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Agenda 2/7/90

Decision 90 02 016 FEB 7 1990

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion into the interstate natural gas pipeline supply and capacity available to California.	I.88-12-027 (Filed December 19, 1988)

(Appearances are listed in Appendix A.)

OPINION

I. Summary of This Decision

This decision announces this Commission's position on issues pertaining to additional natural gas pipeline capacity into California. We quantify a range of need for such capacity in the near-term and the long-term, respectively, of 900 MMcf/d to between 1.6 and 2.1 Bcf/d. We also reiterate our generic conditions, originally set forth in I.88-12-027, which are conditions precedent to support any specific projects. Our objective in quantifying the need for capacity and reiterating conditions is to create an environment for competitive forces to work, consistent with the interests of all California ratepayers, to bring gas reliably and at the lowest cost to serve all Californians.

Our staff shall continue to maintain positions in other forums, such as the Federal Energy Regulatory Commission, consistent with our conditions for supporting a given interstate pipeline project. This decision is intended to be used by our jurisdictional utilities as guidance when they consider possible subscription to additional interstate pipeline capacity.

Part of our original intent was to designate a project, or a group of projects, as optimal for California. We also had encouraged the parties to negotiate among themselves and to present to us a comprehensive settlement for our consideration and possible adoption. No single settlement was reached by the parties in this proceeding, but settlements narrowed the choices among the competing pipelines to a limited number of viable projects. However, we decline to make such a designation, and we decline to adopt the proposed settlements. We have found during the course of this investigation that there has been a continuing evolution in the proposals presented to us. This evolution appears to respond to the dynamics of competitive forces and has generally resulted in terms enhancing the potential value to California of these projects. California will benefit from further negotiation among the various interest groups, subject to the understanding that this Commission will support only those pipeline projects which comply with the conditions we set forth in our Order Instituting Investigation.

The constitutional and statutory responsibilities of this Commission can best be fulfilled by setting out clear conditions for Commission support of new capacity and by allowing competitive forces to further refine the proposals. These forces will determine which of the proposals meeting our conditions will actually be built.

The decision also finds that the Southern California Gas Company's (SoCalGas) Southern Expansion Project of 200 MMcf/d is in the public interest, meets all of the Commission's specified criteria, and should be constructed as soon as possible. The Commission also concludes that the proposal of El Paso Natural Gas Company (El Paso) to supply 200 MMcf/d to SoCalGas for the Southern Expansion should be supported. The decision finds that reallocation of existing pipeline capacity through capacity brokering will not by itself alleviate the shortage of natural gas; nor is there a need at this time to announce principles of cost reallocation should any end users on the existing pipeline system place some of their load on the new pipeline. The opinion rejects all of the proposed offers of settlement on the ground that none of them are in the public interest. Finally, the Commission affirms the ruling of Commissioner Duda in Application (A.) 88-12-049 that a certificate of public convenience and necessity is not required for the SoCalGas Southern Expansion Project.

We have presented the history of the various settlement proposals in some detail to show the changes in position and pipeline capacity allocation that have occurred during the course of these proceedings. Those changes may continue as the reality of the marketplace exerts its influence.

II. Response to Comments on the Proposed Decision

Pursuant to PU Code Section 311, the ALJ's Proposed Decision in this proceeding was published and comments received from the parties. We have carefully considered the many comments filed in this proceeding. In response, we have substantially modified the approach of the Proposed Decision. We find a range of potential need for pipeline capacity, as did the ALJ. However, provided a pipeline project conforms to the conditions we originally announced in I.88-12-027, we will support such a project. We also discuss the various projects' current conformity with our conditions.

We emphasize that there will be no further review of the competing projects at this Commission.[1] The parties failed to negotiate the comprehensive settlement we requested, yet this proceeding has presented an opportunity to fulfill our basic goal of clarifying the conditions under which we will support a given project. We note significant progress in improving the project proposals. The record of this proceeding confirms both the broad applicability of the conditions we originally announced in the OII and the sufficiency of our stated conditions in ensuring that conforming interstate pipeline projects will be in the public interest of California.

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1 This is to be distinguished from the Commission's review of the reasonableness of any utility contracts for capacity or gas supply associated with the new pipeline projects. The conditions for that review are discussed further below. We must also recognize that further proceedings will be required in those instances where a certificate is required before intrastate pipeline construction can begin, such as the intrastate portion of the PGT/PG&E expansion.

III. Purpose of This Proceeding

We instituted this investigation to determine whether additional interstate natural gas pipeline capacity is needed to serve the requirements of California and, if such need is found, in what form it should be met. In our order instituting this investigation, we referred to our study of natural gas requirements over the past four years, our restructuring of the intrastate regulation of natural gas, and the need for parties to make economic decisions based upon a firm set of rules. We believed that the issue of new pipeline capacity could best be resolved through negotiation and settlement by those closest to the scene: the gas distribution companies in California; the pipelines serving California and those seeking to serve California; the gas producers, both in-state and out-of-state; and consumers, including the Commission's Division of Ratepayer Advocates (DRA). Our intent was to provide encouragement to competitive market forces to bring together builders and buyers of pipeline capacity. Our goal was, and is, to improve the access of the pipeline network serving California to long-term, least-cost sources of gas. We emphasized that our goal is to provide enhanced service to <u>all</u> California customers, regardless of whether they are core or noncore, located in southern or northern California, or are large industrial, enhanced oil recovery (EOR), residential, or commercial.

Our Order Instituting Investigation (OII) reviewed the long term trends in the California natural gas market and the impact of recent developments on the federal level. The impact of the Federal Energy Regulatory Commission (FERC) through its Orders 436 and 500 on natural gas production and delivery cannot be minimized. Thus, pipeline customers, such as utilities and noncore customers, have greater access to unbundled transportation services on the interstate system, to purchase gas in the spot market, or to contract directly for supplies with gas producers. And pipelines have been given greater freedom to build new facilities and sell either pipeline-owned or contract carriage gas directly to end users. As a result, gas-on-gas supply competition and transportation-on-transportation competition have increased. We believe that FERC will not protect local distribution companies or their customers from supply or transportation competition by interstate pipelines, brokers, producers, etc. Acting on our belief (see Decision (D.) 85-12-102, D.86-12-009, D.86-12-010, and R.88-08-018), we have completely restructured the regulation of gas utilities within the state and redefined the obligation of gas utilities toward their customers. The gas utilities' obligation to supply noncore customers' gas purchasing needs has been modified to a best efforts obligation that is determined by private contract (D.86-12-010). The gas utility, however, still carries the obligation to provide transportation on behalf of noncore customers. The utilities carry the burden of balancing load and storage to maintain the efficiency of the distribution system for the benefit of all customers.

We focused on current events. The summer of '88 was not good for the gas industry in southern California. The winter had been extremely cold, there had been a severe reduction in hydroelectric power due to drought, there were significant operational problems on the El Paso pipeline, and there was a record heat wave. The combination caused curtailment of natural gas deliveries to electric utilities in the Los Angeles area. The electric utilities switched to oil which exacerbated the air quality problems in the Los Angeles Basin. We noted that while added capacity could solve the peaking problem, so might access to unbundled storage, capacity assignment agreements, increased storage, and better pipeline interconnects between the local distribution companies (LDCs) in California.

We concluded that long-term gas supply planning requires consideration of both peak demand and the need for sufficient capacity to capture the economic benefit of gas-on-gas competition. But we did not reject the use of curtailment; 100% service to all customers 100% of the time is not our goal.

In marking the trend towards more competition in the natural gas industry we are particularly cognizant of the possibility of bypass and its consequences for the core gas user. Bypass is the process by which a large gas customer leaves the LDC system and takes service directly from a pipeline. Uneconomic bypass (from the core user's view) results when the large user leaves the LDC system and removes the financial support for that system and places the burden of maintaining the existing system on a shrinking class of customers who do not have the option to take service directly from a new interstate pipeline. In our OII we said:

> "If the need for new pipeline capacity is confirmed, the challenge for this Commission will be to foster the creation of a pipeline network which will effectively accomplish two goals: first, it must provide least cost, reliable gas supplies and economic, reliable transportation for both core and noncore customers; second, it must preserve the economic foundation upon which California's extensive gas distribution system has been built and maintained. With respect to the latter goal, we continue to oppose bypass of the local distribution systems for the purpose of attracting existing loads away from utility service."

To this end "the development and utilization of transportation facilities in California must be rationalized and regulated by the CPUC."

We acknowledged the needs of the EOR customers in Kern County. These customers require large amounts of natural gas to recover oil from wells which otherwise would be uneconomic to operate. EOR customers assert that they can obtain gas cheaper by bypassing the LDCs and dealing directly with interstate pipelines. Nevertheless, in our opinion, the California market as a whole should define the terms of any new gas supply or capacity additions. We should not be held hostage to the needs of a limited number of industrial customers and producers serving a market of limited duration. The EOR market should not dictate the new supply arrangements which will serve California for the next 30 years or more. Their benefit would come at the expense of California's residential, commercial, and industrial ratepayers not served by the bypass pipeline.

We set forth the goals of a new pipeline capacity policy:

- To ensure that adequate, reasonably priced, stable and reliable supplies are available to the core customer.
- To achieve and maintain access to a diverse pool of gas supplies so that all gas consumers, core and noncore--northern and southern Californian--can obtain adequate, reliable, reasonably priced supplies.
- To reduce the likelihood of peak period curtailments by ensuring that adequate, reasonably priced, reliable transmission access is available to noncore consumers.
- To obtain, where economical, sufficient pipeline capacity to foster active gas-on-gas competition so as to secure the benefits of a competitive market for gas for all California consumers.
- To avoid the negative economic impact of uneconomic bypass of the utility distribution systems.
- To ensure that the costs of new capacity additions, as well as the costs of existing capacity from which load may be displaced because of new capacity, are fairly allocated.

The OII then discussed the method best suited to determine capacity need and fulfillment. We studied proposals for new interstate and intrastate pipeline capacity submitted by the LDCs, the current pipeline operators, and the proposed pipeline operators. We concluded that the participants in the gas market should themselves decide through arms-length negotiations whether or not capacity additions are economically viable, and if so, how much capacity on which pipeline project or set of projects is warranted. In this manner the competitive market would determine the need for new capacity and the most economical method of meeting that need. Recognizing the obligation imposed upon us by law to oversee and approve gas sales and delivery in California, we set forth our criteria for new pipeline additions. These criteria are still the basis for our support of or opposition to any of the proposed pipelines. The specific criteria are restated and discussed in detail in the discussion which follows.

We sought a response by February 1, 1989 from our jurisdictional utilities as to their conclusion on need for additional pipeline capacity and their proposal to implement their conclusion. We encouraged a joint settlement proposal to be approved by us and presented to FERC to obtain certificate authority for any interstate capacity additions required to implement the settlement.

IV. Response to the OII and Issuance of D.89-02-071

The response was gratifying. One joint response and five individual responses were filed by the utilities, as well as a settlement agreement between SoCalGas and Kern River. Those filings, while not a complete settlement of the question of new pipeline capacity, significantly advanced the resolution of this issue.

We issued D.89-02-071 to express our conclusions drawn from the responses and to further encourage the parties to continue seeking a solution to California's natural gas problem based upon the guidelines of the OII. One immediate conclusion we expressed was that an improved level of service for noncore gas customers is warranted. Noncore gas customers are defined as those customers having an annual demand in excess of 250,000 therms and which possess alternate fuel capability.

The utilities' responses concluded that under "certain circumstances", which were not specified, additional pipeline capacity can be economically justified. The utilities did not agree on the amount of new firm capacity which could be economically justified, and determined not to jointly select a preferred project or alternative. However, the utilities stated that there is a need for greater access to firm capacity rights for noncore customers and that projected load factor should not be the single criterion for assessing the justification for new pipeline capacity considering the importance of operating flexibility, supply diversity, and gas-on-gas competition. They acknowledged that, in varying degrees, curtailment, the use of storage, and changes in regulatory policy to increase noncore access to firm capacity and firm storage rights or to liberalize noncore procurement options can lessen the need for new pipeline capacity.

A. Utility Responses

1. Pacific Gas and Electric Company (PG&E)

Citing the need for supply diversity and the demand for additional firm capacity rights, PG&E maintains that new pipeline capacity is needed in California. In its proposal PG&E targets two markets for new capacity: the southern California utility market and incremental portions of the Kern County EOR market.

a. Southern California

PG&E proposes the PG&E/Pacific Gas Transmission Company (PGT) expansion project to meet the needs of the southern California utility market. The project would connect southern California utilities to the Western Canada gas supply region by expanding the existing PGT and PG&E systems. PG&E's project involves completing the looping on PGT's existing pipeline within its existing right-of-way to its connection with PG&E at Malin, Oregon, and a looping of portions of PG&E's existing transmission system from Malin to Panoche Station. From that point, gas will be delivered by displacement on PG&E's existing Line 300. At PG&E's Kern River Station, gas will be delivered to the transmission and distribution system of SoCalGas for subsequent delivery in southern California. PG&E projects that the expansion will provide 600 million cubic feet per day (MMcf/d) of new firm capacity.

PG&E asserts that its expansion project is consistent with Commission objectives. In particular the project will provide additional supply diversity, encouraging gas-on-gas competition and lessen southern California's dependence on the El Paso and Transwestern Pipeline Company (Transwestern) pipelines. PG&E does not propose to bypass SoCalGas's distribution system, and proposes that the costs involved be borne by the new customers on the system. The PG&E portion of the project would be under CPUC jurisdiction, while the PGT portion would be regulated by FERC.

b. Kern County EOR Market

PG&E proposes two options to serve EOR producers insisting on new FERC-regulated interstate capacity. The first is construction of incremental capacity additions to PG&E's existing Line 300 from the California/Arizona border through Kern County. Such an expansion would be FERC-regulated, and sized and timed according to EOR shippers' capacity contracts. The second option is construction of a FERC regulated stand-alone pipeline parallel to Line 300, constructed and operated by a FERC-regulated entity. PG&E believes that contracts for at least 400 MMcf/d of capacity are required to make this option economically viable. Jurisdiction over the new capacity under these options would revert to the Commission upon termination of the individual EOR shipper contracts.

PG&E opposes the major alternatives to additional pipeline capacity. Specifically, PG&E argues that reallocation of firm capacity rights on existing systems would hurt core customers by preventing utilities from utilizing the full system capacity to manage costs for the core customers on a least cost basis. Also PG&E believes curtailment is an inadequate solution given the level of service demanded by utility customers.

2. SoCalGas

SoCalGas expresses no opinion on the need for new pipeline capacity. It leaves to the Commission and the utility customers to determine whether a higher level of service is required. SoCalGas outlines its plan to improve its level of service within the existing pipeline capacity, as well as its proposal to increase pipeline capacity if additional capacity is required.

SoCalGas recognizes that noncore customers are demanding greater access to firm deliverability. To meet these demands SoCalGas negotiated a system of capacity assignment agreements with wholesale and UEG customers. Letters of intent to contract for an assignment of firm capacity were submitted to SoCalGas by San Diego

Gas & Electric Company (SDG&E) and the City of Long Beach.[2] SoCalGas expects that this plan will lead to greater gas-on-gas competition and reduce the likelihood of bypass of the existing utility system.

Should the Commission decide that additional pipeline capacity is needed, SoCalGas proposes an incremental expansion of its existing system by constructing facilities at the California-Arizona border which would increase its ability to receive gas through the El Paso, Transwestern, Northwest, and PGT systems. Additional capacity of up to 400 MMcf/d could be provided at a cost of between $100-125 million.

SoCalGas believes that the capital costs involved in its proposal are substantially less than any of the larger pipeline projects, and that its proposal has the advantage of faster completion in 100 MMcf/d increments. SoCalGas argues that proposals resulting in more than 400 MMcf/d in additional capacity may be uneconomic since the capacity would be underutilized.

Regarding the EOR market, SoCalGas says that it has been meeting the producers' needs, and will continue to compete in the event the EOR market is served by a new interstate pipeline.

SoCalGas supplemented its response with a settlement agreement between itself and Kern River which provides that Kern River shall amend its certificate application with FERC to conform to the agreement, including commitments to deliver all non-EOR gas into SoCalGas's distribution system for delivery, and to give SoCalGas a right of first refusal for all capacity rights not

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2 SoCalGas filed contracts with SDG&E and Edision which were rejected by the Commission without prejudice to refile such agreements if amended to conform to certain criteria set out by the Commission. Renegotiation of such agreements is currently underway with SDG&E, Edison and other large customers of SoCalGas. The Commission will reconsider such amended agreements once they are filed with the Commission.

utilized by EOR customers. In addition, Kern River commits to seeking pregranted abandonment authority from FERC for its facilities within the State of California and to bring those facilities within the jurisdiction of the CPUC after 20 years of service under Section 1(c) of the Natural Gas Act. The agreement is contingent upon the CPUC's agreeing to waive the contract modification provisions of GO 96-A for EOR contracts in force when the jurisdictional reversion occurs. We commented in D.89-02-071 that this agreement is designed to bring the Kern River project within the criteria of I.88-12-027, and on its face does not conflict with the criteria, although other conditions remain to be met, such as economic justification.

3. Southern California Edison Company (Edison)

Edison did not develop a comprehensive gas transportation proposal at this time, but it believes that a new capacity addition of up to 400 MMcf/d for all of southern California is economically justified. Although Edison foresees no increase in its gas usage, it is impacted by the demands of higher priority customers. Edison maintains that the benefits of increased gas-on-gas competition outweigh the costs of increased capacity and that the lower capacity factor which would result from additional pipeline capacity is reasonable. Edison executed a letter agreement with PGT indicating that it is contemplating acquiring 200 MMcf/d of firm capacity on the proposed PG&E/PGT expansion. Edison is also renegotiating with SoCalGas long-term contracts for access to firm transportation capacity on SoCalGas's existing lines. As mentioned above, these contracts were rejected subject to renegotiation purusant to certain conditions imposed by the Commission. The possibility of approval of such contracts does not alter Edison's position on the need for additional capacity.

4. <u>SDG&E</u>

SDG&E supports additional pipeline capacity because it seeks to obtain firm interstate capacity rights. Although SDG&E is also renegotiating long-term contracts with SoCalGas for an allocation of firm capacity, SDG&E still believes additional pipeline capacity up to 700 MMcf/d can be economically constructed. SDG&E itself is interested in obtaining 100 MMcf/d of capacity to a new supply area, of which 25 to 50 MMcf/d would be truly incremental capacity while the remainder would displace load on existing systems.

5. <u>Southwest Gas</u>

Southwest Gas declined to participate because its market in California is small.

B. <u>New Interstate Pipeline Proposals</u>

In D.89-02-071 we reviewed the proposals to provide new or enhanced pipeline service to California. We divided the proposals into three categories: new interstate pipelines, expansions or enhancements of existing interstate or intrastate pipelines, and proposals to provide greater access to existing firm capacity.

The Mojave Pipeline Company (Mojave) has an application pending before FERC for a certificate under Section 7(c) of the Natural Gas Act. Hearings on both the environmental and nonenvironmental issues have been concluded and briefs have been submitted. However, no action on the Section 7(c) certificate applications has been taken by FERC to date. In addition, Mojave filed an optional certificate (OC) application with FERC which proposes an array of new projects, including a 400 MMcf/d line from Topock, Arizona to Kern County. Mojave was granted an OC by the

FERC on May 8, 1989.[3] On February 17, 1989, Mojave and Texaco announced agreement on a contract for 185 MMcf/d of firm capacity on Mojave for a minimum 15-year term, with an option for an additional 50 MMcf/d of interruptible transport capacity. This was Mojave's first major customer commitment and was an important indication that the EOR market is not uniformly intent on direct access to Wyoming supplies.

Mojave joined with SoCalGas and Kern River to file a joint settlement proposal before the FERC to build a combined project wherein Kern River and Mojave would build separate facilities from Opal, Wyoming and Topock, Arizona, respectively, and combine at Barstow, California, building and operating joint facilities from that point to Kern River Station, California. A certificate for that project was issued by the FERC on January 24, 1990.[4] The FERC did not approve the joint settlement, but only issued a certificate for construction and operation of the joint pipeline project.

Kern River has, as indicated above, signed an agreement with SoCalGas which would cause an amendment of its Section 7(c) certificate application at FERC in order to conform to the anti-bypass and jurisdictional requirements of I.88-12-027. The agreement with SoCalGas represented very significant progress to the extent that it was the first time that a major pipeline proponent, and, by implication, the EOR producers which support that pipeline, agreed to terms which significantly reduce the negative impacts of bypass for California ratepayers and preserve

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3 Mojave Pipeline Company, Order Issuing Certificates, 47 FERC P61,200 (1989).

4 See Kern River Gas Transmission Company and Mojave Pipeline Company, Order Issuing Certificates, Granting and Denying Rehearing, and Clarifying and Modifying Prior Order, __ FERC ____, issued January 24, 1990 in Dockets No. CP89-2047-000 and CP89-1-001 and consolidated cases.

California's jurisdiction over its gas distribution facilities. Such a step was essential to begin a move toward a comprehensive settlement which addresses the needs of the EOR and non-EOR markets while meeting the Commission's criteria for new capacity. Subsequently, Kern River joined with Mojave to propose to FERC a joint pipeline project in connection with a settlement with SoCalGas, as discussed previously.

However, as indicated above, the actual certificate decision issued by the FERC did not approve the provisions of the settlement which provide for a reversion of jurisdiction to the CPUC or sale of the in-state facilities to SoCalGas.

Wyoming California Pipeline Company (WyCal) has been granted an OC by FERC to operate from Wyoming to California. Thus, WyCal is the only pipeline with an effective certificate in hand. Whether it meets our OII criteria is still in issue. More recently, the FERC issued another order certificating one of three alternative routes sought by WyCal. Specifically, the FERC certificated a downsized version of the stand-alone WyCal project and rejected two alternatives which would have involved the leasing of PG&E-owned and operated facilities.[5]

Southcoast Transmission Company has, to our knowledge, only recently filed its application with FERC, and has no commitments from major customers.[6] The Southcoast project, as represented by its proponents, would not satisfy the criteria in I.88-12-027 on either bypass or jurisdictional grounds.

Mexus Pipeline Company has not perfected its application at FERC, according to the information available to us, and has no major customer commitments. Neither does Mexus, as proposed,

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5 See Wyoming-California Pipeline Company, Order Issuing Certificate and Amending Prior Orders, __ FERC ____, issued January 24, 1990 in Dockets No. CP90-41-000 et al.

6 We are at this time uncertain if Southcoast's application has been accepted for filing by the FERC.

contain restrictions which satisfy the key bypass and jurisdictional requirements of I.88-12-027.

The APEX project for a Canadian producer-built PGT expansion has not filed any application, and the Commission is uncertain if it intends to file a separate application or proceed on the basis of PGT's own application. Equity ownership by out-of-state producers does not necessarily infringe any of the criteria in I.88-12-027.

Altamont Gas Transportation Project, which had previously modified its has changed its proposal to encompass a direct route from Alberta to southern California, has once again revised its project to connect Wild Horse, Alberta and Opal, Wyoming. As finally modified, the project would not cross the state borders into California and does not bypass any LDC facilities. Subsequently, Altamont entered into an agreement with SoCalGas to provide 200 MMcf/d of gas transportation from Alberta to the interconnection with the Kern River project.

C. Expansion of Existing Pipelines

PGT and PG&E have made a combined proposal to expand incrementally their existing facilities linking California with Canada to obtain an additional 600 MMcf/d of capacity. PG&E and PGT subsequently amended their project description to increase the capacity of the project to 755 MMcf/d. This project, which would be FERC jurisdictional only outside of California and utilize PG&E's regulated facilities within California, is structurally and jurisdictionally consistent with I.88-12-027. PG&E/PGT have filed letters of intent from a large number of potential customers, including Edison and SDG&E, and PG&E itself, to transport gas totaling 750 MMcf/d.

El Paso and Transwestern have separate certificate applications pending before FERC to expand their respective systems for the purpose of supplying gas to the Mojave project. Neither pipeline expansion involves construction within California; therefore, neither is by itself a bypass pipeline. If combined with a jurisdictionally appropriate project within California, El Paso and Transwestern could participate in a project which meets the criteria of I.88-12-027.

SoCalGas has proposed an incremental expansion of its own transmission facilities to provide an additional 400 MMcf/d of capacity. This expansion, if coupled with an incremental increase in El Paso or Transwestern capacity, would meet the key bypass and jurisdictional criteria of I.88-12-027 as all transmission and distribution within California would take place on regulated utility facilities. Subsequently, SoCalGas addressed both in this proceeding and in its then pending general rate case (A.88-12-049), a limited 200 MMcf/d expansion of its southern transmission system.

PG&E has proposed two alternatives for service between Kern County and the Arizona border: an expansion of its own Line 300 and a stand-alone facility paralleling Line 300. Either project could be structured to be temporarily federal in jurisdiction to meet the wishes of EOR producers. So long as jurisdiction was certain to be returned to the CPUC after a fixed period, and commitments against non-EOR bypass were obtained, these projects could meet the criteria set out in I.88-12-027.

D. <u>Agreements for Greater Access to Firm Capacity</u>

SoCalGas has actively sought to contract with its UEG and industrial customers to assign firm capacity rights on the interstate pipelines with which it has service agreements.[7] As such measures do not involve bypass and retain CPUC jurisdiction

7 As indicated previously, the long -term capacity assignment contracts filed with this Commission by SoCalGas were rejected (D.89-12-045.), with leave to refile if amended. Amended agreements have not yet been refiled with the Commission.

over intrastate facilities, they meet the key criteria of I.88-12-027. Agreements to restructure existing capacity in more efficient ways were clearly contemplated by the OII and represent significant progress in resolving the need for a higher level of service without costly new pipeline construction. Such agreements will be considered as alternatives to the construction of new capacity.

E. Summary of D.89-02-071

In D.89-02-071 we summarized the proposed projects to date and said that five projects have the potential to satisfy the Commission's stated criteria for new pipeline capacity: PG&E/PGT, Kern River, SoCalGas's incremental expansion, either version of PG&E's incremental expansion, and SoCalGas's capacity assignment program. The SoCalGas expansion project and the two PG&E projects involving facilities from Kern County to Arizona could also include expansions by either El Paso or Transwestern. We emphasized that with the execution of amended applications and agreements similar to that signed by Kern River other pipeline projects could become viable in the eyes of the Commission. All project proponents who wish to receive equal consideration understand the need to conform to the I.88-12-027 criteria. If more projects meet the criteria then the customers who desire more pipeline capacity will have a greater selection of projects from which to choose.

We noted that utilities which are customers of the gas distribution utilities (Edison, SDG&E, and by virtue of its own electric department, PG&E), are on record as believing that additional pipeline capacity is required. They indicate various degrees of willingness to participate in the construction of such facilities and to sign contracts for firm capacity. Similar comments have been made to the Commission by other parties in recent proceedings on curtailments. For example, at the en banc on long-term gas supply issues held in I.88-08-052 statements supporting the need for new capacity were made by, among others, the Southern California Utility Power Pool, the City of Long Beach, the California Cogeneration Council, the California Industrial Group, Mock Resources, and Chevron U.S.A. The presence of potential customers ready and willing to pay for new capacity is perhaps the clearest indication that the market requires new capacity to function as efficiently as it might.

We also noted other indications of the need for new capacity. Taking into account the recent weather-related curtailments of industrial and electric generation customers in both northern and southern California, noncore customers have experienced four significant curtailments within the last three years, including curtailments during three of the four winters since open access transportation commenced. See I.88-02-013 (curtailment of the winter of 1987-88) and I.88-08-052 (curtailment of August-September 1988 and curtailment of February 1989). We take official notice of the record in those proceedings as part of our consideration of the question of pipeline capacity.

While we remain convinced that curtailment of customers with alternative fuel capabilities is a justifiable and reasonable tool for gas distribution utilities to use to balance gas supply and demand, we are not content to suffer curtailments on a routine basis. As we discussed in I.88-12-027, there are factors which will increase the importance of sufficient access to gas in the California energy markets of the future, such as air quality restrictions on the use of fuel oil for industrial purposes. The number of such curtailments recently experienced may be an indication that structural changes in the market are needed.

We concluded that the frequency of curtailments since the initiation of open access transportation, the comments of numerous end-users and shippers supporting the need for new capacity, the demand for greater access to firm capacity rights, and the existence of utilities willing to construct and pay for new capacity show that a higher level of service reliability for noncore customers is warranted. Along with more efficient utilization of existing pipeline capacity, new pipeline capacity appears to be an appropriate means to provide such a higher level of service. New capacity will enhance the level of service provided to noncore transmission customers, who have been adversely affected by all three recent curtailments.

New capacity will also improve noncore customer procurement options by increasing the number of pipeline routes for moving gas to California, and by driving gas prices lower through enhanced gas-on-gas competition. Additional capacity provides purchasers with an increased ability to switch their purchases from one producing area to another in pursuit of the lowest prices. When pipeline capacity is constrained, customers may be forced to use capacity, and thus to buy from less competitive suppliers, simply to ensure that they receive enough supplies to meet their total demand. Edison has provided an example of this phenomenon with its comparison of the SoCalGas and PG&E portfolio costs contrasted with the varying load factors on the pipelines supplying their systems.

D.89-02-071, while concluding that a higher level of service is reasonable, left open for industry negotiation and possible settlement the choice of method to meet that higher level. Our aim was to bring a comprehensive settlement to FERC for federal certification based on its meeting our standards of ability to attract customers, economic justification (which considers the effects of excess capacity and stranded investment, i.e. existing facilities which are underutilized as a result of load shifting to new facilities), guarantees against bypass, and CPUC jurisdiction.

We directed respondents PG&E, Edison, SoCalGas, and SDG&E to continue to meet with pipelines, end users, producers, and each other to attempt to reach agreements to provide a higher level of service to noncore customers; and to file their agreements with us within sixty days (later extended to June 1). We invited all parties, whether pipelines, end users, producers, or other utilities to submit proposals, either individually or jointly. We said that we favored a settlement, but if none were satisfactory, we would conduct hearings to develop a policy to enhance the level of noncore service. We put all parties on notice that at the hearing we expected evidence on the level of enhanced service to the noncore market, the means of achieving such enhancement, an analysis of alternatives, and an analysis which indicates compliance with the criteria of I.88-12-027.

IV. The Response to D.89-02-071

The response to D.89-02-071 did not meet our expectations. We had hoped for a comprehensive settlement, at least between the jurisdictional utilities, but we received two major proposals which were mutually exclusive (the PG&E/PGT Expansion Project and the SoCalGas-Kern River-Mojave Settlement), plus the WyCal proposal and comments by the principal parties to the investigation. Nevertheless, the proposals were signs of progress. Groups formed, parties took positions, and entities which might have been expected to participate did not, thereby narrowing the choices considerably.

A. PG&E/Wyoming-California Pipeline Company (WyCal)

On March 8, 1989, PG&E and WyCal filed a settlement agreement which they claim meets the criteria of I.88-12-027. The essence of the agreement, as we understand it, is that should WyCal construct a pipeline from the Overthrust gas producing area in Wyoming to California, PG&E shall have the right to purchase 50 MMcf/d of firm transportation capacity on the system for 20 years and PG&E shall have the right to acquire 25% of WyCal. Subject to various contingencies the California portion of the pipeline will become subject to CPUC jurisdiction after 20 years. Either party is permitted to enter into other arrangements with other persons to provide the same service and either party, in its sole discretion, may terminate the agreement on economic grounds. The agreement incorporates the incremental expansion of PG&E's Line 300.

B. DRA

The June 1, 1989 filing of DRA opposes immediate construction of any new pipeline. DRA asserts that:

> "...the existing system is more than adequate to meet the gas requirements of the California market for the next several years at the reliability levels equivalent to those experienced in the past. Based upon currently available forecasts, new interstate capacity will not be required until sometime between 1997 and 2000. This represents the period when gas demand in California will exceed capacity under a cold year scenario. Until then, the integrated California system is capable of meeting the demands of the California market. ...if non-core customers want greater reliability than has historically been provided, they should subscribe to new interstate pipeline capacity directly."

DRA states that given the adequacy of the existing system, the immediate construction of additional pipeline capacity carries substantial risks and minimal benefits. The risks to different customer classes, particularly the core customer, from stranded investment will vary, depending upon the size of the additions and the method of demand cost recovery. DRA maintains that, depending upon whether a 400 MMcf/d or 600 MMcf/d interstate pipeline is constructed, SoCalGas's ratepayers will face a minimum annual increase of $30 to $60 million due to existing customers subscribing to new capacity. Some, but not all, of the costs of this stranded investment may be mitigated in the future through increased throughput on the system.

DRA believes that the benefits from gas-on-gas competition are overstated. Its studies show that the historical relationship between SoCalGas and PG&E gas prices gives no indication that increased gas-on-gas competition will significantly affect the current disparity between their gas prices. Furthermore, the expected benefits or reduction in gas costs from gas-on-gas competition resulting from new capacity additions are significantly lower than the costs of new interstate pipeline capacity. The recent curtailment problems on the SoCalGas system are by themselves insufficient to justify adding additional capacity at this time. The problem is better addressed through the prompt implementation of a program of capacity brokering and storage banking together with more efficient utilization of the existing system through increased interutility transportation.

DRA declares that if the Commission does elect to endorse the construction of additional interstate capacity, steps should be taken to protect ratepayer interests. Noncore customers who want the benefits of additional interstate capacity should bear the risks. In particular, they should be required to subscribe directly for the capacity rather than having the LDC initially subscribe for the capacity and broker it later. If the Commission permits LDCs to construct new intrastate additions or subscribe to additional new interstate capacity to provide a higher level of service to the noncore market then these costs should be allocated directly to those customers. This will provide the LDCs with an incentive not to overinvest in new capacity since shareholders will be at some risk for the recovery of these costs.

Electric utilities regulated by the Commission should be required to provide independent justification for any investment or commitment they intend to make in a new interstate pipeline project.

Any decision to build a new pipeline in order to increase the level of service to the noncore should be accompanied by a reexamination of the way costs are allocated to the noncore. Many costs, including pipeline demand charges, are allocated on the basis of cold year sales to reflect the interruptible nature of noncore service. If excess capacity is going to be installed to virtually eliminate the interruptibility of noncore service, then the cost allocation of current investment needs to be reexamined.

C. PG&E

PG&E reported that marketing of its 600 MMcf/d expansion project was successful. Southern California utilities executed agreements as shippers for the transportation of a total of 350 MMcf/d: SDG&E, 100 MMcf/d; City of Long Beach, 50 MMcf/d; and Edison, 200 MMcf/d. PGT has also received executed agreements from Cascade Natural Gas Corporation, 38.5 MMcf/d; IGI Resources, Inc., 25 MMcf/d; Northwest Natural Gas Company, 40 MMcf/d; and Washington Water Power Company, 100 MMcf/d.

An open season was then conducted to secure commitments from other shippers for the remaining capacity. Interest in the remaining capacity far exceeded the amount available. In total, 1.6 Bcf/d of capacity was requested during the open season, with a substantial number of bidders offering to pay 100% of the total cost of service in a reservation fee. PG&E expects its expansion project to be online late 1993 to enhance reliability, provide access to diverse gas supplies (Canadian), and secure the benefits of gas-on-gas competition.

PG&E urges the Commission to make a finding that California requires new capacity; that at least 600 MMcf/d is needed; that the PG&E/PGT project meets our criteria and should be supported at FERC; and that the decisions of Edison and SDG&E to commit to specific levels of additional transportation capacity on the PG&E/PGT line be approved. PG&E stressed the importance of this Commission's addressing in this investigation the prudence of the regulated shippers' (Edison and SDG&E) commitments to transportation capacity.

D. PG&E/PGT

In addition to its individual response, PG&E joined with PGT in presenting their joint proposal for expanding their pipeline. This proposal supplements the information provided by PG&E's individual filing.

The joint filing shows that nine shippers were awarded firm capacity between Kingsgate, British Columbia and Kern River Station and have executed precedent agreements. These shippers were awarded a pro rata share of their initial capacity requests because they all placed the same value on capacity on a unit basis and their aggregate requests exceed the capacity available from Kingsgate. Three shippers received initial awards for firm capacity between Stanfield, Oregon and Kern River Station and executed precedent agreements. The precedent agreements contractually obligate both utility and nonutility shippers to enter into firm transportation agreements with PGT and PG&E, to seek long-term gas supplies, end use markets, or both; to arrange for gas supply deliveries to the PGT system at either Kingsgate, British Columbia or Stanfield, Oregon; to obtain transportation downstream from Kern River Station; and to seek all necessary regulatory approvals in both the U.S. and Canada. Additionally, and most significantly, the precedent agreements bind the shippers to this project exclusively for the amount of capacity awarded. In short, execution of a precedent agreement commits each shipper to:

- The full capacity they have designated on the expansion;
- Not seeking duplicative capacity on any other proposed project;

- o In the case of end users, utilities or brokers, that they will immediately commence arrangements to commit a gas supply; and

- o In the case of producers or brokers, that they immediately commence arrangements to commit a market.

The joint proposal explains how it meets the criteria of I.88-12-027. It asserts that customers in southern California should be able to obtain Canadian gas at market-based prices within a range that will support the dedication of long-term reserves to southern California.

PG&E asserts that based upon the ratio of reserves to production, long-term resource availability from Canada far exceeds resources from the Southwest. The economic value of this long-term supply advantage is difficult to determine without sufficient deliverability to transport these Canadian supplies to market. Furthermore, as Southwest supply deliverability diminishes and market needs increase in California and other parts of the U.S., the additional supply from Canada will play a major role in ensuring gas deliveries to California will remain competitive. The consensus view in the industry is that finding costs in Canada are now and will be in the future substantially below what they are domestically. In addition, the PG&E/PGT expansion is the most direct, shortest, and least environmentally costly route between the supply and the southern California market. It is the least cost option for moving Canadian gas to the southern California market; therefore Canadian gas should be particularly competitive.

The PG&E/PGT expansion will substantially enhance the state's supply diversity by providing 600 MMcf/d of access to non-Southwest gas for southern California. The expansion will provide a new link to gas supplies originating in Alberta, British Columbia, and even Saskatchewan, Canada. Because of PGT's proximity to Northwest Pipeline Corporation transmission facilities at Stanfield, Oregon, access to Rocky Mountain supplies is also possible. Through diversity, the expansion project offers southern California utilities, as well as other end users, the benefits of enhanced competition, reliability, lower commodity prices, and lower risk of curtailments.

As proposed, shippers who receive transportation service through the expansion will pay the full cost of the project. Customers not utilizing any of the expansion facilities will not pay the costs of the project. The PG&E/PGT expansion raises no jurisdictional issues since the California portion of the expansion will be subject to CPUC regulation. The PGT portion of the expansion will interconnect with PG&E at the California border. PG&E will then move the 600 MMcf/d to PG&E's Kern River Station at which point the gas will move through an intervening regulated distribution company, and on to end users' burner tips. The project does not propose to bypass either the existing system of SoCalGas or of PG&E.

E. SoCalGas

SoCalGas proposed what it considers to be a comprehensive program to meet California's needs. It will provide a high level of service through enhanced utilization of existing intrastate pipeline capacity, storage capacity, and existing interstate pipeline capacity. It will expand its own pipeline system and will enter into contracts with interstate pipeline companies for additional capacity.

SoCalGas will provide firm interstate transport capacity by either assigning or brokering firm interstate capacity to its customers. To enhance reliability of transport gas for UEG requirements on the intrastate system it will reclassify to a higher priority certain volumes available for UEG use. It has implemented a storage program for its noncore customers under which more than 13 Bcf of storage has been subscribed.[8]

SoCalGas states that it continues to enter into long-term transportation contracts with its EOR customers. To date it has contracts for 760 MMcf/d. Its customers include the largest EOR customers in its service territory: Mobil Oil, Shell Oil, Texaco. To provide all of its enhanced services SoCalGas seeks to expand its existing system by 200 MMcf/d, which can be completed in about 18 months. It is also negotiating with all the proposed new pipelines into California for capacity on those systems.

On June 16, 1989, SoCalGas filed what it calls Principles of Agreement with Mojave and Kern River and which it considers to be a settlement agreement. It also filed a separate agreement with Kern River, and later one with Altamont.

The Principles of Agreement recite that Mojave will build a pipeline from Topock, Arizona to Kern County and Kern River will build a pipeline from Opal, Wyoming to Kern County. The pipelines will converge near Barstow, California, downstream of which they will use a common pipe. Mojave will be capable of delivering 400 MMcf/d to the interconnection point and Kern River will be capable of delivering 700 MMcf/d to that point. SoCalGas will commit to 150 MMcf/d of firm capacity on Kern River plus it will be able to contract for shippers making delivery to SoCalGas access to Mojave and Kern River. Transportation rates are subject to negotiation and Mojave and Kern River are free to compete against each other and against other transporters. The California portion of the pipelines will initially be subject to FERC jurisdiction, but after twenty years jurisdiction will revert to CPUC. SoCalGas has the option to purchase 100% of each pipelines' facilities in

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8 We note, however, that only approximately 4 Bcf of gas was injected into storage for noncore customers under the pilot storage banking program because of difficulties in meeting high levels of demand on the system during the initial injection season of the program.

California 20 years after the in-service date, under terms and conditions to be negotiated.

The separate SoCalGas agreement with Kern River permits SoCalGas to transport 150 MMcf/d of Canadian gas on Kern River's system from Opal to Kern County, on terms to be negotiated. The parties agree to work together and cooperate in marketing capacity to SoCalGas's industrial and UEG customers on the Kern River pipeline when delivery is made by Kern River to SoCalGas for redelivery to the end user. SoCalGas has the option to purchase Kern River's California facilities 20 years after the initial date of operation on terms and conditions to be negotiated, and SoCalGas has the option to acquire all firm capacity on Kern River which is not used by Kern River's firm EOR/cogeneration customers. The agreement concludes by listing numerous conditions which permit either party to cancel the agreement in its sole discretion.

On June 23, 1989, SoCalGas filed a separate agreement with Mojave whereby SoCalGas is granted an exclusive option to purchase a 100% ownership interest in that portion of Mojave's pipeline and related system located in California, 20 years after initial operation, on terms to be negotiated, at which time the California facilities shall revert to CPUC jurisdiction. The agreement provides that Mojave's California customers may either use SoCalGas's pipeline to connect to their facilities or may connect directly to Mojave's pipeline, thus bypassing SoCalGas's system.

F. <u>Edison</u>

Edison, in its June 1, 1989 filing, asserts that the PG&E/PGT expansion project meets the Commission's criteria more fully than any other proposed project. As a consequence, Edison has committed to 200 MMcf/d of firm capacity on the expansion pipeline. Additionally, Edison has agreed to take 50 MMcf/d of firm capacity on WyCal's project, should it be built, and has contracted for firm transportation rights for 300 MMcf/d during the summer and 200 MMcf/d during the winter over the SoCalGas system.[9] Edison states, however, that the Commission must address the effect of new capacity on the allocation of costs for existing capacity, in order to permit the market to determine the volume of new capacity which can be developed. In Edison's opinion without some basis for estimating reallocation of such costs, it is not practical for the market to make this determination.

Edison believes that the most important criterion in selecting between pipeline alternatives is the effect on gas-on-gas competition. It maintains that the wellhead cost of natural gas is most important and to assure low cost gas there must be diversity of source. For Edison that means a source outside of the Southwest. Edison makes the flat statement "that additional pipeline capacity to the Southwest is not in the best interests of southern California energy consumers." In support of its conclusion, Edison has entered agreements with PG&E/PGT to transport Canadian gas and with WyCal to transport Rocky Mountain gas.

In its filing Edison emphasizes its position that for new pipelines to be economically justified there must be a reallocation of costs on the existing pipelines. That is, the demand charges of underutilized facilities must be redistributed among customer classes. Edison points out that although the economic benefits to all gas customers of new pipeline capacity to Canada and/or the Rocky Mountains will far outweight their cost, such benefits may not outweigh the cost to the individual customers of the new pipeline without action by the CPUC to reallocate existing interstate pipeline demand charges. Because Edison does not

9 The initial Edison/SoCalGas contract was rejected by D.88-12-045 without prejudice to refile if revised to meet certain Commission-imposed conditions.

believe it is possible for itself, or other gas customers subject to payment of existing allocated demand charges, to responsibly enter into contracts for new capacity without making some assumption in this regard, it has explained its concerns in detail and requests Commission action at this time. Known Commission policy on reallocation of costs at the time new capacity is placed into service is an essential requirement of Edison's support for new capacity. Edison argues:

1. <u>The Need for Cost Reallocation</u>

The total cost of gas delivered at a SoCalGas interconnect is the sum of: (1) the commodity cost of gas, (2) the variable transportation cost, and (3) the pipeline demand charge expressed on a unit volume basis. As a portion of Edison's total gas demand transfers from existing capacity to new capacity, but is still delivered over the local distribution system, the cost of the remaining Edison volumes on the existing capacity increases significantly, unless the pipeline demand charge is reduced. This is because component (3) increases faster due to declining volume than can be offset by the benefits of gas-on-gas competition.

Therefore, even though gas may be priced competitively over new capacity as compared to the current total cost of gas over existing capacity, without reallocation of the demand charge an individual gas purchaser will experience an increase in its total gas cost when it transfers a portion of its demand to new capacity. Edison is convinced that the price of gas delivered over the new capacity cannot be maintained low enough over the long term to offset this effect.

2. The Basis for Cost Reallocation

As Edison believes the benefits to all gas consumers of increased pipeline capacity are evident, reallocation of existing demand charges should reflect the distribution of those benefits.

Currently, interstate pipeline demand charges paid by SoCalGas are allocated to its customers on the basis of cold year throughput. This is so, notwithstanding the fact that the benefits derived from payment of these demand charges are not uniformly shared by all customers. For example, SoCalGas noncore customers do not receive the benefit of gas delivered over PITCO, for which a relatively large demand charge is currently paid.

Therefore, Edison believes that the Commission should reconsider the allocation of all demand charges, and implement changes as necessary to reflect the value received by the various customer classes from the payment of such charges. Within this context, at the appropriate time, a reduction in Edison's allocated share of the demand charge for existing pipeline capacity, resulting from transfer of a portion of its volumes to new capacity, would occur.

Edison believes that the Commission can best assist the market to determine what represents a reasonable addition to existing pipeline capacity by addressing the issue of demand charge reallocation at this time, at least in principle. The extent to which the benefits of gas-on-gas competition are projected to offset the increase in cost for service over existing pipelines, following cost reallocation, will determine the level of market support for construction of new pipelines, at least for gas customers subject to cost allocation by the Commission.

G. SDG&E

SDG&E reports in response to D.89-02-071 that it has signed agreements with SoCalGas and PG&E/PGT. The SoCalGas agreement (subject to Commission approval) will give SDG&E (1) 300 MMcf/d of firm interstate capacity rights now held by SoCalGas, (2) 12.7 billion cubic feet (Bcf) storage rights on SoCalGas, (3) P-3 classification for UEG load, and (4) other benefits.[10] The PG&E/PGT agreement (subject to Commission approval) will give SDG&E 100 MMcf/d of capacity on the expansion pipeline.

In support of its PG&E/PGT agreement SDG&E asserts that having transportation rights will allow it to purchase Canadian gas at favorable prices. SDG&E believes that Canadian supplies are extremely competitive in comparison to SDG&E's current supply areas and supplies in the Overthrust region. SDG&E says that the PG&E/PGT expansion project when combined with competitively priced Canadian gas supplies available for transport to the southern California market is the most economic capacity addition that has been proposed, and it complies with the Commission's criteria for new pipeline capacity additions. The project allows customers in southern California to access long-term gas supplies, enhance transportation reliability, and achieve gas cost reduction. It reaches diverse supply areas, allocates costs only to those using the service, meets jurisdictional concerns, and will not result in bypass of existing distribution facilities subject to Commission jurisdiction.

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10 This contract was subsequently rejected by the Commission without prejudice to refile an amended agreement.

V. The Prehearing Conference

A prehearing conference was held on July 6, 1989 to discuss, among other things, a schedule for submitting proposed settlement agreements and a hearing schedule for other issues. SoCalGas stated that it had entered into settlement agreements with Mojave and Kern River, both separately and jointly, to provide a new pipeline to southern California from Wyoming and the Southwest. PG&E stated that it had entered into a settlement agreement with PGT (an affiliated company) and a group of end users who have agreed to use a new pipeline to be built parallel to PG&E's current pipeline from Canada. Edison stated that it expects to support one or more settlement agreements. WyCal stated that it intends to participate in the hearings and is conducting settlement conferences with the proponents of the various settlement agreements, but has come to no conclusion. WyCal is considering presenting its own proposal to the Commission. SDG&E stated that it supports the PG&E/PGT proposal but would discuss the SoCalGas and WyCal proposals.

The prehearing conference order provided that while settlement negotiations were progressing in compliance with Rule 51.1, we would hold hearings on other issues: (1) the need for additional natural gas, (2) the effect of assignment of firm gas transmission capacity rights, and (3) the effect of new capacity on the allocation of costs for existing capacity.

The presiding ALJ raised the question of imposing a time limit on submission of settlements or unilateral pipeline proposals. After discussion, the ALJ ruled that all proposals must be filed no later than 15 days after the latter of the PG&E proposal or the SoCalGas proposal. (This was later modified to a date certain: August 30.) The parties were admonished to be specific in their pipeline proposals regarding the timing of start of construction and completion, costs of construction and operation, gas-on-gas competition, savings to end users, and in general how the proposal meets the criteria of the OII.

VI. The Hearings

Public hearings were held before ALJ Barnett, starting August 14, 1989, in two phases. Phase I considered the three issues of need, assignment of capacity, and cost allocation.

A. The Need for New Capacity

1. Edison

Edison's witness testified that Edison purchases for transport by SoCalGas a substantial portion of the natural gas it burns. Edison does not currently have access to firm interstate capacity so it can only purchase gas on a best efforts basis. On average Edison can obtain delivery of about 55% of the gas it would wish to purchase for transport. The balance of its desired transportation volume is met by higher cost purchases from SoCalGas and by use of alternate fuel and purchased power. As a result Edison's costs have risen and its quality of service reduced. If new capacity is not added Edison believes these adverse consequences will continue at even greater cost.

The witness recommended added capacity for three fundamental reasons:

1. To provide the benefits to all southern California gas consumers, including Edison, of price competition among gas producers and producing regions. Currently, these benefits are largely being denied by the chronic shortage of available transportation capacity directly connected to the SoCalGas system.

2. To provide the benefits to all southern California gas consumers of a reduction in the demands on the spot market and an increased use of long-term gas procurement

contracts, from new sources of supply, which provide increased security of price and supply. It is not reasonable for electric ratepayers to continue their current heavy reliance on the spot market, or even on short-term procurement contracts.

3. To restore and maintain an acceptable level of service. Edison's level of service has been substantially eroded by increasing EOR and preferential cogenerator demands. However, provision of an acceptable level of service does not mean that Edison is seeking a new, non-interruptible level of service for its entire demand.

The witness believes that an increase in interstate capacity of 400 MMcf/d would pay for itself through a reduction in the average cost of gas of only 3%, which is reasonable to expect. The economics of pipelines, however, would require a project which delivers at least 600 MMcf/d to be profitable; therefore, he recommends a 600 MMcf/d project.

He said that SoCalGas's system is now operating at close to capacity, which hinders its ability to serve its customers and take advantage of competitive prices. New capacity will reduce SoCalGas's average capacity factor. In his opinion, the reduction in SoCalGas's current average capacity factor, which Edison believes defines the need for construction of new capacity, will not result in "idle capacity" or "abandoned facilities," in any meaningful sense of these terms. Such conditions would exist only when the existing capacity was no longer performing a useful function, which is not conceivable if the volume of new capacity constructed is limited as proposed by Edison. The useful function served by such idle capacity is to permit the existence of a competitive market. The capacity is not idle in an economic sense, but is useful and, in fact, is essential to the efficient functioning of a competitive market.

He concluded by saying that the market should not decide how much new capacity ought to be added,

> "not if it is intended that, by deciding this question, the market will itself determine who will no longer pay how much of the existing facility costs. It is straightforward for those, including Edison, who support additional capacity to decide how much pipeline capacity they each wish to support, and to which supply regions. However, currently all gas consumers are subject to paying a share of existing facility costs, as determined by the Commission. To the extent that a consumer's use of new facilities results - or is intended to result - in a reduced revenue contribution to existing facilities, then that is a concern to the Commission and to all gas consumers, and it is not simply a market decision."

2. DRA

A witness for DRA testified that new interstate capacity on the order of 400 MMcf/d to 600 MMcf/d will be needed by 1995 to provide noncore customers the needed flexibility and opportunity to contract for gas on a long-term basis and provide an enhanced level of service with respect to moving gas to California. If SoCalGas's proposed southern expansion of 200 MMcf/d is approved by this Commission and completed prior to that time, it would most likely extend the time that new capacity is required. However, there is no evidence that significant external positive benefits would accrue to core gas customers through the decisions by third parties to expand interstate pipeline capacity to California.

A second witness for DRA testified that although all pipeline proponents say there is a need for additional capacity none have presented signed contracts with firm rates. In DRA's opinion, if there is a real demand for more pipeline capacity then marketplace decisions by customers, reflected by signed contracts for service, will clearly provide the best guide for the Commission in selecting a project to support. DRA believes any rational consumer will only buy what he actually demands based on expected costs compared to expected benefits.

DRA asserts that the current pipeline system in California has capacity that is not being used to the fullest extent. Based on the total gas supply capacity of 5,559 MMcf/d shown in the June 1 California Gas Report (CGR) and 1988 system throughput of 5,271 MMcf/d, nearly 300 MMcf/d of capacity, over 5%, remained unused on the system serving California. While the SoCalGas system was used at a level very close to its rated capacity, the PG&E system had 10% of its capacity unused. DRA generally agrees with the premise that some excess capacity is needed to provide flexibility in purchasing and operations, i.e. provide a safety margin. However, in DRA's opinion, since nearly 5% of the interstate system was left unused in 1988, no additional capacity need be constructed to provide a safety margin or economic leverage to the core market.

DRA believes that 1988 may have been an above average year for gas use in California and that an average year would show even more capacity available on the present system. The witness said that in 1988 this Commission's restructuring of the gas market caused disruptions, storage banking was not fully implemented, weather was hot and dry, it was a poor hydro year, nuclear power production was low, and, in general, the California gas transmission system is being used inefficiently. DRA contends that, if the PG&E and SoCalGas systems were better integrated, curtailments in southern California would lessen and the need for additional capacity would lessen proportionally.

The witness concluded his testimony by stating that according to the 1989 and previous three CGRs, the demand for interstate capacity will outstrip the available capacity sometime between 1994 and 2000 under normal year conditions and around 1993 under cold year conditions. The demand for interstate capacity forecast in the 1989 CGR projects a need for about 700 MMcf/d by 2000 under normal conditions, while the average demand forecast in the three previous CGRs projected a need of about 500 MMcf/d by 2005 under cold year conditions.

Based on the above information, in DRA's opinion between 400 and 600 MMcf/d of additional capacity by 1995 will provide noncore customers with an opportunity to increase the reliability of service they receive and provide the needed flexibility to contract for gas on a long-term basis. This addition will also provide California with increased operational flexibility in the new gas world to the extent that customers are willing to pay for it. Further, an addition of this size would provide southern California with a safety margin similar to that currently enjoyed by northern California.

A third DRA witness testified that DRA found no evidence that expanding capacity would provide significant gas-on-gas competition benefits, especially for core customers. The witness reviewed PG&E's and SoCalGas's cost of gas from California producers, Canadian producers, and Southwest producers. In regard to California producers he said that SoCalGas pays more than PG&E because, among other reasons, SoCalGas bids up the price "to foreclose competitors from these sources." As to Canadian gas he believes any difference in price is not related to gas-on-gas competition but rather due to plant vintage and rate of return regulation.

In regard to Southwest supplies, the witness agrees that PG&E pays less than SoCalGas, but argues that this disparity does not result from gas-on-gas competition. He finds the difference in that SoCalGas has operated since 1986 in a significantly different competitive environment than has PG&E as a result of the Commission's restructuring of the gas market in California. The distinction is seen in terms of the quantity of gas each utility transports for others relative to its purchases of gas for sale.

The composition of SoCalGas's Southwest supplies has changed as noncore customers have migrated away from SoCalGas as a purchaser of gas to doing their own purchasing of gas. The amount of long-term gas purchases are an increasing percentage of the Southwest gas supplies while the percentage of short-term or spot purchases are declining. In a period of excess supplies where long-term contract gas is offered at a premium to spot gas, a re-weighting of purchases toward long-term contract gas has increased the gas cost for SoCalGas vis-a-vis PG&E. This has led to an increasing disparity in the cost of gas from this region for the two utilities. A comparison of PG&E's and SoCalGas's gas costs must account for this difference.

He concluded that DRA in its analysis of the historical operations of the spot gas market finds no evidence of increased gas-on-gas competition with respect to PG&E's excess pipeline capacity and its greater access to Canadian supplies. Much of the disparity in average system gas costs between SoCalGas and PG&E arise because of differing regulatory treatment, rate design differences, differing contracting strategies for California gas, and differences in plant vintage for those assets used to transport Canadian gas. In the spot market where both SoCalGas and PG&E compete there is no evidence that PG&E is able to extract lower prices from suppliers because it has more excess capacity on average and greater access to Canadian supplies than does SoCalGas.

DRA in its June 1, 1989 report indicated that based on its analysis at that time gas-on-gas competition may be responsible for as much as $0.5/Mcf of the difference between PG&E's and SoCalGas's system average gas cost disparity. Since the report was issued DRA has completed further work in this area and based on its analysis of the gas spot market finds no evidence of gas-on-gas competition accruing to core customers as a result of adding new pipeline capacity. In DRA's opinion the concept of gas-on-gas competition has taken on a life of its own far beyond what economic theory and empirical research would indicate. DRA strongly urges that the Commission not base the decision to increase pipeline capacity on an unsupported claim of increased gas-on-gas competition.

3. PG&E

A witness for PG&E testified to the need for new pipeline capacity. He gave three reasons: (1) a large segment of the California market has made commitments for new pipeline capacity, (2) the 1989 CGR shows that current interstate pipeline capacity falls short of future requirements, and (3) in a deregulated gas market California will benefit from increased supply diversity - which can only be achieved through new pipeline capacity to the state.

He prepared two tables based on the CGR:[11]

Table 1

Forecasted Average Daily
Interstate Pipeline Capacity Utilization
(MMcf/d)

	1993		1995		2000		2005		
	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Current Capacity
PG&E	1,897	1,986	1,998	2,204	2,279	2,403	2,336	2,483	2,157
SoCalGas	2,644	2,757	2,728	2,850	3,085	3,209	3,106	3,237	2,500
Total	4,541	4,743	4,726	5,054	5,364	5,612	5,442	5,720	4,657

11 We have modified these two tables slightly to correct for a small error in computation and included the year 2005.

Based upon the current available pipeline capacities of PG&E (2,157: 1,140 on El Paso and 1,017 on PGT) and SoCalGas (2,500: 1,750 on El Paso and 750 on Transwestern), the cold temperature year, average day capacity requirements forecast for the years 1993, 1995, 2000, and 2005 exceed the available capacity for SoCalGas and the state in total in all years. Although PG&E has available capacity in 1993, by 1995 the requirements exceed its available capacity. Table 2 below shows the normal and cold temperature, average day capacity utilization rates for the years 1993, 1995, 2000, and 2005.

Table 2

Average Day
Interstate Pipeline Capacity Utilization Rates
(Percent)

	1993		1995		2000		2005	
	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year
PG&E	87.9	92.1	92.6	102.2	105.7	111.4	108.3	115.1
SoCalGas	105.8	110.3	109.1	114.0	123.4	128.4	124.2	129.5
Average	96.9	101.2	100.9	108.1	114.6	119.9	116.3	122.3

Therefore, based upon the data presented in the 1989 CGR, there is a shortfall of existing interstate pipeline capacity necessary to meet the the future needs of the state. The above data reflects the average of all days during the year, and even with the operation of underground storage the winter season demand will be considerably higher than those shown. The raw cold year data suggests a need for about 400 MMcf/d in 1995, increasing to about 1.1 Bcf/d by 2005, of new pipeline capacity. Additionally, the raw data also suggests for the state on the whole that under normal weather conditions approximately 100 MMcf/d of new capacity will be needed by 1995 and 800 MMcf/d by 2005. Such capacity additions would be used one hundred percent of the time during a cold year, assuming sufficient underground storage existed to balance lower summer demands with the higher winter demands. Such high load factors do not allow gas-on-gas competition to operate effectively.

The PG&E witness said that an 80% load factor is reasonable for a pipeline and therefore additional capacity is needed by at least 1993, especially to assure gas-on-gas competition. He pointed out that with any commodity one can only exert economic leverage when one has the ability to choose a different supplier who is willing to provide a lower price. That is, one can shift purchases or volumes between suppliers. Historical data indicates that once the pipeline capacity to a particular market is being fully used, the producer incentives to compete with each other are markedly reduced. The most powerful economic pressure is when the choice can be made between different producing regions, and this is only possible when sufficient pipeline capacity exists to diverse gas resource basins to allow volumes to be moved between sources. He asserted that an 80% load factor is a reasonable measure of the ability to create such economic leverage. If we assume an EOR market commitment to a new 400 MMcf/d pipeline and an 80% load factor to provide gas-on-gas competition, he concludes there is a need for new capacity of about 750 MMcf/d in 1995 and about 1550 MMcf/d in the year 2000.

A second witness for PG&E testified that PG&E requires an expansion of underground storage cycling capability and new firm transmission capacity by the mid-1990's to meet forecast core and noncore market demands. He based his testimony on studies PG&E has done and on the the CGR projections. He pointed out that California gas production has been declining and continues to decline. In 1985 it was about 466 MMcf/d, most recently it has been in the 300 MMcf/d range, and it is predicted to decline to the low 200 MMcf/d range. Consequently, new out-of-state pipelines must be built. PG&E is expected to need an additional firm 300 MMcf/d by 1995 in its own service area. Without this, reliability of gas service to core customers would be jeopardized and curtailments of noncore gas service would signal the business community that energy reliability in California is wanting and could encourage relocation to other states.

He testified that in order to satisfy abnormal peak day requirements and total requirements on winter days in PG&E's service area over the next few years, PG&E must increase its McDonald Island storage field from its present 27 Bcf of annual cycling capability to 45 Bcf of cycling capability. To satisfy that increased storage capability PG&E will need more flowing gas, which means new pipeline capacity.

On cross-examination when asked about the need for new capacity when the CGR shows that core demand has never exceeded 50% of current capacity on an average day basis he replied that PG&E does not configure it system on average day conditions. The system must provide service based on adverse conditions, wintertime and peak day. He asserted that access to diverse producers and diverse production areas results in lower prices. He referred to PG&E's experience in obtaining supplies from Canada and the Southwest rather than just relying on California sources. He said that as new supply areas became available prices became more attractive and supply became more reliable.

PG&E presented a witness to rebut the DRA conclusion that there is no evidence of increased gas-on-gas competition associated with increased access to interstate pipeline capacity. He testified that his analysis of the DRA's own data supports the conclusion that an increase in pipeline capacity to southern California will substantially reduce gas costs as a result of increased gas-on-gas competition. He quoted a standard economic text for the proposition that "Price will be lower in the market with the greater demand elasticity." Demand elasticity measures the percentage change in quantity relative to the percentage change in price. With respect to gas-on-gas competition, the amount of unused capacity available to a buyer places an absolute limit on the extent to which that buyer can change the quantity purchased in response to a change in price. PG&E, having greater relative access to interstate capacity and supply basins than does SoCalGas, will have more elastic demand with respect to available supplies and, according to theory, will have lower gas costs. PG&E is able to shift significant volumes of gas away from higher cost suppliers and/or convince these suppliers to charge less in order to retain sales. This economic leverage can only be exercised when there is enough pipeline capacity available to shift significant volumes.

He said that DRA found a positive relationship between the amount of Canadian gas in each utility's supply mix and the ratio of southwest supply prices but misinterpreted this result. Far from contradicting the hypothesis that gas-on-gas competition reduces costs, the positive relationship between southwest gas prices and Canadian purchases shows that Canadian and southwest supplies are substitutes and confirms that gas-on-gas competition is working. An increase in PG&E's southwest supply costs increases the economic attractiveness of Canadian supplies. To the extent that pipeline capacity is available, PG&E will be able to substitute Canadian gas for those supplies where price increased. Conversely, a decrease in the cost of southwest gas supplies increases the attractiveness of southwest gas supplies and as additional southwest gas is purchased, the relative proportion of Canadian gas will decline. This produces the positive relationship between southwest prices and Canadian purchases which was reported by DRA and reflects the price induced substitution of one supply for another. The long-term evidence that PG&E has lower southwest supply costs than does SoCalGas is consistent with the gas-on-gas hypothesis.

The witness was critical of the statistical analysis used by DRA in reaching its conclusions. Using his own, more detailed analysis, the witness came to opposite conclusions regarding gas-on-gas competition. He asserted that increasing interstate transmission capacity to southern California by 300 MMcf/d would reduce capacity utilization by a minimum of 12%. A 12% reduction in capacity utilization translates into a 6.29% reduction in southwest gas costs, $.174 per MM/Btu in 1988, based on SoCalGas's gas costs; or three times the reduction found by DRA.

4. SDG&E

A witness for SDG&E testified that additional pipeline capacity to California is needed. He said that over the past two years numerous declared curtailments, as well as undeclared curtailments referred to as "trimmings", have restricted SoCalGas's transportation customers' opportunities to transmit gas to their customers. The immediate causes of these curtailments have been ascribed to various gas supply conditions, extremes in weather, unanticipated variations in gas demand, the transitional state of the Commission's gas industry restructuring process, and maintenance on both interstate and intrastate pipeline systems as well as other factors. Nonetheless, today's storage-rich, transportation capacity-poor gas delivery system for southern California created the context in which these factors could produce transportation capacity limitations. Given that most or all of these factors can be expected to continue, more pipeline capacity into California is needed today. Moreover, as the recent CGR shows, gas demand in California will continue to increase through the rest of the century. The sendout in the southern California region is expected to grow by some 30% by the year 2000 or by over 800 MMcf/d. If this forecast is substantially correct, California noncore customers will experience ever-increasing curtailments in the absence of additional interstate pipeline capacity. SDG&E as a noncore wholesale customer with service obligations to its own core and noncore customers has a special concern that this circumstance be remedied. SDG&E's retail gas loads, both core and noncore, continue to grow. In particular, SDG&E anticipates increased gas loads for its power plants. SDG&E is forecasting an additional need for itself of about 75 MMcf/d of interstate pipeline capacity by 1994 and up to 150 MMcf/d by the end of the century.

He asserted that in the absence of such new capacity, southern California's and SDG&E's ability to realize the benefits of gas-on-gas competition is limited. For this reason, SDG&E has concluded that it is in its customers' best interests to build new capacity to new supply areas. Generally, this new capacity will stimulate increased gas-on-gas competition for the benefit of all customers in California, including those that might not participate directly in one of the new interstate pipeline capacity projects. In addition to cost reductions, diversity of supply will also serve to improve gas supply reliability.

5. <u>South Coast Air Quality Management District (the district)</u>

A witness for the district testified that additional interstate pipeline capacity is needed to eliminate the need for fuel oil use within the South Coast Air Basin. He said that the district is responsible for air quality in four counties: Los Angeles, Orange, Riverside, and the non-desert portion of San Bernardino. It encompasses over 13,000 square miles, over 12 million people, and about 8 million vehicles. It has the worst air quality in the nation. In March 1989 the district proposed the phase out of fossil fuel for stationary sources in the Basin starting in 1993 and completed by 1996. He said that the benefits to the Basin from a switch from fuel oil to natural gas can be quantified at a minimum of about $37 million per one million barrels of fuel oil not burned.

Another witness for the district testified that his analysis showed that to meet market demand southern California requires 425 MMcf/d by 1993 increasing to 820 MMcf/d by 1997. He said that prudent planning requires that supply should meet adverse year conditions, i.e., cold weather and low hydro. He stated that additional capacity will shift market power from the sellers of gas to the buyers. Gas-on-gas competition will confer billions of dollars in benefits to the ratepayers. In his opinion sufficient pipeline capacity does not exist now to fill even current storage capacity. Increasing storage capacity can only help if increased pipeline capacity is provided. He emphasized the need for some slack capacity in the pipeline, about 10%, to provide opportunities for buyers to shop around to take advantage of price changes in different markets. With new capacity he envisions a market of many buyers and many sellers which will be a powerful competitive force, especially so with access to new supply regions.

6. California Energy Commission (CEC)

A witness employed by the CEC sponsored a CEC staff report which showed the need for, and the benefits from, increased gas supply to California. He testified that the report strongly endorses the need for new gas production regions to supply natural gas, that diversity of supply will promote competition. He said the report does not support any particular pipeline proposal or combination of proposals, but concludes that all of the major pipeline additions proposed in this proceeding would have potentially significant economic benefits to California, in the tens of billions of dollars just from lower gas costs, excluding benefits from enhanced levels of service. The greatest benefits, he declared, would accrue from new pipeline capacity to the Rocky Mountain area and Alberta, Canada. The staff report recommends:

1. The state should insure that all administrative barriers to the entry of new

pipelines are eliminated as quickly as possible.

2. Any resolution of the pipeline issue must result in a set of pipelines which, taken together, provide improved access to both the Rocky Mountain and Alberta supply regions.

3. The expansion of intrastate systems and existing interstate routes should also be considered as important options, and should be given expeditious approval by the CPUC and other bodies.

4. Pipelines serving Kern County should also be available for use by consumers in northern and southern California.

The report contained Table 2-1 which showed the expected benefits from new capacity over a 45-year time horizon ranging from $1.6 billion for one pipeline from a current supply region to 14.6 billion if there is expanded pipeline capacity from Alberta to California, a new pipeline from the Rocky Mountains to the EOR region, and new intrastate facilities to allow all regions of California greater access to the expanded supplies.

7. El Paso

A witness for El Paso testified that El Paso supports the need for a higher level of service for noncore customers and believes there is a clear need for additional interstate pipeline capacity to provide this service. He requested the Commission to give explicit criteria, rather than only general guidance, to the jurisdictional utilities regarding the acquisition of firm capacity on new pipelines so that the utilities can act promptly and decisively without fear of after-the-fact disallowance.

In regard to the benefits of gas-on-gas competition he said that he was less certain of the benefits than other witnesses. He pointed out that construction of new capacity to a supply area will change the supply-demand balance in that area. More demand would be created and costs could rise. California is not the only area seeking new gas supplies. New pipelines from other areas to a common supply area will create demand which will cause prices to rise. He suggested less emphasis on gas competition and more emphasis on the tangible benefits which certain forms of new capacity could take, such as providing low cost construction, use of existing facilities, and the ability to increase capacity in small increments to meet increasing demand, rather than one large pipeline that could take years to fill.

On cross-examination he agreed that new capacity would provide an opportunity for competition to lower gas prices, but he didn't believe that access to new regions was necessary to produce that effect. He said the interconnected network of pipelines in the United States was such that virtually all markets are connected to each other. Wyoming gas producers could profitably sell in Florida given the possibility of backhauls and exchanges. The market is taking control and deals are struck which could not have been made prior to the recent restructuring of the industry.

8. Altamont Gas Transportation Project (Altamont)

A witness for the Altamont project, which consists of three of the largest gas producing companies in Canada, testified that California requires additional interstate natural gas transmission capacity to provide incremental supplies of natural gas, both to meet growing demand and to replace declining supplies from California's traditional sources. She said that recent experience in California indicates that when annual gas demand on existing interstate pipelines exceeds an annual load factor of about 90%, supply constraints occur; there are difficulties in arranging gas supplies to meet high consumption levels and still inject sufficient gas into storage for delivery during peak demand periods. Additionally, curtailment in the Los Angeles Basin is becoming less acceptable due to environmental impacts and customer preferences. She believes that by 2010 growth in California will require an additional 1.3 Bcf/d of natural gas, mostly in southern California, from producers in the Rocky Mountains and Canada. By 1995 the additional need would be between 700 and 800 MMcf/d.

She said that current supply areas to California, especially the Southwest, have demands placed upon them from all other sections of the United States and, with pipelines reaching all sections, can easily shift supplies to non-California markets. As a result California must seek new supply areas and therefore needs new capacity to Canada and the Rockies. In her opinion, the CEC staff report and the CGR support her conclusions.

9. Discussion

The evidence in the record in support of the need for additional pipeline capacity was overwhelming. The numbers show the need; and every party endorsed those numbers in one form or another. The current capacity of California's interstate pipelines is 4657 MMcf/d (CGR-1989). The estimated total California demand in a 1993 cold year is 4743 MMcf/d or 101.2% of present capacity, and demand in southern California is 110% of present capacity. The numbers are more convincing as the projection extends outward: 1995 cold year, 108% of present capacity; 2000 cold year, 120% of present capacity; 2005 cold year, 122% of present capacity.

DRA, the only party to oppose construction of new interstate capacity, argues that the interstate shortfall, which it estimates to be 400 to 600 MMcf by 1995, can be satisfied by a more efficient use of the entire California pipeline system, especially with capacity reassignment, capacity brokering, and better interutility cooperation between PG&E and SoCalGas. In our opinion neither reassignment and brokering nor improved interutility cooperation will by themselves solve the problem.

We have set forth above the estimates of the major parties and their supporting arguments. The major parties recommend: Edison--600 MMcf/d by 1995; PG&E--400 MMcf/d by 1995, increasing to about 960 MMcf/d by 2000; SDG&E--800 MMcf/d by 2000; the South Coast district--425 MMcf/d by 1993, increasing to 820 MMcf/d by 1997; and Altamont--700 MMcf/d by 1995 to 1.3 Bcf/d by 2010. The industrial users all want more gas as soon as possible.

The Commission has already concluded that an improved level of service for noncore customers is warranted. We need not recount the effects of recent gas curtailments nor set out in exhaustive repetition the activities of many industrial gas users in their search for new sources of reliable, cheap gas. It is obvious that if no new capacity is built, then, as demand grows, the noncore customer will be curtailed more frequently. Noncore customers, as well as core, need reliable, reasonable, long-term gas transportation systems and fuel. Firm capacity is not available to the noncore and interruptible capacity is, of course, subject to interruption. Noncore customers do not want to commit substantial investment in California without a higher level of assurance than they now have that their natural gas requirements will be met. We cannot assess with any degree of reliability the amount of new capacity required to enhance service to the noncore, but if it takes an additional 400 MMcf/d to meet California's overall needs by 1995, it will take something more to provide enhanced service to the noncore. This will not eliminate interruptible service, but it will provide increased reliability to the noncore. Obviously, planning for the state's long-term needs involves an evaluation of capacity needs well beyond 1995, thus further increasing the needed capacity.

A new pipeline should open up new production areas. We will discuss this point in more detail in our section on competing pipelines, but it is clear to us that a significant aspect of need is to have adequate sources of supply. We discussed the benefits of supply diversity in the OII and need not belabor the point. California is favored with two routes into the state, plus local production. California is a large state where population and industry continue to grow. The evidence shows that local production is in decline, and that production in out-of-state areas now serving California is either static, declining, or increasing, depending on which witness you believe. We need not resolve that conflict; given the need for long-term supplies, we deem it only prudent that we add a third leg to our gas support system.

All of the witnesses agreed that new production areas would provide long-term price and supply stability. A witness testified that Mobil Oil Corporation expects to expand its operations in Kern County and will require 100 MMcf/d of firm transportation within a few years. He said it is essential for Mobil's expansion that it have long-term firm transportation. Witnesses for Texaco and Chevron testified to similar concerns. New pipeline capacity will permit some interruptible customers to acquire long-term firm service, which equates to long-term supplies at prices which the end user can negotiate to its own satisfaction.

Of the many issues that impinged on the question of need for new pipeline capacity, the most contentious was whether new capacity would foster gas-on-gas competition and, if so, whether the savings from the competition would offset the added costs to core customers resulting from diversions from the existing system. DRA asserts that the benefits from gas-on-gas competition are minimal, that those who see great benefits have no empirical evidence to support their position. Taking the contrary position, every other witness testified to the enormous benefits competition would bring: from the estimate of PG&E that the benefits could be about \$.17/MMBtu to CEC's estimate that over the years Californians would save in excess of \$14 billion if all the proposed pipelines were built. We cannot quantify the amount of savings in gas prices to be realized by additional capacity, but we find that the savings will be substantial. DRA's arguments are not persuasive.

PG&E presented a witness who, in our opinion, refuted DRA witness's conclusions about PG&E's use of excess capacity. We are persuaded that PG&E has purchased gas at substantially lower prices than SoCalGas, that the causes are, in part, due to PG&E's access to lower cost Canadian gas and its ability to play the Canadian producers and Southwest producers off against each other, and that its excess capacity is a factor in obtaining low prices. PG&E has, on average, about 10% excess capacity on its interstate system; SoCalGas has none. Therefore, PG&E has an ability to move quickly in obtaining low cost gas while SoCalGas cannot. PG&E can play supply areas off against each other; SoCalGas is constrained.

Notwithstanding DRA's objection to new pipeline capacity, our analysis of the facts DRA has adduced leads us to conclude that a new, independent, gas pipeline would provide an increased probability of not only gas-on-gas competition but also competition related to costs of transportation. If PG&E and SoCalGas are indifferent to producers' prices today, in a future reasonableness proceeding where third parties are shown to be purchasing gas at lower prices the two LDC's would be hard pressed to prove that their over-market prices are reasonable. We firmly conclude that new capacity will increase the likelihood of competitive pricing.

On a full pipeline sellers cannot move more gas by reducing price. Nor can buyers obtain price discounts by offering to buy more gas. When there is insufficient available transportation capacity then that gas which has access to whatever capacity remains available is in a seller's market and can demand a premium price. Because netback pricing, itself, is a restraint on competition, a lack of transportation capacity exacerbates that restraint. Nevertheless, excess capacity is no guarantee of low prices and competition; in fact, a scenario can be posited which would forecast higher prices; but without excess capacity there can be no enhanced reliability and no chance of lower prices. By providing excess capacity, we are creating the opportunity to make better choices. It is against this background of persuasive evidence that new capacity will provide substantial benefits that we approach the task of determining how much additional pipeline capacity is required.

10. <u>The Commission's Conclusions Regarding the Need for Additional Capacity</u>

We find it prudent to adopt a long-term policy on additional interstate pipeline capacity into California. Our adoption of this policy is consistent with our statutory responsibility to ensure that the facilities of the utilities and their means of transmission and distribution of natural gas are reasonable. (P.U. Code Section 761.) The policy is flexible and market-responsive; it recognizes the major planning uncertainties that exist; and it reflects our findings that there is both a current capacity shortage and an increasing need over the long-term.

Considering these factors, we find it prudent to plan for a range of from 900 MMcf/d for the near term and up to 2.1 Bcf/d of capacity additions over the long term (roughly 2005). This finding is consistent with the need estimated in the current <u>California Gas Report</u>, augmented by a system capacity "slack" factor. We believe the record demonstrates the wisdom of planning to allow for additional capacity of up to 20% in order to support the unbundled gas service structure, foster competition (gas-to-gas and pipeline-to-pipeline), and achieve a higher level of reliability of gas service in California. The hearings in this proceeding illuminated the difference in gas costs experienced on the PG&E system (which generally maintained a 10% excess of interstate capacity over demand) compared to SoCalGas (which essentially operated at 100% of capacity in recent years). As discussed above, a number of different factors may contribute to the lower gas costs obtained by PG&E, but we are convinced that additional interstate capacity greatly facilitated PG&E's ability to take advantage of the competitive forces that resulted in lower cost gas supplies. Adding this slack factor to the California Gas Report estimates results in a range of 1.6 Bcf/d to 2.1 Bcf/d additional capacity needed by the state over the long term.[12]

This range of need for capacity additions is higher than many prior estimates, including our own. This changing perception of need responds to several interrelated changes, including our new regulatory structure for natural gas service in California; the increased transportation reliability that the new structure may require; the desire to foster competition through interconnection of California consumers with new producers and new production areas; and the enhanced role of natural gas required to meet air quality mandates. The latter factor could vastly increase gas requirements if certain proposals to improve air quality are implemented as planned. All these considerations lead us to believe that in order to effectively plan for California's long-

12 We derive our need projections, based on data from the California Gas Report (CGR), as follows. For 1995, CGR projects a cold year capacity deficit of about 400 MMcf/d. (Use of cold year throughput is appropriate for capacity planning purposes.) To that deficit, we add a "slack" factor of 10% of total interstate pipeline system capacity, or approximately 500 MMcf/d, to reach a near-term need projection for additional interstate capacity of 900 MMcf/d. For 2005, CGR projects a cold year capacity deficit of about 1.1 Bcf/d. It is appropriate to use a range of slack factors (10-20%) and project a range of need for the 2005 forecast because there is greater uncertainty associated with longer-term projections. Thus we add a slack factor of 500 to 1000 MMcf/d, resulting in a total long-term need projection ranging from 1.6 to 2.1 Bcf/d. We prefer to speak of "near-term" and "long-term" need, rather than the years specified in the CGR, because the timing of the need is part of the uncertainty, and the use of a specific year might imply a greater degree of precision than is warranted.

term natural gas needs, we need to err on the side of higher demand estimates rather than risk significant future shortages of capacity. We are determined to take a long-term planning perspective in this proceeding and have adopted a range of demand estimates to reflect that perspective.

a. The Impact of the New Regulatory Structure

Starting in 1985, this Commission dramatically altered the traditional structure of natural gas service in California. We did this primarily through two major initiatives. First, the LDCs were required to provide intra-utility and inter-utility transportation service on a tariffed basis. Second, gas commodity and gas transportation service to the noncore were unbundled.[13] These initiatives were calculated to position California consumers to capture the benefits of gas price deregulation at the federal level, without bypass of the LDCs.

We realize that the new regulatory structure has major implications for the gas pipeline network. The existing network was sized to provide reliable transportation service under the old, bundled structure. Bundled service needed to be modified for many reasons, but it did have the virtue of minimizing the need for pipeline capacity. This was because the LDC pooled all the downstream consumers while the pipeline company pooled all the upstream producers, with the result that variations in individual consumption or production would generally have little impact on overall gas flows.

With an unbundled structure, gas flowing on a given day is the result of decisions by a large number of individual decision-makers. There is a far greater likelihood (especially in

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13 We are continuing the unbundling of services through our development of a gas storage banking program and of a program to "broker" or otherwise temporarily assign pipeline capacity rights.

the absence of some sort of capacity brokering) of a "lumpy" demand pattern on the system and of idle capacity in the event, e.g., of producer non-performance. In fact, we are convinced that the seemingly paradoxical underutilitzation of interstate facilities experienced in recent years is due in large part to this phenomenon. We view this as clear evidence of the inefficiency of the system when demand approaches 100% of system capacity.

We welcome the gas commodity savings that the unbundled structure provides, but it is now apparent that investment in additional pipeline capacity is necessary in order to realize savings generated by unbundling. There is a relationship between unbundled transmission service and the need for capacity in excess of demand which was not well understood during earlier examinations of California's need for interstate pipeline capacity. The allowance made in today's decision for a capacity "slack" factor recognizes this relationship.[14]

b. Increased Transportation Reliability

Gas transportation service must be reliable in order to achieve our industry re-structuring goals of enhancing gas-to-gas competition and avoiding LDC bypass. Transportation customers whose gas does not arrive cannot plan their operations or calculate their costs with certainty.

Accordingly, we must provide the infrastructure required to support unbundled services. We must compare the costs of additional pipeline capacity to the hidden costs of unreliable transportation service. These hidden costs include expensive

14 Some have argued for a slack factor as high as 20%. We agree that a slack factor that high might be appropriate, especially for long-term planning purposes, but we also believe that the "market" (i.e., those who will use or invest in the new pipelines) is best situated to determine what slack factor should be built into the additional capacity.

standby commodity service from the LDCs, higher system operating costs due to balancing problems, switching to alternate fuels, and worst of all, the inability to profit fully from post-deregulation gas price competition.

New pipelines can enhance reliability not only by providing additional capacity but also by providing access to new producers and new production areas. Such access will also benefit competition, as we discuss below.

As we noted earlier in this proceeding in D.89-02-071, an improved level of transportation service to noncore customers is warranted. Additional pipeline capacity should be constructed to help provide enhanced levels of service to this market segment. From the long-term perspective, it is equally important to ensure adequate transportation service for all customers, including the core, by constructing sufficient pipeline capacity for a wide range of demand forecasts.

c. Clean Air Issues and New Capacity

California's environmental goals, particularly the need to improve air quality, increasingly influence choice of fuels. Because of the cleaner burning characteristics of natural gas as compared to fuel oil (traditionally, the leading alternative to natural gas), it is likely that natural gas will be the fossil fuel of choice for electric generation and various commercial and industrial processes. For this reason, demand for gas is expected to be strong, particularly in Southern California.

Air quality considerations also dictate that curtailment of UEG customers be avoided during the smog season (late summer/early fall). This is the same time frame when the LDCs are filling their storage fields for core customers and, secondarily, for noncore customers purchasing storage banking service. These multiple demands on pipeline capacity mean that capacity constraints may materialize at times other than the traditional peak period (the winter heating season). This occurred last summer when such constraints limited the ability of non-core customers to inject gas into storage under our storage banking pilot project.

We also note that various aspects of the South Coast Air Quality Management District's rules may result in increased electrical generation (e.g., electrified mass transit). Increased electrical load is likely to be met through a variety of sources, among which gas-fired cogeneration and utility generation will play a part.

The impact of these factors is hard to quantify and subject to uncertainty, yet even conservative planning indicates that demand for gas will be strong across many sectors and will continue to strain existing capacity. Numerous recent curtailments in California are evidence of existing demand.

d. Fostering Competition

As we stated earlier, our desire to foster competition in the gas commodity market is one of the driving forces in our new regulatory structure. Furthermore, there is every reason to expect that pipelines serving California will have to offer competitive transmission rates. Both of these factors argue that the cost of additional pipeline capacity must be weighed against the price benefits of increased competition that should reasonably be anticipated to result from expanded access to California consumers.

There is no simple equation that predicts the optimal timing, amount, or location of new capacity required to capture the benefits of increased competition. We can say as a qualitative matter that the long-term benefits of increased competition and access to new supplies to serve California argue strongly for additional pipeline capacity in the range we have adopted today.

B. Capacity Allocation

A witness for DRA testified that the effects of assignment of firm gas transmission capacity rights will provide gas market participants one very important tool that is currently unavailable to them. Use of the brokering tool will promote greater efficiencies on the inter- and intrastate gas system and provide clearer market signals to all segments of the gas industry serving California. A capacity brokering program will allow customers to pick the price they are willing to pay for the service they want and know the risk associated with that choice. He said that there is a high cost as a result of not using the system that is available to its fullest when maximum capacity, including interutility transfer capacity, is required as a result of severe conditions. With a capacity brokering program, both the utilities and the other market participants would have been able to make better decisions based on known costs and risks. DRA believes that with clearer signals, actual cost responsibility for firmer service, and the resulting increased efficiency in the market, reflected through the increased use of the existing system, many of the problems that have occurred in California would have been reduced if not eliminated.

He agreed with PG&E that reshuffling transmission capacity rights does not provide for more capacity, but he said that with capacity brokering the costs are more readily known and the efficiencies gained as a result of this information might very well provide more usable capacity. For these reasons DRA recommends that the Commission move forward with the capacity brokering program and create a mechanism that allows noncore customers the opportunity to obtain firm capacity on the interstate system.

A witness for Edison testified that although existing capacity is physically able to meet California's total demand until the end of the century, capacity which serves Southern California directly is only marginally capable now, and soon will not be capable. Should excess capacity available in Northern California be used to meet the needs of the southern part of the state it would surely increase the cost of gas to Northern California consumers as they would lose available capacity, which is essential to obtaining the benefits of market competition. He said that even if existing facilities were used more efficiently new capacity would still be needed to provide access to new production areas, such as Canada and the Rocky Mountains, which now are nonexistent for Edison.

A witness for PG&E testified that more storage capacity is needed to meet peak core demand swings and can be economically used to support noncore service, to flatten load swings on suppliers, to capture economic benefits of lower summer gas prices, and to offer expanded storage banking to noncore customers. He maintained, however, that reassignment of current capacity to noncore customers was not an alternative to building a new pipeline. Reshuffling transmission capacity rights does not increase overall transmission capacity.

A witness for SDG&E testified that assignment of existing pipeline capacity to SDG&E would not be advantageous nor best serve the public interest of SDG&E's gas and electric customers as would building new pipeline capacity to the Canadian market. Although assignment of firm rights may cause more efficient utilization of existing pipeline capacity, in his opinion, little or no benefit from gas-on-gas competition will be obtained by such assignments, without increased access to production areas other than the Southwest. SDG&E requires firm long-term access to interstate capacity in order to provide its own customers with comparable services offered by SoCalGas and PG&E.

We agree that merely reallocating transmission capacity rights will not provide more capacity. As we discuss below, capacity brokering remains a key criterion for our support for new pipeline capacity. We are currently studying the issues of priority allocation of firm transportation rights in R.88-08-018. hearings in that proceeding have been postponed pending issuance of the Order Instituting Rulemaking that we have issued today to revise our intrastate regulation of gas service. We expect that the proposed rules will alter parties' perceptions of the risks and benefits of capacity brokering, thus making hearings more useful after the policy decisions on the gas regulatory structure have been made. However, we restate our full support for implementation of open and non-discriminatory brokering on all intrastate and interstate pipeline facilities as soon as possible.

C. The Need for Reallocation of Existing Pipeline Costs

1. The Position of the Parties

Demand charges of existing interstate pipelines are paid by the local distribution companies (LDCs): SoCalGas and PG&E. The LDCs then pass on the cost of the pipeline demand charges through the intrastate transportation rates that they charge to their retail and wholesale customers. The cost is allocated among the various customer classes in an annual cost allocation proceeding (ACAP) on the basis of the total volumes that are forecasted to be delivered to each class under a "cold-year" scenario. This method implicitly assumes that all of the LDC's existing customers will continue to move all of their annual take from the LDC over the existing interstate pipeline system.

With the exception of a continuing obligation to pay one year of demand charges, imposed by the LDC's tariff, a customer leaving the LDC's system entirely and taking gas solely from a new interstate pipeline system without the benefit of any LDC distribution would pay only the demand charges imposed by that new pipeline. However, the problem at issue here arises because customers receiving service on a new pipeline--and paying demand charges to that pipeline--will continue to receive gas through the LDC's distribution system.

Under current methodology, those customers will continue to pay their allocated share, based on their forecasted throughput, of the demand charges imposed on the LDC by existing interstate pipeline systems, even if some or all of that throughput does not go through the existing interstate pipeline systems. Those customers will also pay the demand charges imposed by the new pipeline system. Thus, customers of a new pipeline will pay two sets of demand charges: one imposed by the new pipeline for the volumes transported on that system, and a second imposed by the LDC as if the customer were continuing to take 100% of its gas deliveries over the existing pipeline system. This second charge will be imposed even if the customer's only use of the LDC's system is to move gas from the new pipeline to the customer's burnertip.

At the present time SoCalGas's customers pay a pro rata share of the total costs SoCalGas pays for firm transportation service on interstate pipelines. Based upon current rates, SoCalGas pays a $330,000,000 demand charge for this firm capacity, which the Commission allocates to customers on the basis of an adopted forecast of total intrastate deliveries during a cold temperature year. For example, suppose the projected cold year deliveries by SoCalGas to a certain noncore industrial customer are 900 MMcf for a given forecast year. Suppose further that projected cold year deliveries by SoCalGas to all its customers amounted to 900,000 MMcf for the same forecast period. Then assuming a $330 million payment by SoCalGas to existing interstate pipelines, this customer's share of the interstate pipeline demand charges would amount to $330,000. If this same SoCalGas customer were to continue to take service over the existing interstate pipeline system but bypassed the SoCalGas intrastate system, the customer would be assessed no cost for interstate pipeline services, except for any disconnect charges the customer might be obligated to pay during the twelve month period after disconnection. Customers who have left the SoCalGas system are no longer responsible for any charges for existing facilities after the twelve month period. They are simply no longer customers of SoCalGas.

But, if this customer shifted 40% of its deliveries on the interstate system from existing facilities to new facilities, and if all this gas were delivered by SoCalGas over its intrastate system, then the customer would continue to pay $330,000 to SoCalGas, even though its use of existing interstate facilities had been reduced. In addition, the customer would pay costs on the new facilities. If we assume a demand charge for new interstate facilities of $0.50 per Mcf, it would pay $180,000 directly to the new pipeline. The resulting total cost to the customer would be $510,000. This can be seen from the following table:

Table 3

Allocation of Existing and New Interstate Pipeline Demand Charges with No Change in Present Methodology

Delivery over Existing Interstate Pipelines	Allocation Based on Delivery Over Total System
540 MMcf	900 MMcf x $0.37/Mcf = $330,000
Delivery over New Interstate Pipelines	**Demand Charge Paid To New Pipeline**
360 MMcf	360 MMcf x $0.50/Mcf = $180,000
Total Delivery Over Interstate Pipelines	**Total Demand Charge**
900 MMcf	$330,000 + $180,000 = $510,000

This is what is referred to as having to "pay twice" for the same interstate capacity. We must note in passing that the two payments are not actually made for the same capacity, and in fact, under this example, there remains an additional 360 MMcf of capacity available to the customer on the existing interstate facilities. This capacity must be paid for, even if it is not utilized. As the utilities are required by FERC ratemaking to pay demand charges for this capacity whether they utilize it or not, a similar argument can be made that the customers of the LDC must contribute to maintain access to the existing capacity.

A witness for Edison testified that SoCalGas's 1989 ACAP application contains an allocation to Edison of about $34 million in interstate pipeline demand charges. If 1 Bcf/d of new pipeline capacity were to be added to the existing facilities serving southern California and Edison were to use 250 MMcf/d of this new capacity on an average annual basis, and we were to relieve Edison of its SoCalGas demand charge allocation related to that gas, then SoCalGas's core customers would experience not more than a 2.3% increase in total gas costs as a result of higher average transportation costs and assuming no decrease in average gas procurement cost. Edison believes that it is reasonable to expect at least a 3% decrease in average gas procurement cost through the existing southwest pipelines as a result of a 1 Bcf/d reduction in demand on those pipelines. He said that although this analysis assumes the entire 1 Bcf/d of existing southwestern demand is transferred to the new capacity, in reality, growth in total demand will result in a substantially smaller reduction in throughput over existing pipelines. To the extent that the reduction in throughput is smaller, then the increase in unit transportation costs will also be smaller. He contends that costs should be reallocated on a volume basis, consistent with new forecasted volumes on the existing pipelines after the new pipelines enter service. Transporters moving gas through the new pipelines would pay all costs associated with such use directly to the pipelines. Therefore, the added cost of the new pipelines would be included in the reallocation only to the extent that they were paid by the gas utilities themselves. The reduction in throughput on the existing pipelines would result in an increase in the unit transportation rate. Edison believes that this increase will be offset by lower gas procurement costs, due to increased competition for sales by producers served by those pipelines, provided the reduction in throughput is not too great. He declared that Edison would not be willing to commit to new pipeline capacity if the Commission should decide that cost reallocation will not occur. He said that Edison's allocated share of existing facility costs represents partial payment for delivery of an identified volume of gas through those facilities. By committing to new pipeline capacity, Edison would agree to make this same payment a second time for an identical volume of gas. Such double payment would be unfair to Edison's ratepayers and would represent an unwarranted increase in its average cost of gas.

The witness said that Edison would not be willing to commit to new pipeline capacity even if gas producers were willing to pay the equivalent of Edison's existing allocated cost, thus avoiding this double payment. He maintains that it is appropriate for the Commission to consider an adjustment to cost reallocation, based on a determination of unequal sharing of the benefits of the new capacity. However, a long-term commitment to transportation over a new pipeline cannot prudently be based on the expectation that producers served by that pipeline will "net-back" total purchaser costs over the new pipeline[15], so as to match only the variable purchaser costs over the existing pipelines. Although this may occur in the near-term, Edison concludes that it is not a

15 "Net-back pricing: A method of determining wellhead price of oil or gas by deducting from a price paid downstream for the product, the transportation and other costs incurred between the wellhead and the downstream place of sale" (Williams & Myers, Manual of Oil and Gas Terms, 7th Ed. (1987)). In general, netback pricing compels producers to absorb transportation cost increases.

reasonable basis for the long-term commitment required to construct new pipeline capacity, and it would undermine the competitive incentives that additional pipeline capacity should provide to producers with access to existing pipelines.

A witness for SDG&E testified that SDG&E believes that the cost of existing pipelines should be reallocated if new pipeline capacity is constructed into California. He said that SDG&E believes that such a reallocation is appropriate and reasonable if, in fact, a party committing to service on a new pipeline does not need all of the capacity it is currently utilizing on the existing pipelines. The parties who are committing to new pipeline capacity may be freeing up capacity on the existing system which could be used to supply gas to meet needs which could not otherwise be adequately served by the existing interstate system. To the extent that the combined capacity of the new project and the existing system is required to meet the total Southern California customer gas requirements, then the reallocation of pipeline costs could be properly accomplished by application of the current cost allocation methodology. If there is excess interstate capacity into southern California as a result of building one of the new pipeline projects into the state, SDG&E would still recommend reallocating the cost of existing pipeline capacity among all customers in the state, possibly in accordance with the current ACAP cost allocation methodology or some appropriate modification. Although such a reallocation could increase transportation rates for some customers, he expects that can be avoided through gas supply contracting. Further, he believes all customers will benefit from lower relative gas costs caused by the additional competition engendered by new capacity to a supply region willing to price gas competitively. He said that transportation rate increases can be avoided in the event of capacity excesses because Canadian producers are prepared to net-back all of the new pipeline demand charges in the cost of gas at the wellhead in order to be able to sell gas into the southern California market. That is to say, SDG&E asserts that overall gas costs from Canada delivered to the SoCalGas system will be no greater than the delivered gas over the existing system from the Southwest. This implies that there would be increased pipeline capacity to serve gas customers. If this can be realized, then the total cost of gas supply into southern California will not be greater as a consequence of the construction of a new pipeline project to Canada. He stated that SDG&E is prepared to negotiate gas contracts with Canadian producers which would result in the producers netting back the full price of the new interstate pipeline in their gas prices at the wellhead.

DRA asserts that Edison's claimed double payment is illusory. It argues that retention of the existing cost allocation simply insures that all customers continue paying the costs they have imposed on the system. The fundamental cost allocation principle employed by the Commission is that system costs should be borne by the cost causers. The current obligation for pipeline demand charges was incurred by SoCalGas in order to provide service for all customer classes including UEG customers such as Edison. In essence, these costs were incurred in order to insure service for both core and noncore customers, and that is why all customers are currently allocated a portion of these costs. Edison's election to place a portion of its load on a new interstate shouldn't relieve it of its cost responsibility for the existing system until the excess capacity created by Edison's abandonment of the existing system is replaced by demand growth.

DRA analogizes Edison's position with those noncore customers who fuel switch but are nevertheless obligated to continue paying the utility demand charges for up to twelve months, in recognition that although the customer is no longer using the system, the system was built to provide him service, and the utility is still incurring the fixed costs of operating the system.

DRA believes the same logic dictates that Edison and other customers abandoning the existing system in favor of a new interstate pipeline not be relieved of their cost responsibility for the existing system at least until demand growth has filled the empty pipe created by their departure. Since the existing system remains available to serve them, they should continue to pay.

Instead of a double payment, DRA contends the payment of a full share of existing pipeline demand charges by migrating end-users should be viewed as payment for an enhanced level of service. End-users who subscribe to new interstate capacity will inevitably return to the existing system whenever supply problems or price hinder their ability to use their newly acquired firm capacity. New interstate capacity in combination with existing capacity provides enhanced transportation reliability. They should pay for the insurance that the existing system provides.

The potential for lower gas costs, says DRA, is another reason not to reallocate. Parties have continuously argued that a significant amount of excess capacity is a precondition for the successful operation of gas-to-gas competition, because the ability to swing between producing regions will result in lower gas costs. If this is true, then the primary beneficiaries of the lower gas costs resulting from this flexibility will be those end-users who have access to capacity on the new interstate pipeline as well as access to the excess capacity on the existing system. This description fits Edison and other end-users who subscribe to new interstate capacity. Since, according to this argument, they will directly benefit from this excess capacity, they should continue paying for it.

2. Discussion

We are not persuaded that we should announce a position on reallocation at this time, nor should we state that in the event of a particular occurrence, e.g. the in-service date of a new interstate pipeline, we will reallocate costs. Cost reallocation, in a general sense, is part of our regulatory powers, which is exercised in one form or another in almost every major rate case. Should the need arise, we will reallocate. But the need is not present now. Any pronouncement on reallocation could be harmful to the ratepayers.

What Edison and others are seeking is a safety net, assurance that they will not be exposed to a double demand charge for interstate transportation. They want to make what they call a marketplace decision after we have changed the marketplace. We believe the better policy is to let the current competitive forces determine the need for a new pipeline without a statement by us, one way or the other, on reallocation of costs. By letting the competitive forces resolve this issue we are saying, let those who want a new pipeline pay for it. Those who assert that there is pent-up demand and almost certain growth which require new service will not be double charged if their predictions come true. Those leaving the existing systems will be replaced by new users or users increasing their take, thus obviating the need for the LDC to charge those who have abandoned or reduced their reliance on the existing system. If the utilities are to be believed, the problem will cure itself.

On a more practical level, to reallocate costs would be to subsidize the new production areas (or the gas purchasers), a result which is nonsense. Every utility, including Edison, expects the producers in the production areas reached by the new pipeline to charge for gas at a netback price. SDG&E's witness said it succinctly:

> "...Canadian producers are prepared to net-back all of the new pipeline demand charges in the cost of gas at the well-head in order to be able to sell gas into the Southern California market. That is to say, SDG&E believes that overall gas costs from Canada delivered to the SoCal Gas system will be no greater than the

> delivered gas over the existing system from the Southwest. This implies that there would be no additional revenue requirements for gas supplies to Southern California even though there would be increased pipeline capacity to serve gas customers." (SDG&E, Purves, Exh. 19, pp. 8-9.) (Emphasis added.)

We expect that Rocky Mountain producers would do the same.

Edison has made much of its position that the Commission must endorse cost reallocation to avoid the risk of its ratepayers being subjected to double demand payments for the amount of Edison's participation in the new pipeline. Edison's witness stated that Edison would not be willing to commit to new pipeline capacity if the Commission should decide that cost reallocation will not occur. Edison, however, has shown no convincing evidence that its participation in a new pipeline is to the benefit of California, in general, or Edison's ratepayers, in particular. The pipeline will be built with or without Edison. When it is built, it will release capacity on both SoCalGas's system and PG&E's system. Edison, by remaining on SoCalGas's system, will benefit by obtaining enhanced service, although not firm, by avoiding the double demand charge, and by lower gas prices.

Finally, even were we to reallocate interstate demand charges on existing pipelines that might not solve the problem for those who would benefit. The issue of costs is broader than demand charges. The costs of an LDC are recovered in many ways. Should we decide that the double demand charge should be eliminated, reallocation is not the only solution. For those customers who leave the LDC's system but request stand-by service, that stand-by service represents considerable risk to the LDC which must be compensated. For those customers who transport gas on the new interstate pipeline but expect delivery over the LDC's intrastate system, that delivery must be paid for. And we see no reason why part-time customers should be charged the same rate as the customer who takes fully bundled service from the LDC. Those who patronize competitors of an LDC need not receive the same consideration as an LDC's core and core-elect customers. (See Re PG&E Rates (1975) 78 CPUC 638, 727; Associated Gas Distributors v FERC (D.C. Cir. 1987) 824 F 2d 981, 1038.) Customers must bear the full costs of their behavior.

To give some comfort to prospective users of new pipeline capacity, we agree with the proposition that in assessing costs we should not look to just one criterion, such as the projected load factor of new capacity, while ignoring the benefits of operating flexibility. An interstate pipeline operating at 100% load factor 100% of the time is not at its most efficient from its customers' perspective. At that level of use some customers are not being adequately served and prices cannot be at their competitive best. Alleviating capacity restraint on a pipeline system provides benefits to all customers.

D. The Offers of Settlement (Proposed Pipelines)

1. SoCalGas - (Altamont-Kern River-Mojave)

SoCalGas recommends that the Commission support a new integrated interstate pipeline system composed of the Altamont, Kern River, and Mojave projects. The Commission should allow market forces to determine whether the projects are actually constructed.[16]

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16 By way of repetition, SoCalGas originally proposed an offer of settlement between Kern River, Mojave, and itself. Later, Altamont entered into an agreement with Kern River and SoCalGas whereby Kern River would expand its facilities from 700 MMcf/d to 1.2 Bcf/d in order to transport 200 MMcf/d of gas delivered from Altamont to Southern California. Mojave takes no position regarding the Altamont project. Mojave does not regard Altamont as part of its stand-alone or settlement projects.

a. Altamont

Altamont is a joint venture of Amoco Canada Petroleum, Ltd. (Amoco), Petro-Canada Inc. (Petro), and Shell Canada Limited (Shell), formed for the purpose of constructing and operating a natural gas transmission system from the international boundary between the province of Alberta, Canada and the state of Montana to a point of interconnection with the proposed Kern River gas pipeline near Opal, Wyoming. Altamont will be a "transporter" pipeline in interstate commerce and will not engage in buying and selling natural gas. The three Altamont sponsors collectively represented about 25% of Canadian natural gas production in 1988.

The Altamont system, projected to go online in 1993, will consist of approximately 620 miles of 30-inch outside diameter (OD) underground pipeline. The capital cost of the system in 1989 dollars is estimated to be $580 million. The system is designed to receive natural gas at the Alberta, Canada-Montana border and deliver a volume of at least 700 MMcf/d to the terminus of the system at its interconnection with the Kern River system near Opal, Wyoming. All Canadian gas supplies from Alberta, including those that will be delivered to the Altamont system, must be transported through the facilities of NOVA Corporation of Alberta, which operates the only intra-provincial natural gas gathering and pipeline system in Alberta.

Altamont's system is designed and routed to provide direct and efficient access for southern California markets to western Canadian gas supplies. It is anticipated that Altamont's shippers will move their gas from the Altamont system through the Kern River system into southern California. Altamont and Kern River have entered into a contractual arrangement that provides for the interconnection of their systems and for the coordinated operation of the two systems. Once Altamont shippers' gas reaches southern California, it will be moved to end-use markets through the intrastate pipeline facilities of SoCalGas and potentially through other intra-California facilities. When Altamont is constructed, throughput of gas on Kern River will be increased by about 500 MMcf/d.

b. Kern River

Kern River is a general partnership of Williams Western Pipeline Company, an affiliate of The Williams Companies, and Kern River Corporation, an affiliate of Tenneco Inc. Kern River was formed in 1985 to construct, own, and operate a new interstate natural gas pipeline from Wyoming to California to enter the California market as a competitive alternative to the state's existing suppliers.

Kern River applied to FERC in 1985 for a certificate of public convenience and necessity to build its pipeline system from an interconnection with Northwest Pipeline Corporation in southwestern Wyoming to the heavy oil fields near Bakersfield in Kern County, California. The company filed its 1985 application under the traditional procedures of Section 7 of the Natural Gas Act, before FERC adopted its "optional expedited" certificate (OEC) procedures in its Order No. 436. On January 13, 1989, FERC issued its Opinion No. 322 in which it found that Kern River's pipeline can be constructed in an environmentally acceptable manner, subject to the implementation of certain mitigation measures. Kern River has accepted those measures. Kern River is awaiting the initial decision of the presiding administrative law judge on the non-environmental aspects of the application. Kern River expects to commence operations in 1991.

On June 14, 1989, Kern River entered into Principles of Settlement with SoCalGas and Mojave for the purpose of resolving the differences among the three companies with regard to the proposed Kern River and Mojave projects. Pursuant to those Principles of Settlement, the companies signed a definitive

Settlement Agreement on August 31, 1989, and Kern River on September 1, 1989 filed an application with FERC which presents a modified version of the Kern River project. This application in no way supersedes Kern River's prior application which remains pending before FERC.

In the September application, Kern River requested authority to operate its pipeline from the interconnection with Northwest in southwestern Wyoming to Kern County. The capacity of the system remains 700 MMcf/d. In accordance with the Kern River/Mojave/SoCalGas settlement, Kern River now proposes to interconnect its pipeline with Mojave's line and to jointly own with Mojave, as tenants in common, a single pipeline extending from the vicinity of Daggett, California to the oil fields in Kern County. Kern River's project consists of approximately 902 total miles of pipeline (including about 225 miles jointly-owned with Mojave). Kern River, however, proposes its project either as a stand-alone pipeline or as part of the SoCalGas/Mojave/Kern River Settlement Agreement.

Mojave's operating subsidiary will construct and operate the jointly-owned line pursuant to agreement with Kern River and Mojave. The jointly-owned line will have a capacity of 1,100 MMcf/d, the sum of Kern River's proposed stand-alone capacity of 700 MMcf/d and Mojave's proposed stand-alone capacity of 400 MMcf/d. The jointly-owned line will include an interconnection with SoCalGas's facilities in Kern County. Kern River initially will own 63.636% of the joint line, and Mojave will initially own the other 36.364%. Each company initially will control capacity in the jointly-owned line in proportion to its ownership interest and will have separate rates for transportation from its point of origin to its points of delivery to its customers.

Kern River filed its September application pursuant to FERC's OEC procedures. Kern River will provide open-access, non-discriminatory transportation for shippers and consumers of gas.

In accordance with the OEC regulations, Kern River will continue to assume all of the economic risks of its project and will offer both firm and interruptible service at volumetric rates, although it may negotiate with customers for a reservation (demand) charge for firm service. The company will be prohibited from increasing its rates to account for any failure to fully realize its projected volumes. On January 24, 1990, the FERC granted an OC certificate to the joint Kern River/Mojave project, but specifically did not approve the provisions of the settlement offered by Kern River, Mojave and SoCalGas.

c. <u>Mojave</u>

On May 8, 1989, FERC issued Mojave an optional certificate of public convenience and necessity authorizing Mojave to construct its pipeline from Arizona to Kern County. On September 1, 1989, Mojave filed an amendment to its application asking FERC to approve revisions in Mojave's project necessary to implement the Mojave/Kern River/SoCalGas settlement. On January 24, 1990, the FERC denied rehearing on the order granting Mojave's first OC for a stand-alone project and granted an OC certificate for the joint Kern River/Mojave project without approving the terms of the joint settlement submitted by Mojave, Kern River and SoCalGas. In this OII, Mojave has presented its project as either part of the SoCalGas/Mojave/Kern River Settlement Agreement or as a stand-alone pipeline.

Mojave will build a natural gas pipeline and appurtenant facilities from Topock, Arizona to Kern County, California near Bakersfield. Mojave's facilities will initially be capable of transporting approximately 400 MMcf/d of natural gas. From Topock to a point near Daggett, California, Mojave will construct a pipeline (the Common Facilities) in which it and Kern River will each own capacity as tenants in common. The Mojave facility will consist of approximately 159 miles of 24- and 30-inch pipeline extending from near Topock, Arizona to the point of interconnection with the Common Facilities (the Interconnection Point) near Daggett, California, together with one compressor station and appurtenant facilities, to be located in Arizona. The Mojave facility will consist of two segments. The first segment will consists of (1) approximately 17 miles of 24-inch diameter pipeline (Mojave Transfer Line) to be constructed from a tap on an existing 30-inch pipeline owned by Transwestern in Mojave County, Arizona to the proposed compressor station located near Topock, Arizona, and (2) interconnection facilities from a tap on an existing El Paso pipeline immediately south of the proposed Topock compressor station to connect into such compressor station. The second segment will consist of approximately 142 miles of 30-inch diameter pipeline (the Mojave Mainline) commencing at the proposed Topock compressor station, crossing the Colorado River into California, and extending to the Interconnection Point.

The Common Facilities will have a design capacity of 1.1 Bcf/d and will consist of approximately 225.5 miles of 30-, 36-, and 42-inch pipeline, together with appurtenant facilities, extending westward from the Interconnection Point to the Bakersfield area.

The total direct cost in 1989 dollars of the Mojave facility is estimated to be $109,332,000. The cost of the Common Facilities is $204,010,200. Mojave will pay 36.364% of this cost (and own an individual interest in 36.364% of the Common Facilities capacity), and Kern River will pay for and hold the capacity rights in the remaining 63.636% of the Common Facilities. Mojave's share of the cost of the Common Facilities thus will be $74,185,500. After payment of indirect costs, the total cost of the Mojave pipeline is estimated to be $214,405,300.

Mojave proposes to provide transportation of an average daily quantity of 400 MMcf/d, on a contract basis, of natural gas from the interconnections of the Mojave pipeline with existing

Transwestern and El Paso lines near Topock, Arizona through the Common Facilities to Kern County, California. Although Mojave expects that its transportation service will be provided primarily to customers for use in enhanced oil recovery (EOR) and related cogeneration operations in the Kern County area of central California, Mojave will provide transportation service on an open access basis under a blanket certificate issued pursuant to FERC's regulations.

2. WyCal

WyCal is a partnership whose present partners are Coastal Western Pipeline Company and CIG Western Pipeline Company (CIG). WyCal has received a final certificate of public convenience and necessity from FERC pursuant to FERC's optional certificate regulations to construct and operate a large diameter pipeline from the Overthrust gas producing regions of Wyoming to the vicinity of Bakersfield, California. The currently certificated system would allow WyCal to deliver approximately 650 MMcf/d of natural gas from Wyoming and interconnections with El Paso and Transwestern to the EOR market in Kern County and to other markets which are reasonably proximate to the pipeline system. WyCal, however, filed to obtain from the FERC an OC for an amended version of its original project, consisting of a 500 MMcf/d pipeline. This OC was granted by the FERC on January 24, 1990.

As a consequence of its agreements with PG&E and SoCalGas, WyCal also fileed two alternative proposals with FERC. Those alternatives involved the construction and operation of the currently certificated pipeline facilities along the route from Wyoming to the vicinity of the California border near Las Vegas, Nevada. However, instead of constructing a pipeline facility from there to Topock, Arizona and then from Topock to Bakersfield, the alternative would involve the construction of a 30-inch OD pipeline from the California border to an interconnection with PG&E's

existing facilities at a point near Barstow, California known as "Kramer Junction". PG&E has agreed to reinforce its facilities downstream from that point to effectuate deliveries to shippers by incrementally increasing the transmission capacity of its Line 300 to Kern County. The costs of such reinforcement would become part of WyCal's capital costs, and service provided through such facilities would be regulated by FERC, so that WyCal could provide firm, FERC regulated transportation service from the Rocky Mountain area to EOR and other shippers who desire that service in Southern California. This alternative could be in service in 1992.

WyCal also proposed a potential 18-mile, 24-inch OD pipeline interconnecting WyCal and the facilities of SoCalGas which would permit WyCal to deliver gas to SoCalGas for its own account (if it exercises its option to purchase with WyCal) or for shippers who desire SoCalGas to deliver gas for their account. Alternatively, depending upon the preference of the market, an interconnection could be constructed between PG&E's facilities and SoCalGas's facilities east of Kramer Junction to facilitate backhaul deliveries from WyCal to SoCalGas via PG&E. As discussed above, on January 24, 1990, in the same order which granted the amended stand-alone project certificate, the FERC denied certificates to the two alternative proposals of WyCal which would have utilized leased LDC facilities on the grounds that they were contrary to the Natural Gas Act.

3. PG&E

The PG&E/PGT Expansion Project is an incremental addition to the existing PGT and PG&E gas pipeline systems. The existing transmission systems run from Kingsgate, British Columbia (near Eastport, Idaho) to Malin, Oregon and through northern and central California. The current design of the Expansion Project consists of looping (the addition of parallel pipe to existing facilities) of approximately 845 miles of the PG&E/PGT system. The Expansion

Project will be built within existing rights-of-way for approximately 95% of the distance of the project.

The Expansion Project, which is scheduled to be in service in late 1993, will provide firm annual average deliveries of approximately 150 MMcf/d to the Pacific Northwest and approximately 755 MMcf/d to California. The California delivery point is at Kern River Station, the major interconnection between PG&E and SoCalGas. However, to assure firm service in California at the 755 MMcf/d level, the Expansion Project requires looping only to PG&E's Panoche Meter Station in Fresno, California. The cost of the modified Expansion Project, in 1988 dollars, is estimated to be approximately $1.2 billion.

The Expansion Project has the capability to access Alberta and British Columbia gas at the Kingsgate receipt point and British Columbia and the Rocky Mountain gas at the Stanfield, Oregon receipt point where PGT interconnects with the Northwest Pipeline System. Currently, PG&E, as the only firm sales customer of PGT at Malin, brings gas from all three of these sources into California via PGT.

4. Transwestern

Transwestern is a natural gas company which owns and operates approximately 4,500 miles of natural gas gathering and transmission facilities extending from the supply basins in the Texas Panhandle, Western Oklahoma, and the Permian area in West Texas and Southeast New Mexico, across the states of New Mexico and Arizona, to a point on the California border near Needles, California. Gas gathered and transported by Transwestern to the Arizona-California border is delivered to facilities owned by SoCalGas for ultimate consumption in Southern California. Transwestern is an affiliate of Enron Mojave, Inc., a partner in the Mojave Project.

SoCalGas is currently entitled to all of the firm capacity on Transwestern's pipeline system for deliveries at Needles, California. Transwestern provides transportation services to other shippers delivering gas to California customers under its interruptible rate schedule. Transwestern proposes to expand the capacity of its existing system from New Mexico and Arizona by approximately 320 MMcf/d to Needles. The capacity expansion will be accomplished by installing approximately 210 miles of 30-inch pipeline looping, parallel to the existing line. Transwestern states that its proposed expansion will provide additional firm capacity to SoCalGas and PG&E, as well as firm capacity to Mojave. The estimated total cost of the proposed facility expansion is approximately $153 million in 1989 dollars.

5. El Paso

El Paso owns and operates an interstate gas pipeline system which extends from the Permian Basin area of West Texas and Southwest New Mexico, the Texas-Oklahoma Panhandle area, the Anadarko Basin of Southwest Oklahoma, the San Juan Basin of Northwest New Mexico and Southwest Colorado, and the four corners area of Arizona, New Mexico, Utah, and Colorado to termination points at the boundary between California and Arizona near Blythe, California and Topock, Arizona and to a point of termination at the boundary between Arizona and Nevada near Big Bend, Arizona. The system totals approximately 9,300 miles of main pipeline divided primarily between the California Mainline, running from the Permian Basin to the California border near Blythe, California; the San Juan Mainline running from the San Juan Basin to the California border near Topock, Arizona; and the Permian-San Juan crossover, running from the Permian Basin to the San Juan Basin. This system provides about 60% of California's interstate pipeline capacity. Additionally, El Paso is a partner in the Mojave Project.

El Paso currently has three applications before FERC which it asserts will enhance the California market: the expansion of its San Juan Triangle facilities to bring coal seam gas to market, the 200 MMcf/d expansion at its Blythe connection with SoCalGas, and its 200-600 MMcf/d mainline expansion application.

The San Juan Triangle system will allow El Paso to receive and transport to existing market areas substantial quantities of natural gas produced primarily from new coal seam formations which are projected to become available in the near future in the San Juan Basin. This new physical capacity, together with currently unutilized capacity, will enable El Paso to accommodate up to 500 thousand decatherms per day (Mdth/d) of new coal seam production in its San Juan Triangle system at a capital cost of approximately $22.9 million. El Paso has proposed to roll project costs into its existing overall cost-of-service and anticipates that the revenues and expenses associated with the project will not significantly affect El Paso's existing or future rates.

El Paso's Wenden-to-Blythe expansion proposes an additional pipeline loop along a 13-mile segment of the mainline extending westward from Wenden to the system terminus near Blythe, California where the California mainline interconnects with SoCalGas's facilities. These facility additions will result in an expanded delivery capability at Blythe of about 200 Mdth/d at an estimated cost of approximately $13.2 million. The addition is in response to SoCalGas's proposed 200 MMcf/d expansion proposal. The addition will <u>not</u> supply firm gas but the interruptible service will be available approximately 90% of the time.

El Paso's third application requests authority to add between 200 Mdth/d and 600 Mdth/d of incremental capacity, based on final contractual commitments for shippers, to its mainline system for delivery at Topock, Arizona, either to PG&E, SoCalGas, or Mojave.

VII. The New Pipeline Policy of the Commission

A. The Pipeline Market

Today's decision is unique in its frank acknowledgment of uncertainty inherent in all efforts to forecast demand, and in its careful harnessing of competitive forces to attain statutory goals and requirements. As traditional utility services become more and more competitive,[17] responsible regulation can and should enlist competitive forces to the extent that their operation will result in furthering what have always been the goals of public utility regulation: reliable service and reasonable rates.

We know that California needs additional gas pipeline capacity into the state. We do not know precisely how much capacity is needed. We can only say that the need falls somewhere in between the relatively modest amount required in the near-term to ensure reliable service to the core and to connect California to additional producing areas, and the potentially vast amount that would be required in the long-term if the demands of the noncore market and of attaining air quality objectives turn out to be as great as some have projected.

This uncertainty creates great risks. If we forecast a single volume for demand, and require our LDCs and electric utilities to plan for and commit to precisely that amount of additional capacity, we would embark on a course that may result in the wrong timing or the wrong amount of additional capacity. The excess costs of such misguided regulation would be borne primarily by the LDCs' captive customers, namely, core ratepayers. On the other hand, we could forecast a range of demand, and allow the timing and the amount of additional pipeline capacity to be

17 Outstanding examples of this increasing competition are various telecommunications services and electrical generation.

determined primarily by the willingness of those purchasing or investing in capacity to bear the risk of that investment. In other words, those who have the most to gain would rightly bear the risks due to uncertainty.

The record of this proceeding demonstrates that there is both a widespread perception of growing gas demand in California and a willingness to compete to serve that demand. New producers and producing areas seek ready access to the California market. Pipeline companies seek new routes and/or spurs to new areas that can complement their existing facilities. Both producers and pipelines recognize that the California market is large and growing, and they have shown that they are ready to compete for market share. Furthermore, our unbundling of gas commodity and transportation service has alerted the California market to the need to plan for its transport needs. Sophisticated gas purchasers in California can now bargain expertly and exercise leverage in exchange for their subscription to firm capacity rights. This competitive process, in a perfect market, could reasonably be expected to result in an optimal amount of additional pipeline capacity into California.

However, despite assertions to the contrary, there is no true "free" market for pipeline transmission capacity: All pipelines seek regulatory guarantees for their cost recovery, and they could not be financed without this regulatory protection. In one form or another, California consumers or shippers of natural gas from other states or Canada will be required to pay for these projects. The market for pipeline capacity, like most markets in the real world, has imperfections. These arise partly from the impact of regulation, such as the desire of pipelines for cost recovery guarantees or the prior decisions of this Commission opposing bypass pipelines. We sense that California LDCs are reluctant to make firm commitments for additional capacity without affirmative guidance from this Commission. Such reluctance, in the current circumstances, may be causing <u>underinvestment</u> in additional capacity. Elsewhere in today's decision, we provide guidance to the LDCs for committing to additional pipeline capacity on behalf of the core.

Another kind of market imperfection, one that has greatly concerned us, is the possibility that pipeline costs, by one means or another, may be shifted away from the cost-causers. Specifically, to the extent that additional capacity would serve noncore customers it should be paid for by them, not by core ratepayers. If costs were shifted away from the cost-causers, the result would be unfair and would likely lead to <u>overinvestment</u> in additional capacity.

Traditionally, the solution to market imperfections has been to oppose competitive forces through strict regulation, at least in the public utility sector. Increasingly, this traditional solution has come into question. Critics have cited cost overruns and overcapacity in electrical generation as examples of how regulation does not necessarily minimize either costs or risks. Competition has been successfully introduced in electrical generation and other services formerly reserved to regulated monopolies. The question at hand is whether our duty to regulate in the public interest necessarily precludes us from utilizing competitive forces in determining the amount and timing of additional pipeline capacity into California. Pipelines are natural monopolies even where several pipelines serve a given market. It is the CPUC's primary function to regulate monopoly utility services such as gas transmission, even as we loosen regulation over more competitive areas, like the buying and selling of the gas commodity itself.

However, we believe that the time is right for us to guide and work with, rather than command and restrain, the competitive forces engaged in the pipeline market. First, regarding our LDCs, we have developed an appropriate record in this proceeding for modifying our prior position on additional pipeline capacity and for providing the guidance that the LDCs' management needs. We fully expect the LDCs to exercise their own judgment to evaluate the pipeline projects and the timing and amount of additional capacity that best suit each utility's situation. Second, the conditions we have announced for our willingness to support any given interstate pipeline project into California are crafted in large part to ensure appropriate assignment of costs to cost-causers. These conditions send a key message to potential users and sponsors of additional pipeline capacity. These conditions also protect the interests of core ratepayers. Having established these conditions, this Commission has fulfilled its regulatory obligations and enabled competitive forces to work in ways ensuring that private risk-taking will serve the public good.

B. <u>The Commission's Criteria for New Pipelines and the Proposed Settlements</u>

To provide the necessary guidance to the utilities to facilitate new pipeline capacity, we next address the critieria set out in our original decision in this matter, I.88-12-027. After careful consideration of the proposed settlements, and the comments on the proposed decision, we have concluded that with slight modification, our original criteria for new pipeline capacity remain valid and are the proper basis for the Commission's support of any new capacity. We will support new pipeline expansion projects which fully comport with these criteria. We will address each criterion in order, precisely as they were originally stated in I.88-12-027.

1. <u>Economic Justification for New Pipeline Capacity</u>

> The amount of new pipeline capacity proposed must be economically justifiable as a means to provide more reliable access to long-term gas supplies, to enhance

transportation reliability, to achieve gas cost reductions through gas-on-gas competition or to serve incremental demand, including that of EOR customers.

New capacity additions must be economically justified on the basis of total delivered cost of gas from each of the producing areas designated below, including a showing of competitive transmission costs.

These two criteria remain unchanged. There must be a valid need for the proposed capacity addition and a showing that the delivered cost of gas will be competitive. The need for new capacity has been demonstrated to our satisfaction in this proceeding, as discussed herein. The competitiveness of the delivered cost of gas on each pipeline will be demonstrated primarily through the willingness of customers to execute contracts for firm capacity on the new pipeline. Utility contracts for new capacity will remain subject to Commission approval in subsequent proceedings.

2. Supply Diversity

Any new proposal for pipeline capacity should result in an interstate pipeline network which provides California with reliability of access to all the major producing areas within immediate reach of the state. (E.g., Canada, Overthrust, and Southwest, including New Mexico coal seam gas reserves.)

We continue to support increased supply diversity for the state. It is of particular importance to access Wyoming supplies directly and to increase access to Canadian supplies and additional Canadian production areas. Canada and Wyoming were the two regions most preferred by the Southern California utility parties in this proceeding.

We see significant benefits for all gas consumers in accessing a new gas supply region such as Wyoming whose producers have clearly indicated a willingness to compete for market share with our existing suppliers. In addition, any of the proposed projects linking Wyoming with California also improve our network of interstate pipeline suppliers by affording relatively easy interconnections to the British Columbia, San Juan (New Mexico/Colorado), and Alberta[18] gas producing areas.

Improved access to Canadian gas supplies appears to have a number of advantages. Imports of natural gas from Canada have proven over the last few years to be plentiful and very competitive. There is some evidence that improved access to Canadian supplies would induce even more favorable price competition. It is also clear that access to Canadian gas was a major factor in the differential between the respective average gas costs of PG&E and SoCalGas. Finally, the enormous oversubscription of interruptible capacity on PGT's existing facilities, and the full subscription of the expansion project speak eloquently of the market demand for access to Canadian gas supplies. As a long-term supply option, Canadian gas has a number of benefits for California end-users.

While Wyoming and Canadian supplies have been of greatest interest among California utilities who seek <u>new</u> gas supplies, our interest in supply diversity carries with it a strong desire to maintain close ties with our <u>existing</u> suppliers as well. The Southwest, long a major source of gas to California, consists of several producing basins, and each is important to California. We

18 Improved access to Alberta gas supplies via Wyoming would require either expansion of the northern leg of PGT or the construction of the Altamont project.

seek to maintain sufficient pipeline capacity to all these basins even as new supply routes are forged or old ones expanded. For example, we are impressed with the potential for new gas supplies from the coal seam formations in the San Juan basin of New Mexico and Colorado. These formations hold large reserves of easily deliverable gas only a short distance from mainline pipelines (which are substantially depreciated) already serving California. The potential for competitively priced supplies with long reserve lives and high deliverability is attractive. We encourage the existing pipelines serving California to continue to compete for the current and future demand in our state, and coal seam gas will play an important role in that competition.

3. <u>Capacity Allocation</u>

Firm capacity on new interstate pipeline projects should be allocated in advance, by contract, on a long-term basis to California Public Utilities Commission (CPUC)-regulated utilities and their wholesale and utility electric generation (UEG) utility customers. In addition, EOR customers willing to sign firm, long-term commitments to use and pay for interstate pipeline capacity should be accommodated as part of an overall settlement.

Some form of firm capacity brokering should be authorized on the new pipeline additions, rendering incremental firm capacity available for the benefit of both core and noncore customers.

Following the termination of any EOR producer firm capacity contracts involving new capacity additions, and subject to FERC approval, the capacity rights of such EOR customers must be capable of reallocation to the LDCs and other utilities which are firm capacity holders on the same pipeline.

We have consistently supported the development of a program to "broker" or otherwise temporarily assign capacity on natural gas pipelines. Our position is unchanged. Indeed, it is bolstered by the record in this proceeding. We continue to believe that such a program is needed, that it should apply to both interstate and intrastate pipelines, and that it should be implemented on both new and existing pipelines. Our willingness to support a given interstate pipeline project continues to be conditioned on the sponsor's commitment to allow capacity brokering.

Some clarification seems necessary regarding what we mean by "capacity brokering." Where we have discussed "temporary" capacity allocation by brokering of "incremental" capacity, we meant to indicate that the holder of firm capacity rights would reassign those rights to another user of the capacity. However, another definition of capacity brokering may relate to the assignment of primary capacity rights, as when a pipeline proponent wishes to auction portions of a proposed pipeline. This latter definition of capacity brokering can be used to maximize the value of a pipeline and facilitate nondiscriminatory open access. While the latter is of great use for pipeline proponents to identify those that they may contract with for long-term capacity, we are referring tc capacity brokering here as the reassignment of capacity rights on a temporary basis.

The current lack of capacity brokering on pipelines into and within California is a major weakness in the gas market. Without brokering (or similar means by which a holder of firm rights to pipeline capacity could temporarily transfer those rights to a third party), the market function of matching willing buyers and sellers is seriously impeded, and capacity stands idle. By giving gas purchasers access to capacity when they need it, a brokering program could increase pipeline load factors, in effect "adding" capacity. Conversely, if as we suspect, brokering alone proves to be insufficient to facilitate the intrastate transportation of gas delivered to California by new interstate pipelines, we would expect the LDcs to construct sufficient intrastate capacity to match the interstate expansions. As indicated elsewhere in this order, we would provide expedited review and approval of such intrastate capacity additions as are reasonably required.

We conclude that a properly constructed brokering program can work to the benefit of everyone concerned with the natural gas industry, including producers, transporters, and consumers. Such a program is an essential element in the "unbundled" gas industry structure that this Commission and the FERC have fostered.

We acknowledge that brokering presents practical difficulties, especially on an interstate system. There may be no single brokering program that is suitable for all pipelines. However, we note that individual interstate pipelines have cooperated with interested parties to work out brokering or other methods of capacity assignment. Thus, there is already some valuable experience with making brokering work. Also, there has recently been encouraging progress with Transwestern in proceedings ongoing before the FERC, and we urge the FERC's approval of capacity brokering on that system, should the negotiations prove successful.

We note there has been no such progress with El Paso, nor has there been any commitment by PGT to the implementation of a brokering program for existing PGT capacity. We can only repeat that our willingness to support projects to add pipeline capacity is contingent on the sponsor's commitment to making the most efficient use of existing as well as additional capacity.

Brokering or some other appropriate method of capacity assignment is essential to efficient use of pipelines.

Our December 1988 criteria must not be interpreted as indicating a preference for the LDCs to absorb all unused pipeline capacity for the core.[19] To the extent that the criteria set forth in I.88-12-027 required LDCs and other firm capacity holders to have a right of first refusal for any EOR capacity which became available upon the termination of contracts, we modify the criteria to provide that if any capacity becomes available after the expiration of the initial capacity contracts, such capacity shall be reallocated according to a FERC-approved, non-discriminatory allocation system, such as an open season or first-come, first-served.

We no longer insist that all the capacity on a new project must be reserved for electric and wholesale utilities, EOR customers or the LDCs. We note that substantial participation by some or all of those three groups is essential for any project to be viable, but we will not oppose projects in which capacity rights are available to other types of shippers, end-users or producers.

4. Bypass Issues

We continue to prefer that any new interstate capacity should interconnect at the state border with an intrastate pipeline subject to CPUC jurisdiction. The Commission will consider approval of FERC-regulated

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19 The current extent of LDC participation in the proposed pipelines on behalf of their core customers is modest. PG&E has subscribed to 100 MMcf/d on the PGT expansion project, and an additional 50 MMcf/d on WyCal. SoCalGas has subscribed to 200 MMcf/d on Kern River, with an option for 75 MMcf/d on WyCal. We do not expect core participation to increase beyond current levels, simply to maintain a project's viability or to prevent its being downsized.

pipeline facilities initially dedicated to EOR use as a part of an overall settlement if the capacity of such facilities is limited to incremental EOR service or service which does not bypass the distribution utilities.

Our support for the settlement will depend on a commitment from any new pipeline project owner and operator that such a dedicated FERC-regulated EOR facility shall not be extended or expanded to bypass California LDCs to serve non-EOR customers in California, except by interconnection with existing distribution facilities subject to CPUC regulation.

5. Jurisdictional Issues

While new EOR-dedicated capacity may be federally regulated for an extended period of time (e.g. fifteen years) to enable EOR customers to recover a substantial portion of their investment during the period of FERC jurisdiction, after such a period of time has elapsed, jurisdiction over any new pipeline facilities constructed within the State of California must revert to CPUC jurisdiction, preferably through self-implementing arrangements which give a substantial measure of certainty that they will operate as intended in the future. We envision pre-granted abandonment of FERC authorization and arrangements to segment the ownership of facilities within and without the boundaries of the state as potential vehicles for such a jurisdictional reversion.

These two sets of criteria remain the most controversial and the most important to the Commission in reaching an accommodation with pipeline project sponsors and developers. We continue to adhere to the principles set forth in these criteria, and wish to clarify their application. Initially, we restate our strongly held view, "that any new interstate capacity should interconnect at the state border with an intrastate pipeline subject to CPUC jurisdiction." This remains a clear solution to the issues of bypass and jurisdiction. It comports with the original intent of Congress in providing for split jurisdiction between the states and the federal government in the Natural Gas Act; it minimizes the likelihood of any conflict between the jurisdictions; and it has effectively functioned as a regulatory scheme in California for decades.

In I.88-12-027, we held out the possibility of support for FERC-regulated interstate projects which would be initially dedicated to EOR and utility customers as part of a settlement, if the capacity were limited to incremental EOR use, or service which does not bypass the LDC facilities. We also indicated that our support for any such project would depend on a commitment that any FERC-regulated interstate facilities within the state must revert to CPUC jurisdiction after some extended period of time.

Two recent orders of the FERC lead us to believe that the reversion of jurisdiction proposals contained in various settlements may not be feasible, or at least may not be approved by the FERC. In its Order Issuing Certificate and Amending Prior Orders in the WyCal case (Dockets No. CP90-41-000, et al., issued January 24, 1990), the FERC disapproved the alternatives offered by WyCal which would have permitted a joint project with PG&E to be constructed by means of leasing PG&E-constructed facilities appurtenant to Line 300 to WyCal for a specified term of years. The FERC specifically found the proposed arrangement to violate the requirements of the Natural Gas Act. Indeed, the FERC appears to believe that the PG&E-constructed facilities would remain subject to CPUC jurisdiction and thus could not be simultaneously subject to FERC jurisdiction.

In a companion decision, Order Issuing Certificates, Granting and Denying Rehearing, and Clarifying and Modifying Prior Order, issued on January 24, 1990 in the Kern River and Mojave cases (Dockets No. CP89-2047-000 et al. and CP89-1-001 et al.), the FERC made it clear that it was only issuing certificates to Kern River and Mojave and was not approving the joint Kern River/Mojave/SoCalGas settlement, or approving the transfer of jurisdiction of such facilities to the CPUC. The FERC did not specifically express any opinion on the validity of SoCalGas' contractual option to purchase the in-state facilities or upon the merits of any application for pre-granted abandonment, stating that these issues were not before it at this time.

In light of these orders, we cannot find that the settlement provisions submitted to the Commission by these parties will result in a transfer of in-state facilities to either utility ownership or CPUC jurisdiction. Further clarification and/or new decisions by the FERC would be required to assure this Commission that such compromise solutions to the jurisdictional issue can be effective.

We continue to feel strongly that construction of an interstate pipeline to bypass the LDCs will inevitably result in substantial cost reallocation to the captive customers. This is an improper intrusion into the wholly local issue of retail rate design. In addition, we are not satisfied with the provisions of the various settlements filed by the parties which purport to preclude non-EOR bypass. FERC has not yet approved settlement provisions which effectively restrict bypass service directly to an end user, although the settlements clearly do permit service to be made through the LDC through appropriate interconnections.

There are limits to how far this Commission should go in an attempt to facilitate the construction of new pipelines to California. It is one thing to countenance bypass service to the EOR market for a designated period of time as part of a compromise solution. Similarly, it is conceivable that non-EOR bypass in some limited form could be tolerated if that were the only way to expedite new capacity. However, where the proposed settlements contain no effective bar to either EOR or non-EOR bypass, and recent FERC orders give no indication that either a transfer of facilities to LDCs or a pre-granted abandonment will be approved, we must conclude that the jurisdictional criteria set forth in I.88-12-027 have not been satisfied.

Considering these developments, we conclude that our support for new pipeline projects must be conditioned on a strictly objective standard for meeting the original criteria stated in I.88-12-027. Mere representations of a party's intent or understanding will not suffice. To gain Commission support, a project will have to demonstrate one of three things, either 1) a structural solution to prevent bypass, such as a configuration in which the interstate pipeline stops at the border, and a CPUC jurisdictional LDC transports the gas within the state; or 2) final FERC approval of provisions to effectively transfer jurisdiction of facilities within California to CPUC jurisdiction after a stated period of time not to exceed 20 years through pre-granted abandonment; or 3) final FERC approval of an agreement or option for the LDC to purchase the in-state facilities of the interstate pipeline during a simliar time period, thus qualifying the in-state facilities for Hinshaw exemption from FERC regulation.

6. EOR Service Issues

Following a reversion of jurisdiction to the CPUC, EOR contracts for pipeline service will continue to be honored according to their terms for the life of the contracts, including a Commission waiver of the provisions of General Order (GO) 96-A so as to prevent the modification of existing long-term EOR contracts.

We continue to believe that the LDCs represent a viable and competitive means of service for EOR customers. However, if a pipeline project proceeds with a proposal to serve the EOR market under one of the approved scenarios described above wherein the LDC will assume control of the in-state facilities after an extended period of time (e.g. 20 years), we reassure the parties who ship gas over such pipelines that the switch in jurisdiction to the CPUC will not threaten existing transportation agreements.

Accordingly, we affirm our previous position, stated in I.88-12-027, that upon assumption of jurisdiction by the CPUC over any facilities of the pipeline projects which (1) are the subject of this order, (2) exist within the State of California, and (3) were previously interstate facilities, the CPUC will, and by this order does, waive the provisions of General Order 96-A, paragraphs IX and X (A.), thus waiving the Commission's right to modify such contracts. We intend by this action to permit the provisions of such contracts to remain in effect for the life of the contracts in the same manner that they were implemented while the pipeline in question was under FERC jurisdiction.

7. <u>Cost Allocation Issues</u>

> Cost responsibility for new capacity must flow to those customers who will benefit from firm service on the pipeline. We will not place the risk of cost recovery for such facilities on core customers, except to the extent it can be conclusively demonstrated that they benefit from the new facilities. The same principles will be applied to the allocation of the costs of stranded investments and idled capacity.

We likewise reaffirm our original criteria for pipeline cost allocation as set forth in I.88-12-027. Costs shall be allocated to the parties benefiting from new pipeline capacity, in direct proportion to their capacity rights on the new project. Core customers will not be reallocated any costs of existing pipelines at this time. Core customers will only bear such costs of new projects as relate to new capacity for which the LDCs contract to serve the core and which is approved by the Commission. (See also our discussion below regarding guidelines for California utility commitments for additional pipeline capacity.)

8. Procedural Issues

Certification, environmental review, rate design, and cost allocation of the CPUC jurisdictional portion of any proposed transmission project meeting our criteria will be conducted so that all necessary approvals can be issued in the most expeditious manner possible. To allow for such expeditious procedures, we are prepared to utilize our settlement procedures whenever possible.

Specifically, we will be prepared to provide expeditious advance review and approval of certificate applications and contracts submitted by California regulated utilities to implement a comprehensive settlement which meets the criteria set forth herein.

The CPUC will fully cooperate with the FERC and other federal authorities to encourage the issuance of expeditious certificates, environmental authorizations, and other permits required for the FERC-regulated interstate portion of any comprehensive pipeline proposals, provided that such proposals are consistent with the criteria outlined here.

The Commission remains committed to expedited consideration of all pipeline related issues, including environmental reviews and advance review and approval of utility contracts for capacity and gas supply as required to speed the construction of new pipeline capacity. We urge the utilities to finalize such agreements with pipeline sponsors whose projects meet the criteria restated in this order and to submit such contracts for review at the earliest possible time.

C. A Review of the Proposed Pipeline Projects and The Commission's Criteria

In this section, we review the current status of the interstate pipeline proposals, as reflected in the record of this proceeding. Where applicable, we note any aspect of the individual proposals that does not presently conform to the conditions set forth above.[20] In noting nonconforming aspects, we neither condemn nor prefer any project. Our intention is entirely constructive: We are providing objective information to the sponsors of the various pipeline proposals, so that they will know clearly the aspects of their proposals that need further refinement to gain this Commission's support.

We do not dictate to the sponsors how to refine their projects. So long as they conform to the conditions that we have stated all along in this procceeding, they are free to do whatever they feel necessary to compete effectively, secure in the knowledge

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20 We are well aware that the projects have evolved considerably throughout the proceeding and after the close of the record. Indeed, we fully expect competitive forces to work additional changes on each project in the coming months. It is particularly important that all parties realize we can only comment on the projects as they are reflected in our record; thus, some of the nonconformities noted here may well have been cured already. We stress as strongly as possible that no project is "frozen out" by today's decision. We expect and strongly encourage the sponsors to continue to compete to serve the California market, and we are committed to support all of those projects that achieve conformity with our conditions.

that they will have this Commission's support, both in California and before the FERC.

We single out the SoCalGas southern expansion for separate discussion as it is significantly different from the other major pipeline proposals before us.

1. The SoCalGas Southern Expansion Project

SoCalGas intends to expand its transmission system so that it may accept an additional 200 MMcf/d from its interconnection with the facilities of El Paso at the California/Arizona border near Blythe. The expansion consists primarily of looping portions of SoCalGas's "southern system" (lines 2000 and 2001). The looping will be in three separate segments and will consist of a total of 30.3 miles of 30-inch pipeline and 24.4 miles of 36-inch pipeline. The line could be operational by 1991.

In connection with this expansion, El Paso has agreed to undertake the necessary modifications to its facilities and to obtain the necessary regulatory approvals to enable it to deliver an additional 200 MMcf/d to SoCalGas at the Blythe interconnection. The capacity will be provided initially by El Paso on an interruptible, non-discriminatory basis to SoCalGas and other shippers. El Paso expects this additional capacity to be available for utilization in excess of 90% of the year. The estimated direct cost of the expansion to SoCalGas is $44.1 million.

SoCalGas first made its expansion proposal in its test year 1990 rate case (A.88-12-049). In response to a motion by DRA to exclude the issue of the southern system expansion from the rate case, Assigned Commissioner Frederick R. Duda on September 11, 1989 issued his ruling which determined, among other things:

> "1. The interstate capacity benefits of the southern system expansion, together with El Paso's proposed interstate pipeline

proposal, are being considered in I.88-12-027."

* * *

"5. A certificate of public convenience and necessity is not required for the southern system expansion."

We affirm Commissioner Duda's ruling. The Southern Expansion Project meets all of our criteria. It is the least expensive way to bring an additional 200 MMcf/d to California in the shortest time. The gas is needed. Need is shown by the evidence that SoCalGas is presently operating at 100% of capacity; that there have been four major gas curtailments in its service area in the past three years; and that new gas is needed to alleviate air pollution problems in the Los Angeles Basin. No bypass is involved, and the pipeline is entirely subject to our jurisdiction. The gas can serve the EOR market or any of SoCalGas' other markets. Cost allocation will be handled by traditional methods. It is not firm capacity, but 90% of firm is substantial.

In I.88-12-027, we said that we would expedite approvals for those projects which meet our criteria. We will do so for this project. We hold that the project is needed and that a certificate of public convenience and necessity is not required. Environmental review, if required, and issues of cost recovery will be handled in A.88-12-047, and we will resolve these matters promptly so that construction can begin at the earliest time.

2. <u>Conformity With the Criteria Adopted in I.88-12-027</u>.

a. Economic Justification for New Pipeline Capacity

Each of the projects is capable of meeting this criterion. We have determined that there is a need for additional pipeline capacity, and each of the projects can serve in one degree or another both the utility load and the EOR market. As for the showing of competitive delivered gas costs, we will allow the competition between the various projects to resolve that issue, subject only to our responsibility to approve utility contracts for capacity or gas supply.

PGT, Kern River, WyCal and Mojave have all demonstrated some market support for their projects through customer commitments. These vary greatly in degree of commitment, but we expect the competitive forces to quickly move to revise these tentative agreements and replace them with firm agreements now that we have indicated our desire to allow these forces to control the scope of the additional capacity to be built. Transwestern has not yet disclosed any specific customer support for its mainline expansion, nor has El Paso, with the exception of the 200 MMcf/d which SoCalGas will utilize in connection with its southern expansion. However, witnesses for the respective projects testified that there were requests for service from unspecified customers for a portion of the planned capacity. Market support for these projects appears to be unclear.

b. Supply Diversity

The WyCal and Kern River projects clearly enhance supply diversity as they access an entirely new gas supply region, as well as interconnect with Canadian and New Mexico producing regions. PGT's expansion project also enhances supply diversity because it specifically links Canadian supplies to Southern California utility customers. At present only a small amount of Canadian gas is imported to Southern California, and such a linkage would improve overall supply diversity for the state. El Paso and Transwestern do not appear to directly enhance supply diversity for California as they do not provide access to new supply regions. Similarly, the Mojave project does not enhance supply diversity as it interconnects only with El Paso and Transwestern.

c. Capacity Allocation

WyCal, Kern River, and Mojave have all been granted certificates by the FERC which contain capacity brokering rules to be included in the tariffs of those pipelines. Transwestern has put forth settlement proposals, but has not obtained FERC approval of capacity brokering in its current general rate case. Neither El Paso nor PGT have committed to implementation of capacity brokering over their full systems, both existing and proposed expansion.

d. Bypass Issues and Jurisdictional Issues

As previously stated, we continue to prefer that any new interstate pipeline interconnect at the state border with an intrastate pipeline subject to CPUC jurisdiction. PGT is structurally designed to prevent bypass, as all intrastate transportation will occur on PG&E's facilities. Neither El Paso nor Transwestern bypass the LDCs. The Mojave and Kern River combined project and their respective stand-alone projects would bypass the LDCs, as would WyCal under the complete pipeline configuration currently certificated by the FERC. None of the latter three pipelines have been able to implement settlement provisions which completely resolve our jurisdictional concerns at the present time.

e. EOR Service Issues

As we are prepared to waive the provisions of General Order 96-A which permit CPUC modification of contracts, all pipelines can meet this criterion. As we indicated elsewhere, we are willing to do this to foster potential settlement provisions which will resolve the bypass and jurisdictional concerns we have described.

f. Cost Allocation Issues

With one exception, all the pipelines propose that capacity subscribers must contract to pay demand charges and commodity charges that will cover all costs of the project, thus insulating other ratepayers from the cost of these pipelines. PGT has reached agreement with its shippers to consider rolled-in ratemaking[21] treatment for the expansion project in the first rate case to be filed after PGT receives its certificate. Rolled-in ratemaking may cause customers of the existing PGT system to pay for a portion of expansion costs in excess of any benefits received. Both our cost allocation criterion and prior decisions of the Commission are in opposition to rolled-in ratemaking.

g. Procedural Issues

While the various pipeline projects are all in various procedural postures, all have an equal opportunity for expedited consideration by this Commission of any utility contracts for capacity. In addition, as discussed elsewhere, the Commission will actively support any settlement provisions which assist in resolving the jurisdictional concerns expressed in this order, including taking an active role in support of such settlements at the FERC.

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21 Rolled-in ratemaking refers to the inclusion of all pipeline costs, including the costs of any expansion project, in a single rate to be charged to all customers. This contrasts with, for example, the current ratemaking treatment of the pre-build portion of the Alaska Natural Gas Transportation System project on PGT, which serves the Pacific Interstate Transmission Company (PITCO) load. The costs of the pre-build improvements to PGT are incrementally billed only to PITCO, and are not reflected in the rates charged to other PGT customers. Our policy, as announced in the ANGST-PITCO case, is to oppose rolled-in ratemaking.

D. Other Pipeline Projects

We have not included the Altamont Pipeline Project in our review of the proposed pipelines and our adopted criteria. This is because Altamont differs significantly from the other projects considered in this order as it does not cross the border into California. It is a wholly interstate project which serves as an "upstream" supplier to Kern River (or potentially to WyCal). In that regard, we need not address the merits of the Altamont application by this order. Altamont does not directly or indirectly bypass any California LDC, nor does it engage in the local distribution of gas within California. Gas carried by Altamont must reach California by means of other projects which will either be supported or opposed by this Commission based upon their adherence to the criteria we set forth in I.88-12-027 and restate in this decision.

To the extent that a pipeline to Wyoming is built, we believe the construction of Altamont would enhance the supply options available over the Wyoming pipeline and thus be of benefit to California. The extra costs associated with the Altamont project would only be recoverable from California purchasers if competitive with other supplies, thus we need not evaluate the cost of that project at this time. Should SoCal or any other utility sign contracts for firm capacity with Altamont, those contracts would, of course, be subject to CPUC approval and reasonableness review, and cost would be one of the issues reviewed. Accordingly, we make no finding with regard to Altamont, and will not oppose the project in its current form before the FERC. We will intervene in the case for the purposes of monitoring the proceedings and to evaluate the project's impact on California.

There are numerous other pipeline projects which have been proposed from time to time which are not directly at issue in this proceeding. We will not directly comment on or evaluate these pipelines at this time, with one exception. At such time as additional pipeline expansion projects do become viable, the Commission will apply the criteria restated in this order to evaluate its position with respect to such projects.

One pipeline project of interest, but which is not directly before us in this proceeding, is Transwestern's coal seam lateral to connect its mainline with processing plants in the coal seam producing area of New Mexico and Colorado. To the extent such a project enhances the quantity and diversity of supplies available to California over the existing Transwestern mainline, it would clearly enhance the regional gas supply system we rely on. We see no reason to object to such projects. In contrast, a major expansion of the Transwestern mainline will have a much larger impact on the cost of gas moving to California, and would have to conform with our adopted criteria.

E. <u>Guidance to LDCs and Electric Utilities</u>

In this section, we enunciate certain guidelines for our utilities in committing to additional pipeline capacity. We are not relieving the utilities of managerial discretion! They face tough decisions and a lot of hard bargaining in executing their job responsibilities. We intend to set forth sufficient regulatory policy for the utilities to know how their decisions will be judged. Although this Commission recognizes that it cannot bind future Commissions, we believe the policy discussion that follows is wholly consistent with long-standing Commission standards on reasonableness reviews and resource planning.

Core ratepayers will benefit from the enhanced reliability and competition that additional capacity will provide, although demand from noncore customers is the primary factor driving the need for additional pipeline capacity to California at this time. For example, the LDCs can capture for their core market some of the benefits of increased gas-to-gas and pipeline-to-pipeline competition arising from the additional capacity, and all California gas consumers will share in the benefits of increased supply security, both of which require greater "slack" capacity than now exists in the interstate pipeline system serving California. Therefore, we expect that the California LDCs will want to subscribe to part of the additional capacity for the core, as their current preliminary commitments indicate. We would approve LDC subscription for new capacity in a measure proportional to the benefits which will flow to core customers. The generic conditions we have placed on our support of specific projects try to ensure for the core a fair match of benefits and burdens from additional capacity. A fair match also requires that LDC subscriptions be proportionate to core needs.

From this discussion, two conclusions follow. First, LDC subscriptions to additional capacity must be based on reasonable projection of core needs and a resource plan that includes cost/benefit analysis, renewed emphasis on conservation programs, and consideration of the uncertainties inherent in forecasts of demand growth. Second, we repeat that the LDCs are not to increase their current subscriptions on behalf of core customers in order to ensure continued viability of a project in the event that other current subscribers drop out. In other words, core customers (through the LDCs) should not revive projects that the noncore market says should not go forward (or should be downsized).

Correspondingly, we expect that California LDCs, as potential large subscribers to firm capacity, will be in an excellent position to extract favorable terms for long-term supply or capacity agreements. The LDCs should take advantage of the competition among project sponsors to negotiate favorable deals, taking into consideration both costs and risks to core ratepayers. Both LDCs and electric utilities should justify their commitments to the pipeline projects using a long-term analysis, and they should recognize, as the Commission does, that long-term contracts have an important, but not exclusive, role to play in a core procurement strategy. However, a long-term contract has benefits for both the buyer and the seller, and the terms of the commitment should reflect that. We will of course review in appropriate proceedings the reasonableness of the decisions of both the LDCs and electric utilities on subscription to additional capacity.

Our unbundling of natural gas service in California relieved the LDCs of their public utility obligation to provide gas procurement service to the noncore. Such "best efforts" service as the LDCs may continue to provide noncore customers does not justify subscription to additional firm capacity by the LDCs. While we have found it prudent to plan for as much as 2.1 Bcf of additional capacity over the long-term, whether that amount or anything close to that amount actually gets built must depend on the investment decisions of noncore customers and those intending to provide firm service to that market.

F. Utility Equity Participation in New Pipelines

Our comments regarding utility subscription of capacity to serve the core market should be understood to be distinct from the issue of utility participation as an equity owner of a new pipeline. We have no objection to utility investment in new pipelines, either directly or through affiliates. That is a purely managerial decision for the utility and its investors. In fact, we encourage utility equity participation in projects where the utility has contracted for substantial capacity. Equity ownership gives the utility an opportunity to participate in pipeline management decisions and generally reduces the potential for operational problems or bypass. While we do not require equity participation as one of the criteria we will use to evaluate new pipeline projects, we do encourage pipeline sponsors to consider accepting utility investment if it is offered.

G. The CPUC's Position in Ongoing Pipeline Certificate Ligitation

The CPUC has consistently opposed FERC attempts to certificate bypass pipelines and to certificate pipelines using the Optional Expedited Certificate procedure delineated in Order No. 436. We note that several of the most critical of these issues are already before the U.S. Court of Appeals for the District of Columbia Circuit (CPUC v. FERC, Case No. 89-1189, argued January 26, 1990.). So long as projects are proposed which do not comply with the restated criteria contained in this decision, we shall continue to oppose those bypass pipelines and object to FERC preemption of valid state regulation of local distribution associated with such projects. We continue to believe that unrestricted entry of interstate pipelines into California for the purpose of "creamskimming" major industrial customers does significant harm to remaining captive customers. FERC is mistaken in asserting, as it does in its recent WyCal and Kern River/Mojave decisions that all loads to be served by these projects is incremental load. The LDCs have extensive EOR customer demand at this time. That load is the primary target of many of the new pipeline proposals. In addition, several of the pipelines have made no secret of their desire to serve other industrial customers, including but not limited to, Southern California electric utilities. These pipelines clearly have the potential for signficant bypass of the LDCs. Yet the extensive distribution systems built in California to serve these customers would lose substantial customer contributions to their fixed costs.

We continue to oppose the FERC's OEC procedures, which, as recently applied, appear to run afoul of the NGA, NEPA and common notions of fundamental fairness. Our primary concern is that the procedures promote, and too easily permit, bypass which harms captive LDC customers and intrudes on the state's retail rate structure. However, where a pipeline applicant demonstrates a willingness to comply with the criteria we have established to mitigate the adverse impacts of LDC bypass, our practical concerns about the OEC procedures are greatly reduced. Accordingly, we will not oppose pipelines complying with our criteria, even though the FERC certificate sought may be an OEC. We will in all other cases continue to contest OECs.

Accordingly, we will require adherence to the requirements of our pipeline criteria before we authorize the settlement or withdrawal of any of the anti-bypass litigation in which we are now engaged. However, if a pipeline does conform to our criteria, we are convinced that our adopted policy for additional pipeline capacity would provide sufficient protection to California ratepayers to warrant termination of existing litigation over that project. We are prepared to take such steps upon receiving definitive evidence that the project or projects in questions have conformed to our criteria.

VIII. CONCLUSION

We view this decision as a turning point in the struggle to obtain new pipeline capacity for California. We see clear indications that with the specific guidance we have given in this decision, competitive forces will induce the pipeline project sponsors, the utilities, and the potential customers for such pipelines to reach agreement on new projects which will benefit the economy of the entire state. Our desire to facilitate the speedy construction of new pipeline capacity and our desire to avoid the economic consequences of bypass need not be mutually exclusive.

To that end, we wish to repeat that pipeline projects which conform to our criteria will receive enthusiastic Commission support for their projects, both in California and before the FERC. The time is now ripe for competitive forces to bring this proceeding to an end and to set about fashioning the pragmatic, market-based solution which will result in the construction of the new pipelines upon which this state will rely for many years to come.

Findings of Fact

1. The capacity of the interstate and the intrastate pipeline systems serving California is insufficient to prevent periodic peak season curtailments of low priority customers' transportation rights.

2. Noncore customers are unable to obtain firm transportation capacity.

3. In Southern California there is insufficient interstate pipeline capacity access to permit the full benefits of gas-to-gas price competition to reach noncore customers.

4. California has experienced four curtailments of noncore gas service within the last three years, including three of the four winters since open access interstate transportation first became available to California. California is today experiencing curtailment of noncore natural gas service.

5. Each curtailment, whether supply or capacity related, produces a significant negative impact on noncore transportation service.

6. Recurring occasional peak season curtailments of noncore transportation service will continue to occur absent any change in the level of service provided by the utilities.

7. Frequent curtailment of noncore transportation service undermines confidence in the market for gas transportation services, disrupts industrial operations, and reduces the benefits of a competitive interstate gas market available to California consumers.

8. The benefits of a competitive interstate gas market include an efficient allocation of gas supplies, access to a greater diversity of gas supplies, and lower costs of gas through gas-to-gas competition.

9. A comparison of northern and southern California average gas costs and pipeline load factors reveals that added pipeline capacity is a factor in producing lower gas costs through gas-to-gas competition.

10. There is a need for greater access to firm capacity rights on both existing and new pipelines.

11. New interstate and intrastate pipeline capacity will provide the appropriate means to enhance the level of service for noncore customers. Core customers will also benefit from additional capacity.

12. A reasonable forecast of average daily capacity utilization is:

Forecasted Average Daily
Interstate Pipeline Capacity Utilization
(MMcf/d)

	1993		1995		2000		2005		
	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Current Capacity
PG&E	1,897	1,986	1,998	2,204	2,279	2,403	2,336	2,483	2,157
SoCalGas	2,644	2,757	2,728	2,850	3,085	3,209	3,106	3,237	2,500
Total	4,541	4,743	4,726	5,054	5,364	5,612	5,442	5,720	4,657

Average Day
Interstate Pipeline Capacity Utilization Rates
(Percent)

	1993		1995		2000		2005	
	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year	Normal Year	Cold Year
PG&E	87.9	92.1	92.6	102.2	105.7	111.4	108.3	115.1
SoCalGas	105.8	110.3	109.1	114.0	123.4	128.4	124.2	129.5
Average	96.9	101.2	100.9	108.1	114.6	119.9	116.3	122.3

13. There is a need for additional interstate pipeline capacity to Southern California today.

14. There is a near-term need for at least an additional 900 MMcf/d of natural gas to California and for significantly more within the first decade of the 21st century; perhaps as much as 2.1 Bcf/d, cumulatively.

15. Our near-term need estimate of 900 MMcf/d is based upon:

1995 Cold Year Requirement	5,054 MMcf/d
1989 Current Availability	4,657
	397
10% Slack Factor	505
New Capacity Needed by 1995	902 MMcf/d
Use	900 MMcf/d

16. Our long-term need estimate of between 1.6 and 2.1 Bcf/d is based upon:

2005 Cold Year Requirement	5,720 MMcf/d
1989 Current Availability	4,657
	1,063
10% Slack Factor (Normal Yr.)	544
New Capacity Needed by 2005	1,607 MMcf/d
Use	1,600 MMcf/d

2005 Cold Year Requirement	5,720 MMcf/d
1989 Current Availability	4,657
	1,063
20% Slack Factor (Normal Yr.)	1,088
New Capacity Needed by 2005	2,151 MMcf/d
Use	2,100 MMcf/d

17. Additional pipeline capacity will not only satisfy the need for natural gas but also will provide an enhanced level of transportation service to noncore customers; will access new gas production areas; will secure price and supply on a long-term basis; and will permit gas-on-gas and pipeline-on-pipeline competition.

18. A capacity "brokering" program is essential to the efficient utilization of gas pipelines. Such a program should apply both to existing pipelines and to any additonal capacity.

19. We will not announce a position on cost reallocation at this time. To reallocate costs at this time or to announce a position on reallocation of costs would be to subsidize new production areas and new producers. Under the current system of netback pricing there is every reason to believe that new gas producers will absorb the costs of the new pipelines. Producers are prepared to netback all of the new pipeline demand charges in the cost of gas at the wellhead in order to be able to sell gas at competitive prices into the Southern California market.

20. SoCalGas's Southern Expansion Project meets our criteria for a new pipeline and is in the public interest. It is the least expensive way to bring an additional 200 MMcf/d to California in the shortest time. The gas is needed in Southern California today. SoCalGas is presently operating at 100% of capacity; there have been four major gas curtailments in its service area in the past three years; curtailments continue today; new gas is needed to alleviate air pollution problems in the Los Angeles Basin.

21. Given the near-term and long-term needs described in the foregoing findings, and given the competition to serve the California gas market among different producers, production areas, and pipeline projects, it is in the interest of California for this Commission to support any interstate project to build additional natural gas pipeline capacity to California, provided that the project conforms to the conditions set forth in Order Instituting Investigation 88-12-027 as restated in this Decision.

<u>Conclusions of Law</u>

1. Commissioner Duda's ruling in A.88-12-049 that a certificate of public convenience and necessity is not required for the SoCalGas Southern Expansion Project should be affirmed.

2. None of the proposed offers of settlement are in the public interest.

3. Nothing in this decision shall be construed to change or moot the position we have taken in CPUC v. FERC, D.C. Cir. Nos. 89-1189, et al., oral argument held January 26, 1990. The Commission is still aggrieved by the FERC's finding that it is facially preempted by the NGA from certificating local deliveries to California end users and by the federal agency's application of its OC procedures so as to deprive the Commission of its constitutional and statutory rights. Our counsel shall continue to prosecute this and other appeals involving pipelines which have not conformed themselves to our criteria.

4. This Commission should determine whether to support any given interstate project to build additional natural gas pipeline capacity to California based on the project's conformity with the conditions originally set forth in Order Instituting Investigation 88-12-027, as restated in today's decision.

ORDER

IT IS ORDERED that:

1. The General Counsel of this Commission shall represent, before all executive, legislative, and judicial departments of the United States, of California, and elsewhere, that it is the long-term policy of the State of California to support interstate pipeline projects that conform to the conditions set forth in Order Instituting Investigation 88-12-027 as restated in this decision and to oppose such projects that do not conform to those conditions.

2. The ruling of Commissioner Duda in A.88-12-049 that a certificate of public convenience and necessity is not required for SoCalGas's Southern Expansion Project is affirmed.

This order is effective today.

Dated FEB 7 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I will file a written concurring opinion.
/s/ G. MITCHELL WILK
President

I will file a written concurring opinion.
/s/ FREDERICK R. DUDA
Commissioner

I will file a written concurring opinion.
/s/ STANLEY W. HULETT
Commissioner

I will file a written concurring opinion.
/s/ JOHN B. OHANIAN
Commissioner

I CERTTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

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G. MITCHELL WILK, Commissioner, concurring:

Today, we issue two orders that should be viewed together as the next logical steps in our evolving gas regulatory framework.

Without question, the most vital next step is resolution of the pipeline capacity issue. What began as a narrowly defined debate over gas supply to the Enhanced Oil Recovery (EOR) market has now been appropriately addressed by this Commission as a long-term strategic policy for access to a greater diversity of additional gas supplies for California's future. It couldn't have come at a better time. Had we listened to parties calling for a pipeline to serve only the EOR market, we might have seriously short-changed this State's economic and energy future.

California enjoys a position as the largest single domestic market for natural gas, and our needs are growing, especially in the face of new environmental priorities. We should exercise this market power to serve the best interests of both our core and noncore markets. Today's order on pipeline capacity reflects our long-held priorities and policies, with which most of the pipeline proponents have, to varying degrees, complied. It is now up to the considerable competitive forces between the various proposed projects and their intended customers to determine which project(s) should be constructed, when, and how large they should be. It is appropriate, and consistent with my long-held view, that such forces are able to make these decisions without the implied arrogance of government intervention into such details.

While the delay in reaching this decision may have frustrated some parties, all factual evidence as reflected in the ever-evolving project proposals demonstrates conclusively that our process has worked. It is now up to the project sponsors and their customers, including the utilities, to accept their responsibilities and make the market work: The ball is no longer in our court; the regulators have acted.

The ultimate costs associated with new pipeline capacity designed for California's growing needs should be born by those who benefit, and both core and noncore are advantaged by additional, even reasonable "excess" capacity. Any future cost allocation proceedings before the Commission should recognize this result.

Turning to the OIR, I believe this rulemaking is an essential and logical follow-up to the process of "re-examination" started by last fall's En Banc hearing. I have been frustrated with the direction and results of our original gas policies, and thus felt both the En Banc and the OIR approach would serve to expeditiously identify problems and correct them.

The proposed rules address noncore issues and the occasionally awkward participation of our gas and electric utilities in the noncore marketplace. The overwhelming evidence from the En Banc was the need to "level the playing field" (assuming, of course, both new pipeline capacity and a program of capacity allocation are in place). Today's OIR will hopefully stimulate more than just the predictable expressions of economic self-interest, whether producer, transporter, or user. Instead, I look to the parties to help this Commission formulate policies that will both promote and realize the benefits of a competitive noncore market. I strongly believe there can be no sacred cows except the insulation of the core (both electric and gas) from excessive risk.

In the final analysis, the success of our gas program will be evidenced by <u>both</u> a secure core at fair prices <u>and</u> a competitive noncore marketplace where buyer can meet seller on fair terms.

G. MITCHELL WILK, Commissioner

February 7, 1990
San Francisco, California

I.88-12-027
D.90-02-016

FREDERICK R. DUDA, Commissioner, concurring.

I concur with and strongly support the majority opinion, and applaud the President's Office for its efforts in formulating this important decision. My comments are directed only to some differences in emphasis in the text of the majority opinion.

I am very encouraged by the majority opinion's strong reliance on competitive forces to decide the timing, sequence, and ultimate capacity of new gas pipeline increments to California. I add some emphasis to explain the basis upon which these competitive forces rest. Total delivered cost of gas should be a major factor in the determination of the new pipeline capacity that is built to serve California. I believe that the low cost producing regions will join the lowest cost and most efficient pipeline projects to create access to California. Competitive forces will be further defined after implementation of our OIR on gas procurement. Cost allocation principles defined in the majority opinion should be adhered to strictly; I believe the clear signal to pipeline project proponents is that we do not want to see cross-subsidies, particularly those that shift costs onto core customers.

I believe that by this Order we are clearly signaling that we want competition within and among producing regions and pipe-on-pipe competition as well. We want capacity brokering to create intra-regional gas-on-gas competition in Canada and in the U.S. Capacity brokering can facilitate nondiscriminatory open access to pipeline capacity, which also creates inter-regional gas-on-gas and pipe-on-pipe competition. In this way pipelines will compete directly through solicitation of support from end-users on a total delivered cost of gas basis.

While the decision essentially states that capacity brokering should be done in the secondary market, some form of capacity bidding seems appropriate to allocate capacity among subscribers to new pipeline increments, i.e., to allocate capacity in the primary capacity market. While we should be concerned to not alter existing commitments between pipeline sponsors and subscribers to new pipeline capacity, I believe the Commission desires to have the most efficient use possible of new (and existing) capacity, which points to the use of some form of bidding for primary capacity subscription.

With respect to the new regulatory framework we set forth in this Order and the companion OIR, I believe that with more competitive forces there will be substantially greater efficiency in the use of pipelines. Although with greater unbundling transactions are more complex and there have been barriers to pipeline access and use, I believe that increased competition through new procurement rules and capacity brokering can increase the efficiency of use of both new and existing pipelines. Actual experience will hopefully prove this to be correct.

Regarding the relative merits of various pipeline proposals, we have discussed PGT, Kern, WyCal, and the Southern Expansion in favorable terms, but did not discuss Altamont or the Transwestern Expansion in any detail. I would emphasize the value of both the Altamont and Transwestern projects and the opportunities they may represent for additional low cost gas delivery. Altamont should be encouraged as a separate source of gas supplies from somewhat different supply regions than those to which PGT provides access. Transwestern should be recognized for its dedicated service to California and for its access to reliable Southwest gas supplies. I am personally impressed with developments on coal-seam (coal-bed methane) gas supplies in Colorado and New Mexico. I have confidence that current technical advances will bring this gas resource to California at competitive prices in the near future. Our order today is formulated to encourage these kinds of developments.

I enthusiastically join my fellow Commissioners in this unanimous decision.

Frederick R. Duda

Frederick R. Duda, Commissioner

February 7, 1990
San Francisco, California

STANLEY W. HULETT, Commissioner, Concurring:

Not usually given to writing concurring opinions for decisions with which I agree, I feel compelled in this matter to take this opportunity to make several comments on this proceeding and its outcome.

First, this decision is, to my mind, the decision with the largest economic impact on California of the many decisions we have made here during my tenure. No decision will affect so many Californians, both directly and indirectly, as the decision on the need and timing of new pipeline capacity for the state. Clearly, as the state's electric utilities and other industries move away from using environmentally inferior crude oil in order to improve the state's air quality, natural gas becomes the predominant fuel in the state's energy mix. With this decision, we allow companies to make investments in pipelines to new supply areas, areas not previously accessible by California, and traditional areas that have provided California inexpensive supplies for 30 years.

I am convinced that these new pipelines would never have reached the decision point had not this Commission shown the foresight and courage to address this highly complicated issue in OII 88-12-027. A myriad of proposals faced this state's regulated utilities and major industrial customers. Under normal market conditions, the decision would have progressed towards completion based on the relative competitive merits of each proposal. In a regulated market, though, the Commission is obliged to provide a basis for the regulated utility to participate in one or more projects with the comfort of knowing the proposal meets the criteria as established by the Commission.

Not only has this Commission had to establish the criteria for ranking the various projects but it has also had to battle the Federal Energy Regulatory Commission (FERC) in the federal courts. In my judgment, FERC abdicated its responsibility by authorizing virtually every project before it, in a process that failed to recognize any role for California's regulators to play in protecting the interests of all ratepayers, large and small.

The decision we make here appropriately recognizes the role that the competitive market plays in choosing new pipeline capacity. We have declined to authorize specific projects, except to compare them to the criteria established in OII 88-12-027. This is a proper role for regulators to play in the marketplace and will preserve the proper competitive market for the parties to judge each proposal.

Our major thrust was to seek diversity of supply for California and I believe that the decision gives the appropriate weight to diversity, while at the same time recognizing that we must look to the major new sources of natural gas in the western hemisphere.

There is absolutely no question about the need for substantial new capacity for California. As we stated in this decision, the demand for gas has grown and will continue to grow exponentially. This Commission must see to it that this demand is met with the lowest price and greatest reliability that is available in the market place. In my judgment, our decision here today will result in substantial new capacity being added expeditiously, including some upgrades of existing facilities that will take advantage of opportunities immediately available to increase the reliability of the system.

This Commission must also see to it that the intrastate facilities that complement this new interstate capacity will be approved expeditiously. We must not allow bureaucratic intransigence to restrict the orderly process to bring this new capacity to the burner tip.

I.88-12-027
D.90-02-016

Obviously, the fuel of choice for the next decades will be natural gas. This decision properly recognizes that eventuality and creates the proper climate for the parties to move forward with capacity enhancement projects.

Stanley W. Hulett, Commissioner

San Francisco, California
February 7, 1990

I.88-12-027
D.90-02-016

John B. Ohanian, Commissioner, concurring

Today ends a long and difficult journey to reach a decision on the way in which new interstate natural gas pipeline capacity should be determined. The Commission faced a choice between government determination of what will work, and allowing the private market to make the determination of what will work. We have now made the decision that the marketplace should decide.

This is not an easy decision for a regulatory body. We are charged with protecting the economic interests of California as a state, and with ensuring reliable and low cost service to the tens of millions of Californians. We have enhanced these roles through this decision.

We have established criteria for acceptable pipeline proposals which will protect the captive residential customers from the dangers of bypass and allocation of costs from uneconomic projects.

Our criteria give guidance to California's jurisdictional utilities as to which projects are acceptable. It also provides these utilities with the necessary direction to use their negotiating power to achieve acceptable settlements with project sponsors. Let me stress that equity ownership by California utilities in the new and additional projects is very important. Such participation mitigates against many of the concerns I have about specific projects. The issue of bypass, for example, is clearly abated in the event of utility equity participation. Reliability in meeting public utility obligations is also enhanced by equity ownership by California utilities.

The Commission has made an affirmative finding that additional capacity is needed. I am in complete agreement with this finding. We have also recognized the long-term need for capacity into the next century. My belief is that we are already well behind in the process. We need that new capacity today. This means that time is of the essence.

On this point I wish to make it clear that I do not believe the Southern California Gas Company southern expansion meets the long-term requirements of the state. This expansion is a band-aid for the short term, a bridge to completion of new projects. The interuptible nature of the capacity from El Paso combined with the growing demands of the full requirements customers east of California makes it clear that this capacity will decline in reliability over time. If this expansion can not be completed well before other projects, its value is markedly reduced. I also wish to stress that the uncertainties surrounding our utility's relationships with El Paso should be taken into account during the FERC proceeding for the El Paso portion of the expansion.

At the same time, the Commission has carefully avoided making the decisions which are best reached in the market place. It is the competitive financial market which can best assess competing claims of cost-effectiveness and supply security. The market can best match suppliers and end users. It is for competing parties acting in their own self-interest, with their own resources at stake, to make the decisions of who, what and when. I also expect that new projects will be complementary to the existing system, as well as to any other new construction. This complementarity should enhance overall reliability for gas deliveries to California as well as within California. While this is something the market will consider, it is worth reminding the parties of this.

The Commission is fulfilling its responsibility to the people of California to allow this process to occur within the parameters we have established. Such major and complex decisions made by government fiat can generally be correct only by happenstance.

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It is also not the role of this Commission to preside over a command economy and determine the economic winners and losers. There is no shortage of examples of failed government edicts that attempted to substitute for market decisions. This is especially true when the decision makers are not using their own resources. The project which can put together an acceptable package first, including financing, will be the first to construct the new project. This competition will provide California with the needed capacity at the earliest possible date.

Each of the Commissioners has taken an active interest in this case. Each Commissioner has also given careful thought and devoted countless hours of study and discussion to these complex issues. We have patiently exchanged and evaluated many different ideas and concepts in reaching this point. I wish to thank each of my colleagues for the wealth of ideas they have provided, and for the consideration given to my thoughts and concerns.

John B. Ohanian, Commissioner

February 7, 1990
San Francisco, California