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Decision 88-12-099 December 19, 1988

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into natural gas procurement and system reliability issues.	R.88-08-018 (Filed August 10, 1988)
Order Instituting Investigation into natural gas procurement and system reliability issues deferred from D.86-12-010.	I.87-03-036 (Filed March 25, 1987)

(See Decision 88-11-034 for appearances.)

INTERIM OPINION: MARKET-BASED ALLOCATION OF PIPELINE CAPACITY; CORE ELECTION; END-USE PRIORITY OF EOR CUSTOMERS

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This order addresses an important set of issues which we believe should become the focus of this proceeding--the central question of how to allocate pipeline capacity among the California natural gas utilities, other gas suppliers, and noncore customers who wish to transport their own gas supplies.

This OIR had its genesis in I.87-03-036, our investigation into the procurement and system reliability issues which we deferred from our landmark natural gas policy order, D.86-12-010. Following several rounds of comments on gas procurement issues in I.87-03-036, we began a rulemaking proceeding with R.88-08-018 (August 10, 1988). The August 10 order contained a set of proposed rules which would resolve the procurement issues which had emerged in I.87-03-036. Since then, we have received two rounds of comments on these proposals: opening comments on October 19, 1988, and reply comments on November 9, 1988. Appendix A lists the parties who have filed comments in R.88-08-018.

Since August 10, we have issued two orders with impacts on R.88-08-018. D.88-10-054 (October 26, 1988) directed that we would consider as part of R.88-08-018 the question of whether to approve a mechanism whereby the weighted average cost of gas (WACOG) of the core gas portfolio would change if forecasted and actual core gas costs differed by more than a certain "trigger" amount. Such a "Core Gas Cost Trigger Mechanism" has been advanced in a stipulation submitted by Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and Toward Utility Rate Normalization (TURN). In addition, on November 9, 1988, we issued D.88-11-034, approving a program of unbundled gas storage banking for noncore customers. As this order will discuss at several points, the issues which we resolved in our storage decision have important parallels and connections with the procurement issues in this case; the similarities are especially important on the key question of allocating storage and pipeline capacity.

I. BACKGROUND: R.88-08-018

In the rules which we proposed in R.88-08-018, we were guided by the conviction that it would be unwise, with only a few months of experience with our new natural gas regulatory structure, to undertake major changes in our program. Therefore, R.88-08-018 concentrated on solving identified problems with the new program, and on the carefully limited testing of new ideas. R.88-08-018 identified four principal goals:

1) **Continuing to work toward equitable access to the storage and transportation systems for all gas customers, regardless of their procurement choice.** This effort included proposing a priority charge system which would function to ration, on a coordinated and economic basis, both intrastate and interstate pipeline capacity. We emphasized that reaching this open access goal requires careful consideration and compromise to avoid harmful impacts on core customers.

2) **Allowing the utilities, on a limited, trial basis, some degree of greater flexibility in procuring gas for noncore customers.** We stated that this flexibility must be conditioned so as not to have an adverse impact on core customers. The amount of flexibility which we proposed to grant to the utilities was also made contingent on the utilities' progress in providing open access to their transmission and storage systems.

3) **Finetuning the existing procurement rules, with an emphasis on helping the utilities to deal with what appeared to be the new difficulties accompanying their**

responsibility to operate an integrated transmission and distribution system in the new era of unbundled services. These problems included nonperformance by spot suppliers, load balancing and accounting problems with transport-only service, and the greater planning uncertainties for the utility when large users assume the primary responsibility for procuring gas supplies. The new services proposed in the rules as "finetunings" to our program included 30-day firm procurement service and standby service.

4) **Formalizing the "hands off" approach to core sequencing policy which the Commission has followed in recent years.** We also expressed a willingness to judge the utilities' core procurement efforts on the basis of their overall portfolio management.

This order will address directly only those issues related to the first of these goals. A second decision, which will follow in the near future, will deal with the remaining issues.

II. <u>OVERVIEW</u>

The comments which we have received in this docket reflect recent events in the California gas market, and indicate to us, more than ever, the central importance of the question of how to allocate access to pipeline capacity, at both the intrastate and interstate levels. The event which brought the capacity allocation issue to the fore was the implementation on July 1, 1988, of new rates on the El Paso Natural Gas (El Paso) pipeline. The new rates include an "unbundling" of the pipeline's charges for mainline transportation, gathering, and processing, and represent a significant overall increase over prior rates. This restructuring of El Paso's rates has resulted in economic incentives for interruptible shippers on the El Paso system, including PG&E and

SoCal, to purchase "off-system" gas at the points where El Paso interconnects with other pipelines, instead of gas from producers who are directly connected to the El Paso system. In addition, gas demand in California has been high, fueled by a strong economy and the second year of a drought, which has dramatically increased the demand for gas in electric utility powerplants. There has also been increasing pressure to maximize the use of gas, and to minimize the use of dirtier alternate fuels, in regions of the state which suffer from poor air quality.[1] The impact of these developments has been to produce capacity bottlenecks at the receipt points into the El Paso system where the most economical gas can be purchased. Shippers who now have lower priority on El Paso's queue for interruptible transportation have experienced great difficulty in moving the most economical gas to customers in California. As a result of these problems, we have been asked to take action which essentially would result in the reallocation of pipeline capacity to California.[2]

The problem of pipeline capacity allocation also stands out as the leading unresolved issue when we review from a broad perspective our efforts to restructure the gas industry in California. We have recognized, virtually from the beginning of our restructuring efforts, that ultimately our program will require some means to make firm transportation available to all

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1 See, for example, D.88-08-052, an emergency order designed to minimize the curtailment of gas service during the peak smog season in the Los Angeles area.

2 See the "Joint Emergency Motion of Mock Resources, Inc. and the California Industrial Group Requesting that the Commission Direct Southern California Gas Company and Pacific Gas and Electric Company to Develop a Plan to Use their Interruptible Interstate Transportation Capacity on Behalf of Noncore Customers and their Suppliers," filed October 14, 1988.

shippers.[3] Access to more reliable pipeline capacity is necessary in order to provide end users with a wider range of options for contracting for gas supplies on a long-term basis. A broader ability to make long-term gas supply arrangements, with associated firm transportation, will encourage long-term investments in the development of new gas reserves, and will widen the scope of the gas-to-gas competition which our program has sought consistently to foster. Obviously, firm transportation to California involves the interstate pipelines regulated by the Federal Energy Regulatory Commission (FERC), as well as the distribution companies which are subject to our jurisdiction. The complex issues surrounding the need to coordinate capacity allocation on both the intrastate and interstate pipelines, as well as delays in the restructuring of the pipeline-distributor relationship, have long prevented us from moving forward to make firm transportation more widely available.[4]

We believe that the moment has arrived to take this long-delayed step, and to begin to establish an economically efficient means to provide shippers other than the utilities with firm transportation for gas moving to California. This opportunity may soon be available, for several reasons. First, there are ongoing settlement discussions in El Paso's current general rate case; the resolution of this case should provide the restructuring of El Paso's relationship with its California utility customers necessary to make firm transportation more widely available. We anticipate that PG&E and SoCal will convert a portion of their firm sales entitlements on El Paso to firm transportation rights. In addition, we are working to ensure that the El Paso settlement

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3 See R.86-06-006, pp. 21-22, and D.86-12-010, pp. 33-41.

4 See D.86-12-010, pp. 40-41; I.87-03-036, pp. 5-6; D.87-10-043, pp. 25-26; and D.87-12-039, p. 108.

provides the utilities with the opportunity to obtain the right to assign firm transportation rights to other parties. Similar flexibility may be obtained in the upcoming Transwestern Pipeline general rate case. Thus, the stage could be set for the development of a method whereby the utilities will be able to assign their firm capacity rights to whoever wishes to obtain firm transportation to California. Second, we believe that the FERC is likely to be receptive to allowing California to develop, at least on a trial basis, a capacity allocation program for the pipelines which supply the state. As we will discuss further below, we believe that a coordinated intra/interstate capacity allocation program will require FERC concurrence, at least to the extent of approving the settlements under which the California utilities will be able to assign their firm transportation rights on the interstate pipelines. The most expeditious and efficient means of obtaining this approval appears to be as a part of settlements of current general rate cases or gas inventory charge (GIC) cases.

Given this situation, we strongly believe that our first order of business should be to investigate and to establish the details of how an integrated intra/interstate capacity allocation program will function. We intend to have a program ready to put into place once FERC acts to provide the necessary concurrence in the current pipeline cases or other appropriate forums. The program will also deal expeditiously with the basic problem underlying the troubles faced this summer by noncore customers such as the members of the California Industrial Group (CIG), and by marketers such as Mock Resources. Moreover, we believe that progress on the capacity allocation question will help to resolve many of the disputes evident on this record concerning other procurement issues. Fundamentally, the utilities' current superior access to both firm and interruptible pipeline capacity has generated the need to place restrictions on the utilities' procurement activities in the noncore market. We believe that a market-based capacity allocation program, providing efficient and equitable access to firm transportation, will calm much of the debate on how to structure the utilities' noncore procurement activities, a debate which encompasses the Tussing proposal, core election, the marketing of excess core supplies, multiple supply portfolios, 30-day firm procurement, and standby charges. Therefore, this decision will focus on the general outlines of the capacity allocation program which we intend to investigate in more detail in the immediate future. In general, we prefer to defer making significant changes in the current structure of the utilities' procurement activities, until we tackle what we see as the more fundamental problem of capacity allocation.

III. THE MARKET-BASED ALLOCATION OF PIPELINE CAPACITY

In R.88-08-018 we expressed support for the idea, which SoCal had proposed in I.87-03-036, of a system to allocate on a coordinated basis both intrastate and interstate pipeline capacity. Under the SoCal plan, the allocation would be market-based, using customer bids to pay for priority of access to capacity. We stated in the rulemaking order that core customers should have first access to pipeline capacity; as a result, we also expressed the view that core elect customers should pay for the high priority access to pipeline capacity which accompanies service from the core portfolio. We proposed that the revenues from capacity priority bids should be used to offset the noncore market's share of intrastate transmission and interstate pipeline demand charges. We also supported the proposal of Salmon Resources and Mock Resources (Salmon/Mock) to give long-term transportation customers--those with contracts whose original term is five years or more--the right to match whatever priority charge is necessary in order for them to maintain their place in the priority queue. We asked for comments on a number of issues on which we did not express a view, including:

1) The federal issues raised by the coordinated auctioning of intrastate and interstate pipeline capacity;

2) How core elect customers should pay for the high priority access to pipeline capacity which they receive as part of the utility's core portfolio;

3) Whether capacity should be allocated on a pipeline-specific or on an overall system-wide basis;

4) The impact of the operational differences between the SoCal and PG&E systems; and

5) The appropriateness of recent changes in the end-use priority applicable to the steaming operations of enhanced oil recovery (EOR) customers.

A. The Need, Feasibility, and Timing of an Allocation Mechanism

The comments filed on R.88-08-018 continue to show broad support for the idea of a coordinated, market-based mechanism to allocate both intrastate and interstate pipeline capacity. Significantly, PG&E has now embraced the concept, and is working actively to prepare a comprehensive proposal. Support also comes from SoCal, from wholesale customers such as San Diego Gas & Electric Company (SDG&E) and the cities of Long Beach and Palo Alto, from a representative of large users (CIG), from the brokers Salmon/Mock and Trigen Resources (Trigen), and from the Division of Ratepayer Advocates (DRA). Transwestern Pipeline states that it is willing to work with the Commission and other California parties in order to develop the concept. Rather than elaborate on the supporting comments, our discussion in this section will focus on the arguments of those who disagree with the direction of R.88-08-018 on this issue, and on the debate on "how far, how fast?" to proceed.

Several parties did question the need for a single, coordinated mechanism to allocate both intrastate and interstate pipeline capacity. The Canadian Producer Group (CPG) argues that no capacity constraints exist on the PG&E system, and therefore that the implementation of such a mechanism for PG&E is unnecessary at this time. The CPG believes that, in a situation where such a mechanism is not needed, it will function only to collect premiums from risk-averse customers, and that recycling these premiums to other noncore customers will only create confusing signals to both the utility and its customers. The answer to the capacity bottlenecks on the El Paso system, the CPG believes, lies in the reformation of El Paso's new rate structure. The consumer group TURN recommends that a bidding system for capacity priority be limited to the purpose for which it was conceived in earlier stages of our restructuring program--determining which customers are curtailed in the event of pipeline capacity constraints. The state Department of General Services (DGS) wants to retain the current end-use priority system, in recognition of the requirements of Public Utilities Code Section 2771, and because DGS believes that the current system is still workable. DGS would allow bidding for priority only **within** each of the current priority classes. In a similar vein, Southern California Edison (Edison) cautioned us to clarify the relationship between a capacity allocation mechanism and the end-use priority system.

Parties also commented on the administrative feasibility of auctioning pipeline capacity. The Industrial Users believe that the administrative complexity of capacity auctioning raises serious questions about the feasibility of the idea. TURN suggests that it would be prudent to experiment with bidding as a means to allocate capacity during curtailments, before expanding the concept to include access to capacity at all times. Even SoCal, which first proposed such a mechanism almost a year ago, maintains that the administrative requirements are "substantial," and cites the many other administrative changes which it must implement in order to accommodate the new regulatory framework. SoCal believes that it will not be able to accept capacity priority bids until 9 or 10 months after a Commission order authorizing such a system. SoCal also believes that a system which allocates capacity on a pipeline-specific basis is "unworkable for the forseeable future." SoCal's estimate of the time required to implement such a system drew a strong reply from CIG. CIG recites the long history of Commission support for a capacity priority charge based on bidding, and notes that SoCal itself proposed an integrated priority charge mechanism in February, 1988. CIG also mentions the active discussions over the past six months of an "interim" mechanism to allocate grandfathered interruptible rights, stating that the details of implementing such an arrangement would be very similar to a capacity allocation program for firm transportation. CIG believes that these circumstances indicate that the California utilities have been "on notice" that an integrated capacity allocation program will be adopted, and should be able to implement such a program within 60 days of the receipt of the necessary FERC approvals. If the utilities cannot meet such a schedule, CIG believes that a substantial portion of the utilities' pipeline demand charges should be assigned to the shareholders.

CIG, Salmon/Mock, and Agland Energy Services (Agland) believe that the Commission can, and should, take immediate action to order the utilities to use their grandfathered interruptible capacity rights "on behalf of" noncore customers.[5] Such an "interim" step would be possible without FERC approval, CIG and Salmon/Mock argue, based upon what they believe are recent liberal

5 This is the proposal which CIG and Mock advanced in their October 14 joint emergency motion (see footnote 2, above), and which they renew in their comments in this docket.

FERC interpretations of the "on behalf of" requirement of Section 311 of the Natural Gas Policy Act (NGPA), and under the condition that the utilities temporarily take title to the gas while it is moving on the interstate system.[6] Agland suggests several ways in which such a program could make use of the utilities' existing administrative procedures. These parties believe that such an "interim" program would allow noncore customers to improve their access to pipeline capacity immediately, until a permanent capacity allocation program, based upon firm transportation rights, can be established.

Administrative and legal objections have been raised to the "interim" program of CIG, Salmon/Mock, and Agland. SoCal believes that such a program is more complicated than it can handle now, due to the current lack of information from the pipelines which would be necessary for SoCal to manage the allocation of capacity at numerous receipt points. PG&E urges the Commission to focus on a long-term solution, rather than waste time now seeking a "quick fix." CPG disputes the assertion that the "interim" program would not be subject to FERC jurisdiction. In CPG's view, use by the California utilities of their grandfathered capacity rights "on behalf of" certain shippers would run afoul of the Section 311 rules and FERC standards for non-discriminatory transportation.[7]

6 The primary FERC order which CIG and Salmon/Mock cite as permitting their proposal is Hadson Gas Systems, Inc., 44 F.E.R.C. p. 61,082 (1988).

7 CPG notes that the rules for Section 311 transportation (15 U.S.C. Section 3371) allow only certain types of transportation, including transportation by an interstate pipeline on behalf of a local distribution company or intrastate pipeline. CPG contends that Section 311 makes no reference to transportation "on behalf of" an end user, such as a noncore customer of a California utility. CPG does not believe that such users can be

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The CPG contends that the FERC is unlikely to accept an arrangement which skirts the Section 311 rules through the artifice of a temporary transfer of title to the California utilities.

Many parties, including SoCal, PG&E, CIG, CPG, and DRA, state that FERC concurrence in the settlements of pipeline cases will be necessary in order to implement a capacity allocation or "brokering" mechanism based on the utilities' firm transportation rights. Several commenters note that this Commission itself, in its comments to the FERC on the capacity brokering Notice of Proposed Rulemaking (NOPR), has recognized that consistency between Commission and FERC rules is necessary before capacity brokering can be implemented in California.

Discussion: We believe that a market-based capacity allocation program is desirable, feasible, and can be implemented in the near future. The major benefits of such a mechanism are not as a "quick fix" to the problems which were experienced this summer on the El Paso system, which we view as due largely to the implementation of a new rate design on that system. Instead, such a mechanism would supply an important missing piece from our new regulatory structure: access to more reliable pipeline capacity

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the "on behalf of" entities, as the CIG/Salmon/Mock proposal requires. CPG also comments that the issue in the Hadson case, on which CIG and Salmon/Mock rely, was how remote from a transaction the "on behalf of" utility could be while still permitting the transaction to go forward. The case does not address the issue of whether an "on behalf of" local distribution company (such as a California utility) could itself implement transportation for a shipper other than one selected in accordance with FERC standards for non-discrimination. CPG believes that the Hadson case does not sanction a California utility improving a shipper's rights to capacity on El Paso, for example, beyond what that shipper already posesses under the current FERC allocation scheme.

for a wider range of gas producers, shippers, and end users. Improved access to firm transportation would encourage the long-term supply arrangements which are necessary to support investments in finding and developing new gas supplies. The attractiveness of the California market to gas suppliers will be increased as the scope of possible supply arrangements expands. The greater variety of transactions will stimulate gas-to-gas competition, to the benefit of the ultimate consumer.

Our long-term perspective on the benefits of market-based capacity allocation has important implications for how we will proceed to develop such a mechanism. First, we doubt the wisdom of attempting to put an "interim" program into place immediately, as CIG and Salmon/Mock urge. The preponderance of the legal analysis presented in the comments shows that ultimately our program may require at least the FERC's concurrence in the pipeline general rate cases and GIC proceedings. In addition, CPG's analysis of the NGPA Section 311 rules and the Hadson case convinces us that the legality of the proposed "interim" program is debatable. In addition, we recognize that the implementation of any new capacity allocation scheme will be complex. Although we do agree with the CIG that SoCal's administrative requirements seem excessive, we cannot ignore the administrative burden on the utilities. As a result, we prefer to proceed to implement one permanent mechanism, rather than to force the utilities to change their administrative and operating procedures twice--once for an "interim" program, and again for the "final" one. Generally, we think it best to pursue the program for which there is the most widespread support within California. That program is a market-based allocation mechanism, with the utilities obtaining the ability to assign on an economic basis the firm transportation rights which they will have under the FERC's Order 500.

We do realize that lower priority interruptible shippers such as CIG and Salmon/Mock have faced, and may again face, significant problems with access to capacity. Therefore, we will proceed quickly to develop the details of our capacity allocation program, so that the mechanism can be implemented expeditiously once the necessary federal approvals are received.[8] We will set an implementation goal of 90 days after the receipt of these approvals. We agree with CIG that the period which SoCal claims to require to implement this program is excessively long, considering that SoCal itself proposed a similar system almost a year ago. This decision will discuss the general framework for our program, will outline the issues which remain to be resolved, and will order the utilities to file detailed proposals consistent with this framework, within 60 days from today. We will hold hearings on these plans promptly after they have been filed. We will also order the utilities to pursue the necessary FERC concurrence in the appropriate pipeline general rate cases, GIC proceedings, or other FERC forums; in the record of this case, both PG&E and SoCal have made commitments to pursue these approvals.

B. <u>The Framework of the Program</u>

The record in this case is obviously not detailed enough for us to specify completely the market-based capacity allocation mechanism which we wish to see adopted. However, R.88-08-018 did generate considerable commentary on many of the important elements of such a program. We do have enough information to adopt a general framework for the program, and to specify the unresolved issues which we want the utilities to cover in the proposals which we are ordering them to file.

8 We are also aware that CIG, Mock, other concerned shippers, and the utilities are continuing to discuss other measures to facilitate third-party transportation, measures which would be easier to implement than a capacity allocation scheme. We continue to support and to encourage these discussions.

1. **General Principles.** Although some parties criticized as "vague" PG&E's principles for an integrated capacity allocation mechanism, we believe that, with very little modification, they are appropriate for the general framework of our program. PG&E's principles reflect the goals of our new regulatory structure, recognize the need for the capacity allocation mechanism to be acceptable to the FERC, and are consistent with our perspective, stated above, on the benefits of a capacity allocation program. As we read them, casting them into terms applicable to SoCal as well as to PG&E, these principles are:

1) The program should help to meet core procurement goals through encouraging gas-to-gas competition.

2) Core-elect customers should pay for the secure access to pipeline capacity which core portfolio service provides.

3) The program should be consistent with the capacity rights which the utilities have on the interstate pipelines which serve them, including the firm transportation rights which they may acquire in current pipeline cases, under the FERC's Order 500 regulations.

4) The firmness of the capacity allocated to a noncore customer under this program should be independent of whether that customer purchases gas from the utility or from another supplier.

5) Noncore customers should have the flexibility to coordinate the integrated access to pipeline capacity with the storage banking services available as a result of D.88-11-034.

6) The costs of access to firmer pipeline capacity should be borne by those noncore customers who benefit.

7) The value of capacity allocated to noncore customers should be determined by a market-

based mechanism, not by a cost allocation process.

8) The program should encourage the maximum efficient use of transportation capacity over the long term.

9) The integrated capacity allocation mechanism must be acceptable to both the Commission and the FERC.

The capacity allocation proposals which we will order PG&E and SoCal to submit must be consistent with these principles. We hope in the remainder of this order to begin to dispel any of the "vagueness" which lingers about these principles. As guidance to the parties and to stimulate discussion, we will offer in the sections which follow our preliminary thoughts on some of the issues which the utilities' proposals must address.

2. **Specificity of the Allocation.** R.88-08-018 raised the issue of whether the capacity allocation mechanism will function to allocate pipeline capacity on a pipeline-specific basis. SoCal and TURN fear that such specificity may be difficult to administer; SoCal's original proposal only contemplated allocating capacity to transport-only customers as a group. However, PG&E proposes to focus its program not only on an allocation of capacity to specific pipelines, but to the various producing areas which each pipeline serves. PG&E believes that each producing area has "different capacity constraints and supply/demand/cost relationships, resulting in different priority values to PG&E's core portfolio customers and to transport customers." SDG&E and Trigen concur with the need for a pipeline-specific allocation. CIG also agrees, and makes the important observation that bidding for capacity only makes sense if a customer has already lined up a supplier at a price certain, and therefore has in fact locked itself into a pipeline-specific route. In addition, CIG notes that the FERC's capacity brokering NOPR appears to require a pipeline-specific allocation.

We agree with these parties that a workable program probably will have to allocate capacity at least on a pipeline-specific basis, and perhaps to each producing area served by a particular pipeline, due to the significant differences between producing areas. We acknowledge that the greater the specificity of the allocation, the larger the problem of administering the system. An important element in our review of the utilities' proposals will be to determine the appropriate balance between specificity and administrative feasibility.

3. **Treatment of the Core Portfolio.** There was no disagreement with the idea that core customers should have the top priority to pipeline capacity.[9] As we will discuss at length later in this order, we continue to believe, given the current circumstances in the industry, that the utilities should continue to offer a core elect option to noncore customers. Core elect customers will have to pay for the preferential access to pipeline capacity which they will receive as participants in the core portfolio. Having settled that, the next question is how much flexibility to allow the utility in its use of pipeline capacity to serve the core portfolio. The basic problem is illustrated by the extreme viewpoints. At one end, as Salmon/Mock advocate, we could require the utilities to relinquish all pipeline capacity that is in excess of core (priority 1 and 2A) requirements. As several parties noted, such a requirement could cause the relinquished rights to be lost permanently to whoever was next on the FERC queue for firm transportation. The relinquishment of excess capacity could result in a lack of pipeline capacity to serve "peak day"

9 As stated in R.88-08-018, this should include access to capacity needed to move volumes to be injected into storage to provide core protection. These volumes would be based upon the "final" storage target adopted by the utility pursuant to our new gas storage program (see D.88-11-034, pp. 2-15).

core demands caused by unexpectedly cold weather. The core could also suffer from the utility's lack of flexibility to shift core purchases as gas prices change. The opposite viewpoint is SoCal's assertion that it has no "excess" capacity rights, because it may in the future need full pipelines, presumably as well as maximum storage withdrawals, to meet "peak day" core needs. This assertion suggests that SoCal is unwilling to implement a capacity allocation scheme based upon firm transportation rights, because SoCal's core customers may need to use all of those rights on a few very cold days.[10] Such a position undermines our goal of making reliable transportation more widely available, and ignores ways of reaching that goal while protecting what we agree is the utility's critical responsibility to supply "peak day" core needs.

The answer lies between these two viewpoints. We clearly do not want the utilities to **relinquish** their firm capacity rights, due to the risk that the rights might be lost permanently. We prefer them to **assign** those rights to other parties for a defined period and under specified terms and conditions. Our real problem is to determine what terms and conditions are necessary to attach to capacity allocation so that core consumers will be adequately protected, yet noncore customers will have access to more reliable transportation through purchasing assigned capacity. Clearly, this will be an important issue in the next stage of this proceeding, one that we expect the utilities to highlight in their proposals.

At this stage, we have some preliminary thoughts on how to strike this balance. We believe that the utilities should attach a condition to all assigned capacity which allows them to recall that capacity to meet "peak day" core needs. We would

10 SoCal admits that it does not need its full interstate pipeline capacity to serve core needs "the vast majority of the time."

expect the utilities to inform the customers to whom they assign capacity how often they expect to exercise that recall right, based upon historical experience. We also suspect that the utility should retain a limited amount of flexibility to shift their core portfolio purchases among pipelines and producing areas, or to increase their total core portfolio purchases if demands exceed forecasts.[11] For example, under our core procurement guidelines, most of the gas purchased for the core portfolio will be long-term supplies. Many of the long-term supplies which the utilities now purchase have prices which are fixed for a year. We anticipate that the utilities should be able readily to determine, looking ahead for a year, what pipeline capacity they will require to deliver such supplies. Our procurement guidelines have also suggested that the utilities should purchase some short-term or spot gas for the core portfolio. These are the purchases for which the utilities may need the most flexibility in their access to pipeline capacity.

4. **The Capacity Requirements of Wholesale Customers.** We continue to believe, as stated in R.88-08-018, that the core loads of wholesale customers must share, with the core load of the primary utility, top priority to pipeline capacity. We concur with Palo Alto's comment that this means that wholesale core loads will have parity of access to capacity with the core load of the primary utility.

Although the idea of parity of access to capacity for wholesale core loads is settled, there may remain some dispute on how to implement this concept. Our recent storage decision provided one model for determining how much pipeline capacity

11 This is apparently what TURN has in mind when it urges us to provide the core portfolio with the top priority to enough capacity "to ensure efficient system operations."

should be allocated to wholesale core loads (see D.88-11-034, p. 20). We allowed a wholesale customer to have access to storage capacity equal to the proportion of the primary utility's fixed costs of storage which are allocated to that wholesale customer's core load, based upon our allocation factor for storage costs (peak season cold year sales). SDG&E has suggested another method, using the relative cost allocations for service for core <u>and noncore</u> customers.[12] From its total allocation for both the core and the noncore, the wholesale utility would then make its own decision on the amount of capacity needed for core service. The capacity remaining after this choice would then be allocated according to a bidding procedure. SDG&E is willing to place itself at risk for the capacity costs allocated to the amount of core transmission which it chooses, in order to remove any doubts that it might claim a greater amount of core capacity than necessary. We are attracted to SDG&E's proposal, because it appears consistent with our desire that wholesale customers have the primary responsibility to serve their core customers, as well as the tools and the flexibility necessary to carry out that duty. The capacity allocation proposals which the primary utilities will file should address the treatment of wholesale core loads, including comments on SDG&E's plan.

SDG&E perceptively raises another implication of wholesale core parity: what if a utility and its wholesale customers desire access to pipeline capacity to purchase core supplies in a certain producing area, in a quantity that is greater than the amount of pipeline capacity available to that area? Our initial reaction is that a pro-rata allocation, based upon total core loads of each utility, would be fair.

12 For pipeline capacity, these allocations are based upon cold year sales.

5. **Treatment of Revenues from a Capacity Allocation Mechanism.** The comments which we have received raise no strong objections to the proposal in R.88-08-018 that revenues from a capacity allocation mechanism should be used to offset both intrastate transmission costs and interstate pipeline demand charges assigned to the noncore class. However, we suspect that a number of different approaches may develop on this issue, and we do not want at this time to restrain the debate. CIG does suggest an upfront credit to noncore customers based upon utility forecasts of these revenues, with a balancing account to ensure that the utility is kept whole if the forecast is inaccurate. We believe that the CIG suggestion deserves further scrutiny, as we agree with CIG that the up-front credit would have the important benefit of limiting price-signal distortions which might result from a lag between when a customer bids for capacity, and when that customer sees the results of the bidding in his rate.

6. **Cogeneration Parity and the End-use Priority System.** In this order we are proposing a significant expansion of the "priority charge" concept which we have discussed in several decisions since D.86-12-010. The market-based mechanism which we want to develop will not only decide the curtailment order if capacity constraints develop, but will also serve to allocate access to firm transportation capacity. There are several statutory requirements which the utilities must consider in designing their mechanisms. One is the "cogeneration parity" requirement of Public Utilities Code Section 454.7, which mandates that the Commission provide cogeneration with the highest possible priority. The second is the end-use priority system established

pursuant to Public Utilities Code Sections 2771-2774.[13] We have previously concluded that an economically-based priority system for noncore customers is consistent with this statute, and have decided that end-use priorities should be used among customers paying the same (or zero) priority charge.[14] At this time, we believe that these conclusions can continue to apply to a capacity allocation mechanism. For example, under a pipeline-specific allocation, for customers who pay the same for capacity on a particular pipeline, we propose to use the end-use system to determine priority among these users. This may also satisfy the requirements of Section 454.7, as well, because cogenerators would be assured of a higher priority than other noncore customers who pay a similar price for capacity.

7. **Capacity Priority for End-users with Long-term Transportation Contracts.** R.88-08-018 favored a Salmon/Mock proposal to give customers with long-term transportation agreements signed after December 3, 1986, the right to match whatever priority charge is necessary to allow them to maintain their place in the priority queue.[15] Several parties continue to disagree with this idea. SDG&E argues that EOR customers with special low rates should not be allowed to bid for priority along with "other noncore customers who carry their full weight in rates." Unless EOR

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13 For example, Edison raised in its comments the need to clarify the relationship between a capacity allocation mechanism, such as SoCal proposed, and the end-use priority system required in these Public Utilities Code sections.

14 See D.86-12-010, pp. 119-123.

15 We defined a "long-term transporter" as a transportation customer with a contract that has an original term of five or more years. Customers with long-term transportation contracts signed on or before December 3, 1986, would have their capacity priority defined according to the policy we set out in D.87-12-039.

customers are willing to pay "full fare", they should have the lowest priority to capacity. SoCal, with the CIG's concurrence, is at the other end of the spectrum on this issue: SoCal renews its argument, which we rejected in R.88-08-018, that long-term transporters should have the highest priority among all noncore customers, due to the commitment which they have made to stay on the utility's system. PG&E takes a middle ground: it does not disagree with the Salmon/Mock matching idea, but suggests that this should not be the only option. PG&E believes that the dependable revenue stream of a long-term transportation commitment has a value which may not be reflected accurately by requiring such a customer to match bids made by customers who may have a much shorter time horizon.

We continue not to see a need to give long-term transporters the automatic highest priority access to capacity among noncore customers, as SoCal and CIG propose. We note that the Cogenerators of Southern California (CSC), which filed comments on behalf of several EOR cogeneration projects with long-term transportation contracts, states that its members are willing to pay for access to capacity, so long as they have the opportunity to match the bids paid by utility electric generation (UEG) customers. We also reject SDG&E's position, which is plainly inconsistent with our long-held commitment that EOR transportation customers should be able to "buy up" in priority. PG&E is welcome in its capacity allocation proposal to present another option for dealing with long-term transporters, so long as that plan falls between the extremes which we have rejected.

8. **A Secondary Market for Capacity.** We urge the utilities to consider in their proposals the provision of a secondary market for assigned capacity. We believe that a secondary market could increase significantly the efficiency of an allocation system. It would provide a second opportunity for parties who bid too low in the original auction for the capacity

which they need. Conversely, parties who purchase too much capacity, or whose capacity needs change between primary auctions, would have the opportunity to lay off excess capacity in the secondary market. We also suggest that capacity sub-assigned in the secondary market must retain all recall rights which were attached to the original assignment agreement.

C. Core Election

A major issue posed in R.88-08-018 is how core elect customers should pay for their superior access to capacity. Before we discuss the specific comments on this issue, we need to address the threshold question of whether to retain the core elect option. Salmon/Mock and DRA both propose that core election should be eliminated.

Salmon/Mock agree that core elect customers should pay for the access to capacity which they receive as participants in the core portfolio. However, Salmon/Mock believe that charging core elect customers for such access is an "extremely difficult and complex task." Salmon/Mock believe that all three of the payment proposals suggested in R.88-08-018 would result in core elect customers receiving the same treatment as core customers with respect to capacity, without paying the full costs of core service. As a result, Salmon/Mock argue that core election should be eliminated, and that all noncore customers should have a one-time opportunity to become core customers, and to pay a bundled core rate.

DRA also believes that providing a core elect option is overly complex. In addition to the issue of paying for pipeline capacity access, DRA cites the related problem of the core elect paying for the access which they receive to storage capacity. DRA also notes the still-unresolved question of how to bill core elect customers when the actual core WACOG differs from the forecasted price, and possible problems with the electric departments of combined utilities who elect into the core. DRA cites PG&E's

experience since May 1: DRA believes that the large amount of core election on the PG&E system has forced PG&E to purchase more expensive spot gas for the core portfolio, driving up the actual core WACOG. DRA characterizes PG&E's core elect customers as "price chasers" who are more interested in low prices than the supply security of the core portfolio. DRA thinks that the noncore customers' limited desire for supply security can be met through a noncore portfolio which may include long-term supplies; the price of this portfolio would vary every 30 days. More fundamentally, DRA does not believe that core election provides the utilities with enough monopsony power to lower significantly the core portfolio price, especially given what DRA sees as the evolution of the national gas market into "a pure commodity market" where long-term prices will track the spot market. Finally, DRA warns the Commission that prices of Canadian gas have not always been so low; five years ago, under a different regulatory regime, Canadian gas was California's most expensive supply source.

CIG, SoCal, CSC, Edison, TURN, PG&E, and CPG all support retaining the core elect option. CIG submits that core election should be retained for the present, because it is the only source of supply security for noncore customers who are unable or unwilling to cope with the present lack of reliable transportation. CIG disputes DRA's statement that all noncore customers are price chasers, citing the fact that, unlike the experience on the PG&E system, few of SoCal's noncore customers elected into the core in August, when spot prices rose above SoCal's core WACOG. In a similar vein, PG&E notes that its core elect customers had to choose that option when the core WACOG was higher than spot prices. Although there has been little core election on the SoCal system, SoCal, CSC, and Edison all argue that it would be poor public policy to change such a significant "rule of the game" so soon after the new regulatory structure was implemented.

TURN and PG&E present extensive arguments that core election is presently producing important benefits to both core and noncore customers. PG&E asserts that its negotiating experience with its Canadian suppliers indicates that core election provides the important bargaining chip of a broad-based, high load factor market that includes customers with competitive options to gas service. PG&E recites the Commission decisions which established core election, to show that the mechanism is functioning just as it was intended to do. PG&E cites the significantly lower gas prices which northern California has enjoyed in recent years, compared with southern California, as evidence of the importance of this leverage. TURN discusses at length PG&E's existing contractual relationship with its Canadian suppliers, in an effort to determine the likely impact of the abolition of core election on PG&E's core customers and on prices in California as a whole. TURN notes that without the leverage of the core elect market, the Canadians would be free to price their sales to the core market just below the competing supplies of long-term gas from the Southwest. Recently, these alternative core supplies have been at least $0.50 per MMBtu more expensive than the $1.81 per MMBtu Canadian price. TURN also believes that Tier 2 Canadian gas sold to the noncore portfolio would have tracked rising spot prices, which have been well above $1.81 per MMBtu for most of the past year. Thus, TURN concludes that core election has undoubtedly benefitted both PG&E's core and noncore customers, and that it would be a serious tactical error for the Commission to discard the core elect option just a few months before PG&E begins the next annual price redetermination. TURN thinks that the next price redetermination will provide an empirical test of whether core election will continue to produce significantly lower gas costs for PG&E's market. TURN also confronts the longer-term question of whether California consumers would be better off if the Commission took action, such as ending core election, to make capacity available on the Pacific Gas

Transmission (PGT) pipeline. Such a step would be designed to stimulate competition among Canadian suppliers, in the hope that significant supplies could be obtained for much less than $1.81 per MMBtu. TURN argues that regardless of whether such cheap supplies are available, the impact of such a move would not fall evenly on all customers. Some noncore customers might benefit from cheaper Canadian spot gas, but the Alberta and Southern (A&S) producers could ask very high prices for the core supplies which PG&E must purchase to meet its 50% take-or-pay obligation to A&S. TURN fears that this could lead to a repeat of the take-or-pay problems which have plagued the El Paso system. TURN concludes:

> While a fully competitive gas market on both sides of the border may be in everyone's long-term best interests, TURN must caution that the path selected to pursue that goal is equally as important as the objective itself. The shortest route may not be the most productive one if it leads over a cliff.

TURN recommends that in the future the Commission should explore how to attain a fully competitive market for Canadian gas from which all customer classes can benefit.

CPG presented the most vigorous defense of core election. CPG disputes DRA's suggestion that an assessment of core election should be based upon the degree of monopsony power which core election provides to the utilities. CPG argues that the clear benefits which core election has provided to PG&E's ratepayers are the result of the large volume sales and high load factors which core election has made possible; in other words, core election allows the Canadian producers to provide PG&E with volume-related discounts. These discounts are not a function of market power, but are instead economies of scale and operation. CPG confirms PG&E's assertion of the importance of core election in last year's price redetermination:

> CPG members' agreement to sell gas to Alberta & Southern, for resale to PGT and then to PG&E's core portfolio, at a commodity price of $1.81

> per MMBtu for a full one-year term, was fully and consciously based on the premise that such a price would prove attractive enough to attract a very large volume of core-elect as well as core load, and thereby achieve a high load factor for wellhead sales. Without such an assurance of high volumes and load factors, the price of gas to the core portfolio would not have been, and cannot be, so attractive.

CPG notes that DRA argues that the large quantity of core election on the PG&E system has forced PG&E to buy increasingly expensive spot gas to meet the core elect load. CPG remarks that this effect is not due to core election, but to our policy of requiring that some spot gas be taken for the core market; CPG also asserts that the beneficial volume and load factor effects of core election are much greater than the increase due to the spot gas takes. Regarding DRA's reminder that Canadian gas was once very expensive, CPG states that Canadian producers, regulators, and government all recognize that Canadian gas prices must be market-responsive in order to have access to U.S. markets. Finally, CPG joins PG&E in protesting that abolishing core election is not the way to deal with the complexities in our regulatory program which the core elect option may create. CPG cites PG&E's new willingness, expressed in its comments in this docket, to develop a core elect charge based on the access to storage and to pipeline capacity which these customers receive. This is the way to deal with the core elect issue on its merits, CPG believes, rather than by making a disruptive, fundamental change in the new regulatory structure. CPG contends that abolishing core election would "reinforce skepticism about regulatory credibility and consistency in California."

Discussion. We will retain the core elect option. Fundamentally, we recognize the need for a degree of regulatory stability and consistency in our new program. We agree with CSC that we need more experience, under a variety of circumstances, with the new regulatory framework before making major modifications to it. We have recognized that core elect customers are not paying for the high priority access to storage and pipeline capacity which they receive. We believe that the responsible way to deal with this issue is to develop an appropriate charge for this access. This confronts the problem on its merits, in an evolutionary way, without taking the revolutionary step of abandoning a procurement option which appears, based upon our limited experience to date, to have benefited a broad range of gas consumers.[16] Eliminating the core elect option at this time would cast doubt on the stability of the structure which we have established. This would be precisely the wrong signal to send at a time when we are focusing on improving the attractiveness of the California market for long-term, secure supply arrangements.

A central goal of our new regulatory structure has been to capture the benefits of the more open and competitive gas market for <u>all</u> gas consumers in California. We conceived the core elect option as an important element in reaching that goal, and our limited experience to date indicates that it has worked. PG&E's customers enjoy the lowest gas prices in the state. TURN's analysis of current gas supply arrangements demonstrates that, absent core election, the price of Canadian gas to both the core and the noncore markets would be much higher. The parties on both sides of the last Canadian gas price redetermination make this assertion as well. We agree with TURN that, given the current structure of gas supply relationships, we should not throw away what is now a significant bargaining chip. R.88-08-018 noted the problems which sales gas from the domestic pipelines has had in

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16 This is also the way we dealt with the same issue, concerning the access of core elect customers to storage capacity, in D.88-11-034.

recent years in competing with Canadian supplies. Recently, SoCal has obtained one-year contracts for significant supplies from the Southwest at prices well below pipeline supplies, yet still above Canadian prices. Until the domestic suppliers are able to compete effectively with the Canadians, we may need to retain the bargaining leverage of core election in order to retain the benefits of economical Canadian supplies.

We also find that the evidence to date is inconclusive on whether, as DRA suggests, noncore customers are simply price-seekers. CIG, which represents a number of noncore customers, notes that core election currently provides the many noncore customers who do not want to transport their own gas with the only option for a secure gas supply. The theme of this order has been the need to increase access to firm transportation, in order to allow noncore customers to purchase and transport secure supplies. However, there is clearly much to be accomplished before we can realize this goal, and we agree with CIG that we need to retain the core elect option at least until a capacity allocation program is functioning.

Ultimately, our long-term perspective on core election is dependent on how the market develops once our capacity allocation mechanism is in place. What happens once access to firm transportation is increased will determine the future need for options such as core election. The market may develop new mechanisms for aggregating gas supplies which, like core election, provide to all gas consumers the benefits of competition among gas supplies and among alternate fuels. We agree with TURN that our reasons for retaining the core elect option at this time are based on a tactical perspective; this perspective, however, does not detract from our current interest in using this option to maintain mutually beneficial long-term arrangements with willing producers.

Returning to the design of a capacity allocation mechanism, R.88-08-018 suggested three possible ways in which core elect customers might pay for their superior access to pipeline capacity:

1) A cost-based surcharge on the core elect procurement rate would be set equal to the difference, on a per therm basis, between what the core and the noncore contribute to the utility's fixed costs for intrastate transmission and for pipeline demand charges. As a second-best alternative to no such surcharge, CPG supports this method, because it is the only one which is cost-based. CPG would exclude from the surcharge intrastate transmission costs (which are not constrained) and all pipeline demand charges except those on PGT (which is the pipeline which carries the bulk of core supplies).

2) The surcharge would be set at whatever level is necessary, based on the results of the capacity allocation auction, to allow the utility to sequence the supplies which it requires for the core portfolio. This concept receives preliminary support from SoCal, SDG&E, and CIG, and resembles the approach we used for the core elect in our gas storage decision, D.88-11-034.

3) Core elect customers themselves would bid for capacity, on the same basis as other noncore customers. If a core elect customer does not bid enough to obtain access to the core portfolio, that customer would be charged the standby rate for service from the core portfolio. Salmon/Mock favor this alternative, if core election is retained.

PG&E believes that what customers pay for capacity under a capacity allocation mechanism will vary among pipelines and producing areas, as operational circumstances and spot market prices vary. PG&E comments that these price relationships may have little to do with the costs of core portfolio service, which is based upon long-term supplies that may be purchased from different sources. PG&E does not support any of the above alternatives, but promises that its capacity allocation proposal will include a charge designed "to cover properly allocated costs and reflect the benefits of such service without making core-election prohibitively expensive."

We agree with the general principles which PG&E proposes for such a charge, but at this point there is clearly no consensus among the parties on how to set this charge. This issue should be covered in the utilities' proposals, and undoubtedly will be debated further in the hearings which will follow.

D. The End-use Priority for Enhanced Oil Recovery

R.88-08-018 asked for comments on the debate which has arisen over the end-use priority of EOR customers. PG&E remarks that D.86-12-010 reduced the end-use priority system to P1-P5, and required that the curtailment order for supply shortages should follow the existing end-use priorities. PG&E believes that it accurately implemented the intent of this order in its new tariffs, by placing EOR steaming customers in Priority 4, along with other boiler fuel users with a peak day demand of 750 Mcfd or more. PG&E argues that a change to the existing end-use system would have been required to place EOR users in Priority 5, which is defined to be for power plant service. PG&E believes that its actions have been fully consistent with the structure of the end-use priority system, as established by Public Utilities Code Sections 2771 and 2772 and relevant Commission decisions. In Resolution G-2819 (August 10, 1988), we approved a similar change for SoCal, pending further review of the issue in this proceeding. SoCal's position in this case is that whatever priority is assigned to EOR customers, that priority should be uniform statewide.

UEG customers, joined by DGS, DRA, and CIG, argue strongly that EOR steamflood use should be placed in a priority below electric utility powerplants. SCUPP and Edison note that they have filed petitions for rehearing of Resolution G-2819, in which they argue that we moved EOR customers to Priority 4, ahead of most UEG usage, without reaching a determination about which customers provide the greater public benefits and serve the greater public need, as required in Sections 2771 and 2772. The UEG customers believe that placing EOR steamflood customers, who now account for about 100 MMCfd of load on the SoCal system, ahead of UEG users will result in higher costs for electric ratepayers. These increased costs will result from more frequent and longer-lasting curtailments of UEG gas service, which will require increased fuel oil inventory costs and the use of more expensive energy resources to replace larger amounts of natural gas. Air quality will be degraded due to the increased use of fuel oil in electric powerplants. SCUPP notes further that, once EOR steamflood customers sign long-term transportation contracts, they will be able to "buy up" in priority. SCUPP believes that these users thus do not need the additional benefit of Priority 4 status for their current operations. No EOR steamflood customers filed comments on this issue.

Edison has correctly characterized our past decisions on this issue. In R.86-06-006 we proposed:

> ...we believe eventually there should be only five [end-use] categories. Having upwards of the eight basic categories which have evolved today makes, in our view, for a needlessly complex end-use system. We will place EOR customers in the P5 priority designation for short- and long-term sales. (p. 26)

We adopted this change, as proposed, in D.86-12-010:

> As originally proposed in the OIR, we will reduce the number of end-use priorities to five. (P. 121.)

In its tariffs implementing D.86-12-010, SoCal correctly placed EOR customers in Priority 5. PG&E placed EOR customers in Priority 4, based upon a narrow reading of just D.86-12-010. PG&E appears to have neglected to check R.86-06-006 to determine how we intended to treat EOR customers when we reduced the number of end-use priorities to five.

In view of this history, we will direct the utilities to place EOR steamflood operations in Priority 5, along with electric powerplant use. We agree with the UEG customers that their arguments about the burdens on electric customers from increased curtailments have merit. We also note that this represents an improvement in the priority status of EOR steamflood customers, compared with their original Priority 7 assignment.

<u>Findings of Fact</u>

1. A combination of factors, including high demand and a new rate structure, produced capacity constraints last summer on the El Paso Natural Gas pipeline.

2. Providing access to firmer interstate pipeline capacity is an important element still missing from our new natural gas regulatory structure.

3. Access to more reliable transportation will encourage longer-term gas supply arrangements and will broaden the scope of gas-to-gas competition.

4. Providing firm transportation to California will require the coordinated allocation of capacity on both the systems of the California utilities and on the interstate pipelines which serve the state.

5. There may soon be opportunities, in the form of settlements of pending pipeline cases, to obtain the FERC concurrence necessary to implement a capacity allocation mechanism.

6. A program which allocates firm capacity may help to calm many of the current debates over the structure of the utilities' procurement activities.

7. Such a program is administratively feasible.

8. The administrative burdens of implementing a capacity allocation program will be less if we do not make the utilities change their procedures twice - once for an "interim" program and again for a "final" program.

9. The principles which PG&E proposes, as stated in the body of this opinion, are appropriate for the capacity allocation program which we would like to see implemented.

10. As the specificity of the capacity allocation increases, so will its administrative complexity.

11. The following are major issues which must be decided in the design of a capacity allocation mechanism:

a) How specific should the allocation be?

b) How much flexibility should the utility have in its use of pipeline capacity to serve the core portfolio?

c) What terms and conditions are necessary to attach to assigned capacity?

d) How should parity of access for wholesale core loads be implemented?

e) How should we treat, for ratemaking purposes, revenues from a capacity allocation mechanism?

f) How will such a program satisfy the statutory requirements of Public Utilities Code Sections 454.7 and 2771-2772?

g) How should the program treat customers with long-term transportation contracts signed after December 3, 1986?

h) Is a secondary market for capacity appropriate?

i) How much should core elect customers pay for the high priority access to pipeline capacity which they receive?

12. The core elect option has provided benefits to all gas consumers and should be retained, pending the development and implementation of our capacity allocation mechanism and further experience with how the gas market develops.

13. Curtailing EOR steamflood loads ahead of UEG usage could raise costs to electric ratepayers.

Conclusions of Law

1. The FERC is likely to be receptive to allowing California to develop a capacity allocation program.

2. A capacity allocation mechanism which coordinates both intrastate and interstate capacity will require at least FERC concurrence in the settlements of ongoing pipeline cases.

3. The California utilities should be ordered to work to obtain such approvals in these cases.

4. The "interim" buy/sell proposal of CIG and Salmon/Mock may conflict with NGPA Section 311 rules and with FERC standards for non-discriminatory transportation.

5. If the utilities relinquish their firm pipeline capacity rights, they may lose them permanently.

6. A capacity allocation program must meet the requirements of Public Utilities Code Sections 454.7 and 2771-2772.

7. EOR steamflood customers should be assigned to Priority 5.

8. This decision should be made effective immediately in order to have a capacity allocation program ready to implement once the necessary FERC concurrence is secured in the pipeline cases.

INTERIM ORDER

IT IS ORDERED that Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCal) shall file and serve on all parties to this proceeding, within 60 days from the effective date of this decision, detailed proposals, in the form of written testimony, for a market-based pipeline capacity allocation program. This program shall integrate the allocation of both intrastate and interstate pipeline capacity. These proposals shall follow the general principles set forth in this order, and shall address the issues which this order has identified. PG&E and SoCal shall work to obtain from the Federal Energy Regulatory Commission, in current and future interstate pipeline general rate cases, gas inventory charge cases, or other appropriate forums, the necessary concurrence to permit the implementation of their proposals. PG&E and SoCal shall keep the Commission's Legal Division fully informed of the status of these efforts.

IT IS FURTHER ORDERED that PG&E and SoCal shall assign EOR steamflood customers to End Use Priority 5, and shall by appropriate advice letter filings change their tariff rules accordingly.

This order is effective today.

Dated December 19, 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser, Executive Director

APPENDIX A

PARTIES FILING COMMENTS

Agland Energy Services, Inc.
California Energy Commission
California Gas Producers Association
California Industrial Group
Canadian Producer Group
City of Long Beach
City of Palo Alto
Cogenerators of Southern California
Department of General Services
Division of Ratepayer Advocates
El Paso Natural Gas Company
Imperial Irrigation District
Industrial Users
Mock Resources, Inc.
Natural Gas Clearinghouse Inc.
Pacific Gas and Electric Company
Salmon Resources Ltd.
San Diego Gas & Electric Company
Southern California Edison Company
Southern California Gas Company
Southern California Utility Power Pool
State of New Mexico
Toward Utility Rate Normalization
Transwestern Pipeline Company
Trigen Resources Corporation
United States Borax & Chemical Corporation
Westcoast Energy Inc.

(END OF APPENDIX A)

COM/DV/rtb

ORIGINAL

Decision 88 12 099 DEC 19 1988

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into natural gas procurement and system reliability issues.	R. 88-08-018 (Filed August 10, 1988)
Order Instituting Investigation into natural gas procurement and system reliability issues deferred from D. 86-12-010.	I. 87-03-036

(See Appendix B for appearances.)

INTERIM OPINION

This order addresses an important set of issues which we believe should become the focus of this proceeding -- the central question of how to allocate pipeline capacity among the California natural gas utilities, other gas suppliers, and noncore customers who wish to transport their own gas supplies.

This OIR had its genesis in I. 87-03-036, our investigation into the procurement and system reliability issues which we deferred from our landmark natural gas policy order, D. 86-12-010. Following several rounds of comments on gas procurement issues in I. 87-03-036, we began a rulemaking proceeding with R. 88-08-018 (August 10, 1988). The August 10 order contained a set of proposed rules which would resolve the procurement issues which had emerged in I. 87-03-036. Since then, we have received two rounds of comments on these proposals: opening comments on October 19, 1988, and reply comments on November 9, 1988. Appendix A lists the parties who have filed comments in R. 88-08-018.

Since August 10, we have issued two orders with impacts on R. 88-08-018. D. 88-10-054 (October 26, 1988) directed that we would consider as part of R. 88-08-018 the question of whether to approve a mechanism whereby the weighted average cost of gas (WACOG) of the core gas portfolio would change if forecasted and actual core gas costs differed by more than a certain "trigger" amount. Such a "Core Gas Cost Trigger Mechanism" has been advanced in a stipulation submitted by Pacific Gas and Electric (PG&E), Southern California Gas (SoCal), and Toward Utility Rate Normalization (TURN). In addition, on November 9, 1988, we issued D. 88-11-034, approving a program of unbundled gas storage banking for noncore customers. As this order will discuss at several points, the issues which we resolved in our storage decision have important parallels and connections with the procurement issues in this case; the similarities are especially important on the key question of allocating storage and pipeline capacity.

I. BACKGROUND: R. 88-08-018

In the rules which we proposed in R. 88-08-018, we were guided by the conviction that it would be unwise, with only a few months of experience with our new natural gas regulatory structure, to undertake major changes in our program. Therefore, R. 88-08-018 concentrated on solving identified problems with the new program, and on the carefully limited testing of new ideas. R. 88-08-018 identified four principal goals:

> 1) Continuing to work toward equitable access to the storage and transportation systems for all gas customers, regardless of their procurement choice. This effort included proposing a priority charge system which would function to ration, on a coordinated and economic basis, both intrastate and interstate pipeline capacity. We emphasized that reaching this open access goal requires careful consideration and compromise to avoid harmful impacts on core customers.
>
> 2) Allowing the utilities, on a limited, trial basis, some degree of greater flexibility in procuring gas for noncore customers. We stated that this flexibility must be conditioned so as not to have an adverse impact on core customers. The amount of flexibility which we proposed to grant to the utilities was also made contingent on the utilities' progress in providing open access to their transmission and storage systems.
>
> 3) Finetuning the existing procurement rules, with an emphasis on helping the utilities to deal with what appeared to be the new difficulties accompanying their responsibility to operate an integrated transmission and distribution system in the new era of unbundled services. These problems included nonperformance by spot suppliers, load balancing and accounting problems with transport-only service, and the greater planning uncertainties for the utility when large users assume the primary responsibility for procuring gas supplies. The new services proposed in the rules as "finetunings" to our program included 30-day firm procurement service and standby service.

> 4) Formalizing the "hands off" approach to core sequencing policy which the Commission has followed in recent years. We also expressed a willingness to judge the utilities' core procurement efforts on the basis of their overall portfolio management.

This order will address directly only those issues related to the first of these goals. A second decision, which will follow in the near future, will deal with the remaining issues.

II. OVERVIEW

The comments which we have received in this docket reflect recent events in the California gas market, and indicate to us, more than ever, the central importance of the question of how to allocate access to pipeline capacity, at both the intrastate and interstate levels. The event which brought the capacity allocation issue to the fore was the implementation on July 1, 1988, of new rates on the El Paso Natural Gas (El Paso) pipeline. The new rates include an "unbundling" of the pipeline's charges for mainline transportation, gathering, and processing, and represent a significant overall increase over prior rates. This restructuring of El Paso's rates has resulted in economic incentives for interruptible shippers on the El Paso system, including PG&E and SoCal, to purchase "off-system" gas at the points where El Paso interconnects with other pipelines, instead of gas from producers who are directly connected to the El Paso system. In addition, gas demand in California has been high, fueled by a strong economy and the second year of a drought, which has dramatically increased the demand for gas in electric utility powerplants. There has also been increasing pressure to maximize the use of gas, and to minimize the use of dirtier alternate fuels, in regions of the state which suffer from poor air quality.[1] The impact of these developments has been to produce capacity bottlenecks at the receipt points into the El Paso system where the most economical gas can be purchased. Shippers who now have lower priority on El Paso's queue for interruptible transportation have experienced great difficulty in moving gas to customers in California. As a result of these problems, we have been asked to take action which essentially would result in the reallocation of pipeline capacity to California.[2]

The problem of pipeline capacity allocation also stands out as the leading unresolved issue when when we review from a broad perspective our efforts to restructure the gas industry in California. We have recognized, virtually from the beginning of our restructuring efforts, that ultimately our program will require some means to make firm transportation available to all shippers.[3] Access to more reliable pipeline capacity is necessary in order to provide end users with a wider range of options for contracting for gas supplies on a long-term basis. A broader ability to make long-term gas supply arrangements, with associated firm transportation, will encourage long-term investments in the development of new gas reserves, and will widen the scope of the gas-to-gas competition which our program has sought consistently to foster. Obviously, firm transportation to California involves the interstate pipelines regulated by the Federal Energy Regulatory Commission (FERC), as well as the distribution companies which are subject to our jurisdiction. Lack

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1 See, for example, D. 88-08-052, an emergency order designed to minimize the curtailment of gas service during the peak smog season in the Los Angeles area.

2 See the "Joint Emergency Motion of Mock Resources, Inc. and the California Industrial Group Requesting that the Commission Direct Southern California Gas Company and Pacific Gas and Electric Company to Develop a Plan to Use their Interruptible Interstate Transportation Capapcity on Behalf of Noncore Customers and their Suppliers," filed October 14, 1988.

3 See R. 86-06-006, pp. 21-22, and D. 86-12-010, pp. 33-41.

of progress at the FERC on capacity allocation on the interstate pipelines, as well as delays in the restructuring of the pipeline-distributor relationship, have long prevented us from moving forward to make firm transportation more widely available.[4]

We believe that the moment has arrived to take this long-delayed step, and to begin to establish an economically efficient means to provide shippers other than the utilities with firm transportation for gas moving to California. This opportunity may soon be available, for several reasons. First, there are ongoing settlement discussions in El Paso's current general rate case; the resolution of this case should provide the restructuring of El Paso's relationship with its California utility customers necessary to make firm transportation more widely available. PG&E and SoCal undoubtedly will convert a portion of their firm sales entitlements on El Paso to firm transportation rights. In addition, we are working to ensure that the El Paso settlement provides the utilities with the opportunity to obtain the right to assign firm transportation rights to other parties. Similar flexibility may be obtained in the upcoming Transwestern Pipeline general rate case. Thus, the stage could be set for the development of a method whereby the utilities will be able to assign their firm capacity rights to whoever wishes to obtain firm transportation to California. Second, we believe that the FERC is likely to be receptive to allowing California to develop, at least on a trial basis, a capacity allocation program for the pipelines which supply the state. As we will discuss further below, we believe that a coordinated intra/interstate capacity allocation program will require FERC concurrence, at least to the extent of approving the settlements under which the California utilities will be able to assign their firm transportation rights on the interstate pipelines. The most expeditious and efficient means of obtaining

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4 See D. 86-12-010, pp. 40-41; I. 87-03-036, pp. 5-6; D. 87-10-043, pp. 25-26; and D. 87-12-039, p. 108.

this approval appears to be as a part of settlements of current general rate cases or gas inventory charge (GIC) cases.

Given this situation, we strongly believe that our first order of business should be to investigate and to establish the details of how an integrated intra/interstate capacity allocation program will function. We believe that this merits top priority in order to have a program ready to put into place once FERC acts in the current pipeline cases. It will also deal expeditiously with the basic problem underlying the troubles faced this summer by noncore customers such as the members of the California Industrial Group (CIG), and by marketers such as Mock Resources. Moreover, we believe that making progress on the capacity allocation question will help to resolve many of the disputes evident on this record concerning other procurement issues. Fundamentally, it is the utilities' current superior access to both firm and interruptible pipeline capacity which has generated the need to place restrictions on the utilities' procurement activities in the noncore market. We believe that a market-based capacity allocation program, providing efficient and equitable access to firm transportation, will calm much of the debate on how to structure the utilities' noncore procurement activities, a debate which encompasses the Tussing proposal, core election, the marketing of excess core supplies, multiple supply portfolios, 30-day firm procurement, and standby charges. Therefore, this decision will focus on the general outlines of the capacity allocation program which we intend to investigate in more detail in the immediate future. In general, we prefer to defer making significant changes in the current structure of the utilities' procurement activities, until we tackle what we see as the more fundamental problem of capacity allocation.

III. THE MARKET-BASED ALLOCATION OF PIPELINE CAPACITY

In R. 88-08-018 we expressed support for the idea, which SoCal had proposed in I. 87-03-036, of a system to allocate on a coordinated basis both intrastate and interstate pipeline capacity. Under the SoCal plan, the allocation would be market-based, using customer bids to pay for priority of access to capacity. We stated in the rulemaking order that core customers should have first access to pipeline capacity; as a result, we also expressed the view that core elect customers should pay for the high priority access to pipeline capacity which accompanies service from the core portfolio. We proposed that the revenues from capacity priority bids should be used to offset the noncore market's share of intrastate transmission and interstate pipeline demand charges. We also supported the proposal of Salmon Resources and Mock Resources (Salmon/Mock) to give long-term transportation customers -- those with contracts whose original term is five years or more -- the right to match whatever priority charge is necessary in order for them to maintain their place in the priority queue. We asked for comments on a number of issues on which we did not express a view, including:

1) the federal issues raised by the coordinated auctioning of intrastate and interstate pipeline capacity;

2) how core elect customers should pay for the high priority access to pipeline capacity which they receive as part of the utility's core portfolio;

3) whether capacity should be allocated on a pipeline-specific or on an overall system-wide basis;

4) the impact of the operational differences between the SoCal and PG&E systems; and

5) the appropriateness of recent changes in the end-use priority applicable to the steaming operations of enhanced oil recovery (EOR) customers.

A. <u>The Need, Feasibility, and Timing of an Allocation Mechanism</u>

The comments filed on R. 88-08-018 continue to show broad support for the idea of a coordinated, market-based mechanism to allocate both intrastate and interstate pipeline capacity. Significantly, PG&E has now embraced the concept, and is working actively to prepare a comprehensive proposal. Support also comes from SoCal, from wholesale customers such as San Diego Gas and Electric (SDG&E) and the cities of Long Beach and Palo Alto, from a representative of large users (CIG), from the brokers Salmon/Mock and Trigen Resources (Trigen), and from the Division of Ratepayer Advocates (DRA). Transwestern Pipeline states that it is willing to work with the Commission and other California parties in order to develop the concept. Rather than elaborate on the supporting comments, our discussion in this section will focus on the arguments of those who disagree with the direction of R. 88-08-018 on this issue, and on the debate on "how far, how fast?" to proceed.

Several parties did question the need for a single, coordinated mechanism to allocate both intrastate and interstate pipeline capacity. The Canadian Producer Group (CPG) argues that no capacity constraints exist on the PG&E system, and therefore that the implementation of such a mechanism for PG&E is unnecessary at this time. The CPG believes that, in a situation where such a mechanism is not needed, it will function only to collect premiums from risk-averse customers, and that recycling these premiums to other noncore customers will only create confusing signals to both the utility and its customers. The answer to the capacity bottlenecks on the El Paso system, the CPG believes, lies in the reformation of El Paso's new rate structure. The consumer group Toward Utility Rate Normalization (TURN) recommends that a bidding system for capacity priority be limited to the purpose for which it was conceived in earlier stages of our restructuring program -- determining which customers are curtailed in the event of pipeline capacity constraints. The state Department of General Services (DGS) wants to retain the current end-use priority system, in recognition of the requirements of Public Utilities Code Section 2771, and because DGS believe that the current system is still workable. DGS would allow bidding for priority only within each of the current priority classes. In a similar vein, Southern California Edison (Edison) cautioned us to clarify the relationship between a capacity allocation mechanism and the end-use priority system.

Parties also commented on the administrative feasibility of auctioning pipeline capacity. The Industrial Users believe that the administrative complexity of capacity auctioning raises serious questions about the feasibility of the idea. TURN suggests that it would be prudent to experiment with bidding as a means to allocate capacity during curtailments, before expanding the concept to include access to capacity at all times. Even SoCal, which first proposed such a mechanism almost a year ago, maintains that the administrative requirements are "substantial," and cites the many other administrative changes which it must implement in order to accomodate the new regulatory framework. SoCal believes that it will not be able to accept capacity priority bids until 9 or 10 months after a Commission order authorizing such a system. SoCal also believes that a system which allocates capacity on a pipeline-specific basis is "unworkable for the forseeable future." SoCal's estimate of the time required to implement such a system drew a strong reply from CIG. CIG recites the long history of Commission support for a capacity priority charge based on bidding, and notes that SoCal itself proposed an integrated priority charge mechanism in February, 1988. CIG also mentions the active discussions over the past six months of an "interim" mechanism to allocate grandfathered interruptible rights, stating that the details of implementing such an arrangement would be very similar to a capacity allocation program for firm transportation. CIG believes that these circumstances indicate that the California utilities have been "on notice" that an integrated capacity allocation program will be adopted, and should be able to implement such a program within 60 days of the receipt of the necessary FERC approvals. If the utilities cannot meet such a schedule, CIG believes that a substantial portion of the utilities' pipeline demand charges should be assigned to the shareholders.

CIG, Salmon/Mock, and Agland Energy Services (Agland) believe that the Commission can, and should, take immediate action to order the utilities to use their grandfathered interruptible capacity rights "on behalf of" noncore customers.[5] Such an "interim" step would be possible without FERC approval, CIG and Salmon/Mock argue, based upon what they believe are recent liberal FERC interpretations of the "on behalf of" requirement of Section 311 of the Natural Gas Policy Act (NGPA), and under the condition that the utilities temporarily take title to the gas while it is moving on the interstate system.[6] Agland suggests several ways in which such a program could make use of the utilities' existing administrative procedures. These parties believe that such an "interim" program would allow noncore customers to improve their access to pipeline capacity immediately, until a permanent capacity allocation program, based upon firm transportation rights, can be established.

Administrative and legal objections have been raised to the "interim" program of CIG, Salmon/Mock, and Agland. SoCal believes that such a program is more complicated than it can handle now, due to the current lack of information from the pipelines which would be necessary for SoCal to manage the allocation of capacity at numerous receipt points. PG&E urges the Commission to focus on a long-term solution, rather than waste time now seeking a "quick fix." CPG disputes the assertion that the "interim" program

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5 This is the proposal which CIG and Mock advanced in their October 14 joint emergency motion (see footnote 2, above), and which they renew in their comments in this docket.

6 The primary FERC order which CIG and Salmon/Mock cite as permitting their proposal is Hadson Gas Systems, Inc., 44 F.E.R.C. p. 61,082 (1988).

would not be subject to FERC jurisdiction. In CPG's view, use by the California utilities of their grandfathered capacity rights "on behalf of" certain shippers would run afoul of the Section 311 rules and FERC standards for non-discriminatory transportation.[7] The CPG contends that the FERC is unlikely to accept an arrangement which skirts the Section 311 rules through the artifice of a temporary transfer of title to the California utilities.

Many parties, including SoCal, PG&E, CIG, CPG, and DRA, state that FERC concurrence in the settlements of pipeline cases will be necessary in order to implement a capacity allocation or "brokering" mechanism based on the utilities' firm transportation rights. Several commenters note that this Commission itself, in its comments to the FERC on the capacity brokering Notice of Proposed Rulemaking (NOPR), has recognized that consistency between Commission and FERC rules is necessary before capacity brokering can be implemented in California.

Discussion: We believe that a market-based capacity allocation program is desirable, feasible, and can be implemented in the near future. The major benefits of such a mechanism are not as a "quick fix" to the problems which were experienced this summer

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7 CPG notes that the rules for Section 311 transportation (15 U.S.C. Section 3371) allow only certain types of transportation, including transportation by an interstate pipeline on behalf of a local distribution company or intrastate pipeline. CPG contends that Section 311 makes no reference to transportation "on behalf of" an end user, such as a noncore customer of a California utility. CPG does not believe that such users can be the "on behalf of" entities, as the CIG/Salmon/Mock proposal requires. CPG also comments that the issue in the <u>Hadson</u> case, on which CIG and Salmon/Mock rely, was how remote from a transaction the "on behalf of" utility could be while still permitting the transaction to go forward. The case does not address the issue of whether an "on behalf of" local distribution company (such as a California utility) could itself implement transportation for a shipper other than one selected in accordance with FERC standards for non-discrimination. CPG believes that the <u>Hadson</u> case does not sanction a California utility improving a shipper's rights to capacity on El Paso, for example, beyond what that shipper already posesses under the current FERC allocation scheme.

on the El Paso system, which we view as due largely to the implementation of a new rate design on that system. Instead, such a mechanism would supply an important missing piece from our new regulatory structure: access to more reliable pipeline capacity for a wider range of gas producers, shippers, and end users. Improved access to firm transportation would encourage the long-term supply arrangements which are necessary to support investments in finding and developing new gas supplies. The attractiveness of the California market to gas suppliers will be increased as the scope of possible supply arrangements expands. The greater variety of transactions will stimulate gas-to-gas competition, to the benefit of the ultimate consumer.

Our long-term perspective on the benefits of market-based capacity allocation has important implications for how we will proceed to develop such a mechanism. First, we doubt the wisdom of attempting to put an "interim" program into place immediately, as CIG and Salmon/Mock urge. The preponderance of the legal analysis presented in the comments shows that ultimately our program will require at least the FERC's concurrence in the pending pipeline general rate cases and GIC proceedings. In addition, CPG's analysis of the NGPA Section 311 rules and the Hadson case convinces us that the legality of the proposed "interim" program is debatable. In addition, we recognize that the implementation of any new capacity allocation scheme will be complex. Although we do agree with the CIG that SoCal's administrative requirements seem excessive, we cannot ignore the administrative burden on the utilities. As a result, we prefer to proceed to implement one permanent mechanism, rather than to force the utilities to change their administrative and operating procedures twice -- once for an "interim" program, and again for the "final" one. Generally, we think it best to pursue the program for which there is the most widespread support within California. That program is a market-based allocation mechanism, with the utilities obtaining FERC concurrence to assign on an economic basis the firm transportation rights which they will have under the FERC's Order 500.

We do realize that lower priority interruptible shippers such as CIG and Salmon/Mock have faced, and may again face, significant problems with access to capacity. Therefore, we will proceed quickly to develop the details of our capacity allocation program, so that the mechanism can be implemented expeditiously once the necessary federal approvals are received.[8] We will set an implementation goal of 90 days after the receipt of these approvals. We agree with CIG that the period which SoCal claims to require to implement this program is excessively long, considering that SoCal itself proposed a similar system almost a year ago. This decision will discuss the general framework for our program, will outline the issues which remain to be resolved, and will order the utilities to file detailed proposals consistent with this framework, within 60 days from today. We will hold hearings on these plans promptly after they have been filed. We will also order the utilities to pursue the necessary FERC concurrence in current pipeline general rate cases or GIC proceedings; in the record of this case, both PG&E and SoCal have made commitments to pursue these approvals.

B. The Framework of the Program

The record in this case is obviously not detailed enough for us to specify completely the market-based capacity allocation mechanism which we wish to see adopted. However, R. 88-08-018 did generate considerable commentary on many of the important elements of such a program. We do have enough information to adopt a general framework for the program, and to specify the unresolved

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8 We are also aware that CIG, Mock, other concerned shippers, and the utilities are continuing to discuss other measures to facilitate third-party transportation, measures which would be easier to implement than a capacity allocation scheme. We continue to support and to encourage these discussions.

issues which we want the utilities to cover in the proposals which we are ordering them to file.

1. General Principles. Although some parties criticized as "vague" PG&E's principles for an integrated capacity allocation mechanism, we believe that, with very little modification, they are appropriate for the general framework of our program. PG&E's principles reflect the goals of our new regulatory structure, recognize the need for the capacity allocation mechanism to be acceptable to the FERC, and are consistent with our perspective, stated above, on the benefits of a capacity allocation program. As we read them, casting them into terms applicable to SoCal as well as to PG&E, these principles are:

1) The program should help to meet core procurement goals through encouraging gas-to-gas competition.

2) Core-elect customers should pay for the secure access to pipeline capacity which core portfolio service provides.

3) The program should be consistent with the capacity rights which the utilities have on the interstate pipelines which serve them, including the firm transportation rights which they may acquire in current pipeline cases, under the FERC's Order 500 regulations.

4) The firmness of the capacity allocated to a noncore customer under this program should be independent of whether that customer purchases gas from the utility or from another supplier.

5) Noncore customer should have the flexibility to coordinate the integrated access to pipeline capacity with the storage banking services available as a result of D. 88-11-034.

6) The costs of access to firmer pipeline capacity should be borne by those noncore customers who benefit.

7) The value of capacity allocated to noncore customers should be determined by a market-based mechanism, not by a cost allocation process.

8) The program should encourage the maximum efficient use of transportation capacity over the long term.

9) The integrated capacity allocation mechanism must be acceptable to both the Commission and the FERC.

The capacity allocation proposals which we will order PG&E and SoCal to submit must be consistent with these principles. We hope in the remainder of this order to begin to dispel any of the "vagueness" which lingers about these principles. As guidance to the parties and to stimulate discussion, we will offer in the sections which follow our preliminary thoughts on some of the issues which the utilities' proposals must address.

2. Specificity of the Allocation. R. 88-08-018 raised the issue of whether the capacity allocation mechanism will function to allocate pipeline capacity on a pipeline-specific basis. SoCal and TURN fear that such specificity may be difficult to administer; SoCal's original proposal only contemplated allocating capacity to transport-only customers as a group. However, PG&E proposes to focus its program not only on an allocation of capacity to specific pipelines, but to the various producing areas which each pipeline serves. PG&E believes that each producing area has "different capacity constraints and supply/demand/cost relationships, resulting in different priority values to PG&E's core portfolio customers and to transport customers." SDG&E and Trigen concur with the need for a pipeline-specific allocation. CIG also agrees, and makes the important observation that bidding for capacity only makes sense if a customer has already lined up a supplier at a price certain, and therefore has in fact locked himself into a pipeline-specific route. In addition, CIG notes that the FERC's capacity brokering NOPR appears to require a pipeline-specific allocation.

We agree with these parties that a workable program probably will have to allocate capacity at least on a pipeline-specific basis, and perhaps to each producing area served by a particular pipeline, due to the significant differences between producing areas. We acknowledge that the greater the specificity of the allocation, the larger the problem of administering the system. An important element in our review of the utilities' proposals will be to determine the appropriate balance between specificity and administrative feasibility.

3. **Treatment of the Core Portfolio.** There was no disagreement with the idea that core customers should have the top priority to pipeline capacity.[9] As we will discuss at length later in this order, we continue to believe, given the current circumstances in the industry, that the utilities should continue to offer a core elect option to noncore customers. Core elect customers will have to pay for the preferential access to pipeline capacity which they will receive as participants in the core portfolio. Having decided that, the next question is how much flexibility to allow the utility in its use of pipeline capacity to serve the core portfolio. The basic problem is illustrated by the extreme viewpoints. At one end, as Salmon/Mock advocate, we could require the utilities to relinquish all pipeline capacity that is in excess of core (priority 1 and 2A) requirements. As several parties noted, such a requirement could cause the relinquished rights to be lost permanently to whoever was next on the FERC queue for firm transportation. At a minimum, the relinquishment of excess capacity could result in a lack of pipeline capacity to serve "peak day" core demands caused by unexpectedly cold weather. The core could also suffer from the utility's lack of flexibility to shift core purchases as gas prices change. The opposite viewpoint is SoCal's assertion that it has no "excess" capacity

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9 As stated in R. 88-08-018, this should include access to capacity needed to move volumes to be injected into storage to provide core protection. These volumes would be based upon the "final" storage target adopted by the utility pursuant to our new gas storage program (see D. 88-11-034, pp. 2-15).

rights, because it may in the future need full pipelines, presumably as well as maximum storage withdrawals, to meet "peak day" core needs. This assertion suggests that SoCal is unwilling to implement a capacity allocation scheme based upon firm transportation rights, because SoCal's core customers may need to use all of those rights on a few very cold days.[10] Such a position undermines our goal of making reliable transportation more widely available, and ignores ways of reaching that goal while protecting what we agree is the utility's critical responsibility to supply "peak day" core needs.

The answer lies between these two viewpoints. We clearly do not want the utilities to relinquish their firm capacity rights, due to the risk that they might be lost permanently. We prefer them to assign those rights to other parties for a defined period and under specified terms and conditions. Our real problem is to determine what terms and conditions are necessary to attach to capacity allocation so that core consumers will be adequately protected, yet noncore customers will have access to more reliable transportation through purchasing assigned capacity. Clearly, this will be an important issue in the next stage of this proceeding, one that we expect the utilities to highlight in their proposals.

At this point, we will put down our preliminary thoughts on this issue, as guidance to the parties and to stimulate discussion. We believe that the utilities should attach a condition to all assigned capacity which allows them to recall that capacity to meet "peak day" core needs. We would expect the utilities to inform the customers to whom they assign capacity how often they expect to exercise that recall right, based upon historical experience. We also suspect that the utility should retain a limited amount of flexibility to shift their core

10 SoCal admits that it does not need its full interstate pipeline capacity to serve core needs "the vast majority of the time."

portfolio purchases among pipelines and producing areas, or to increase their total core portfolio purchases if demands exceed forecasts.[11] For example, under our core procurement guidelines, most of the gas purchased for the core portfolio will be long-term supplies. Many of the long-term supplies which the utilities now purchase have prices which are fixed for a year. We anticipate that the utilities should be able readily to determine, looking ahead for a year, what pipeline capacity they will require to deliver such supplies. Our procurement guidelines have also suggested that the utilities should purchase some short-term or spot gas for the core portfolio. These are the purchases for which the utilities may need the most flexibility in their access to pipeline capacity.

4. **The Capacity Requirements of Wholesale Customers.** We continue to believe, as stated in R. 88-08-018, that the core loads of wholesale customers must share, with the core load of the primary utility, top priority to pipeline capacity. We concur with Palo Alto's comment that this means that wholesale core loads will have parity of access to capacity with the core load of the primary utility.

Although the idea of parity of access to capacity for wholesale core loads is settled, there may remain some dispute on how to implement this concept. Our recent storage decision provided one model for determining how much pipeline capacity should be allocated to wholesale core loads (see D. 88-11-034, p. 20). We allowed a wholesale customer to have access to storage capacity equal to the proportion of the primary utility's fixed costs of storage which are allocated to that wholesale customer's core load, based upon our allocation factor for storage costs (peak

11 This is apparently what TURN has in mind when it urges us to provide the core portfolio with the top priority to enough capacity "to ensure efficient system operations."

season cold year sales). SDG&E has suggested another method, using the relative cost allocations for service for core and noncore customers.[12] From its total allocation for both the core and the noncore, the wholesale utility would then make its own decision on the amount of capacity needed for core service. The capacity remaining after this choice would then be allocated according to a bidding procedure. SDG&E is willing to place itself at risk for the capacity costs allocated to the amount of core transmission which it chooses, in order to remove any doubts that it might claim a greater amount of core capacity than necessary. We are attracted to SDG&E's proposal, because it appears consistent with our desire that wholesale customers have the primary responsibility to serve their core customers, as well as the tools and the flexibility necessary to carry out that duty. The capacity allocation proposals which the primary utilities will file should address the treatment of wholesale core loads, including comments on SDG&E's plan.

SDG&E perceptively raises another implication of wholesale core parity: what if a utility and its wholesale customers desire access to pipeline capacity to purchase core supplies in a certain producing area, in a quantity that is greater than the amount of pipeline capacity available to that area? Our initial reaction is that a pro-rata allocation, based upon total core loads of each utility, would be fair.

5. **Treatment of Revenues from a Capacity Allocation Mechanism.** The comments which we have received raise no strong objections to the proposal in R. 88-08-018 that revenues from a capacity allocation mechanism should be used to offset both intrastate transmission costs and interstate pipeline demand charges assigned to the noncore class. However, we suspect that

12 For pipeline capacity, these allocations are based upon cold year sales.

a number of different approaches may develop on this issue, and we do not want at this time to restrain the debate. CIG does suggest an upfront credit to noncore customers based upon utility forecasts of these revenues, with a balancing account to ensure that the utility is kept whole if the forecast is inaccurate. We believe that the CIG suggestion deserves further scrutiny, as we agree with CIG that the up-front credit would have the important benefit of limiting price-signal distortions which might result from a lag between when a customer bids for capacity, and when that customer sees the results of the bidding in his rate.

6. **Cogeneration Parity and the End-use Priority System.** In this order we are proposing a significant expansion of the "priority charge" concept which we have discussed in a variety of decisions since D. 86-12-010. The market-based mechanism which we want to develop will not only decide the curtailment order if capacity constraints develop, but will also serve to allocate access to firm transportation capacity. There are several statutory requirements which the utilities must consider in designing their mechanisms. One is the "cogeneration parity" requirement of Public Utilities Code Section 454.7, which mandates that the Commission provide cogeneration with the highest possible priority. The second is the end-use priority system established pursuant to Public Utilities Code Sections 2771-2774.[13] We have previously concluded that an economically-based priority system for noncore customers is consistent with this statute, and have decided that end-use priorities should be used among customers paying the same (or zero) priority charge.[14] At this time, we believe that these conclusions can continue to apply to a capacity allocation

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13 For example, Edison raised in its comments the need to clarify the relationship between a capacity allocation mechanism, such as SoCal proposed, and the end-use priority system required in these Public Utilities Code sections.

14 See D. 86-12-010, pp. 119-123.

mechanism. For example, under a pipeline-specific allocation, for customers who pay the same for capacity on a particular pipeline, we propose to use the end-use system to determine priority among these users. This may also satisfy the requirements of Section 454.7, as well, because cogenerators would be assured of a higher priority than other noncore customers who pay a similar price for capacity.

7. **Capacity Priority for End-users with Long-term Transportation Contracts.** R. 88-08-018 favored a Salmon/Mock proposal to give customers with long-term transportation agreements signed after December 3, 1986, the right to match whatever priority charge is necessary to allow them to maintain their place in the priority queue.[15] Several parties continue to disagree with this idea. SDG&E argues that enhanced oil recovery (EOR) customers with special low rates should not be allowed to bid for priority along with "other noncore customers who carry their full weight in rates." Unless EOR customers are willing to pay "full fare", they should have the lowest priority to capacity. SoCal, with the CIG's concurrence, is at the other end of the spectrum on this issue: SoCal renews its argument, which we rejected in R. 88-08-018, that long-term transporters should have the highest priority among all noncore customers, due to the commitment which they have made to stay on the utility's system. PG&E takes a middle ground: it does not disagree with the Salmon/Mock matching idea, but suggests that this should not be the only option. PG&E believes that the dependable revenue stream of a long-term transportation commitment has a value which may not be reflected accurately by requiring such

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15 We defined a "long-term transporter" as a transportation customer with a contract that has an original term of five or more years. Customers with long-term transportation contracts signed on or before December 3, 1986, would have their capacity priority defined according to the policy we set out in D. 87-12-039.

a customer to match bids made by customers who may have a much shorter time horizon.

We continue not to see a need to give long-term transporters the automatic highest priority access to capacity among noncore customers, as SoCal and CIG propose. We note that the Cogenerators of Southern California (CSC), which filed comments on behalf of several EOR cogeneration projects with long-term transportation contracts, states that its members are willing to pay for access to capacity, so long as they have the opportunity to match the bids paid by utility electric generation (UEG) customers. We also reject SDG&E's position, which is plainly inconsistent with our long-held commitment that EOR transportation customers should be able to "buy up" in priority. PG&E is welcome in its capacity allocation proposal to present another option for dealing with long-term transporters, so long as that plan falls between the extremes which we have rejected.

8. **A Secondary Market for Capacity.** We urge the utilities to consider in their proposals the provision of a secondary market for assigned capacity. We believe that a secondary market could increase significantly the efficiency of an allocation system. It would provide a second opportunity for parties who bid too low in the original auction for the capacity which they need. Conversely, parties who purchase too much capacity, or whose capacity needs change between primary auctions, would have the opportunity to lay off excess capacity in the secondary market. We also suggest that capacity sub-assigned in the secondary market must retain all recall rights which were attached to the original assignment agreeement.

C. Core Election

A major issue posed in R. 88-08-018 is how core elect customers should pay for their superior access to capacity. Before we discuss the specific comments on this issue, we need to address the threshold question of whether to retain the core elect option. Salmon/Mock and DRA both propose that core election should be eliminated.

Salmon/Mock agree that core elect customers should pay for the access to capacity which they receive as participants in the core portfolio. However, Salmon/Mock believes that charging core elect customers for such access is an "extremely difficult and complex task." Salmon/Mock believes that all three of the payment proposals suggested in R. 88-08-018 would result in core elect customers receiving the same treatment as core customers with respect to capacity, without paying the full costs of core service. As a result, Salmon/Mock argue that core election should be eliminated, and that all noncore customers should have a one-time opportunity to become core customers, and to pay a bundled core rate.

DRA also believes that providing a core elect option is overly complex. In addition to the issue of paying for pipeline capacity access, DRA cites the related problem of the core elect paying for the access which they receive to storage capacity. DRA also notes the still-unresolved question of how to bill core elect customers when the actual core WACOG differs from the forecasted price, and possible problems with the electric departments of combined utilities who elect into the core. DRA cites PG&E's experience since May 1: DRA believes that the large amount of core election on the PG&E system has forced PG&E to purchase more expensive spot gas for the core portfolio, driving up the actual core WACOG. DRA characterizes PG&E's core elect customers as "price chasers" who are more interested in low prices than the supply security of the core portfolio. DRA thinks that the noncore customers' limited desire for supply security can be met through a noncore portfolio of long-term gas whose price varies every 30 days. More fundamentally, DRA does not believe that core election provides the utilities with enough monopsony power to lower significantly the core portfolio price, especially given what DRA

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sees as the evolution of the national gas market into "a pure commodity market" where long-term prices will track the spot market. Finally, DRA warns the Commission that prices of Canadian gas have not always been so low; five years ago, under a different regulatory regime, Canadian gas was California's most expensive supply source.

CIG, SoCal, CSC, Edison, TURN, PG&E, and CPG all support retaining the core elect option. CIG submits that core election should be retained for the present, because it is the only source of supply security for noncore customers who are unable or unwilling to cope with the present lack of reliable transportation. CIG disputes DRA's statement that all noncore customers are price chasers, citing the fact that, unlike the experience on the PG&E system, few of SoCal's noncore customers elected into the core in August, when spot prices rose above SoCal's core WACOG. In a similar vein, PG&E notes that its core elect customers had to choose that option when the core WACOG was higher than spot prices. Although there has been little core election on the SoCal system, SoCal, CSC, and Edison all argue that it would be poor public policy to change such a significant "rule of the game" so soon after the new regulatory structure was implemented.

TURN and PG&E present extensive arguments that core election is presently producing important benefits to both core and noncore customers. PG&E asserts that its negotiating experience with its Canadian suppliers indicates that core election provides the important bargaining chip of a broad-based, high load factor market that includes customers with competitive options to gas service. PG&E recites the Commision decisions which established core election, to show that the mechanism is functioning just as it was intended to do. PG&E cites the significantly lower gas prices which northern California has enjoyed in recent years, compared with southern California, as evidence of the importance of this leverage. TURN discusses at length PG&E's existing contractual relationship with its Canadian suppliers, in an effort to determine the likely impact of the abolition of core election on PG&E's core customers and on prices in California as a whole. TURN notes that without the leverage of the core elect market, the Canadians would be free to price their sales to the core market just below the competing supplies of long-term gas from the Southwest. Recently, these alternative core supplies have been at least $0.50 per MMBtu more expensive than the $1.81 per MMBtu Canadian price. TURN also believes that Tier 2 Canadian gas sold to the noncore portfolio would have tracked rising spot prices, which have been well above $1.81 per MMBtu for most of the past year. Thus, TURN concludes that core election has undoubtedly benefitted both PG&E's core and noncore customers, and that it would be a serious tactical error for the Commission to discard the core elect option just a few months before PG&E begins the next annual price redetermination. TURN thinks that the next price redetermination will provide an empirical test of whether core election will continue to produce significantly lower gas costs for PG&E's market. TURN also confronts the longer-term question of whether California consumers would be better off if the Commission took action, such as ending core election, to make capacity available on the Pacific Gas Transmission (PGT) pipeline. Such a step would be designed to stimulate competition among Canadian suppliers, in the hope that significant supplies could be obtained for much less than $1.81 per MMBtu. TURN argues that regardless of whether such cheap supplies are available, the impact of such a move would not fall evenly on all customers. Some noncore customers might benefit from cheaper Canadian spot gas, but the Alberta and Southern (A&S) producers could ask very high prices for the core supplies which PG&E must purchase to meet its 50% take-or-pay obligation to A&S. TURN fears that this could lead to a repeat of the take-or-pay problems which have plagued the El Paso system. TURN concludes:

> While a fully competitive gas market on both sides of the border may be in everyone's long-term best interests, TURN must caution that the path selected to pursue that goal is equally as important as the objective itself.

> The shortest route may not be the most productive one if it leads over a cliff.

TURN recommends that in the future the Commission should explore how to attain a fully competitive market for Canadian gas from which all customer classes can benefit.

CPG presented the most vigorous defense of core election. CPG disputes DRA's suggestion that an assessment of core election should be based upon the degree of monopsony power which core election provides to the utilities. CPG argues that the clear benefits which core election has provided to PG&E's ratepayers are the result of the large volume sales and high load factors which core election has made possible. Core election allows the Canadian producers to provide PG&E with volume-related discounts; these are not a function of market power, but are instead economies of scale and operation. CPG confirms PG&E's assertion of the importance of core election in last year's price redetermination:

> CPG members' agreement to sell gas to Alberta & Southern, for resale to PGT and then to PG&E's core portfolio, at a commodity price of $1.81 per MMBtu for a full one-year term, was fully and consciously based on the premise that such a price would prove attractive enough to attract a very large volume of core-elect as well as core load, and thereby achieve a high load factor for wellhead sales. Without such an assurance of high volumes and load factors, the price of gas to the core portfolio would not have been, and cannot be, so attractive.

CPG notes that DRA argues that the large quantity of core election on the PG&E system has forced PG&E to buy increasingly expensive spot gas to meet the core elect load. CPG remarks that this effect is not due to core election, but to our policy of requiring some spot gas to be taken for the core market; CPG also notes that the beneficial volume and load factor effects of core election are much greater than the increase due to the spot gas takes. Regarding DRA's reminder that Canadian gas was once very expensive, CPG states that Canadian producers, regulators, and government all recognize that Canadian gas prices must be market-responsive in order to have access to U.S. markets. Finally, CPG joins PG&E in protesting that abolishing core election is not the way to deal with the complexities in our regulatory program which the core elect option may create. CPG cites PG&E's new willingness, expressed in its coments in this docket, to develop a core elect charge based on the access to storage and to pipeline capacity which these customers receive. This is the way to deal with the core elect issue on its merits, CPG believes, rather than by making a disruptive, fundamental change in the new regulatory structure. CPG contends that abolishing core election would "reinforce skepticism about regulatory credibility and consistency in California."

Discussion. We will retain the core elect option. Fundamentally, we recognize the need for a degree of regulatory stability and consistency in our new program. We agree with CSC that we need more experience, under a variety of circumstances, with the new regulatory framework before making major modifications to it. We have recognized that core elect customers are not paying for the high priority access to storage and pipeline capacity which they receive. We believe that the responsible way to deal with this issue is to develop an appropriate charge for this access. This confronts the problem on its merits, in an evolutionary way, without taking the revolutionary step of abandoning a procurement option which appears, based upon our limited experience to date, to have benefited a broad range of gas consumers.[16] Eliminating the core elect option at this time would cast doubt on the stability of the structure which we have established. This would be precisely the wrong signal to send at a time when we are focusing on improving the attractiveness of the California market for long-term, secure supply arrangements.

16 This is also the way we dealt with the same issue, concerning the access of core elect customers to storage capacity, in D. 88-11-034.

A central goal of our new regulatory structure has been to capture the benefits of the more open and competitive gas market for all gas consumers in California. We conceived the core elect option was an important element in reaching that goal, and our limited experience to date indicates that it has worked. PG&E's customers enjoy the lowest gas prices in the state. TURN's analysis of current gas supply arrangements demonstrates that, absent core election, the price of Canadian gas to both the core and the noncore markets would be much higher. The parties on both sides of the last Canadian gas price redetermination make this assertion as well. We agree with TURN that, given the current structure of gas supply relationships, we should not throw away what is now a significant bargaining chip. R. 88-08-018 noted the problems which sales gas from the domestic pipelines has had in recent years in competing with Canadian supplies. Recently, SoCal has obtained one-year contracts for significant supplies from the Southwest at prices well below pipeline supplies, yet still above Canadian prices. Until the domestic suppliers are able to compete effectively with the Canadians, we may need to retain the bargaining leverage of core election in order to retain the benefits of economical Canadian supplies.

We also find that the evidence to date is inconclusive on whether, as DRA suggests, noncore customers are simply price-seekers. CIG, which represents a number of noncore customers, notes that core election currently provides the many noncore customers who do not want to transport their own gas with the only option for a secure gas supply. The theme of this order has been the need to increase access to firm transportation, in order to allow noncore customers to purchase and transport secure supplies. However, there is clearly much to be accomplished before we can realize this goal, and we agree with CIG that we need to retain the core elect option at least until a capacity allocation program is functioning.

Ultimately, our long-term perspective on core election is dependent on how the market develops once our capacity allocation mechanism is in place. What happens once access to firm transportation is increased will determine the future need for options such as core election. The market may develop new mechanisms for aggregating gas supplies which, like core election, provide to all gas consumers the benefits of competition among gas supplies and among alternate fuels. We agree with TURN that our reasons for retaining the core elect option at this time are based on a tactical perspective; this perspective, however, does not detract from our current interest in using this option to maintain mutually beneficial long-term arrangements with willing producers.

Returning to the design of a capacity allocation mechanism, R. 88-08-018 suggested three possible ways in which core elect customers might pay for their superior access to pipeline capacity:

> 1) A cost-based surcharge on the core elect procurement rate would be set equal to the difference, on a per therm basis, between what the core and the noncore contribute to the utility's fixed costs for intrastate transmission and for pipeline demand charges. As a second-best alternative to no such surcharge, CPG supports this method, because it is the only one which is cost-based. CPG would exclude from the surcharge intrastate transmission costs (which are not constrained) and all pipeline demand charges except those on PGT (which is the pipeline which carries the bulk of core supplies).
>
> 2) The surcharge would be set a whatever level is necessary, based on the results of the capacity allocation auction, to allow the utility to sequence the supplies which it requires for the core portfolio. This concept receives preliminary support from SoCal, SDG&E, and CIG, and resembles the approach we used for the core elect in our gas storage decision, D. 88-11-034.
>
> 3) Core elect customers themselves would bid for capacity, on the same basis as other noncore customers. If a core elect customer does not bid enough to obtain access to the core portfolio, that customer would be charged the standby rate for service from the core

portfolio. Salmon/Mock favor this alternative, if core election is retained.

PG&E believes that what customers pay for capacity under a capacity allocation mechanism will vary among pipelines and producing areas, as operational circumstances and spot market prices vary. PG&E comments that these price relationships may have little to do with the costs of core portfolio service, which is based upon long-term supplies that may be purchased from different sources. PG&E does not support any of the above alternatives, but promises that its capacity allocation proposal will include a charge designed "to cover properly allocated costs and reflect the benefits of such service without making core-election prohibitively expensive."

We agree with the general principles which PG&E proposes for such a charge, but at this point there is clearly no consensus among the parties on how to set this charge. This issue should be covered in the utilities' proposals, and undoubtedly will be debated further in the hearings which will follow.

D. <u>The End-use Priority for Enhanced Oil Recovery</u>

R. 88-08-018 asked for comments on the debate which has arisen over the end-use priority of EOR customers. PG&E remarks that D. 86-12-010 reduced the end-use priorty system to P1-P5, and required the curtailment order for supply shortages should follow the <u>existing</u> end-use priorities. PG&E believes that it accurately implemented the intent of this order in its new tariffs, by placing EOR steaming customers in Priority 4, along with other boiler fuel users with a peak day demand of 750 Mcfd or more. PG&E argues that a change to the <u>existing</u> end-use system would have been required to place EOR users in Priority 5, which is defined to be for power plant service. PG&E believes that its actions have been fully consistent with the structure of the end-use priority system, as established by Public Utilities Code Sections 2771 and 2772 and relevant Commission decisions. In Resolution G-2819 (August 10, 1988), we approved a similar change for SoCal, pending further review of the issue in this proceeding. SoCal's position in this case is that whatever priority is assigned to EOR customers, that priority should be uniform statewide.

UEG customers, joined by DGS, DRA, and CIG, argue strongly that EOR steamflood use should be placed in a priority below electric utility powerplants. SCUPP and Edison note that they have filed petitions for rehearing of Resolution G-2819, in which they argue that we moved EOR customers to Priority 4, ahead of most UEG usage, without reaching a determination about which customers provide the greater public benefits and serve the greater public need, as required in Sections 2771 and 2772. The UEG customers believe that placing EOR steamflood customers, who now account for about 100 MMCfd of load on the SoCal system, ahead of UEG users will result in higher costs for electric ratepayers. These increased costs will result from more frequent amd longer-lasting curtailments of UEG gas service, which will require increased fuel oil inventory costs and the use of more expensive energy resources to replace larger amounts of natural gas. Air quality will be degraded due to the increased use of fuel oil in electric powerplants. SCUPP notes further that, once EOR steamflood customers sign long-term transportation contracts, they will be able to "buy up" in priority. SCUPP believes that these users thus do not need the additional benefit of Priority 4 status for their current operations. No EOR steamflood customers filed comments on this issue.

Edison has correctly characterized our past decisions on this issue. In R. 86-06-006 we proposed:

> ... we believe eventually there should be only five [end-use] categories. Having upwards of the eight basic categories which have evolved today makes, in our view, for a needlessly complex end-use system. We will place EOR customers in the P5 priority designation for short- and long-term sales. (p. 26)

We adopted this change, as proposed, in D. 86-12-010:

> As originally proposed in the OIR, we will reduce the number of end-use priorities to five. (p. 121)

In its tariffs implementing D. 86-12-010, SoCal correctly placed EOR customers in Priority 5. PG&E placed EOR customers in Priority 4, based upon a narrow reading of just D. 86-12-010. PG&E appears to have neglected to check R. 86-06-006 to determine how we intended to treat EOR customers when we reduced the number of end-use priorities to five.

In view of this history, we will direct the utilities to place EOR steamflood operations in Priority 5, along with electric powerplant use. We agree with the UEG customers that their arguments about the burdens on electric customers from increased curtailments have merit. We also note that this represents an improvement in the priority status of EOR steamflood customers, compared with their original Priority 7 assignment.

Findings of Fact

1. A combination of factors, including high demand and a new rate structure, produced capacity constraints last summer on the El Paso Natural Gas pipeline.

2. Providing access to firmer interstate pipeline capacity is an important element still missing from our new natural gas regulatory structure.

3. Access to more reliable transportation will encourage longer-term gas supply arrangements and will broaden the scope of gas-to-gas competition.

4. Providing firm transportation to California will require the coordinated allocation of capacity on both the systems of the California utilities and on the interstate pipelines which serve the state.

5. There may soon be opportunities, in the form of settlements of pending pipeline cases, to obtain the FERC concurrence necessary to implement a capacity allocation mechanism.

6. A program which allocates firm capacity may help to calm many of the current debates over the structure of the utilities' procurement activities.

7. Such a program is administratively feasible.

8. The administrative burdens of implementing a capacity allocation program will be less if we do not make the utilities change their procedures twice - once for an "interim" program and again for a "final" program.

9. The principles which PG&E proposes, as stated in the body of this opinion, are appropriate for the capacity allocation program which we would like to see implemented.

10. As the specificity of the capacity allocation increases, so will its administrative complexity.

11. The following are major issues which must be decided in the design of a capacity allocation mechanism:

a) How specific should the allocation be?

b) How much flexibility should the utility have in its use of pipeline capacity to serve the core portfolio?

c) What terms and conditions are necessary to attach to assigned capacity?

d) How should parity of access for wholesale core loads be implemented?

e) How should we treat, for ratemaking purposes, revenues from a capacity allocation mechanism?

f) How will such a program satisfy the statutory requirements of Public Utilities Code Sections 454.7 and 2771-2772?

g) How should the program treat customers with long-term transportation contracts signed after December 3, 1986?

h) Is a secondary market for capacity appropriate?

i) How much should core elect customers pay for the high priority access to pipeline capacity which they receive?

12. The core elect option has provided benefits to all gas consumers and should be retained, pending the development and implementation of our capacity allocation mechanism and further experience with how the gas market develops.

13. Curtailing EOR steamflood loads ahead of UEG usage could raise costs to electric ratepayers.

Conclusions of Law

1. The FERC is likely to be receptive to allowing California to develop a capacity allocation program.

2. A capacity allocation mechanism which coordinates both intrastate and interstate capacity will require at least FERC concurrence in the settlements of ongoing pipeline cases.

3. The California utilities should be ordered to work to obtain such approvals in these cases.

4. The "interim" buy/sell proposal of CIG and Salmon/Mock may conflict with NGPA Section 311 rules and with FERC standards for non-discriminatory transportation.

5. If the utilities relinquish their firm pipeline capacity rights, they may lose them permanently.

6. A capacity allocation program must meet the requirements of Public Utilities Code Sections 454.7 and 2771-2772.

7. EOR steamflood customers should be assigned to Priority 5.

8. This decision should be made effective immediately in order to have a capacity allocation program ready to implement once the necessary FERC concurrence is secured in the pipeline cases. These cases are now in the settlement process.

INTERIM ORDER

IT IS ORDERED that Pacific Gas and Electric Company and Southern California Gas Company shall file, within 60 days from the effective date of this decision, detailed proposals, in the form of written testimony, for a market-based pipeline capacity allocation program. This program shall integrate the allocation of both intrastate and interstate pipeline capacity. These proposals shall follow the general principles set forth in this order, and shall address the major issues which this order has identified. PG&E and SoCal Gas shall work to obtain from the FERC, in current and future interstate pipeline general rate cases or gas inventory charge cases, the necessary concurrence to permit the implementation of their proposals. PG&E and SoCal Gas shall keep the Commission's Legal Division fully informed of the status of these efforts.

IT IS FURTHER ORDERED that PG&E and SoCal Gas shall assign EOR steamflood customers to End Use Priority 5.

This order is effective today.

Dated DEC 19 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners