **EC96-19, et al., Comments of DWR, p. 34, filed 09/02/1997; EC96-19-029 & ER96-1663-030, Comments and Protest of DWR, p. 9, filed 08/05/1998**.	ER97-2358-002, et al.
560.	Proposed ISO Tariff Change to Procure and Settle Replacement Reserves on the Same Basis. The ISO is proposing to file a tariff amendment with FERC to "make clear" that Replacement Reserves will be procured and settled on the same basis. We gather from the discussion at the meeting that the ISO intends to request that this tariff amendment be applied retroactively. As was noted at the meeting, the existing tariff language requires the ISO to allocate the cost of Replacement Reserves on a zonal basis only when there is, in fact, congestion in the day-ahead market. Imagined congestion, i.e. congestion that is in the mind of the ISO and not actually on the transmission system, is not a basis for allocating such costs zonally. **SDG&E**	
562	(a) Section 5.2.7 of the ISO tariff should be revised to conform to the ISO's existing practice of recovering certain RMR contract costs (e.g., costs incurred by the ISO for ancillary service capacity arranged by the ISO pursuant to an RMR Dispatch Notice) from all scheduling coordinators rather than from "the utility that is a party to the TCA in whose Service Area the Reliability Must-Run Generating Unit is located". This revision distinguishes between RMR contract costs that are incurred as a result of local reliability requirements and RMR contract costs that are incurred as a result of grid-wide reliability requirements. Section 5.2.7 should be revised to read as follows: The ISO shall recover the costs it incurs through payments under each Reliability Must-Run Contract for local Reliability Must-Run services from the utility that is a party to the TCA in whose Service Area the Reliability Must-Run Generating Unit is located after deducting the amounts received by the Reliability Must-Run Owner from Scheduling Coordinators for Energy and Ancillary Services, as set forth in Appendix H of the Settlement and Billing Protocol. The ISO shall prepare and send to each utility in accordance with the relevant ISO Protocol an invoice in respect of all such local Reliability Must-Run service costs incurred under all such contracts relating to that utility's Service Area. The ISO shall recover the costs it incurs through payments under each Reliability Must-Run Contract for grid-wide Reliability Must-Run services from Scheduling Coordinators as set forth in Appendix H of the Settlement and Billing Protocol. The ISO shall prepare and send to each Scheduling Coordinator in accordance with the relevant ISO protocol an invoice in respect of all such grid-wide Reliability Must-Run services costs incurred." **SDG&E**	

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574.	The ISO proposes to modify the ISO tariff to eliminate references to "proxy prices" for Energy bids associated with self-provided Ancillary Services. The ISO's discussion of this issue suggests that these proxy prices are not needed because the ISO considers only capacity prices in its bid evaluation for Ancillary Service capacity. The discussion then goes on to say that the BEEP functionality makes no distinction with respect to Energy bids associated with self-provided Ancillary Services versus bid Ancillary Services. SDG&E is confused by this discussion because self-provided ancillary services, by definition, are not included in the ISO's ancillary services auction. Further, self-provided ancillary services are included in the BEEP merit order stack so that the ISO knows when to call on energy from this capacity. A "proxy price" is required for self-provided ancillary services in order that BEEP can determine where self-provided ancillary services fit into the merit order stack of resources available to respond to real-time imbalances. This merit order stack includes both self-provided ancillary service capacity as well ancillary service capacity arranged through the ISO's own ancillary services auction. Based on the information provided by the ISO, SDG&E questions whether the subject tariff references should be eliminated. **SDG&E**	
575.	Proposal to Bill Ancillary Services Based on Metered Demand There is widespread concern about market participants avoiding ancillary services charges— currently settled on the basis of scheduled load— by under-scheduling load. SDG&E supports changes which would allocate ancillary service costs on the basis of metered load rather than scheduled load. The ISO has presented 3 options for implementing an ancillary service cost allocation based on metered load: 1) Bill strictly based on metered load, 2) Bill on the basis of metered load but account for each scheduling coordinator's use of scheduled firm imports (based on the final import schedule), scheduled hydro and scheduled thermal generation to establish the scheduling coordinator's obligation to pay ancillary service costs (a scheduling coordinator's reserve obligations are 0%, 5% and 7% to the extent their load is being served by firm imports, hydro generation and thermal generation respectively); 3) Bill on the basis of metered load but account for each scheduling coordinator's use of metered firm imports (metered imports are deemed equal to the real-time scheduled imports), metered hydro and metered thermal generation to establish the scheduling coordinator's obligation to pay ancillary service costs (a scheduling coordinator's reserve obligations are 0%, 5% and 7% to the extent their load is being served by firm imports, hydro generation and thermal generation respectively). **SDG&E**	
576.	The ISO has proposed eliminating payments for ancillary service capacity and associated instructed energy to the extent the underlying capacity is determined to not be available. SDG&E has supported this concept with the condition that the ISO find a way to (1) exempt regulation capacity from this mechanism, and (2) account for energy which is taken by the ISO pursuant to an RMR Dispatch Notice or other out-of-market call. To date, we have not seen anything that gives us confidence that the ISO can exempt regulation capacity from this mechanism, other than completely exempting any unit selected for any non-zero quantity of regulation capability (either through the ISO's ancillary service auction or through an RMR Dispatch Notice). Until the necessary corrective mechanisms are developed, SDG&E is forced to oppose the proposal to eliminate payments for ancillary service capacity and associated instructed energy to the extent the underlying capacity is determined to not be available. **SDG&E**	

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577.	Pricing of Uninstructed Imbalance Energy. The ISO proposes to implement new pricing for uninstructed imbalance energy that would reduce payments for uninstructed generation deviations in the positive direction and increase charges for uninstructed generation deviations in the negative direction. These changes in pricing are designed to create an incentive for market participants to submit supplemental energy bids that, when acted upon by the ISO, translate into instructed generation deviations. SDG&E initially supported this proposal with the priviso that regulating units and units subject to RMR Dispatch Notices be exempted since it is the ISO and not the unit owner that controls the output of these units. Based on input provided at the October 7, 1998Market Issues Forum,and on the fact that the ISO has yet to explain how regulating units and units subject to RMR Dispatch Notices would be exempted from this pricing mechanism, we have changed our position. Given the apparent complexity of the software necessary to implement the ISO's proposal, the possibility that ongoing improvements in the BEEP functionality will reduce the opportunity for market participants to benefit from uninstructed deviations, and the fact that the ISO has yet to provide a satisfactory explanation of how regulating units and units subject RMR Dispatch Notices would be exempted from this pricing mechanism, SDG&E opposes the ISO proposal to revise the pricing of uninstructed energy deviations. **SDG&E**	
578.	Proposal to Revise Deadline for Supplemental Energy Bids. SDG&E supports revising the deadline for Supplemental Energy bids to 60 minutes versus the existing 45-minute deadline. **SDG&E**	