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Decision 97-04-042 April 9, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of Southern California Edison Company (U 338-E) To Adopt The Performance Based Ratemaking and Incentive Based Ratemaking Mechanisms Specified in D.95-12-063, as Modified by D.96-01-009, and Related Changes.	Application 96-07-009 (Filed July 15, 1996)
Application of San Diego Gas & Electric Company for authority to implement a Fossil Generation Performance-Based Ratemaking Mechanism (U 902-E).	Application 96-07-010 (Filed July 15, 1996)
Application Of Pacific Gas and Electric Company To Adopt Performance-Based Ratemaking (PBR) For Generation And To Change Electric Revenue Requirements Subject To PBR, Effective January 1, 1998. (Electric) (U 39 E)	Application 96-07-018 (Filed July 15, 1996)

INTERIM OPINION

1. Summary

In these applications California's largest investor-owned electric utilities are proposing to implement performance-based ratemaking (PBR) mechanisms and to address other matters related to their generation assets. To clarify the scope of issues to be considered in this consolidated proceeding, the Commission describes its role vis-à-vis the roles of the Federal Energy Regulatory Commission (FERC) and the Independent System Operator (ISO) with respect to transmission system reliability and related market power issues. With the passage of Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854), the Commission finds that the ISO, under FERC oversight, has a primary role in addressing system reliability needs. The Commission's own role is an important but in several respects a supportive one. Proposals that this Commission make substantive determinations regarding reliability matters that are ultimately reserved to the ISO are found to exceed the scope of this ratemaking proceeding.

This decision also clarifies the Commission's plan for cost recovery related to the operation of fossil-fueled generating plants. Finally, it addresses the ability of utilities to shut down fossil generation facilities that are not needed for reliability purposes.

2. Background

Decision (D.) 95-12-063 dated December 20, 1995 (the Preferred Policy Decision), as modified by D.96-01-009 dated January 10, 1996, directed Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) to file applications to establish separate generation and distribution PBR mechanisms consistent with the policies outlined in the decision. (Preferred Policy Decision, mimeo., Ordering Paragraph 17, p. 223.) Each application was required to include a discussion of strategies to mitigate horizontal market power concerns.[1]

D.96-03-022 dated March 13, 1996 (the First Roadmap Decision) modified Ordering Paragraph 17 of the Preferred Policy Decision by extending the filing date for the PBR applications to July 15, 1996. The utilities filed these generation PBR applications in accordance with this decision.

Protests to one or more of the applications were filed by Toward Utility Rate Normalization (TURN)[2], Office of Ratepayer Advocates (ORA), Independent Energy

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[1] "Market power is the ability of a particular seller or group of sellers to maintain prices above competitive levels for a significant period of time." (Preferred Policy Decision, mimeo. p. 90.) "[Horizontal] market power can take place at any level of the production chain if there are significant barriers to entry or few market participants." (*Id.*, p. 97.)

[2] TURN announced on November 13, 1996 that it was changing its name to The Utility Reform Network and retaining the acronym TURN.

Producers (IEP), California Industrial Users, and Cogeneration Association of California (CAC).

Following the first prehearing conference (PHC), held on September 17, 1996, these matters were consolidated by an Assigned Commissioner's Ruling (ACR) dated October 2, 1996. The October 2 ACR set a workshop with several objectives, among them to identify issues appropriate for consideration in a phase of this proceeding designated for common issues. The ACR also set a second PHC, held on October 22, 1996, which was convened immediately following the workshop.

Pursuant to procedures adopted at the October 22 PHC, comments incorporating and restating informal pre-workshop comments submitted in response to the October 2 ACR were filed on October 28, 1996. Briefs on common questions were filed on November 18, 1996 and reply briefs were filed on November 26, 1996.[3]

The Preferred Policy Decision provided that each distribution utility would retain ownership of its hydroelectric and geothermal generating assets, and it encouraged utilities to submit PBR proposals for these plants. Edison and PG&E have done so in their respective applications, while SDG&E does not own such plants. In addition, Edison has proposed separate ratemaking treatment for its Santa Catalina Island generation assets, and it has included cost separation testimony with its application. These aspects of the applications are not immediately at issue and are not addressed in this decision.[4]

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[3] Briefs were filed by Edison, SDG&E, PG&E, ORA, California Energy Commission (CEC), IEP and California Cogeneration Council (CCC), California Large Energy Consumers and California Manufacturers Association, Coalition of California Utility Employees (CUE), U.S. Generating Company (USGen), Watson Cogeneration Company (Watson), and the Energy Producers and Users Coalition (EPUC) and CAC. Replies were filed by Edison, SDG&E, PG&E, ORA, CEC, IEP/CCC, CUE, EPUC/CAC, and the City and County of San Francisco (CCSF).

[4] Edison also submitted cost separation testimony in Application (A.) 96-12-009, et al., our consolidated unbundling proceeding. By ruling issued in that docket on January 31, 1997, the assigned Administrative Law Judge confirmed that the unbundling

Footnote continued on next page

The applicant utilities have offered different approaches for dealing with reliability which assume varying degrees of Commission involvement in the determination of which generating units are needed for local reliability and related matters. Recognizing the need for consistent assumptions, the workshop participants agreed that the following question should be briefed and resolved by the Commission before further processing of these applications occurs:

> What role, if any, should the Commission play relative to the FERC and the ISO in review and decision making regarding the issues involved in the use of generation contracts, PBRs, or cost-of-service ratemaking to ensure continued reliability and mitigate market power?

The workshop revealed several specific issues that are associated with this question, including the criteria for determining whether a generating station is designated as needed for local reliability; the designation of generation stations needed for local reliability and the Commission's role in reviewing related factual and policy issues; the appropriate general structure of reliability contracts, PBRs, or cost-of-service ratemaking; cost parameters within the reliability contract or PBR, and the role of the Commission in reviewing the cost bases of reliability contracts or PBR; and coordination with the Competition Transition Charge (CTC) proceeding. Finally, to the extent we determine that we have a role in these matters, the parties ask that we indicate what forums, proceedings, and procedural vehicles should be used in resolving these issues.

3. The Proposals for Fossil Generation

In this section, we provide an overview of the applicants' proposals for fossil generation to set the background for our analysis of the issues now before us.

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proceeding is the place to discuss costing methodologies, performance of cost studies for the components of electric service, functional unbundling of generation, transmission, and distribution costs. We will not consider Edison's cost separation testimony in this proceeding.

3.1 Edison

3.1.1 Reliability Generation

For utility-owned fossil generation needed to safeguard transmission system stability during the initial years of transition to the ISO market structure, Edison seeks this Commission's concurrence with an approach that is based upon FERC-approved local reliability contracts between Edison and the ISO. Edison notes that the ISO will be responsible for dealing with local generation and transmission issues in a manner that preserves system reliability. These contracts would give the ISO the right to call upon and dispatch generating units during those hours when they must operate to protect local reliability. The contracts would provide an incentive for Edison to bid energy into the Power Exchange (PX). Market revenues net of this incentive would be flowed through to customers who are responsible for bearing the costs of local reliability contracts. According to Edison, these contracts will ensure continued availability of generation when called upon by the ISO for local reliability support and will preclude the potential for localized market power associated with such units through cost-based call prices.

Edison also seeks this Commission's concurrence with its assessment of the number of stations needed for local reliability support. Early studies by Edison indicate that five stations are needed. However Edison believes that certain transmission upgrades may reduce the number of stations needed for local reliability to two, Alamitos and Huntington Beach. Edison seeks Commission authorization for funding of transmission investments that would reduce the number of generating stations needed for local reliability.[5] Finally, Edison asks the Commission to find the cost basis of the proposed local reliability contracts to be reasonable.

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[5] Edison has filed A.96-11-047 for ratemaking treatment of its proposed transmission upgrades.

3.1.2 Other Fossil Generation

With respect to recovery of operating costs (i.e., costs other than those associated with a fossil unit's undepreciated book value; also, "nonsunk" costs), we have provided that:

> "If the [PX] clearing price exceeds the cost of running fossil fueled generating units, utilities should be able to earn up to 150 basis points above their authorized return for distribution rate base before additional profits are used to reduce [CTC]." (Preferred Policy Decision , mimeo., Conclusion of Law 63, p.211.)

Edison seeks approval of a specific method for implementing this "fossil fuel cost recovery mechanism" in connection with its generation which is deemed not needed for reliability. Edison also seeks "clarification" that once the new generation market commences, utilities will have discretion to shut down fossil generation not covered by local reliability contracts. Edison takes the position that shareholders should not be at risk for recovery of future operation and maintenance (O&M) and new capital expenditures solely from market revenues unless it can both shut down such generation assets at its sole discretion and recover reasonable, unavoidable "shutdown O&M" costs through the CTC.[6]

Since its proposals are based upon market-based pricing, yet FERC may not authorize utilities to receive market-based rates until sufficient divestiture of generating assets is accomplished, Edison proposes a temporary, contingency ratemaking plan that would be implemented if divestiture of 50% of its fossil generation units is not accomplished by January 1, 1998.[7] Under the contingency proposal, Edison would

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[6] The issues of transition cost eligibility and potential cost recovery for fossil unit decommissioning are being addressed in the transition cost proceeding. (A.96-08-001, et al.)

[7] In A.96-11-046 Edison seeks authority to sell all of its gas-fired fossil generation units.

receive revenues according to the terms of its 1995 general rate case until such divestiture is completed.

3.2 PG&E

PG&E proposes to separate its fossil plants into those that are "constrained-on" by the ISO, because the ISO needs those plants to maintain transmission system reliability, and "energy-commodity" plants.[8] PG&E does not propose adoption of a PBR mechanism for either category of its fossil generation. Sunk costs would be recovered directly through the CTC. All other costs to operate PG&E's fossil units (i.e., fuel, O&M, administrative and general (A&G), and incremental capital additions) would be recovered through the ISO and the PX, as described below.

3.2.1 Reliability Generation

For constrained-on fossil units, PG&E proposes to recover nonsunk costs through FERC-approved short-term contracts with the ISO for ancillary services, i.e., services needed by the ISO to ensure transmission system reliability. These contracts would provide for recovery of all of the plant's fixed operating costs and that portion of variable operating costs incurred in providing ancillary services. PG&E anticipates that the ISO could use competitive procurement processes to determine which plants would receive contracts for ancillary services. PG&E proposes that these constrained-on units would also sell into the PX, incurring additional variable operating costs related to such sales. PG&E would offset the CTC account with PX revenues that exceed the additional variable operating costs.

As a contingency proposal, PG&E proposed an interim PBR mechanism for constrained-on fossil plants. This mechanism would be effective only if the FERC has not approved ISO contracts for ancillary services by the start of the PX operation. However, in comments submitted on October 28, 1996, PG&E suggests that hearings on this backup proposal be held only if it appears that the ISO will not have FERC-

[8] In A.96-11-020 PG&E seeks authority to sell its Hunters Point, Morro Bay, Moss Landing, and Oakland generation plants.

approved, constrained-on contracts in place by January 1, 1998, or if those contracts in combination with FERC treatment of sales into the PX do not cover PG&E's costs.

3.2.2 Other Fossil Generation

For energy-commodity fossil plants, PG&E would be at risk for the nonsunk costs. It would only recover operating costs through PX revenues. Like Edison, PG&E proposes that it be permitted to retain up to 150 basis points above the authorized distribution return for PX revenues above operating costs. Any additional amounts would be used to offset the CTC account. PG&E asserts it would have the right to shut down fossil plants believed by PG&E to be unprofitable, subject to Commission approval.

3.3 SDG&E

SDG&E concluded that on an interim basis, all of its 1,973 megawatts (MW) of fossil generation within the San Diego Basin, including 1,641 MW of fossil steam capacity and 332 MW of combustion turbine capacity, is required to ensure that service quality and reliability are not compromised. SDG&E sees this condition as prevailing during an interim period while the PX market is developing, and until economic alternatives to assure reliability, such as new generation and demand-side management, become available. SDG&E has also concluded that the PX market revenues earned by its San Diego Basin fossil generation will be insufficient to recover the costs of providing this reliability generation.

Where Edison and PG&E propose to use FERC-approved ISO contracts, SDG&E proposes a CPUC-jurisdictional Fossil Generation PBR Mechanism to address these conditions and to mitigate horizontal market power associated with its San Diego Basin units during some hours of the year.[5] With the commencement of the ISO/PX

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[5] In an analysis filed with FERC, SDG&E determined that it is likely to have market power within the San Diego Basin during approximately 750 hours of the year when the ability to import energy is exceeded and in-basin generation must be used to provide both energy and voltage support.

operations and implementation of the new Fossil Mechanism, SDG&E's current Generation and Dispatch PBR mechanism would be terminated.

SDG&E proposes to bid each of its nonnuclear San Diego Basin units into the PX each hour at the variable cost of the unit. It would: recover fixed O&M costs, an allocation of A&G costs, and fixed gas pipeline capacity charges by means of a PBR revenue requirement formula; reduce fixed costs recovered through the PBR by any excess of PX revenues over the bid amount; and establish time-sensitive retail rates to encourage development of demand-side bidding and an elastic response to real-time pricing. SDG&E proposes a fossil generation availability indicator to provide an incentive to ensure that fossil units are available when called upon by the ISO/PX for reactive power, voltage support, or transmission stability. Depending on SDG&E's performance as measured against industry averages, it could earn a reward or incur a penalty of up to $2 million in any annual period. SDG&E considers its proposal as transitional, and proposes a term of three years for its operation.

4. Discussion

4.1 The Commission's Role in Reliability and Market Power Determinations

There are two general approaches to resolving the question of our role. The first holds that the ISO, subject to FERC jurisdiction, has responsibility for determining and meeting its reliability needs, and that this Commission should not undertake reliability determinations that are reserved to the ISO. The positions taken by ORA and PG&E are generally representative of or consistent with this approach. The other approach, suggested in varying degrees by most of the other parties, recognizes both the role of the ISO and the jurisdiction of FERC but would have this Commission assume a more proactive role, at least on a transitional basis. We recognize that there are multiple aspects to reliability, some of which fall under state or concurrent jurisdiction. However, as explained below, we generally find that the course suggested by ORA and PG&E is the more appropriate one for us to follow in this PBR proceeding.

We first note that, taken together, numerous provisions of AB 1890 have placed operational control of utility transmission assets in the ISO, and have vested immediate responsibility for reliability resources with the ISO, subject to federal jurisdiction, consistent with the Federal Power Act, 16 USC § 824.[10] After stating the Legislature's intent to direct the creation of the ISO as a new market institution with centralized control of the statewide transmission grid, and charged with both efficient use and reliable operation of the grid, the "preamble" to AB 1890 provides in part that:

> "...It is the further intent of the Legislature to direct the Independent System Operator to seek federal authorization to perform its functions and to be able to secure the generation and transmission resources needed to achieve specified planning and operational reserve criteria. It is the further intent of the Legislature to require development of maintenance standards that will reduce the potential for outages and secure participation in the operation of the Independent System Operator by the state's independent local publicly owned utilities." (AB 1890, Section 1(c).)

AB 1890 states the importance of reliability and addresses the relationship of the transmission system thereto:

> "The Legislature finds and declares that in order to ensure the success of electric industry restructuring, in the transition to a new market structure it is important to ensure a reliable supply of electricity. Reliable electric service is of paramount importance to the safety, health, and comfort of the people of California. Transmission connections between electric utilities allow them to share generation resources and reduce the number of power plants necessary to maintain a reliable system....The proposed restructuring of the electricity industry would transfer responsibility for ensuring short- and long-term reliability away from electric utilities and regulatory bodies to the Independent System Operator and various market-based mechanisms...." (Section 334.[11])

The Legislature then defines the responsibilities of the ISO in considerable detail, providing among other things that:

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[10] As EPUC/CAC points out, federal jurisdiction over wholesale sales and interstate transmission of electricity is plenary. *FPC v. Southern California Edison Co.*, 376 U.S. 205, 215-16 (1964); *Mississippi Power & Light Co. v. Mississippi ex rel. More*, 487 U.S. 354, 371 (1988); *California Pub. Util. Comm'n v. FERC*, 900 F.2d 269, 274 (D.C. Cir.1990); and *Florida Power & Light Co.*, 40 FERC ¶ 61,045, at 61,120 (1987).

[11] Unless otherwise indicated, all section references are to the Public Utilities Code.

"The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council." (Section 345.)

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"The Independent System Operator shall *immediately* participate in all relevant Federal Energy Regulatory Commission proceedings. The Independent System Operator shall ensure that additional filings at the Federal Energy Regulatory Commission request confirmation of the relevant provisions of this chapter and seek the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council." (Section 346, emphasis added.)

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"The Independent System Operator shall adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under its control no later than March 31, 1997. The standards, which shall be performance or prescriptive standards, or both, as appropriate, for each substantial type of transmission equipment or facility, shall provide for high quality, safe, and reliable service...." (Section 348.)

Having addressed the role and the responsibilities of the ISO, the Legislature also defines our role with respect to matters involving the ISO, including reliability. Section 365(a) provides that the Commission shall, among other things,

"...participate fully in all proceedings before the Federal Energy Regulatory Commission in connection with the Independent System Operator and the independent Power Exchange, and shall encourage the Federal Energy Regulatory Commission to adopt protocols and procedures that strengthen the reliability of the interconnected transmission grid, encourage all publicly owned utilities in California to become full participants, and maximize enforceability of such protocols and procedures by all market participants."

In addition, Section 350 directs the ISO to report to the Legislature on several matters, among them reliability issues including generation reserves. With respect to this report, Section 350 assigns a consultation role to this Commission as well as the

CEC, the Western Systems Coordinating Council, and concerned regulatory agencies in other states.

The principle that the ISO is responsible for determining system reliability needs was endorsed by this Commission in a filing submitted in FERC's market power proceeding:

> "It is the CPUC's position that the ISO, not the Applicants, should determine what is needed for system reliability. Moreover, the CPUC believes that the ISO should designate the types of reliability *services* it needs and be free to contract with whichever generators it chooses, including, but not limited to the Applicants, in order to procure those services." (*Initial Comments of the Public Utilities Commission of the State of California On Market Power Issues*, Docket No. ER96-1663-000, filed October 16, 1996, p. 15.)

After briefs were filed in this proceeding, FERC issued its "Order Providing Guidance and Convening a Technical Workshop," *Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company*, 77 FERC ¶ 61,265 (December 18, 1996). Significantly, FERC agreed that the ISO and not the utilities should designate which facilities are classified as "must-run." FERC noted that the ISO "will have the necessary information and technical expertise to make the determinations, and it will have no incentive to discriminate among generators." (*Id.*, mimeo. at p. 41.)

Through AB 1890, the Legislature has attached great importance to the need for reliable electric services in California. Having done so, it has charged the ISO, operating under FERC jurisdiction, with immediate responsibility to determine standards and resource needs for transmission system reliability. In addition, FERC has determined that the ISO, not the investor-owned utilities, should determine its own reliability needs. Clearly, our role in these matters is important, but largely one of supporting and facilitating: to consult with the ISO and participate in FERC proceedings in continuation of the cooperative federalism that has characterized industry restructuring to date.

It is true that reliability and market power issues arise in state-jurisdictional proceedings, and that we have the duty and authority to consider anti-competitive impacts of our adopted policies and decisions. Furthermore, Section 362 places responsibility upon this Commission, in state proceedings pursuant to Sections 455.5, 851, or 854, to ensure that facilities needed to maintain the reliability of the electric supply remain available and operational, consistent with maintaining open competition and avoiding an overconcentration of market power. However, determinations of which reliability services are needed for system reliability are for the most part not ours to make. Thus, we generally concur that:

> "The whole notion of unbundled reactive power/voltage control services designed to support a statewide ISO controlled transmission system which includes both municipally and investor owned utilities is a creature of statute with the passage of AB 1890. This statute...transfers jurisdiction and authority over procurement and its market power implications to the ISO under FERC authority." (ORA Opening Brief, p. 5.)

SDG&E has argued in effect that we should take the initiative to determine the ISO's reliability needs now because the ISO will not be ready to do so for some time. Similarly, CEC likewise contends that while the market should ultimately determine how reliability needs are met, it will be unable to do so by the beginning of 1998. Watson urges us to take the lead role in assessing factual issues concerning the utilities' designations of must-run units. IEP/CCC believes it is unclear when the ISO will be functional, and recommends that we provide a temporary forum for consideration of the ISO protocol for analyzing reliability needs and for compensating providers of services for which there may be no competitive alternative.

We cannot embrace these suggested approaches. We recognize that, as a general proposition, unanticipated problems and potential delays can be expected to accompany the initial operations of any new organization. We further recognize that whether there is or soon will be a competitive market for reliability services is an open question (and one not appropriately resolved in this ratemaking proceeding). Still, we find little reason to proceed with the assumption that, despite its clear mandate to begin operations immediately, the ISO will be unable to determine its fundamental reliability needs for an extended period of time.

Certainly, Sections 348 and 350 require a rapid startup for the ISO. Moreover, there are sound policy reasons for not simply assuming the ISO will be unable to meet its obligations. Bearing in mind that one of our fundamental restructuring goals is "to allow competition for traditional monopoly services to flourish where conditions are ripe" (Preferred Policy Decision, Conclusion of Law 1, mimeo. p. 201), we support policies that are directed towards or consistent with development of a competitive market for ancillary services, including reactive power and voltage support services needed for transmission system reliability. We are concerned that by assuming that the ISO needs our preliminary designations of utility-owned reliability units in order to jump-start its operations, and using this proceeding to make such designations, we could actually thwart development of such a competitive market.[11]

In view of the enactment of AB 1890 and the progress of FERC proceedings to implement restructuring, we believe conditions will be ripe for movement to a competitive market for reliability services. The Legislature envisions market participation by publicly-owned utilities, and we note, for example, that USGen has stated that it has plans to build and operate a generation station in San Diego County which could provide reactive power and voltage support, among other services. In addition, nongeneration alternatives may be a part of the ISO's tools for achieving transmission system reliability. The range of market options available to the ISO will most likely be broader than the possibilities offered in these applications. We prefer to enable the ISO to define its needs, and to go to the market to fulfill those needs, without any pre-established generating unit selection criteria or unit designations.

We wish to emphasize that our holding on the scope of this proceeding does not represent any reluctance on our part to act to ensure the existence of a reliable transmission system during the transition to a fully competitive generation industry and beyond. We have provided input on reliability and market power issues to FERC as a party to its proceedings and we will continue to do so. In addition, we fully intend to

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[11] The potential competitive implications of these applications may be significant. As ORA points out, Edison and SDG&E designated extensive fossil resources as needed for reliability services, 6,600 MW in Edison's case and 1,973 MW in SDG&E's case.

act on our own initiative and in our own proceedings when our jurisdiction and authority to do so are triggered. As previously indicated, Section 362 assigns to this Commission direct responsibility to consider reliability and related market power issues in plant shutdown and divestiture proceedings brought under Sections 455.5, 851, and 854. In such proceedings we must ensure that facilities needed to maintain the reliability of electric supply remain available and operational. Accordingly, market power and reliability are being examined in Edison's and PG&E's divestiture proceedings. (A.96-11-046 and A.96-11-020, respectively.) Furthermore, the Commission shares responsibility for some aspects of reliability such as those regarding siting and safety. Finally, to the extent that jurisdictional issues affecting system reliability are not fully settled, we will work diligently to participate in appropriate state and federal forums to resolve such issues.

We conclude that we should not use this ratemaking proceeding to conduct a broad investigation of the ISO's reliability needs and how they will be met. Given the ambitious scope of activities associated with electric industry restructuring, our efforts (as well as those of utilities and interested parties) to encourage development of a competitive market and to mitigate market power can be applied more effectively in the other arenas such as our divestiture proceedings and FERC proceedings. To the extent that these applications ask us to adopt utility designations of must-run or constrained-on generation plants, the criteria for making such determinations, how those units would be called upon when needed, the appropriate form of contracts for reliability, or how generation owners would be paid by the ISO for providing reliability services, such proposals are beyond the scope of this proceeding. This includes Edison's request that we concur with its assessment of the number of generating stations required to be placed under contract to maintain current reliability standards on the Edison system. The same holds for Edison's proposal which asks that we find the detailed cost basis of its proposed local reliability contracts to be reasonable.

SDG&E has stated it would seek to withdraw its application and concentrate its efforts in FERC proceedings if we determine that our examination of reliability issues should be undertaken before FERC. (Tr. PHC-2, p. 81.) In addition, we note that in *Joint*

Comments of Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company on The Technical Conference on Market Power Mitigation, submitted before FERC in Docket No. ER96-1663-000 on January 27, 1997, SDG&E has stated that notwithstanding its proposal to subject all of its nonnuclear generation to a PBR mechanism, "[i]n the interest of simplicity and uniformity, [it] is prepared to join in the proposal by Edison and PG&E and withdraw its PBR, provided that the California Public Utilities Commission...concurs." (*Id.*, p. 5.) Accordingly, we provide that SDG&E may file a motion for leave to withdraw its application.

4.2 Cost Recovery for Fossil Generation

AB 1890 provides that we have continuing authority for rate regulation of utility-owned fossil plants in accordance with Sections 216(h) and 377.[13] Thus, we will continue to have jurisdiction over the disposition of revenues earned under reliability contracts and from sales into the PX. To provide guidance to the parties, we will clarify an aspect of our policies for fossil generation cost recovery.

In the Preferred Policy Decision, we discussed our general approach to transition cost recovery, one which has essentially been affirmed by AB 1890. With respect to recovery of nonsunk costs, we provided the following:

> "All other costs of running [fossil fueled] units, including capital costs not yet incurred, will be subject to recovery through the prices received from the [PX], with one limited exception. For those units that are primarily needed for reactive power/voltage control, if the costs of running these units (including capital costs not yet incurred) exceed the [PX] clearing price, utilities may seek partial recovery of operating costs up to the year 2003, subject to performance-based ratemaking, until or unless market based prices for reactive power/voltage control are set by the FERC. Further, if no recovery for reactive power/voltage control is sought, and the [PX] clearing price exceeds the costs of running these units (including capital costs not yet incurred), utilities may retain profits providing up to 150 basis points above their authorized return for distribution rate base.

[13] While our immediate concern is with fossil-fueled units, we recognize that Sections 216(h) and 377 make no distinction between fossil and nonfossil generation assets.

> Any further profits will be used to reduce CTC." (Preferred Policy Decision, mimeo. p. 135.)
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> "If the [PX] clearing price exceeds the cost of running fossil fueled generating units, utilities should be able to earn up to 150 basis points above their authorized return for distribution rate base before additional profits are used to reduce CTC." (*Id.*, Conclusion of Law 63, p.211.)

AB 1890 addresses capital additions, but it is silent on the 150 basis points allowance described above, other than for PG&E. Section 367(c)(1) provides that earnings from PG&E's reactive power/voltage support plants or units will be retained by PG&E, and not used to offset transition cost recovery. A question that arises is whether fossil units which are *not* deemed needed for reactive power/voltage support (or voltage control)[11] are eligible for the 150 basis points allowance. Edison's and PG&E's applications reflect the position that these units are eligible. We hold, however, that they are not.

The language at page 135, quoted above, provides that "[f]urther, if no recovery for reactive power/voltage control is sought...," the allowance is applicable. This might be read to support the position that generation assets which are not needed for reactive power/voltage control are eligible for the allowance, but when this language is read in the context of the sentence that immediately precedes it, which sentence allows partial operating cost recovery for units which are needed primarily for reactive power/voltage control, the quoted language, with its introductory "Further," should be read to apply solely to such units. This interpretation is supported in D.96-12-077 (at p. 31) and in the *Joint Assigned Commissioners' Ruling Providing Additional Procedural Guidance On Phase 2 Issues and Providing Notice of Workshops* (Joint Ruling), issued

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[11] Some parties have urged us to consider a broader array of reliability or ancillary services rather than just reactive power and voltage support. SDG&E, for example, contends that reliability "should encompass all circumstances where generation may be needed to be kept available or incur an unacceptable risk that load may not be served." (SDG&E Opening Brief, p. 3.) Consistent with our discussion of our role in making reliability determinations, we do not attempt to resolve this matter here.

February 3, 1997 in A.96-08-001, et al. Referring to page 135 of the Preferred Policy Decision, the Joint Ruling provides:

> "In the Policy Decision, for plants characterized as reactive power/voltage control units for which the utilities do not seek transition cost recovery, the Commission found that it was appropriate to allow the utilities to retain an incentive of up to 150 basis points above their authorized rate of return for distribution rate base, to the extent that the [PX] clearing price exceeds the cost of running these plants." Joint Ruling, pp. 7-8.)

Since it is not qualified as to reliability or nonreliability units, Conclusion of Law 63 might be read to support the utilities' proposals. However, in Ordering Paragraph 17 of the Preferred Policy Decision, we ordered the utilities to file PBR applications consistent with the policies outlined in the decision. This requires the utilities to look at the discussion and the policies outlined therein. They cannot rely solely on the lack of qualifying language in Conclusion of Law 63. The evidence from several sources is clear that the 150 basis point allowance in the Preferred Policy Decision applies only to fossil plants deemed needed for reactive power/voltage support. As noted in the Joint Ruling issued in the CTC proceeding, the applicability and mechanics of the 150 basis points allowance for such plants will be considered there.

At the same time, we recognize that PBR proposals often feature sharing mechanisms that allow shareholders to retain earnings above their authorized rate of return, within a range. We will not dismiss the current proposals without first providing opportunity for consideration on their merits, but the proponents must show that such allowances are required to further the goals and objectives for electric industry restructuring. To the extent the generation PBRs being considered in this proceeding have such allowances, they are properly considered here as part of those incentive proposals.

4.3 Shutdown of Fossil Generation Facilities

Section 455.5(a) allows the Commission, in establishing rates, to eliminate consideration of the value of, and disallow expenses related to, any generation facility which has been out of service for nine consecutive months. Section 455(b) requires utilities to report on such outages, and Section 455(c) requires the Commission to institute an investigation to determine whether to reduce the utility's rates accordingly. The workshop participants proposed that we address a series of questions focusing on the ability of utilities to shut down fossil generation. Parties were allowed to brief these questions, some of which are resolved by our holding on the role of the ISO in making reliability determinations.

There is agreement among utilities that since they will be at risk for recovery of operating costs from market-based revenues, it is reasonable that they be given discretion to shut down fossil generation facilities which are not needed for local reliability. Beyond this general agreement in principle, the parties' views on Section 455.5 and its applicability diverge somewhat. Edison believes that Section 455.5 is an anachronism which dates back to an era of traditional regulation. Edison urges us to seek appropriate amendments to the statute. PG&E asserts that nothing in Sections 362 or 455.5 prohibits a utility from shutting down a fossil generation station which is not deemed required for reliability without first seeking and obtaining Commission authority to do so. However, PG&E acknowledges that Section 455.5 requires an after-the-fact review of that decision. SDG&E suggests that under Section 455.5(f), the Commission could simply find that any generation facility not being dispatched by the ISO is plant held for future use. This would have the effect of rendering other parts of Section 455.5 inapplicable. CUE, joined by CCSF, argues that utilities may not shut down generating plants without first obtaining our permission to do so, based on a finding that the plant is not needed for reliability.

No party stated an objection to the basic premise that a quid pro quo of exposing utilities to market risks for fossil generation is providing for the reasonable discretion to shut down plants instead of enduring continuing losses. We concur that restructuring fundamentally changes the regulatory compact, and, therefore, that utilities should have reasonable discretion to shut down plants that are deemed too costly to run and that are not needed for reliability. As SDG&E succinctly puts it, "[t]he basis of a market system is that incentives will drive the market, and no entity should be required to operate at a loss." (SDG&E Opening Brief, p. 8.) But Section 455.5, which addresses ratemaking, does not itself impose undue burdens on utilities. In particular, as PG&E notes, it does not require a utility to receive advance permission before shutting down a generation facility.[15]

Further, the ratemaking provisions in Section 455.5(a), with which Edison appears to be most concerned, are discretionary. This Commission may, but is not required to, eliminate consideration of the plant's value or disallow expenses in establishing rates. If a utility can demonstrate that its decision to shut down a plant is consistent with Section 362 and that is has taken reasonable actions to reduce continuing plant costs, there should generally be no adverse rate or revenue recovery consequences to the utility as a result of that decision.

We think SDG&E generally offers a reasonable approach for application of Sections 362 and 455.5 to plant shutdowns. However, we are not prepared to make a blanket determination on the basis of this record that all generation plants not needed by the ISO for reliability purposes constitute plant held for future use. We prefer a case-by-case approach. Pursuant to Section 455.5(b), utilities should periodically report to us on any plans to shut down generation. They should not wait until nine consecutive months after shutdown to do so. Utilities may use such reports to propose that specific facilities be considered plant held for future use under Section 455.5(f). In considering whether to institute investigations pursuant to Section 455.5(c), we will have the opportunity to consider whether the asset should be treated as plant held for future use.

It may be, as Edison argues, that when Section 455.5 was enacted, "it did not contemplate the comprehensive and massive changes now occurring in California

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[15] We reject CUE's assertion that, notwithstanding the clear language of Section 455.5, the "history of AB 1890" requires that utilities now seek advance permission to shut down generating plants. If anything, the legislative history argues against this interpretation. As CUE points out, the Legislature was indeed deeply concerned with reliability issues when it enacted AB 1890. If the Legislature had thought that a new requirement for prior review of utility decisions to shut down generation plants was required to ensure reliability, it would have so provided.

under electric industry restructuring." (Edison Opening Brief, pp. 8-9.) But in AB 1890, the Legislature implemented that comprehensive restructuring through numerous amendments and additions to the Public Utilities Code. One such addition, Section 362, requires that we consider reliability and market power in proceedings brought under Section 455.5 as well as Sections 851 and 854. Significantly, the Legislature chose not amend Section 455.5 itself. We conclude that while the utilities have raised legitimate concerns regarding the market risk of cost recovery for fossil generation, we need not advance recommended amendments to Section 455.5 at this time.

Findings of Fact

1. The ISO, under FERC jurisdiction, has the authority and responsibility for obtaining ancillary services needed for transmission system reliability.

2. FERC has jurisdiction to decide market power issues associated with the designation of must-run generating units.

3. FERC has agreed that the ISO, not the utilities, should determine the facilities that are classified as must-run.

4. This commission has several defined responsibilities with respect to reliability of the transmission system to be operated by the ISO, but it does not have primary jurisdiction to determine the ISO's reliability needs and how those needs will be procured.

5. This Commission will consider reliability and market power issues in proceedings brought before it under Sections 455.5, 851, and 854; in FERC proceedings; and in consultation with the ISO in reports which the ISO must submit to the Legislature.

6. Read as a whole, the language at page 135 of the Preferred Policy Decision which authorizes utilities to retain profits providing up to 150 basis points above their authorized return on distribution rate base applies only to those fossil units that are primarily needed for reactive power/voltage control. This interpretation is supported by D.96-12-077 and in the February 3, 1997 Joint Ruling in A.96-08-001.

7. Because Ordering Paragraph 17 of the Preferred Policy Decision requires utilities to base their PBR proposals on the policies outlined therein, the lack of qualifying language in Conclusion of Law 63 of the Preferred Policy Decision cannot be used to support a claim that the 150 basis points allowance applies to fossil units that are not primarily needed for reactive power/voltage control.

8. In AB 1890, the Legislature, through Section 362, addressed reliability concerns related to utility decisions to shut down fossil generation.

Conclusions of Law

1. Proposals that this Commission designate the generating assets that will be needed by the ISO for transmission system reliability, how those assets will be called upon when needed, or how the owners of those assets will be paid by the ISO for providing reliability services, exceed the scope of this proceeding.

2. Under Sections 216(h) and 377, we will retain jurisdiction over utility-owned generation which has not undergone market valuation.

3. We intend that the 150 basis points allowance which was adopted in the Preferred Policy Decision will be applied only to fossil units which are primarily needed for reactive power/voltage control.

4. Neither Section 362 nor Section 455.5 requires that utilities obtain advance authority to shut down generation plants.

INTERIM ORDER

IT IS ORDERED that:

1. This consolidated proceeding shall be conducted in a manner consistent with the foregoing discussion, findings, and conclusions. Within 15 days of the date of this order, parties may file Prehearing Conference Statements setting forth positions on remaining issues to be resolved in this proceeding, including factual issues requiring evidentiary hearing. Thereafter, the Administrative Law Judge shall set a prehearing conference to determine the need for evidentiary hearings, scheduling, and related matters.

2. San Diego Gas & Electric Company may file a motion for leave to withdraw its application within ten days of the date of this decision.

This order is effective today.

Dated April 9, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners