UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

City of Vernon, CA	**)**	**Docket No. EL00-105-007**
California Independent System Operator Corporation	**)** **)**	**Docket Nos. ER00-2019-007**

BRIEF ON EXCEPTIONS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Dated: January 28, 2005

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FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)** **)**	**Docket Nos. ER98-997-000** **ER98-1309-000**

BRIEF ON EXCEPTIONS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to Rule 711 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.711, the California Independent System Operator Corporation ("ISO") submits its Brief on Exceptions in this proceeding.

I. Summary

The Initial Decision properly concluded that, under the ISO Tariff and Commission precedent, the ISO's Operational Control[1] of a facility or Entitlement is a prerequisite to the inclusion of the facility or Entitlement in a Participating Transmission Owner's Transmission Revenue Requirement. The Initial Decision erred, however, in interpreting the ISO Tariff and Commission precedent such that the ISO does not have Operational Control of an Entitlement outside the ISO Control Area for which it has not established Scheduling Points, even though the Participating Transmission Owner has transferred legal authority over the facility to the ISO through the Transmission Control Agreement.

The ISO Tariff defines Operational Control in terms of the *rights* of the ISO regarding the facilities of Participating Transmission Owners; it contains no

[1] Capitalized terms not otherwise defined have the meaning given them in Appendix A of the ISO Tariff.

reference to scheduling procedures or models. Opinion No. 445, *Southern California Edison Company,* 92 FERC ¶ 61,070 (2000), and the order denying rehearing, *Southern California Edison Company*, 108 FERC ¶ 61,085 (2004), upon which the Initial Decision relies, simply provide that utilities that wish to receive "credit" for their facilities or Entitlements – *i.e.*, to recover their costs – must execute the Transmission Control Agreement and provide the ISO with the authority to schedule on the facilities and Entitlements. The orders make no reference to the establishment of scheduling procedures or models. There is no support in the ISO Tariff or Commission precedent for the Initial Decision's grafting of new criteria onto the definition of Operational Control.

The Initial Decision also erred in finding that the ISO's delay in the establishment of Scheduling Points was unreasonable. The ISO presented unrebutted testimony that the delay from the time Vernon became a Participating Transmission Owner until the time Southern Cities indicated their intent to become Participating Transmission Owners was attributable to the diversion of the ISO's internal resources to addressing the California energy crisis. The Initial Decision rejected this testimony on the basis that the energy crisis ended coincident with the end of the refund period. There is no logical connection between the end of the refund period (which simply marked the institution of mitigation measures) and the need for the ISO to devote its resources to the energy crisis. Indeed, the implementation of the Commission's mitigation measures required a significant commitment of ISO internal resources. The Commission should therefore reject the Initial Decision's conclusion that the delay was unreasonable.

II. Statement of the Case

A. Background

As the Initial Decision noted, the fundamental facts concerning Vernon's Entitlements in the Mead-Adelanto Project ("MAP") and the Mead-Phoenix Project ("MPP") are not in dispute. Initial Decision (hereinafter "I.D.") at P 45. The Commission approved the transfer of Vernon's facilities and Entitlements to the ISO's Operational Control on January 9, 2001. *Id. citing California Independent System Operator Corporation*, 94 FERC ¶ 62,016 (2001). On February 21, 2001, the Commission approved the Transmission Control Agreement executed by Vernon, effective January 1, 2001. *Id. citing California Independent System Operator Corporation*, 94 FERC ¶ 61,141 (2001).

The MAP and MPP are outside the ISO Control Area. *Id.* Unlike the case of facilities inside the ISO Control Area, for the ISO to schedule transactions on the MAP and MPP Entitlements through the ISO's Scheduling Infrastructure or "SI", it was necessary for the ISO to develop software to establish Scheduling Points for the MAP and MPP Entitlements. This is the result of the radial branch group methodology employed by the ISO for transactions on lines outside the ISO Control Area. Branch groups terminate at Scheduling Points. Ex. No. ISO-1 at 6.

The ISO did not establish Scheduling Points for Vernon's MAP and MPP facilities until January 1, 2003. I.D. at P 45. Thus, the ISO could not and did not schedule Vernon's use of the facilities prior to that time. *Id.*

The ISO explained at the hearing, and there was no evidence to the contrary, that although the ISO had intended to create Scheduling Points for the MAP and

MPP Entitlements upon assuming Operational Control of the Entitlements, and took actions preparatory to creating such Scheduling Points (Ex. No. ISO-1 at 6), the ISO was forced to delay the creation of such Scheduling Points due to the California energy crisis, which placed great demands and an increased workload on ISO employees. Ex. ISO-1 at 6; Tr. 529, 566. Nonetheless, the ISO intended to develop the Scheduling Points once the ISO had the opportunity to devote attention to them. The ISO believed that at any point during the two-year disputed period, it would have taken the ISO about three months to establish Scheduling Points, assuming manpower and other resources were available to devote to this task. Tr. 579-80.

In the summer of 2002, the schedule for establishing the Scheduling Points was affected by the anticipated addition of the Southern Cities as New Participating TOs, for whom Scheduling Points on the same transmission facilities would need to be developed. Due to the nature of the radial branch group scheduling model, it was reasonable for the ISO to wait until these entities turned over Operational Control of their shares of relevant facilities prior to developing modeling for Vernon's Entitlements on a stand-alone basis. It was simply more efficient to design a model and Scheduling Points looking at the Vernon and Southern Cities facilities as a whole than to try to do so in a piecemeal fashion, once it became clear that the Southern Cities also would be joining the ISO as Participating Transmission Owners. For these reasons, Scheduling Points for the Vernon Entitlements were not operational until January 1, 2003, the date on which the Southern Cities joined the ISO. Tr. 569; 580.

B. The Initial Decision

In the rulings relevant to the ISO's Exceptions, the Initial Decision concluded that that the MAP and MPP were not under the ISO's Operational Control prior to January 1, 2003, and that therefore their costs should not be included in Vernon's TRR prior to that time. I.D. at P 58. The Initial Decision based this conclusion on the facts described above and an interpretation of Commission precedent and the ISO Tariff. The Initial Decision found "[p]articularly relevant" a passage from Opinion No. 445 describing Order No. 888, inter alia, as requiring that integration necessitates that "'the transmission provider must be able to provide transmission service to itself or other transmission customers over [the relevant] facilities.'" I.D. at P 48, *quoting* Opinion No. 445 at 61,256. The Initial Decision also quoted with approval the statement in footnote 21 of Opinion No. 466 that "'actual, physical operational control of the facilities is the determining factor, … rather than the mechanism employed to transfer control.'" I.D. at P 49, *quoting* Opinion No. 466 at P 13, n. 21.

In addition, the Initial Decision cited the rehearing order of Opinion No. 445, *Southern California Edison Company*, for the principles that "'the transmission provider must be able to provide transmission service to itself or other transmission customers over [the relevant] facilities, i.e., the transmission provider must have operational control over [the relevant] facilities,'" and that it must also provide capability and reliability benefits in order to be eligible for credits. I.D. at P 50, *quoting* 108 FERC ¶ 61,085 at PP 8, 10. The Initial Decision found "particularly relevant" the passage in *Southern California Edison* that reads "'If the California ISO did not have operational control over [the relevant] facilities, it could not use them to provide transmission service to its customers ….'" *Id., quoting* 108 FERC ¶ 61,085 at P 11.

The Initial Decision found that the ISO did not "schedule, coordinate schedules or offer transmission access" over the Entitlements during 2001 or 2002 and that the ISO admitted it was unable to provide comparable non-discriminatory transmission access to its Market Participants to the Entitlements. I.D. at P 52. According to the Initial Decision, because the Entitlements were not scheduled though the ISO, they did not provide service to anyone but Vernon, and hence did not provide reliability benefits to the ISO Controlled Grid. *Id.*

Among other findings, the Initial Decision found the two-year delay in establishing scheduling points unreasonable, noting that the California energy crisis "did not even last that long" and citing the Commission's termination of the refund period effective June 20, 2001. I.D. at P 53. Because the Southern Cities did not apply to become PTOs until July 2002, or 18 months after Vernon, the Initial Decision did not accept the ISO's explanation that, once the energy crisis abated, it made sense to coordinate the scheduling procedures with those to be developed for the Southern Cities. I.D. at P 55.

In addition, the Initial Decision finds that the ISO overcollected Vernon's Transmission Revenue Requirement but that refunds are not necessary, because the ISO can net out the overcollection through its balancing account.

III. Exceptions

The ISO excepts to the following conclusions of the Initial Decision, which are based on errors of law and fact:

1) The Initial Decision erroneously found that Commission precedent or the ISO Tariff dictate that the establishment of Scheduling Points is a prerequisite to the ISO's Operational Control of an Entitlement or facility outside of the ISO Control Area;

2) The Initial Decision erroneously found that the ISO's Operational Control of an Entitlement or facility outside of the ISO Control Area requires more than that the ISO have the legal authority under the Transmission Control Agreement to provide transmission access to ISO customers on the Entitlement or facility;

3) The Initial Decision erroneously found that the ISO's delay in the establishment of Scheduling Points for the MAP and MPP was unreasonable; and

4) The Initial Decision erroneously found that refunds are not appropriate to address any overcollection of Vernon's Transmission Revenue Requirement because such overcollection can be netted out through the ISO's balancing account.

IV. Policy Considerations Warranting Commission Review

The issues on which the ISO files its Exception are fundamental to the ability of the ISO to expand the ISO Controlled Grid in a manner to provide transmission access to its customers more reliably and efficiently: they concern the ability of Participating Transmission Owners to recover their Transmission Revenue Requirements. The expansion of the ISO Controlled Grid beyond the facilities of the original three investor owned utilities was among the goals of the legislation establishing the ISO. *See* Cal. Pub. Util. Code §§ 330(m), 9600. The Commission has repeatedly recognized the value of the addition of new Participating Transmission Owners. *See, e.g., California Indep. Sys. Operator Corp.,* 91 FERC ¶ 61,205 at 61,722 (2000); *see also California Indep. Sys. Operator Corp.,* 104 FERC ¶ 61,062 at P 29 (2003); *California Indep. Sys. Operator Corp.,* 102 FERC ¶ 61,058 at P 2 (2003).

Critical to the willingness of a utility to join the ISO, of course, is the assurance that the utility will continue to recover the revenue requirement associated with the facilities that it places under the ISO's Operational Control. If the Initial Decision is allowed to stand, however, a potential utility may be presented with circumstances under which, for reasons beyond its control, it is not permitted fully to recover its costs. Under the Initial Decision, the utility's recovery would be determined not by whether the facilities or Entitlements are legally placed under the ISO's Operational Control and not by whether the facilities qualify as integrated network facilities, but by whether external circumstances permitted the ISO to establish Scheduling Points for the facilities simultaneously with the effective date of the transfer in the Transmission Control Agreement as approved by the Commission.

The introduction of this risk of nonrecovery, and the resulting significant disincentive to participating in the ISO, requires Commission review.

V. Argument

A. The Initial Decision Erred by Concluding the Operational Control Requires the Establishment of Scheduling Points

The Initial Decision properly concluded from Opinions No. 445 and 466, and the orders denying rehearing of each, that the ISO's Operational Control of a facility or Entitlement is a prerequisite to the inclusion of the costs of that facility or Entitlement in a Participating Transmission Owner's Transmission Revenue Requirement. I.D. at P 48. As the I.D. observed, "Operational Control" is defined in the ISO Tariff as follows:

> The Rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.

I.D. at P 46. The I.D. further correctly concluded from Opinion No. 445 and its order on rehearing that Operational Control requires that the ISO be able to provide transmission service to its customers over the facilities. I.D. at PP 50-51.

The error of the I.D. lies in its misunderstanding of the requirement that the ISO be "able to provide transmission service to its customers." Nothing in the Commission's orders or the ISO Tariff suggests that the ISO's ability to provide transmission service, for the purpose of the existence of Operational Control, is dependent upon the existence of Scheduling Points. Rather, Operational Control is established by the ISO's *legal* ability, *i.e., authority* to use the capacity of the transmission facilities or Entitlements to provide transmission services to its customers. As stated in the Tariff definition of Operational Control, it is the "*rights* of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs." ISO Tariff Appendix A, Master Definitions Supplement (Emphasis added).

The Initial Decision reads far too much into Opinion No. 445 and the rehearing order on that opinion when it infers from those opinions an additional requirement that the ISO establish Scheduling Points in order to have Operational Control over Entitlements outside the ISO Control Area. The determinative factor in those orders was that the facilities were owned by utilities that were not Participating Transmission Owners, *i.e.,* utilities that had not *legally* provided the ISO authority to

Schedule on their facilities by executing the Transmission Control Agreement. Specifically, the issue in the Opinion No. 445 proceeding was whether owners of transmission Entitlements that were *not* Participating Transmission Owners (including Vernon itself at that time) should receive credits for their customer-owned transmission facilities. The Commission in Opinion No. 445 stated that "if the California ISO has no operational control over these facilities, it can not use them to provide transmission service to its customers." Opinion No. 445 at 61,255. The Commission found that until Vernon and the others joined the ISO *by executing the Transmission Control Agreement*, the ISO could have no Operational Control over their facilities (Opinion No. 445 at 61,255), and that "in order for the Municipals to receive credits for their facilities, they must join the California ISO and thereby *allow scheduling and control* of the facilities by the transmission owner." *Id.* at 61,256 (emphasis added). A transmission owner "join[s] the California ISO" by executing the Transmission Control Agreement and thereby giving the ISO Operational Control over the owner's facilities, i.e., the legal authority, stemming from the contract, to make transmission service available over them. This, of course, is precisely what Vernon has done. The Commission did not imply in either order that additional action was necessary.

In short, in Opinion No. 445, Vernon and the others had allowed the ISO no legal authority to Schedule the facilities, and hence no Operational Control; here, as the Commission stated in Opinion No. 445 was necessary in order to receive a credit, Vernon *has allowed* the ISO that legal authority by executing the Transmission Control Agreement. The rehearing order merely reviewed the requirements for credits for customer-owned facilities and reiterated that this *legal* authority, the transfer of Operational Control, was the prerequisite for recovery of costs under the circumstances presented by the ISO Controlled Grid.

The Initial Decision's reliance on footnote 21 in Opinion No. 466, I.D. at P 49, is also misplaced. Although the Commission indicated in footnote 21 that Operational Control requires that the ISO have "physical control" of the facilities, the Commission provides no basis for the Initial Decision's inference that "physical control" means "actions taken to implement and provide" access to and use of the facilities. I.D. at P 51. In footnote 21, the Commission was not implying that legal control of facilities was insufficient to establish Operational Control. It was not presented with such a question and was not establishing a distinction between legal control to exercise physical control and the act of exercising such control. Rather, the Commission was responding to the issue (which had been addressed in the initial decision in that docket) of whether a filing under Section 203 was a necessary prerequisite for Operational Control. It simply stated that the *mechanism* by which operational control is assumed is irrelevant, *i.e.*, whether it be by a Section 203 filing or (as was the case in Opinion No. 466), a subsequent listing in the ISO Transmission Registry, or otherwise. The Commission did *not* state that legal authority to exercise operational control is insufficient or even that it is distinguishable from physical control.

In fact, the ISO had complete legal authority to exercise physical control of the facilities during the disputed period. That the ISO could at any time (had the internal resources been available) have implemented Scheduling Points demonstrates that the ISO's "physical control" of the MAP and MPP was the same on January 1, 2001, as on January 1, 2003.

Although the Initial Decision discusses the reasons why the ISO did not establish the Scheduling Points, and whether the length of the delay is reasonable, ultimately those factors are irrelevant. The manner in which the ISO operates its Operational Control does not determine the existence of Operational Control. The record is clear that no party approached the ISO about establishing Scheduling Points; no party filed a complaint with the Commission about the lack of scheduling procedures. The disallowance of Vernon's Transmission Revenue Requirement is not the proper mechanism to ensure the implementation of Scheduling rights.

B. The Initial Decision Erred in Concluding that the Delay in the Establishment of Scheduling Points Was Unreasonable

The ISO presented testimony explaining that the delay in the establishment of Scheduling Points, from the December 2000 until the Southern Cities made known their intention to become Participating Transmission Owners in the summer of 2002, was due to the need to devote resources to issues raised by the California energy crisis. Ex. ISO-1 at 7-8; Tr. 529, 570, 579-80. There is no record evidence contradicting that testimony. Nonetheless, the Initial Decision discounted that testimony, concluding that the energy crisis did not last that long. I.D. at P 53. The Initial Decision's only support for its conclusion is the Commission's decision to end the refund period on June 20, 2001. *Id.* n. 38.

The Initial Decision erroneously equates the end of the refund period with the end of the intense need to devote resources to the resolution of the energy crisis. The Commission ended the refund period on June 20, 2001, because it imposed mitigation measures effective that date, not because the crisis (and the need for mitigation) was over. *San Diego Gas & Electric Company, et al*., 96 FERC ¶ 61,120 (2001) at 61,501; *see also San Diego Gas & Electric Company, et al*., 95 FERC 61,418 (2001).[2] What the Initial Decision fails to take into account is that the Commission's mitigation measures imposed very significant demands on ISO resources in order to implement those measures, demands that did not ease for a long period.

As the Commission is well aware, for example, the must-offer and price mitigation requirements directed by the Commission have involved a highly complex and contentious process. ISO staff needed to develop a must-offer procedure, gain Commission approval, and implement and administer the procedure. The process has required repeated revisions to the procedures in response to Commission orders or other concerns. *See, e.g*., *San Diego Gas & Electric Company, et al,* 95 FERC ¶ 61,115 (2001) at 61,355-56; *San Diego Gas & Electric Company, et al,* 95 FERC ¶ 61,418 (2001) at 62,553; *San Diego Gas & Electric Company, et al*, 97 FERC ¶ 61,293 (2001) at 62,363-64; *California Independent System Operator Corp.*, 99 FERC ¶ 61,296 (2002). In response to the energy crisis, the Commission also imposed significant reporting obligations on ISO scheduling personnel. *San Diego Gas & Electric Company, et al,* 93 FERC ¶ 61,294 (2000) at 62,012 (ISO to submit monthly report on all bids above $150); *San Diego Gas & Electric Company, et al,* 95 FERC ¶ 61,115 (2001) at 61,360 (ISO required to provide weekly reports on

[2] Indeed, the market mitigation measures the Commission put in place to combat the crisis were originally to expire on April 26, 2002 (95 FERC ¶ 61,115 at 61,354) but were later extended to September 30, 2002 (95 FERC ¶ 61,418 at 62,657), a mere three months prior to the establishment of the scheduling points.

schedule, outage, and bid data); and *San Diego Gas & Electric Company, et al*., 95 FERC ¶ 61,418 (2001) at 62,567 (ISO to provide quarterly reports on conditions in the California market). Other tasks the ISO was ordered to perform by the Commission that impacted on its scheduling arrangements included outage coordination (*San Diego Gas & Electric Company, et al,* 95 FERC ¶ 61,115 at 61,355) and the development and implementation of underscheduling penalties (*San Diego Gas & Electric Company, et al*, 93 FERC ¶ 61,294 (2000) at 61,982). Moreover, the proceedings resulting from the energy crisis matters have resulted in massive amounts of discovery of market and operations data posed on the ISO, making significant demands on the time of ISO personnel.

From the beginning, the Commission recognized that key to resolving the energy crisis and preventing its recurrence was the elimination of inefficiencies in the ISO markets and operations. *San Diego Gas & Electric Company, et al,* 93 FERC ¶ 61,294 (2000). In late 2001, the Commission recognized the need to continue market mitigation with only minor modifications. *San Diego Gas & Electric Company, et al*, 97 FERC ¶ 61,275 (2001) at 62,172. In addition, however, the Commission directed the ISO to undertake another major effort. In the December 2001 Order, the Commission had directed the ISO, as part of the effort to resolve the energy crisis, to file a congestion management redesign, but had had not acted on and ISO request for an extension of time. The Commission directed the ISO to file a Congestion Management Redesign – which as the Commission is aware is a very significant undertaking – by May 2002. 97 FERC at 62,230.

All of these Commission directives flowed directly from the energy crisis and occupied ISO scheduling personnel well into the Summer of 2002, when it became apparent that the Southern Cities would join the ISO as Participating Transmission Owners. The Initial Decision's conclusion that the ISO's delay in establishing Scheduling Points was unreasonable is not supported by any record evidence and indeed is contrary to the only record evidence on the issue. The Commission action on which the Initial Decision relies also provides no support for its conclusion. Accordingly, the Commission must reverse that conclusion.

C. The Initial Decision Erred by Concluding that Any Overcollection of Vernon's Transmission Revenue Account Could Be Netted Out Through the ISO's Balancing Account

The Initial Decision noted:

> Vernon argues that refunds cannot be ordered since it is a non jurisdictional entity. Suffice to state that "refunds" are not being ordered in this case. The decision above means that the ISO over collected concerning Vernon's TRR. Consequently, this overage can be netted out in the ISO's balancing account. *But cf. San Diego Gas & Electric*, 96 FERC ¶ 61,120 (2001) (refunds in the California spot markets ordered by the Commission).

I.D. at P 58, n. 41. The Initial Decision erred because there is no mechanism in the ISO Tariff for using a balancing account to net out overcollection of Transmission Revenue Requirements. Vernon is incorrect, however, that it would not be subject to refunds. Section 16.2 of the Transmission Control Agreement provides:

> Each Participating TO, whether or not it is subject to the rate jurisdiction of the FERC under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its TO Tariff and do all other things required of a Participating TO to implement any FERC order related to the ISO Tariff, including any FERC order that requires the ISO to make payment adjustments or pay refunds to, or receive prior period overpayments from, any Participating TO. All such refunds and adjustments shall be made, and all other actions taken, in

accordance with the ISO Tariff, unless the applicable FERC order requires otherwise.

Because the ISO Tariff is a formula rate, a reduction in Vernon's Transmission Revenue Requirement for 2001 and 2002 would necessitate that the ISO make refunds, for which Vernon would be responsible under TCA Section 16.2.

VI. Conclusion

For the reasons described above, the Commission should reject the Initial Decision's findings described in the ISO's Exceptions above.

Respectfully submitted,

__***/s/ Michael E. Ward***___

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Date: January 28, 2005

CERTIFICATE OF SERVICE

I hereby certify I have this day served the foregoing document on each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Folsom, CA, on this 28th day of January, 2005.

/s/ Geeta O. Tholan
Geeta O. Tholan