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Order Instituting Rulemaking into natural gas procurement and reliability issues

Decision No. 92–07–025, Rulemaking No. R.88–08–018 (Filed August 10, 1988)

California Public Utilities Commission

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(See Appendix A for appearances.)

PANEL: [*1] Daniel Wm. Fessler, President; John B. Ohanian, Patricia M. Eckert, Norman D. Shumway, Commissioners

OPINION: OPINIONToday's decision adopts final rules for implementing brokering of firm interstate capacity using the transportation rights held by Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCalGas) on the interstate natural gas pipeline systems. The rules we adopt today are consistent with the more general capacity brokering program adopted in Decision (D.) 91–11–025 with minor changes required to accommodate the FERC's "capacity reallocation" rules.This decision adopts rules for certain rates and cost allocation matters, capacity curtailments and priority of service, certain operational issues, and core subscription services. It also addresses utility incentive proposals which would promote efficient use of existing pipeline capacity commitments. Among other things, today's decision:* Allocates "stranded" interstate capacity costs to all customers with a limit on the amounts which may be allocated to core customers;* Allocates to noncore transportation customers the costs associated with noncore transportation [*2] rate discounts;* Directs the utilities to reserve core subscription capacity using the coincident peak–month demand of both the core and core subscription classes;* Clarifies rules for core aggregators under the new capacity brokering programs;* Directs the utilities to curtail all utility electric generators (UEG) loads ahead of all cogenerator loads in each curtailment period; and* Declines to adopt an incentive mechanism for the utilities which would provide risks and rewards for management of interstate capacity.I. BackgroundFor several years we have stated our intent to develop capacity brokering programs for SoCalGas and PG&E. As described more fully in D.91–11–025, capacity brokering allows noncore customers and other shippers to use utility rights for firm transportation service over the interstate gas pipeline system. Brokering provides these gas shippers access to firm interstate transportation which they have not had in the past. We adopted the major elements of capacity brokering programs in D.91–11–025 and stated our intent to hold hearings on implementation issues. D.91–11–025 identified several outstanding implementation issues:* Unbundling intrastate [*3] and interstate rates;* Appropriate restrictions on full–requirements service;* Procedures for rotating customer curtailments;* An appropriate reservation of capacity for core subscription service for San Diego Gas & Electric Company (SDG&E);* Sales between customers of firm intrastate transportation in the event of a curtailment;* The costs of Pacific Interstate Transportation Company (PITCO) and Pacific Offshore Pipeline Company (POPCO) gas supplies and allocation of the costs of unmarketable supplies between core and noncore customers;* The extent to which PG&E's utility electric generator (UEG) should have access to California supplies and the nature of that access;* The appropriate allocation of unrecovered costs associated with core subscription and interstate pipeline capacity (unrecovered intrastate transportation costs were added to this list by D.92–02–042, denying rehearing of D.91–11–025);* The costs and benefits of PG&E enhancing its storage facilities;* Rules which integrate transportation–only service for core aggregation customers with capacity brokering policy; and* Incentives for assuring that utilities do not hold more interstate capacity than [*4] needed to serve their core loads.

This decision covers these issues and several related issues raised by the parties:* PG&E's proposal to include in rates the costs of 200 million cubic feet per day (MMcf/d) of capacity on the Transwestern Pipeline system;* PG&E's proposal to allocate firm surcharge revenues to all noncore customers;* Core subscription reservations;* Balancing services;* Timing of open seasons;* Priority over Line 300;* SDG&E's core subscription service;* Treatment of bids below 70 percent of the as–billed rate;* Secondary brokering of firm capacity;* Notice of UEG elections to cogeneration customers;* Rates for UEG and cogeneration customers;* Curtailments during periods of system overpressurization;*

Services to wholesale customers; and* Tariff filing and timing of implementation.The Commission will consider in subsequent hearings the wisdom of brokering intrastate capacity and whether existing arrangements between SoCalGas and its affiliates, PITCO and POPCO, should be changed to permit increased competition for related transportation and gas supplies.Numerous parties participated in hearings held on capacity brokering implementation [*5] issues. The following parties filed briefs:PG&ESoCalGasSDG&ESouthwest Gas Corporation (Southwest)Division of Ratepayer Advocates (DRA)Toward Utility Rate Normalization (TURN)California Industrial Group, California Manufacturers Association, and California League of Food Processors (CIG)Access Energy Corporation (Access Energy)City of Palo Alto (Palo Alto)City of Long Beach (Long Beach)City of Vernon (Vernon)California Department of General Services (DGS)Southern California Utility Power Pool and Imperial Irrigation District (SCUPP)Southern California Edison Company (Edison)California Cogeneration Council (CCC)Cogenerators of Southern California (CSC)Watson Cogeneration Company (Watson)McFarland Energy, Inc. (McFarland)Indicated ProducersState of New Mexico, Energy, Minerals and Natural Resources Department, and New Mexico State Land Office (New Mexico)California Gas Marketers Group (CGMG)El Paso Natural Gas Company (El Paso)Transwestern Pipeline Company (Transwestern)Kern River Gas Transmission Company (Kern River)II. Effect of FERC Actions on California Capacity Brokering ProgramsAs we stated in D.91-11-025, this Commission's [*6] capacity brokering program is subject to conditions which may be imposed by the FERC. On April 8, 1992, the FERC issued Order 636 which resolves outstanding issues relating to allocation of firm interstate pipeline capacity. n1

n1 Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Docket No. RM 91-11-000, et al., 59 FERC Paragraph 61,030 (1992).

In summary, the decision adopts guidelines for what the FERC now calls "capacity reallocation." Under Order 636, firm capacity holders may "release" existing capacity rights to the pipeline companies which will attempt to market the capacity. Alternatively, firm capacity holders may also market existing capacity themselves. If they undertake such "pre-arranged deals," the arrangements must be posted on the pipeline company's electronic bulletin board and are subject to a right of first refusal after other bidders have an opportunity to outbid the first deal. Both options make firm capacity holders liable for the tariffed costs of unmarketable capacity and require successful capacity bidders to contract directly with the pipeline company. [*7] Certain details of capacity reallocation would be worked out in the pipeline companies' "restructuring" proceedings. The pipeline companies serving California must submit proposals in these proceedings by the end of 1992.Order 636 does not conflict with the provisions of D.91-11-025 in which we adopted capacity brokering programs for PG&E and SoCalGas. That is, the utilities may broker capacity. n2 Under Order 636, the resulting "pre-arranged deals" will be subject to the posting and second bidding process to be held by the pipeline companies under the FERC's oversight. Additionally, Order 636 requires PG&E to become a firm transportation customer of Pacific Gas Transmission Company (PGT) even if PG&E does not exercise, by October 1, 1992, its conversion rights under 18 CFR Section 284.210, as directed in D.91-11-025. In light of the FERC's requirement that PG&E utilize firm transportation rights to transport gas once PGT has complied with the FERC's Order 636, we find the requirement in D.91-11-025 - that PG&E convert the remainder of its firm sales rights to firm transportation rights by October 1, 1992 - to be unnecessary. We will therefore modify D.91-11-025 to omit this [*8] October 1, 1992 conversion requirement.

n2 Order 636 states that it rejects "capacity brokering" programs. In so stating, the FERC makes clear that it is rejecting programs which local distribution utilities and state regulators oversee from start to finish in favor of programs which are ultimately subject to FERC jurisdiction. Order 636 does not, however, prohibit the local distribution utilities from making "pre-arranged deals" which are then subject to a second bidding process under the control of the pipeline. Capacity brokering, as we have called it, is one method of soliciting "pre-arranged deals." We therefore do not depart from our requirements that the utilities engage in nondiscriminatory open seasons to broker capacity in order to enter into the pre-arranged deals to be posted in the pipelines' electronic bulletin boards. For the sake of simplicity, we will continue to call our program "capacity brokering" even though arrangements which evolve from the program are subject to a second round of bidding after arrangements posted by the pipeline companies. We refer to the FERC's program as "capacity reallocation."

Although Order 636 does not appear inconsistent with [*9] the essential provisions of our adopted program, its issuance does require reconsideration of the timing of capacity brokering. Order 636 mandates implementation of capacity reallocation programs prior to the 1993-1994 heating season. The FERC's timetable, however, does not preclude earlier implementation in cases where a pipeline company has an approved program. Order 636 in fact encourages earlier implementation. Under the circumstances, earlier implementation may be possible for at least one pipeline company serving California.On March 3, 1992, Transwestern submitted to the FERC a settlement which was joined by this Commission and others, and which if approved by the FERC, would set into motion capacity allocation over Transwestern by Fall 1992. n3 The settlement proposes a program that is essentially consistent with the rules adopted in Order 636 and D.91-11-025. On May 11, 1992, the Commission filed a motion for speedy approval of the settlement in order that California may move forward with capacity brokering over Transwestern. If the FERC approves the settlement in the near future, capacity reallocation over Transwestern may be possible during 1992. Capacity reallocation [*10] over El Paso and PGT, however, is unlikely to take place this year. It is possible, however, that the FERC would approve a capacity reallocation program on one of those pipelines before the other. In such cases, the Commission must decide whether to introduce capacity brokering on only part of the interstate pipeline system used by SoCalGas or PG&E.

n3 Transwestern Pipeline Company, FERC Docket No. CP88-133-004.

If the Commission were to order capacity brokering over only one of the pipelines serving a California utility, the utility would operate with two sets of rules for noncore transportation services: one set would govern capacity over one pipeline and another which would govern the existing "buy-sell" arrangements between the utilities and customers seeking to move gas using the utilities' firm transportation.The parties do not comment on the specifics of how such a dual program would work, but they do make general comments. PG&E and CPA believe the Commission must await the FERC's final restructuring orders before it can move forward with capacity brokering. CGMC and CIG believe a dual program is unwise because it would be confusing to customers. Other parties, [*11] including SoCalGas, DRA, and Indicated Producers, believe that the Commission should keep an open mind regarding partial program implementation. SoCalGas, however, believes that a dual program may present insurmountable operational problems. DRA comments that further delays in capacity brokering will increase the risk of stranded investment.We do not wish to delay capacity brokering any longer than necessary. As time passes, the likelihood of stranded investment increases as new pipeline projects come on line. Capacity brokering may alleviate the risk of stranded capacity. We are not concerned that a dual program will cause inordinate customer confusion. As we envision a dual program, customers would merely have one more transportation option. We will therefore direct the utilities to implement capacity brokering over a single pipeline, if one pipeline company receives FERC authorization for capacity reallocation before the other pipeline company serving the same utility.All program changes established in D.91-11-025, and this order, will be deferred until a utility is able to broker capacity on one or more interstate pipelines. All program and ratemaking changes established [*12] in D.91-11-025, and this order, will be implemented for a utility that may, pursuant to FERC order, broker capacity on both pipelines (referring to El Paso and PGT for PG&E and to El Paso and Transwestern for SoCalGas). In cases where a utility may broker capacity on only one of its serving pipelines, the following rules would apply:The rules and services adopted in D.90-09-089, as modified, shall be retained with the exceptions set forth herein which pertain to services over pipelines for which capacity is brokered. Customers who do not wish to participate in capacity brokering retain their existing service options, and will be subject to the rules set forth in D.90-09-089, except as set forth below.The utility shall unbundle its noncore transportation rates for customers who commit to the utility's brokered interstate capacity. The rate for these customers shall include all costs associated with intrastate service, including any transition or stranded costs allocated to noncore transportation rates but shall not include interstate demand charges. Cost allocation principles adopted herein will also take effect.Customers who do not participate in capacity brokering will [*13] be billed according to rules adopted in D.90-09-089.Customers who successfully bid for brokered capacity or who can demonstrate a contractual commitment to a marketer, producer, or broker who has successfully bid for brokered capacity may abrogate outstanding commitments for bundled transportation services adopted in D.90-09-089. The contractual commitment must be for capacity brokered by the serving utility and for a period no less than the customer's remaining commitment to the utility for bundled service. Such customers may purchase intrastate service under any of the existing service levels which are to be unbundled, as set forth above."Buy-sell" arrangements adopted in D.90-09-089 will be eliminated over pipelines for which capacity brokering is in place.The rules adopted in D.90-09-089, as modified, will be eliminated for SoCalGas when capacity brokering is available over El Paso and Transwestern or when SoCalGas has relinquished all interstate pipeline capacity in excess of its core requirements, whichever comes first.The rules adopted in D.90-09-089, as modified, will be eliminated for PG&E when capacity brokering is available over El Paso and PGT or when PG&E has [*14] relinquished all interstate pipeline capacity in excess of its core requirements, whichever comes first.Finally, we will add one more provision for capacity brokering. Under Order 636, a utility holding pipeline capacity is ultimately liable for payments to the pipeline company for brokered capacity even in cases where a shipper using brokered utility capacity fails to pay the pipeline company. In order to protect utilities and their customers, we will require shippers who purchase brokered capacity to contract directly with the utility in addition to the pipeline company. A contract between the utility and the shipper shall specify the utility's rights against the shipper in a case where the shipper fails to pay the pipeline company for contracted transportation services.III. Rates and Cost Allocation

A. Unbundling Intrastate and Interstate RatesInterstate and intrastate transportation has been generally provided to most customers as a combined, or "bundled," service because few customers have been able to gain access to unbundled interstate transportation. Under existing rate structures, interstate demand charges that utilities pay pipelines for transportation [*15] are allocated to intrastate transportation rates. This rate design convention has not until recently been an important issue because few customers have been able to obtain interstate services independently from PG&E and SoCalGas. Customers who subscribe to a bundled transportation service are indifferent to how costs are allocated between intrastate and interstate pipeline transportation rates.Several new pipelines are under construction or have recently been placed in service, and customers now have the option to purchase interstate service from providers other than SoCalGas and PG&E. Such customers naturally do not wish to pay for the utilities' interstate demand charges as part of their intrastate rates.D.91-11-025 stated our intent to unbundle interstate demand charges from intrastate transportation rates so that customers who obtain their own interstate services do not pay "double demand charges." Unbundling interstate demand charges from intrastate rates also reduces the total cost of transportation to customers who purchase gas produced within California.In this proceeding, PG&E and SoCalGas presented illustrative rates which unbundle interstate demand charges from [*16] intrastate transportation rates. Their proposals were not controversial with the minor exception that SoCalGas included demand charges in its procurement rates. SoCalGas should change its rates to include demand charges only in transportation rates.

B. The Costs of PITCO and POPCO Gas Supplies and Allocation of the Costs of Unmarketable Supplies Between Core and Noncore CustomersD.91-11-025 directed SoCalGas to submit information regarding the costs of PITCO and POPCO gas. The information would permit the Commission to determine the extent to which PITCO and POPCO gas costs exceed market prices and to allocate those excess costs concurrent with unbundling transportation rates. The decision stated our intent to allocate those excess costs to all customers. Such an allocation is consistent with our past treatment of gas supply "transition" costs which cannot be recovered directly because of changes in industry structure.SoCalGas proposes that PITCO/POPCO costs should be determined in a manner consistent with the Minimum Purchase Obligation (MPO) concept, which we have used in cost allocation proceedings to identify gas costs which exceed the adopted Weighted Average [*17] Cost of Gas (WACOG) (see, for example, D.91-12-075). SoCalGas excludes from the calculation the cost of the PITCO/POPCO supplies themselves, federal offshore supplies, and other California supplies because these supplies are not competitive. It adds the average cost of El Paso and Transwestern capacity to reflect the fact that POPCO prices include delivery to the California border. SoCalGas proposes a change to the MPO calculation to reflect the increased value of California supplies which occurs when interstate demand charges are unbundled from intrastate transportation rates.SoCalGas testified that PITCO and POPCO gas costs exceed market prices by approximately $124 million annually. It proposes to allocate these costs between core and noncore customers on the basis of cold-year throughput.Edison, CIG, and Indicated Producers join with SoCalGas in recommending costs be allocated based on cold-year throughput.DRA and TURN recommend allocating costs on an equal-cents-per-therm basis, consistent with the Commission's treatment of other utility supplies which are no longer marketable.Discussion. We will adopt SoCalGas' estimate of excess PITCO and POPCO gas costs, but [*18] we will not modify the MPO because the matter is beyond the scope of this proceeding. This adjustment increases SoCalGas' MPO cost estimate by about $9 million to $17 million.PITCO and POPCO costs are clearly gas supply projects which are no longer marketable. They are, therefore, "transition costs" as we have defined such costs. Consistent with our treatment of other gas supplies which we designated "transition" costs in D.87-12-039, we will allocate the costs of PITCO and POPCO supplies on an equal-cents-per-therm basis.

C. The Appropriate Allocation of Unrecovered Costs Associated with Core Subscription, Intrastate and Interstate Pipeline CapacityA major source of contention in this proceeding was the allocation of unrecovered costs associated with what we call "stranded" capacity, that is, transportation service which cannot be marketed at the full cost of the service. Such stranded capacity can occur on the interstate system and intrastate system for any of several reasons. Interstate capacity now held by the utilities could become stranded because it is less attractive to shippers than newly constructed capacity. In 1992, at least two new major pipelines, [*19] the Mojave Pipeline and the Kern River Pipeline, have commenced providing service. The addition of this new capacity has reduced demand for existing transportation capacity held by SoCalGas and PG&E on the El Paso and Transwestern systems.An additional reason for stranded capacity cost is FERC policy which prohibits the utilities from charging more than the pipeline companies' tariffed rates for brokered interstate capacity. This limitation is referred to as the "as-billed cap." FERC policy does not prohibit the utilities from discounting from tariffed rates. The combination of the as-billed cap with the ability to discount almost assuredly creates a revenue shortfall for brokered interstate capacity.Stranded capacity could also occur as a result of the reservation of transportation capacity for core subscription customers. D.91-11-025 directed the utilities to set aside enough capacity to provide core subscription service to all customers who choose the service in the first open season. Stranded costs could occur if demand for the core subscription service declines in subsequent years or if the utilities are unable to broker excess core subscription capacity in off-peak [*20] periods.Finally, the fully allocated costs of serving intrastate transportation customers could be underrecovered because interruptible intrastate transportation rates are set at cost and may be discounted to individual customers.These cost allocation issues are addressed more fully below.1. Unrecovered Interstate Revenue RequirementAs discussed above and in D.91-11-025, FERC policy provides that brokered capacity may not be priced at a level which exceeds the pipeline company's tariffed rate (the "as-billed cap"). When capacity is constrained, the as-billed cap would be unlikely to cause an underrecovery of revenues because customers would be willing to pay the full rate for capacity. However, we anticipate considerable excess capacity in future years which will drive down the value of existing capacity. Because of these circumstances, the utilities are unlikely to recover the full amount which they must pay to the pipelines for the capacity. D.91-11-025 stated our intent to consider how these "stranded" costs should be allocated among customers.SoCalGas, PG&E, SCUPP, CGMG, Kern River, and CIG propose that all customers bear stranded interstate transportation costs; [*21] this would be accomplished by allocating demand charges on a cold-year basis. These parties argue that requiring noncore customers to bear all of the costs of stranded investment will promote bypass and that noncore customers did not cause the stranded investment problem and should, therefore, not alone bear the burden of the costs.DRA and TURN argue that noncore customers alone should bear the costs of stranded interstate capacity. TURN suggests that if the Commission requires the core to share the costs of stranded investment, it do so by allocating those costs on an equal-cents-per-therm basis. It suggests core customers' liability for these costs be limited to 10% of the total capacity held on each pipeline. TURN proposes 10% because the Commission identified this percentage in D.90-02-016 as a reasonable amount of system "slack" capacity.Discussion. In D.91-11-025, we established reasonable reservations of interstate capacity for the utilities' core customers. The reservations were, generally, based on peak core demand so that some capacity will be unused during off-peak periods. Remaining capacity is reserved for noncore customers (including core subscription customers). [*22] Capacity for both the core and noncore customers may become stranded because it cannot be brokered at the full as-billed rate.No party to this proceeding has proposed that the noncore share costs of "excess" interstate capacity reserved by the core even though there is ample evidence to suggest that core customers will be paying "excess" costs. The core will pay a premium for reliable service by bearing 100% of the cost of a large reservation of interstate capacity. PG&E's core reservation is about twice the core's average annual demand. SoCalGas' core reservation is about 20% higher than average annual demand.As TURN suggests, the core would probably be better off reserving a "baseload" of firm capacity and bidding with other customers for brokered capacity. At this point, such a policy is not an option because we have established core reservations. We recognize, however, that the core reservations we adopted allocate substantial risk to the core. Accordingly, core customers are not insulated from stranded costs.Although no party proposes that the noncore share the stranded costs associated with the core reservation, several parties suggest that core customers should [*23] share the cost of stranded capacity which has been historically used to serve noncore customers (albeit, on a less reliable basis for low-priority customers). We have stated many times our view that the core class should share the costs of a program or investment from which it benefits. Some parties to this proceeding have proposed that the core class should bear a share of stranded costs because the core will benefit from additional competition which would result from capacity brokering. We agree that competition in noncore markets may ultimately benefit the core. However, we have no evidence that the core will benefit from capacity brokering. In fact, the evidence suggests that capacity brokering by itself is likely to increase the risk and cost of gas service to the core.Capacity brokering is a method of improving the access of noncore customers to firm interstate transportation capacity and to less expensive gas supplies. In order to improve access for the noncore, the core must give up access that it has had in the past. That is, the utilities have purchased core supplies in basins where prices are lowest. The utilities' flexibility in purchasing the lowest cost supplies [*24] has been generally unfettered by considerations of noncore purchasing. With capacity brokering (and also to some extent under the rules adopted in D.90-09-089), the utilities will not have the flexibility they have had to buy the least expensive gas supplies for the core. This reduced flexibility which will persist at least in the short term will probably mean higher gas prices for the core.In addition to this, we have no evidence that capacity brokering will, by itself, drive down the price of gas generally even though the noncore will have access to less expensive supplies. To the contrary, capacity brokering increases the nubmer of potential buyers in the market. An increase in buyers generally increases the competition between buyers for supplies, a circumstance which improves the negotiating position of sellers. While we cannot conclude that gas prices will in fact rise because of changed circumstances in California, we certainly cannot conclude that capacity brokering will force gas prices down. The increased competition spurred by capacity brokering, therefore, does not appear to offer any benefits to the core in terms of lower gas prices.At the same time, capacity [*25] brokering alone will not improve the position of the core, we recognize that capacity brokering is not the cause of excess capacity. As CIG points out, the reasons for excess capacity are many and include FERC and Commission decisions to "let the market decide" how much new capacity should be constructed and delays in implementing capacity allocation programs which would promote more efficient use of the existing system. Thus, it is not capacity brokering which is the cause of excess capacity and associated stranded costs.We have consistently stated our intent that rates should better reflect costs. In this case, we cannot allocate to interstate customers the costs of stranded interstate investment primarily because of the as-billed rate cap adopted by the FERC. Instead, we must impose associated unrecovered costs on customers of intrastate services.Determining who imposed the costs of the system is largely a matter of perspective. From CIG's standpoint, noncore customers are not responsible for stranded costs because the costs are associated with excess capacity which results from conditions over which individual customers had no control. From TURN and DRA's standpoint, [*26] the core is already overburdened by the reservation adopted in D.91-11-025. It appears that both are correct.Because no specific class of customers is responsible for stranded costs, we will allocate some of those costs to all customers. In light of the substantial benefits to the noncore which arise from the implementation of capacity brokering and other related actions we take today, we will change the existing allocation somewhat. As TURN suggests, we will direct the utilities to allocate stranded interstate costs to all customers on an equal-cents-per-therm basis. The limit of the core class' liability for these stranded costs is the cost of 110% of existing capacity held for the core class on each pipeline. Because we have found that amount to be a beneficial level of slack capacity, we believe 10% is a reasonable figure for determining the core class' responsibility over and above the capacity held to serve the core during peak periods. This cap would limit the core's annual liability to the cost of 107 MMcf/d on SoCalGas' system and 120 MMcf/d on PG&E's system, in addition to the reservations already allocated to the core. This cost allocation will apply to all core [*27] and noncore transportation customers, including contract customers (except those whose contracts have fixed prices), consistent with D.91-11-025. It will also apply to the core and noncore loads of wholesale customers because we see no logical distinction between those customers and any others for purposes of allocating stranded costs.This cost allocation procedure will apply to core subscription service. Rates for that service shall also include all stranded costs incurred with a given 2 year reservation period, consistent with D.91-11-025, which found that core subscription service should be cost-based. However, it should be clarified, as stated in our November policy decision, that an open season will be held every two years, during which time a new core subscription reservation will be established for each utility in part due to the Commission mandated step-down of core subscription by the UEG departments for combined gas and electric utilities. As a result of a new open season, any excess capacity would be available for brokering with any resulting stranded costs treated the same as other stranded costs and allocated to all customers as discussed above.As CIG suggests, [*28] we will not include in rates forecasts of stranded interstate costs at this time. Considering the changes taking place in the interstate gas markets, forecasts are so speculative as to be meaningless. D.91-11-025 established that stranded costs would be recovered by way of a surcharge termed the Interstate Transition Cost Surcharge (ITCS). We will direct the utilities to include stranded costs in their ITCS accounts for recovery under established ratemaking mechanisms.2. Noncore Discounting of Intrastate TransportationWe have long recognized that utilities may need to negotiate discounts from default tariff rates for some noncore customers. Starting with the Commission's 1987 implementation decision in the rate design phase of the gas industry restructuring (26 Cal. PUC 2d, 213 (1987)), the policy has been to recognize that such negotiated rates benefit all customer classes by retaining load and increasing revenue contribution over what it would be otherwise. As such, discounting rates for some noncore customers has been viewed as generating incremental revenues which would not otherwise be recovered at default tariff rates. The effect is to benefit all customer classes [*29] by spreading the fixed costs of the system over a larger base.This policy has been affirmed in subsequent Annual Cost Allocation Proceedings (ACAPs) for both PG&E and SoCalGas (see e.g. 36 Cal. PUC 2d, 148 (1990) and 38 Cal. PUC 2d, 77 (1990)). Except for TURN, all parties who addressed this issue, including DRA, supported retention of the current revenue allocation associated with discounted rates.We are not pursuaded to recast this issue as "unrecovered intrastate revenue requirement" and as such restrict revenue requirement responsibility to the noncore class. There is no evidence in this proceeding to suggest that rate discounts to certain noncore cutomers are harmful to other ratepayers or result in any subsidization of noncore rates. A simple rhetorical recasting of the issue does not justify a change in Commission policy. We will retain the existing Commission policy that finds discounts to default tariffed rates for certain noncore customers have system benefits and, as such, the revenue requirement impact should be allocated over all customer classes.3. Brokering Excess Capacity and Allocation of Revenues from Capacity BrokeringCapacity allocated to both [*30] core and noncore customer classes will be brokered as it becomes available (for the core, capacity will be brokered during off-peak periods). We must determine how to allocate revenues or billing credits resulting from brokering among core, core subscription, and noncore classes.PG&E proposes that all revenues acquired from brokering be allocated first to the noncore. Remaining revenues would be allocated to core and core subscription customers on a pro rata basis. PG&E explains its position by stating that an allocation to the noncore first will minimize stranded costs. SoCalGas makes a similar recommendation by proposing that excess noncore capacity be brokered before core capacity is brokered.We do not understand PG&E's argument that allocating brokering revenues to noncore customers will minimize stranded costs. We can only assume that, by definition, such an allocation will minimize stranded costs to the noncore rather than the core.Our role is and has always been the protection of customers who do not have options to utility services and who would, without regulatory oversight, be subject to unfair pricing and inadequate levels of service. We would not burden the [*31] core class by directing the utilities to reduce the liability of noncore customers ahead of captive core customers without a showing that core customers would be better off, for example, by mitigating bypass. No party has made such a showing. We will, as TURN suggests, direct the utilities to broker core, core subscription, and noncore capacity on a pro rata basis and to allocate associated credits to each of the classes accordingly. "Pro rata" in this instance is defined as a proportionate share of capacity on each pipeline, e.g. for PG&E, 10% of total capacity commitments on El Paso and 10% of total capacity commitments on PGT.At TURN's suggestion, we also make explicit our intention that the utilities, on behalf of core customers, may purchase brokered capacity in the same manner as any other market participant. Although we do not foresee a need for such purchases at this time, it was not our intent in D.91-11-025 to preclude this option.

D. PG&E's Proposal to Include in Rates the Costs of 200 MMcf/d of Capacity on the Transwestern Pipeline SystemIn D.91-11-025, we adopted for PG&E a reservation of 1200 MMcf/d of interstate capacity for the core. Half of the capacity [*32] would be over the El Paso system, half over the PGT system. During the course of these hearings, PG&E presented evidence that it had entered into an agreement with Transwestern which would provide it with 200 MMcf/d of firm access to the San Juan Basin on the Southwest system. It appears that the agreement is final, pending resolution of outstanding applications for rehearing before the FERC.PG&E believes that securing the additional Transwestern capacity will increase competition on the pipelines and thereby reduce gas prices enough to offset the additional demand charges. PG&E proposes that the core bear the costs of 150 MMcf/d of capacity over the Transwestern system. The remaining 50 MMcf/d of Transwestern capacity would be allocated to PG&E's electric department. Although the core would bear the costs of the new capacity, the core would not be entitled to more than the existing 600 MMcf/d of capacity at the border. PG&E advocates inclusion of the costs of the capacity in core and core subscription rates, subject to reasonableness reviews. Transwestern supports PG&E's proposal.PG&E proposes to substitute Transwestern capacity for El Paso capacity for the core and PG&E's [*33] electric department. Kern River opposes this substitution, arguing that the result would be further constraints on taking Southwest gas over Line 300 and increased stranded capacity. Kern River also states that if the costs associated with stranded Transwestern capacity were included in noncore rates, new pipeline customers would effectively subsidize PG&E's Transwestern commitment. Indicated Producers, DGS, and CIG also argue that noncore customers should not bear the costs of the Transwestern capacity.TURN objects to core customers bearing all of the risk for the new capacity except that TURN does not object to including a pro rata share of the capacity as part of the existing core reservation of 1200 MMcf/d. DRA objects to any rate recovery of the Transwestern costs, recommending that the costs be included in a memorandum account subject to reasonableness review. El Paso takes a similar view, arguing that PG&E's Transwestern commitment is so unlikely to be cost-effective that no cost recovery should be permitted until after a finding of reasonableness.Discussion. The Transwestern capacity to which PG&E has committed may increase competition among suppliers for sales [*34] to California customers. The evidence in this proceeding, however, does not allow us to draw any conclusions regarding whether the additional $24 million in demand charges will be offset by lower gas prices in an amount sufficient to make the commitment cost-effective.We are especially concerned about PG&E's new commitment in light of system constraints. "Take-away" capacity for transporting Southwest gas is currently limited to that which is available over Line 300, PG&E's intrastate pipeline which connects to the El Paso and Transwestern system. Line 300 cannot move more gas than PG&E already receives from the El Paso system. Without an expansion of Line 300, therefore, 200 MMcf/d of additional Southwest capacity will be stranded whether or not there is demand for it.D.91-11-025 stated that the implementation hearings in this proceeding would not be a forum to consider changes to the rules adopted in that decision. For that reason, PG&E's proposal to allocate a share of the Transwestern capacity to the core is outside the scope of this proceeding. However, the allocation of associated costs is a matter we will address.In D.91-07-007, we declined to pre-approve the contract [*35] between PG&E and Transwestern, thereby putting PG&E at risk for the capacity. Earlier, in D.90-02-016, we stated that additions to capacity would be considered in light of market demands. Both of these decisions suggested that PG&E would take the risk for the capacity to which it has now committed on Transwestern's system.We decline to include in either core rates or noncore rates the costs of PG&E's commitment to additional capacity over Transwestern's system. PG&E may enter the costs into its balancing account. We will review those costs in PG&E's next gas reasonableness review. If, as PG&E argues, the capacity will pay for itself by way of reduced gas costs, PG&E should be confident that it will recover the demand charges associated with the Transwestern capacity.

E. PG&E's Proposal to Allocate Firm Surcharge Revenue to All Noncore CustomersIn Rulemaking (R.) 90-02-008 we established firm and interruptible service levels. The firm service rate included a surcharge which was to be subsequently redistributed to interruptible customers.PG&E now proposes to allocate these surcharge revenues to all noncore customers. This is a matter which is beyond the scope of [*36] this proceeding. We see no reason to change a policy which was the subject of substantial debate in another proceeding. Surcharge revenues should be credited to the bills of customers who subscribed to interruptible (Service Level (SL) 3 through SL-5) during the previous period.

F. Rates for UEG and Cogeneration CustomersCCC objects to the cogenerator rates proposed by SDG&E and PG&E. According to CCC, SDG&E, and PG&E's cogenerator rates do not implement the provisions of D.91-11-025, in which the Commission directed the utilities to set cogenerator rates equal to UEG rates (rates for sales of gas to the utility's electric department) on a service level basis. CCC observes that these cogenerator rates average in the cost of core UEG igniter fuel charges even though the UEG's noncore rates do not include any core charges. SDG&E's cogenerator rates also include discounts its UEG might get for taking interruptible service.On a related issue, PG&E and CCC filed a joint stipulation in this proceeding regarding the appropriate methodology for setting Schedule G-PO3 rates for cogenerators who sell electricity to PG&E under Energy Payment Option 3 of Interim Standard Offer [*37] 4 contracts.We agree with CCC that PG&E and SDG&E should calculate cogenerator rates equal to UEG rates on a service level basis and will direct them to modify their rates accordingly. No party objects to the joint stipulation of PG&E and CCC regarding the method for setting the Schedule G-PO3 rates, and we will adopt it.IV. Curtailments and Priority

A. Procedures for Rotating Customer CurtailmentsD.91-11-025 adopted a settlement provision that firm noncore customers would be curtailed on a rotating basis. We stated, however, that the specific procedure for rotating customer curtailments should be nondiscriminatory. With that in mind, we directed the utilities to present a description of how they would order customer curtailments.Two issues arose over curtailment order. PG&E proposes to place portions of its UEG's demand in each of five rotating blocks, and to place cogenerators in five additional rotating blocks. Apparently, it would go through the first five blocks before curtailing cogenerators, but would curtail cogenerators ahead of its UEG when the UEG has been curtailed in previous curtailment episodes. CCC opposes PG&E's proposal because it is contrary [*38] to D.91-11-025 and would permit UEGs to be served ahead of cogenerators during some curtailment episodes. D.91-11-025 addressed this issue in several ways. We do not need to revisit the issue here except to say that where UEGs and cogenerators pay the same percentage of default rate, cogenerators will always receive priority ahead of UEGs. PG&E misconstrues D.91-11-025. When the cogenerator pays the same or higher percentage of default rate, the utilities shall curtail all of their UEG volumes ahead of any cogenerator volumes in each curtailment episode. They should modify their tariffs accordingly. We comment that nothing in this decision should be construed to permit the utilities to curtail industrial customers ahead of cogenerators except as provided in D.91-11-025.The second issue regards SoCalGas' proposal to curtail the largest customers first on the basis that it may need to divert large quantities of noncore gas on short notice. Indicated Producers argue such a practice would be discriminatory and that SoCalGas has not explained how circumstances have changed to warrant a change in curtailment policy. We agree with Indicated Producers that SoCalGas should endeavor [*39] to curtail customers on a rotating basis except, of course, in emergency situations where core service might otherwise be jeopardized.

B. Sales of Firm Intrastate Transportation Between Customers in the Event of a CurtailmentD.91-11-025 did not adopt a brokering mechanism for intrastate capacity. It did, however, direct the utilities to submit proposals whereby customers with firm intrastate service could negotiate their priority with other customers in the event of a curtailment. SoCalGas proposed that intrastate customers be permitted to transfer or reallocate required gas diversions among themselves. SCUPP and TURN support SoCalGas' proposal.We agree that SoCalGas' proposal promotes a more efficient use of the system by allowing customers who place a high value on reliability to negotiate the order of diversions with other customers. We will adopt SoCalGas' proposal and will direct PG&E to offer a similar opportunity to its large intrastate transportation customers. PG&E's proposal to require 72 hours notice is rejected in cases where the assignment takes place between customers actually using the gas. We also reject PG&E's proposed requirement that a customer [*40] using less than 5 MMcf/d must assign all of its firm rights.

C. Priority Over Line 300PG&E proposes to give priority for transportation over its Line 300 to interruptible intrastate shippers using the El Paso system, or those who substitute new capacity for El Paso capacity, over firm intrastate shippers using the Kern River system. It defends this proposal on the basis that it minimizes stranded costs by improving the value of El Paso capacity.TURN objects to PG&E's proposal. TURN argues that firm customers should have priority over interruptible customers and that PG&E's proposal is discriminatory.We agree with TURN that PG&E provides no sound basis for discriminating between gas supplies transported over the various pipeline systems. We comment that Line 300 would not be constrained if PG&E had not committed to 200 MMcf/d of Transwestern capacity which, coincidentally, PG&E proposes to use as a substitute for El Paso capacity. We will direct PG&E to take volumes into Line 300 on behalf of customers according to the rules we have adopted, notwithstanding which pipeline company transported the gas.

D. Curtailments During Periods of System Overpressurization [*41] SoCalGas explains that situations may arise when SoCalGas must refuse to accept gas from interstate pipelines even though it has sufficient intrastate capacity to receive the gas. If this situation occurs under conditions of excess supply (when storage is nearly full and injection capacity is low), pressure on the system could become dangerously high. SoCalGas proposes in such situations to reduce nominations on a pro rata basis according to priorities on the interstate pipeline system. To offset any inequitities under such circumstances, it would waive resulting imbalance charges.Edison and SCUPP oppose SoCalGas' proposal, arguing that nominations should be reduced based on "customer-specific actions" rather than pro rata. Edison believes this alternative basis for reductions will be available soon when electronic metering technology is installed, allowing SoCalGas to determine which customers have over-nominated supplies.SCUPP also asks the Commission to confirm the curtailment order proposed by the SoCalGas witness:Deliveries to storage under the G-STOR tariff;Standby service for interruptible customers;Standby service to firm noncore transmission service customers; [*42] Interutility transportation service;Interruptible transportation service; andFirm noncore transportation service.SDG&E also opposes SoCalGas' proposal, stating that the proposal will not ensure that shippers with firm intrastate service will have their gas delivered first even though the problem is on the intrastate system. Instead, it will ensure that shippers who have purchased brokered interstate capacity from SoCalGas will have their gas delivered firm, regardless of whether they have firm intrastate service. SDG&E suggests curtailments be ordered on a pro rata basis according to the percentage of default rate paid by intrastate customers.We will adopt SCUPP's proposal. Instead of reducing deliveries pro rata, overpressurization problems should be resolved by requiring customers who are causing a system imbalance to reduce their deliveries into the system. Excess deliveries, i.e., positive imbalances, into the SoCalGas system should be handled in the same manner as curtailments of "standby service" and "buy-back service" are presently handled under SoCalGas' Rate Schedule No. G-IMB.We will also adopt SCUPP's proposed order of curtailment.V. Core Subscription [*43] Service

A. Appropriate Restrictions on Full-Requirements ServicePG&E proposes to differentiate between full-requirements and partial-requirements core subscription customers for the purpose of recovering interstate demand charges. PG&E proposes demand charges and penalties for partial-requirements customers which it would not apply to full-requirements customers.New Mexico objects to this proposal on the basis that it would unreasonably induce customers to become full-requirements customers. Similarly, Indicated Producers object to the utilities' proposed core subscription rate design, which is primarily volumetric. Indicated Producers believe that under such a rate design, core subscription service will be artificially attractive because individual customers may not pay the full as-billed rate for service. As a result, according to Indicated Producers, nonutility shippers will be placed at a relative disadvantage.Discussion. We share New Mexico's concerns that imposing restrictions on partial-requirements customers which do not apply to full-requirements customers may be unreasonably discriminatory. We, therefore, reject the proposed differentiation. The [*44] utilities' rate design for partial-requirements customers shall be the same as the rate design for full-requirements customers.As for the core subscription rate design, we respond to Indicated Producers' concerns by observing that under any rate structure, the core subscription class as a whole will pay the as-billed rates for service. We respond further to the concerns of New Mexico and Indicated Producers in the discussion on core subscription reservations below.

B. Reservations of Core Subscription Capacity for PG&E and SoCalGasPG&E proposes to base its core subscription reservation of transportation capacity on the aggregate peak-month demand of customers who sign up for the service. TURN argues that a more efficient use of the capacity would be for PG&E to reserve enough capacity for the coincident peak-month demand of both the core and core subscription classes. TURN believes the total capacity reservation for those two classes would be reduced by 181 MMcf/d compared to PG&E's proposal. DRA opposes TURN's proposal on the basis that core subscription rates would be artificially lower because of its use of core capacity, making the service more attractive but not [*45] recovering its full cost of service.SoCalGas proposes to reserve capacity based on the coincident peak-month demand of both the core and core subscription classes, as TURN proposes for PG&E.Discussion. We agree with SoCalGas and TURN that basing core subscription reservations on the coincident peak month for the core and core subscription services promotes an efficient use of interstate capacity. It makes little sense to develop separate capacity reservations for the two customers classes when those customer classes are purchasing gas from the same portfolio. Combining the core and core subscription reservations will reduce risk to the core during the core subscription peak month. SoCalGas' and TURN's proposal may also result in lower rates to the core subscription class and reduce the risk of stranded capacity allocated to the core subscription service.Some parties believe the effects of combining the core and core subscription demand will be to make core subscription artificially attractive. We do not agree that this is necessarily the case when the proposal is considered in combination with other policies we adopt today. The risk of stranded investment for PG&E's [*46] core subscription customers is substantial because D.91-11-025 established a schedule to phase out PG&E's electric department option to take core subscription service. We have allocated to core subscription rates all of the costs association with stranded investment of core subscription capacity.We will adopt the proposal of SoCalGas and TURN to combine the core and core subscription reservations. This will assure the most efficient use of core capacity and keep costs down for both the core and core subscription classes. In order to assure that core subscription customers pay the full costs of service, we also adopt a proposal offered by CGMG that each core subscription customer will pay a reservation charge that is based upon the customer's proportionate share of the full amount of the interstate capacity that the utility has reserved for the entire core portfolio. The reservation charge would apply to both full-requirements and partial-requirements customers.

C. An Appropriate Reservation of Core and Core Subscription Services for SDG&ED.91-11-025 did not adopt a core subscription reservation for SDG&E, deferring the issue to these later hearings. SDG&E states it [*47] will reserve core subscription capacity pursuant to its open season. No party objects to this proposal, and we will adopt it. We also adopt as reasonable SDG&E's core reservation of 90 MMcf/d of capacity from SoCalGas.

D. SDG&E's Core Subscription ServiceSDG&E proposes to limit its core subscription service to customers who use less than 7 MMcf/d. Its UEG, which uses more than 7 MMcf/d, would be exempt from this condition.CCC objects to this restriction as discriminatory because it would permit SDG&E's UEG to qualify for core subscription but deny the service to a handful of cogenerators. D.91-11-025 rejected such limitations on core subscription service and preferences for UEGs over cogenerators. We will not adopt SDG&E's proposal to limit core subscription service on the basis of customer demand.VI. Other Service and Operational Issues

A. The Extent to Which PG&E's Electric Department Should Have Access to California Supplies and the Nature of that AccessD.91-11-025 stated our intent to consider whether PG&E's UEG should have access to California supplies and also the nature of that access. The regulatory treatment of PG&E's UEG has been an issue [*48] of some controversy during these proceedings because of a concern by some that PG&E gives special deference to its UEG at the expense of other customers.PG&E proposes that its UEG have access to California supplies equal to that of any noncore customer. DRA supports PG&E's position.CIG opposes PG&E's unrestrained access to California supplies. CIG observes that PG&E's gas department purchases gas on behalf of PG&E's UEG. Under the circumstances, PG&E will have superior access to information about the producers, their contracts, and their contracting procedures. CIG recommends that PG&E's UEG be prohibited from taking California gas until and unless it contracts for such supplies separately from PG&E's gas department. DGS expresses similar concerns and suggests that the Commission order PG&E's UEG to conduct its own gas purchasing except for volumes purchased under the core subscription service.Discussion. We remain concerned that PG&E's UEG not receive preferential access to California supplies. D.91-11-025 required PG&E to purchase gas supplies for its UEG separately from those purchased for the utility system except where PG&E would otherwise avoid penalties in existing [*49] contracts. We trust that PG&E is complying with this restriction, even though its gas department may act as agent for its UEG. We believe existing rules provide some protection against preferential access to California supplies. If any party believes PG&E is using its intrastate system to disadvantage a competitor of its UEG or noncore customers, generally we will entertain that party's proposals for further restrictions on PG&E's access to California supplies.

B. The Costs and Benefits of PG&E Enhancing its Storage FacilitiesD.91-11-025 directed PG&E to provide an analysis of enhancing its storage facilities. We did so to determine whether PG&E's core pipeline capacity reservation might be economically reduced with the addition of storage.PG&E presented bare-bones testimony which did not support expansion of storage facilities for core customers. In light of industry changes, PG&E seeks Commission guidance as to its obligation to provide storage services for noncore customers.We are considering in this proceeding the wisdom of expanded storage facilities in our investigation of the prospects for expanding Line 300. We, therefore, defer discussion of this matter [*50] to a later decision. PG&E's obligation to provide storage service to noncore customers is not a matter within the scope of this proceeding. We comment, however, that PG&E's obligation to noncore customers is changing as competitive access to gas supply facilities increases. Some parties have raised concerns that storage provided by nonutility entities may be available to customers, but will be useful only if the Commission establishes rules for access to that storage. At this time, access to nonutility storage facilities is a matter which requires further consideration in I.87–03–036. Utility obligations to provide noncore storage facilities are appropriately considered in that context.

C. Rules Which Integrate Transportation–only Service for Core Aggregation Customers with Capacity Brokering PolicyD.91–02–040 adopted rules to permit core customers to aggregate loads for purposes of purchasing their own gas supplies and subscribing to utility transportation services. D.91–11–025 directed the utilities to integrate these rules with their capacity brokering programs.Access Energy, representing the interests of "core aggregators," generally supports the utilities' proposals [*51] in this proceeding but suggests a few minor modifications:Capacity assigned to the aggregator should be able to be increased or decreased on a monthly basis to reflect additions to or deletions from the core transport load represented by the aggregator;The assignment of capacity to the aggregator should cover the full term of the services to be rendered by the aggregator under the program;Core aggregators must have the right to use available alternative capacity, in place of or in addition to the reserved space assigned to them; andCore aggregators should be able to avoid demand charges when they use available alternative capacity to the extent the utility is able to rebroker or reassign reserved capacity.CIG argues that a bundled interstate and intrastate service should not be made available to core aggregators because it is not available to noncore customers.In response to Access Energy's recommendations, PG&E comments that it will be unable to broker capacity on behalf of individual core aggregators and suggests those customers rebroker the capacity on their own using PG&E's electronic bulletin board.Discussion. We will adopt the utilities' proposals for core [*52] aggregators with most of the modifications proposed by Access Energy. In light of PG&E's comment that it cannot separate a single customer's capacity from the pool of capacity it holds, core aggregators should broker their own capacity rather than rely on the utilities to do so. At the suggestion of Access Energy, we also remind the utilities that they should anticipate that core aggregator programs may be extended beyond the pilot programs, which currently extend to July 31, 1994.Finally, we comment that the utilities' proposals to assign interstate capacity to core aggregators could jeopardize their capacity rights if they are outbid when the pipelines post their pre–arranged deals. If assigning capacity to core aggregators might jeopardize the reliability of their service or is in compatible with FERC rules, the utilities should design contracts for core aggregators which assure core aggregators will not be outbid during the posting period required under FERC rules, and consistent with other provisions adopted in this decision.

D. Balancing ServicesD.91–11–025 adopted balancing services, which provide noncore customers with utility backup supplies or storage when [*53] their actual deliveries do not match their nominations. In this proceeding, PG&E proposes to curtail balancing and standby services for interruptible customers ahead of balancing services for firm customers. SoCalGas makes a similar proposal. D.91–11–025 provided that balancing charges would be assessed only after customers over–or under–delivered volumes in excess of 10% of nominations.CIG does not oppose PG&E's proposal but suggests that tariff language permit balancing customers to stay within the 10% tolerance levels over the period when balancing service is curtailed before they are assessed penalties. Several parties oppose what they believed was a proposal by PG&E to curtail interruptible transportation service in order to provide balancing and standby service to firm transportation customers.We agree that balancing and standby services for interruptible customers should be curtailed ahead of the same services for firm customers. All balancing services, however, should be curtailed ahead of any transportation service. We will also direct the utilities to retain this 10% balancing tolerance during curtailment periods, as CIG suggests.

E. Secondary Brokering of [*54] Firm CapacityIndicated Producers, TURN, CIG, and CGMG propose that the utilities permit secondary brokering by shippers who wish to resell the capacity purchased from the utilities. The parties comment that the ability to rebroker capacity will assure a more efficient market and reduce stranded capacity by making that capacity more attractive.Although we have expressed our interest in secondary brokering, the utilities did not propose secondary brokering programs. We will direct the utilities to amend their proposed tariffs to provide for secondary brokering to the extent it would be consistent with FERC orders. Secondary brokering should be implemented concurrent with capacity brokering programs.

F. Notice of UEG Elections to Cogeneration CustomersD.91–11–025 directed the utilities to offer rate parity between UEG and cogeneration customers, and to notify cogeneration customers of UEG capacity reservations prior to the time the cogeneration customers would need to bid for capacity.SoCalGas proposes to notify cogeneration customers of the volume and term of each UEG election, but not the rate. The cogeneration customer could then specify in a "blind bid" whether [*55] it wished to take service at the same rate as the UEG. PG&E makes a similar proposal. Both PG&E and SoCalGas comment that it is unreasonable to provide the rate information in advance of the bid because it would provide cogenerators with a competitive advantage in procuring gas.CCC believes the utilities' proposals do not provide cogenerators with adequate information. It states that cogenerators cannot make bids without knowing the price of a contract, especially considering that UEGs pass along their costs dollar–for–dollar to their ratepayers.Following hearings, CCC and PG&E submitted a joint agreement on this matter. The agreement proposes that cogenerators have the option to engage in a blind bid, as SoCalGas proposed, or to submit an independent bid whose rate would match the UEG's rate if the UEG rate is lower for capacity in the same pool.We believe the joint agreement between CCC and PG&E is reasonable. SoCalGas' proposal does not, on its own, provide cogenerators with enough information for them to make informed choices about transportation purchases. We concur with CCC that UEGs may have little incentive to bid at the low end of a range of rates because UEGs [*56] may pass along their reasonable costs to ratepayers. We will adopt the provisions of the joint agreement and direct SoCalGas to submit tariffs which implement the provisions of the joint agreement between CCC and PG&E.

G. Services to Wholesale CustomersThe utilities proposed methods for assigning capacity to core loads of wholesale customers. PG&E proposes, among other things, to provide an initial set of options for wholesale customers to obtain capacity. If wholesale customers require additional capacity at a later date, their options will be the same as those available to other shippers. Southwest opposes PG&E's proposal to provide wholesale customers with an initial option and to then absolve itself of future responsibility for wholesale core loads. Palo Alto is concerned that PG&E might be able to curtail simultaneously all of the noncore load of a wholesale customer. Palo Alto proposes that PG&E negotiate with its wholesale customers the manner in which it will rotate curtailments of noncore customer loads.PG&E's method of providing service options to wholesale customers is reasonable. It would be inequitable to force other PG&E customers to bear the risk [*57] for future demands of wholesale customers.We agree with Palo Alto that it should be permitted to negotiate curtailments of its noncore loads with PG&E. We add a condition that a wholesale customer's noncore loads shall be subject to curtailments that are proportionate to those of other noncore customers. PG&E should amend its proposed tariffs accordingly.

H. Treatment of Bids Below 70 Percent of the As–Billed RateIn D.92–02–042, the Commission modified D.91–11–025 by eliminating a requirement that bids for interstate capacity be no lower than 70 percent of the as–billed rate. In response, PG&E proposes to include two clauses in its interstate capacity agreements that are designed to minimize the potential for stranded costs. One would allow PG&E to terminate the capacity agreement if PG&E ever receives relinquishment rights for the capacity. The other would allow PG&E to terminate the agreement if a bid were received at a higher rate than the rate in the contract. The current contract holder would have an opportunity to match the higher bid before its agreement is displaced.We appreciate PG&E's effort to minimize stranded investment by proposing these contract provisions. [*58] We are concerned, however, that they may have an effect that is opposite to what PG&E intends. That is, customers may find brokered capacity less attractive because of these contract provisions. We will permit PG&E to include a contract clause which provides that, in cases where PG&E has an opportunity to relinquish capacity, the customer has a choice of giving up the capacity or paying the full as–billed rate. This provides some protection against stranded investment, but is not likely to reduce dramatically the value of brokered capacity during the initial brokering period.VII. Incentives for Assuring that Utilities Do Not Hold More Interstate Capacity than Needed to Serve Their Core LoadsD.91–11–025 stated our interest in developing an incentive mechanism which would impose some risk of stranded capacity on utility shareholders and thereby encourage the utilities to hold no more interstate capacity than is required by core and core subscription customers.SoCalGas and PG&E oppose such an incentive mechanism. SoCalGas argues stranded capacity is likely to result from regulatory restructuring decisions, rather than those which are in control of utility management. [*59] It states the policies of the FERC and this Commission regarding new pipeline construction is to "let the market decide," a policy which has promoted the excess capacity which it now anticipates. SoCalGas also states the Commission and the FERC have not provided corresponding opportunities to permit the utilities to offer existing capacity to large customers. It points to the Commission's rejection of long–term contracts with large customers and the FERC's failure to approve capacity brokering certificates. SoCalGas believes it should not bear the brunt of these policies. PG&E points out that it has no control over its existing capacity commitments through 1997 on El Paso, and 2005 on PGT, and argues reasonableness reviews provide adequate incentives for relinquishing capacity when it is possible to do so.SoCalGas proposes that if the Commission adopts an incentive mechanism, it should be prospective in application. Specifically, SoCalGas proposes that any incentive mechanism be applied only to capacity acquired after the issuance of D.91-11-025, in which the Commission first signaled such an incentive might be appropriate. It suggests the incentive should provide opportunities [*60] for gain as well as the potential for losses and should recognize the benefits of 20% "slack" capacity.DRA, TURN, CIG, and New Mexico propose incentive mechanisms with risks ranging from 10-25% of associated revenues. The parties propose "slack" factors of 10-20%. TURN's proposal would provide the utilities an opportunity for reward by permitting them to retain 10% of the revenues they receive from brokering unused core and core subscription capacity. DRA has a similar opportunity for reward. Watson proposes that the utilities should get no balancing account treatment for stranded costs, even those which are found to be prudent.SCUPP proposes a more stringent set of rules by eliminating from TURN and DRA's proposal an initial allowance of capacity for which the utilities would not be at risk. SCUPP argues that an incentive mechanism is appropriate in that the utilities' rate bases will increase as a result of excess interstate capacity as they build additional intrastate capacity to accommodate increased demand. It reminds the Commission that the FERC has required the interstate pipeline utilities to share the risk of transition costs and recommends similar treatment here. [*61] New Mexico comments that adopting SoCalGas' proposal for applying an incentive only after D.91-11-025 is an empty gesture because of the improbability that any capacity will be added for many years. New Mexico proposes that at some point, the Commission phase out the ITCS which is designed to allow the utilities to recover stranded costs.Discussion. Considering the prospects for excess capacity, we would like to design an incentive mechanism which would encourage the utilities to relinquish or market capacity whenever possible. Any such incentive should be fair. SoCalGas convinces us that an incentive which applies to existing capacity commitments may not be fair. While we do not agree with all of SoCalGas' observations about the reasons for excess capacity, we recognize that regulatory policy and other circumstances beyond the utilities' control may have contributed to the abundance of pipeline capacity which is under construction, and which will affect the attractiveness of existing capacity. A prospectively applied incentive, such as that proposed by SoCalGas, will probably have little effect: the record suggests the utilities will not need new pipeline capacity for [*62] many years. If the utilities enter into any new commitments, they will carry a substantial burden to show that the benefits of those commitments clearly outweigh the costs.In addition, any incentive mechanism we may adopt could be counter-productive in combination with other ratemaking policies. That is, an incentive mechanism adopted which addresses interstate capacity could affect utility behavior in unintended ways because of other circumstances influencing utility decision-making. We are currently considering ratemaking incentives more generally in Investigation 90-08-006. Incentives such as those proposed by the parties in this proceeding may make more sense in the broader context of that proceeding.For these reasons, we do not adopt an incentive mechanism today. We will, however, clarify our intent with respect to the use of the ITCS. That mechanism was established in D.91-11-025 to account for stranded costs associated with liabilities which existed at the time D.91-11-025 was issued. Accordingly, we will direct the utilities to eliminate the use of the ITCS for each existing liability on the day that liability is no longer in effect. For example, PG&E would no [*63] longer recover any El Paso demand charges through the ITCS beginning in 1997. Utility commitments made after issuance of D.91-11-025 shall not be included in the ITCS.Finally, our rejection of an incentive mechanism is not a signal that we will take for granted the utilities' management of interstate pipeline capacity commitments, including new commitments, relinquishment of existing capacity, and the reasonableness of discounts from the as-billed rates for brokered capacity. We expect the utilities to make all reasonable efforts to manage interstate pipeline capacity in the most cost-effective way possible.VIII. Tariff Filings and Implementation Dates

A. Timing of Open SeasonsD.91-11-025 sets forth procedural guidelines for capacity brokering, including guidelines for "open seasons," periods during which customers inform the utilities of their service choices. PG&E proposes to hold open seasons for interstate pipeline capacity, intrastate transportation services, and core subscription services simultaneously rather than in succession. PG&E believes its proposed procedure will provide customers with the maximum amount of time to consider their choices.New Mexico [*64] opposes PG&E's schedule on that basis that it is inequitable to participants who do not select core subscription service.The rules adopted in D.91-11-025 provide that an open season should be first conducted for core subscription services, and that remaining capacity would be offered subsequently. We, therefore, see no need to change the rule adopted in D.91-11-025. PG&E should hold an open season for core subscription prior to its open season for unbundled interstate capacity.

B. Tariff Filings and Timing of ImplementationWe will direct the utilities to file tariffs, by July 31, 1992, to implement the provisions of this order. The tariffs should be identical to those presented as exhibits in this proceeding except to the extent they must be changed to make them consistent with this order. Protests to the tariffs will be considered; however, they should be limited to identifying tariff language which conflicts with this order. Protests should identify such conflicts clearly, should identify language in this decision which is in conflict with the tariffs, and should propose alternate tariff language. The tariffs will be deemed approved November 1, 1992, if no further [*65] Commission action is taken after the tariffs are filed.Of course, the filing and effectiveness of tariffs is subject to action by the FERC. Tariff filings should incorporate the rules and policies of the FERC as they become available. Where the utility changes tariffs from those submitted as evidence in this proceeding, the utility shall identify the change and note FERC orders which correspond to each change.IX. The Motions of Kern River and SunriseTwo motions have been filed to establish tracking accounts for the interstate pipeline demand charges that are included in utility transportation rates. The first motion was jointly filed January 14, 1992 by Kern River Gas Transmission Company, Amoco Production Company, Chevron USA Inc., Mobil Natural Gas Inc., and Union Pacific Resources Company (jointly, Kern River). The second motion was filed on April 9, 1992 by Sunrise Energy Company and SunPacific Energy Management, Inc. (Sunrise).Currently, utility transportation costs for interstate and intrastate transportation facilities are "bundled" in noncore transportation rates. Accordingly, intrastate transportation rates presently include interstate demand charges incurred [*66] by the utilities.In recent months, newly-constructed interstate pipeline facilities have begun moving gas into California. Customers of these facilities as well as holders of relinquished interstate capacity do not use the utilities' interstate pipeline transportation rights. They do, however, use the utilities' intrastate system for moving gas within the state. The rates paid by these customers, therefore include a share of demand charges incurred by the utilities for interstate transportation. As such, customers relying on non-utility owned interstate capacity are paying for interstate capacity twice, hence the term "double demand charge."Kern River and Sunrise have filed motions asking the Commission to require SoCalGas and PG&E to establish accounts which would track the interstate demand charges paid by customers who do not use utility-held interstate transportation. The Commission would determine at a later date how to allocate the revenues booked to the tracking account.Kern River and Sunrise argue that the existing circumstance is unfair and sends a signal that discourages new investment in pipeline facilities. Sunrise comments that the utility rates have caused [*67] economic hardship for customers who have acquired their own capacity rights.Several parties filed responses to the motions: SoCalGas, DRA, SCUPP, and TURN. SCUPP supports the motions. SoCalGas objects to the motions to the extent they would result in changes to cost allocation established in D.91-12-075 (SoCalGas' most recent cost allocation decision). SoCalGas points out that D.91-12-075 declined to reallocate existing demand charges away from users of new interstate facilities, finding that the interstate rights of SoCalGas provide security for noncore customers. SoCalGas points out that customers of newly-constructed interstate facilities made commitments without any guarantee from the Commission as to any particular cost allocation. DRA and TURN make similar comments.

DiscussionThe "double demand charge" problem is an interim problem that will exist until the Commission unbundles interstate pipeline demand charges from intrastate transportation rates. In our November policy decision in this docket and subsequently in SoCalGas' latest cost allocation proceeding we stated our commitment to unbundling demand charges concurrent with the introduction of capacity brokering. [*68] Although parties have long been on notice that the Commission would deal with this issue when capacity brokering was implemented, the continuing delay in implementation of this program has now caused us to rethink the wisdom of this policy.Because non-utility owned and controlled interstate pipeline capacity has been placed into service significantly before a capacity brokering program could be implemented, there now exists a mismatch which is causing pricing distortions as well as market disruptions. The Commission has long supported the notion of a "level playing field" as a means of encouraging competition in the restructured gas industry. The current situation distorts the ability of those entities holding firm interstate capacity to effectively compete in the market. Further, the regulatory lag engendered by the delay in implementation of capacity brokering hampers the ability to market firm interstate capacity given the bias caused by the continued bundling of interstate and intrastate transportation rates.For these reasons we will grant the motions filed by Kern River and Sunrise to establish an interim tracking account for interstate pipeline demand charges that are [*69] embedded in the intrastate transmission rates of customers that receive their gas over interstate capacity that is not owned and controlled by the California LDCs. A tracking account should be established by each [B the LDCs effective the date of this order. However, we will defer determination, at this time, as to the allocation of the tracking account dollars among customer classes. This is an issue to be examined in each LDCs cost allocation proceeding.

Findings of Fact1. The FERC issued Order 636 on April 8, 1992 addressing capacity reallocation programs for interstate pipeline companies.2. SoCalGas' proposed procurement rates include demand charges.3. Modifications to the MPO, such as those proposed by SoCalGas in estimating the excess costs of PITCO and POPCO supplies, are outside the scope of this proceeding.4. Several factors have contributed to the likelihood of excess supply of interstate capacity. No single customer group is responsible for this condition.5. Discounts of intrastate transportation rates for some noncore customers who would otherwise reduce or eliminate their gas service are beneficial to all classes of ratepayers.6.

Interstate [*70] capacity reserved for both the core and noncore classes may be underutilized, thereby imposing a risk of stranded investment.7. Determining the treatment of PG&E's commitment to 200 MMcf/d of Transwestern capacity is outside the scope of this proceeding.8. The issue of whether to credit the revenues from the firm service surcharge to interruptible customers or firm customers is outside the scope of this proceeding.9. PG&E and SDG&E propose to calculate cogenerator rates by averaging in the cost of core UEG igniter fuel charges.10. PG&E and CCC filed a joint stipulation setting forth a method for developing Schedule G–PO3 rates. The joint stipulation is unopposed.11. D.91–11–025 requires all UEG load to be curtailed ahead of any cogenerator loads in each curtailment episode.12. D.91–11–025 requires customers to be curtailed on a rotating basis notwithstanding customer size.13. SoCalGas' proposal to permit customers to transfer or reallocate gas diversions among themselves promotes system efficiency.14. PG&E proposes different rate designs for full–requirements core subscription customers and partial–requirements core subscription customers which may unreasonably [*71] promote full–requirements service.15. SDG&E proposes to limit its offering of core subscription service to customers with demand less than 7 MMcf/d (excluding its UEG).16. Issues relating to the cost–effectiveness of expanding PG&E's storage facilities are to be considered in a further phase of this proceeding pursuant to the assigned Commissioner's ruling.17. CCC and PG&E proposed that the utilities should give cogenerators the option to engage in a blind bid or to submit an independent bid whose rate would match the serving UEG's rate if the UEG rate is lower for capacity in the same pool.18. Regulatory policy and other circumstances beyond the utilities' control may have contributed to excess interstate capacity held by the utilities and to new pipeline construction which reduces the value of capacity held by the utilities.19. A regulatory incentive relating to excess interstate capacity may provide unintended incentives for counter–productive utility decision–making.20. Because of the prospects for considerable excess capacity, the utilities will carry a substantial burden to show the reasonableness of new capacity commitments and efforts to relinquish existing [*72] capacity.21. The requirement of Order No. 636 that capacity shall be released on a nondiscriminatory basis should apply to all pre–arranged deals, including the pre–arranged deal between PG&E and its UEG department.22. The Commission intends that the utilities' assignment of firm capacity rights to core aggregators shall be consistent with Order No. 636 and with the applicable interstate pipelines' tariffs.23. The bidding procedures and the "open season" procedure under D.91–11–025 must be changed to conform with the requirement, in Order No. 636, that a shipper that receives released firm capacity shall make payment directly to the pipeline.24. The utilities may have an opportunity to relinquish interstate capacity pursuant to FERC order.25. In recent months newly–constructed pipeline facilities have begun moving gas to California.26. Customers of new pipeline facilities as well as holders of relinquished interstate capacity do not use the utilities' interstate pipeline transportation rights.27. Customers relying on non–utility owned interstate pipeline capacity are paying for this capacity twice, hence the term "double demand charge".28. The "double demand [*73] charge" problem will continue until demand charges are unbundled concurrent with the introduction of capacity brokering29. Implementation of capacity brokering on all interstate pipelines is delayed past the date envisioned in D.91–11–025.

Conclusions of Law1. The capacity brokering rules set forth in D.91–11–025, as modified, do not conflict with the program envisioned by the FERC in Order 636.2. Pursuant to Order 636, shippers who use brokered capacity will contract directly with the interstate pipelines.3. Contractual arrangements under capacity brokering, as envisioned in D.91–11–025, are equivalent to "pre–arranged deals", as described by FERC, and are subject to the posting and right of first refusal process set forth in Order 636.4. All program changes established in D.91–11–025, and this order, should be deferred until a utility is able to broker capacity on one or more interstate pipelines.5. All program and rulemaking changes established in D.91–11–025, and this order, should be implemented for a utility that may, pursuant to FERC order, broker capacity on both pipelines over which the utility has capacity commitments.6. In cases where a utility [*74] may broker capacity on only one of its serving pipelines, the utility should be required to broker that capacity pursuant to the provisions set forth in Appendix B of this decision.7. Utility tariffs should require that all customers who receive brokered utility capacity must contract with the utility holding the firm capacity in addition to contracting with the pipeline company pursuant to FERC orders.8. Capacity brokering over a pipeline serving California should be implemented within 90 days following a FERC order authorizing that pipeline company's capacity reallocation program.9. SoCalGas should unbundle demand charges from core and core subscription procurement rates, and include demand charges only in transportation rates for these customers.10. SoCalGas' method for estimating excess PITCO and POPCO supplies is reasonable with the exception that the method should not include modifications to the MPO.11. It is reasonable to allocate the excess costs of PITCO and POPCO supplies on an equal–cents–per–therm basis to all customers.12. The costs of excess interstate capacity should be allocated to all customer groups except that the core should not assume more than [*75] the total annual costs of 10% of interstate capacity commitments over core reservations adopted in D.91–11–025.13. Core subscription customers should assume liability for all stranded costs arising from unused capacity reserved during a 2 year reservation period for the core subscription service with the understanding that a new core subscription reservation will be established during an open season held every two years.14. The existing discount adjustment mechanism and method of allocating costs associated with discount rates for intrastate transportation for some noncore customers should be continued.15. The utilities should allocate interstate capacity on a pro rata basis between the core and noncore and should allocate associated credits accordingly.16. Costs associated with PG&E's commitment to Transwestern capacity should not be included in rates at this time. PG&E may enter into its balancing account the costs of the new capacity, subject to reasonableness review proceedings.17. PG&E and SDG&E should modify their cogenerator rates so that they are equal to UEG rates on a service level basis.18. The joint stipulation submitted by CCC and PG&E regarding G-PO3 [*76] rates should be adopted.19. The utilities' tariffs should provide that, where UEGs pay the same percentage of default rate or less than cogenerators, all UEG loads shall be curtailed ahead of any cogenerator loads in each curtailment episode.20. The utilities' tariff should provide for curtailments on a rotating basis notwithstanding customer size except in emergency circumstances.21. The utilities should permit intrastate transportation customers to negotiate among themselves the order of diversions.22. PG&E should give priority to firm intrastate transportation customers over Line 300 rather than to interruptible intrastate customers using the El Paso system or customers who substitute new capacity for El Paso capacity.23. During periods of system overpressurization, all noncore customers, wholesale customers, and the SoCalGas gas supply department (as agent for the core customers) should be required to bring their deliveries into the system to within 10 percent of their actual gas usage for the curtailment period or face curtailment penalties.24. Core subscription customers should pay reservation charges equal to each core subscriber's expected demand in the peak [*77] month of the core subscription class times the weighted average cost of the utility's reserved interstate capacity.25. SDG&E's proposal to reserve core subscription capacity pursuant to an open season is reasonable.26. SDG&E's proposal to limit core subscription to customers whose demand is less than 7 MMcf/d should be rejected because it unreasonably discriminates against SDG&E's largest customers.27. SDG&E's proposed core reservation of 90 MMcf/d of SoCalGas capacity is reasonable.28. The utilities' proposals for integrating their core transportation services should be adopted except that: (1) core aggregators should be permitted to increase or decrease capacity on a monthly basis; (2) assignment of capacity should cover the full term of the services to be rendered by core aggregators; and (3) core aggregators should have the right to use "alternative available capacity." The utilities should be directed to ensure that assignments of firm interstate capacity to core aggregators are consistent with Order No. 636 and the applicable interstate pipelines' tariffs.29. The utilities should implement secondary brokering concurrent with the implementation of capacity brokering [*78] and consistent with FERC rules.30. The utilities should give cogenerators the option to engage in a blind bid or to submit an independent bid whose rate would match the serving UEG's rate if the UEG rate is lower for capacity in the same short-term or long-term pool, consistent with the joint stipulation submitted by CCC and PG&E.31. Wholesale customers should be permitted to negotiate the timing and extent of curtailments for noncore load with the utilities, with the condition that wholesale customers' noncore loads should be subject to curtailments which are proportionate to those of other noncore customers.32. The utilities should include provisions in their service agreements which would require the customer to either give up the capacity or pay the full as-billed rate in cases where the utility receives relinquishment rights for the capacity.33. The utilities should eliminate the use of the ITCS for each existing liability on the day that liability is no longer in effect. New utility commitments should not be included in the ITCS.34. The utilities should conduct open seasons pursuant to the procedures established in D.91-11-025, subject to the requirement that [*79] the open seasons shall be consistent with the requirements of Order No. 636 and the applicable interstate pipelines' tariffs.35. Capacity brokering should be implemented within 90 days following an FERC order authorizing a pipeline company's capacity reallocation program.36. PG&E, SoCalGas, and SDG&E should be ordered to file, by July 31, 1992, tariffs implementing the provisions of this decision.37. The utilities should relinquish interstate capacity, not needed to serve the core, pursuant to FERC policy, in cases where it would be cost-effective to do so.38. The Commission should grant the request (filed as a motion) of Kern River to establish tracking accounts for interstate demand charges paid by noncore customers who do not use utility-held interstate pipeline facilities.39. The Commission should grant the request (filed as a motion) of Sunrise to establish tracking accounts for interstate demand charges paid by noncore customers who do not use utility-held interstate pipeline facilities.ORDERIT IS ORDERED that:1. All program changes established in Decision (D.) 91-11-025, and this order, are deferred until a utility is able to broker capacity on one [*80] or more interstate pipelines. Pacific Gas and Electric Company is no longer required to convert its remaining firm sales rights on Pacific Gas Transmission Company to firm transportation rights on October 1, 1992.2. All program and rulemaking changes established in D.91-11-025, and this order, shall be implemented for a utility that may, pursuant to Federal Energy Regulatory Commission (FERC) order, broker capacity on both pipelines over which the utility has capacity commitments.3. In cases where a utility may broker capacity on only one of its serving pipelines, the utility shall broker that capacity pursuant to the provisions set forth in Appendix B of this decision.4. Utility tariffs shall require that all customers who receive brokered utility capacity must contract with the utility holding the firm capacity in addition to contracting with the pipeline company pursuant to FERC orders.5. Capacity brokering over a pipeline serving California shall be implemented 90 days following a FERC order authorizing that pipeline company's capacity reallocation program.6. PG&E, Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E) shall, by [*81] August 12, 1992, file tariffs consistent with this decision. The tariffs shall be identical to those offered as evidence in this proceeding, except to the extent changes are required as set forth herein or by orders of the FERC which permit capacity brokering but require modifications to this Commission's adopted rules.7. SoCalGas' procurement rates shall not include demand charge components.8. SoCalGas shall allocate the excess costs of Pacific Interstate Transportation Company (PITCO) and Pacific Offshore Pipeline Company (POPCO) supplies to all customers on an equal-cents-per-therm basis.9. The costs of excess interstate capacity shall be allocated to all customer groups except that the core should not assume more than the total annual costs of 10 percent of interstate capacity commitments over core reservations adopted in Decision 91-11-025. Core subscription rates shall also include the costs of all unused interstate capacity reserved during a given 2 year reservation period for that service with the understanding that a new core subscription reservation will be established during an open season held every two years.10. The utilities shall continue to allocate to [*82] all customer classes the revenue shortfall associated with noncore transportation rate discounting from default tariff rates.11. The utilities shall allocate interstate capacity on a pro rata basis between the core and noncore classes, and shall allocate associated credits to those classes accordingly.12. PG&E may enter the costs of Transwestern Pipeline Company capacity in its balancing account subject to reasonableness review.13. Utility rates for cogenerators shall be equal to utility electric generator (UEG) rates on a service-level basis.14. The joint stipulation submitted in this proceeding by PG&E and the California Cogeneration Council (CCC) regarding Schedule G-PO3 rates is adopted.15. All UEG loads shall be curtailed ahead of any cogenerator loads in each curtailment episode when UEGs pay the same percentage of default rate or less than cogenerators.16. The utilities shall curtail noncore customers on a rotating basis notwithstanding customer size except in emergency circumstances. During periods of potential system overpressurization, SoCalGas shall curtail customers on a pro rata basis according to priority on the intrastate system.17. Utilities shall [*83] permit intrastate transportation customers to negotiate among themselves the order of gas supply diversions pursuant to this decision.18. Core subscription rates shall include reservation charges equal to each core subscriber's expected demand in the peak month of the core subscription class times the weighted average cost of the utility's reserved interstate capacity.19. Core subscription service shall be available to all noncore customers, regardless of size.20. Core transportation service shall (1) permit core aggregators to increase or decrease capacity on a monthly basis; (2) assign capacity over the full term of the services to be rendered by core aggregators; and (3) permit core aggregators to use "alternative available capacity." If assigning capacity to core aggregators would be inconsistent with FERC rules or would jeopardize reliable service to core aggregators, the utilities shall develop contracts for core aggregators which assure reliable service to them, consistent with FERC rules.21. SoCalGas and PG&E shall implement secondary brokering concurrent with the implementation of capacity brokering and consistent with FERC rules.22. The joint stipulation regarding [*84] cogenerator bidding procedures filed by CCC and PG&E is adopted.23. The utilities shall, at the request of wholesale customers, negotiate the timing and extent of curtailments for noncore load with the condition that wholesale customers' noncore loads should be subject to curtailments which are proportionate to those of other noncore customers. This decision does not alter rules adopted in D.91-11-025 regarding curtailments between SoCalGas and SDG&E.24. SoCalGas and PG&E shall include in their service agreements provisions which would require the customer to either give up capacity or pay the full as-billed rate in cases where the utilities receives relinquishment rights for the capacity.25. The utilities shall not enter into the Interstate Transition Cost Surcharge accounts any liabilities which accrued after issuance of D.91-11-025.26. This proceeding will remain open for the purpose of assuring that Commission policy is consistent with that of the FERC, and for considering issues related to (1) brokering programs for intrastate capacity and (2) whether existing arrangements between SoCalGas and it affiliates, PITCO and POPCO, are should be changed to promote competition [*85] for related transportation and gas supplies.27. The motion of Kern River Gas Transmission Company and others, filed January 14, 1992, is granted effective the date of this order.28. The motion of Sunrise Energy Company and SunPacific Energy Management, Inc., filed April 9, 1992, is granted effective the date of this order.29. PG&E and SoCalGas shall establish tracking accounts for interstate demand charges paid by noncore customers who do not use utility-held interstate pipeline facilities.This order is effective today.Dated July 1, 1992, at San Francisco, California.APPENDIX AList of AppearancesRespondents: Keith Melville and Beth Bowman, Attorneys at Law, for San Diego Gas & Electric Company; David J. Gilmor and Thomas R. Brill, Attorneys at Law, for Southern California Gas Company; and Lise Jordan, Attorney at Law, for Pacific Gas and Electric Company.Interested Parties: Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael Alcantar, for Cogenerators of Southern California; Brady & Berliner, by Roger A. Berliner, Attorney at Law, for Alberta Petroleum Marketing Commission; Knox, Lemmon & Brady, Matt Brady, Attorney at Law, and John [*86] Baca, for State of California, Department of General Services; Ariel

Calonne, City Attorney, for the City of Palo Alto; Jerome Candelaria and Joe Koury, Attorneys at Law, for McFarland Energy, Inc.; Rand Carroll, Attorney at Law, for the State of New Mexico; Cross Border Services, by Catherine M. Elder, and Messrs. Brady & Berliner, by Peter G. Hirst, Attorney at Law, for Watson Cogeneration Company; Jackson, Tufts, Cole & Black, by William H. Booth and Evelyn K. Elsesser, Attorneys at Law, for Indicated Producers; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization; Messrs. McHenry & Staffier, by John Staffier, Attorney at Law, and Greg Giesbrecht for Pan–Alberta Gas, Ltd.; Annette Gilliam and Stephen E. Picket, Attorneys at Law, for Southern California Edison Company; Graham & James, by Peter W. Hanschen and Melissa S. Waksman, Attorneys at Law, for Kern River Gas Transmission Company; Steve Harris, for Transwestern Pipeline Company; R. W. Beck & Associates, by David T. Helsby, for R. W. Beck & Associates; Michael Hopkins, for City of Glendale; Phillip D. Endom, Arthur R. Formanek, and Phyllis Huckabee, Attorneys [*87] at Law, for El Paso Natural Gas Company; Morrison & Foerster, by Joseph M. Karp, Attorney at Law, for California Cogeneration Council; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for Simpson Paper Company; Carolyn Kehrein, for Procter & Gamble Manufacturing Company; Luce, Forward, Hamilton & Scripps, by John W. Leslie, Attorney at Law, for California Gas Marketers Group; William Marcus, for JBS Energy,Inc.; Daniel Mason, for NT Company; Sutherland, Asbill & Brennan, by Keith R. McCrea and Michael T. Mishkin, Attorneys at Law, for California Industrial Group, California League of Food Processors, and California Manufacturers Association; Barakat & Chamberlin, by Melissa Metzler, for Barakat & Chamberlin; Leamon W. Murphy, for Imperial Irrigation District; Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Utility Power Pool; Robert L. Pettinato, for Los Angeles Department of Water and Power; Anderson, Donovan & Poole, by Edward G. Poole, Attorney at Law, for Anderson, Donovan & Poole; Marron, Reid & Sheehy, by E. Lewis Reid, Attorney at Law, for Marron, Reid & Sheehy; Donald [*88] W. Schoenbeck, for RCS; Thomas R. Sheets and John C. Walley, Attorneys at Law, for Southwest Gas Company; Andrew J. Skaff, Attorney at Law, for Kenneth Energy Systems; Armour, Goodin, Schlotz & MacBride, by James D. Squeri, Attorney at Law, for KELCO Division of Merck & Company, Inc.; Ronald V. Stassi, for City of Burbank; Alex Szabo, for City of Pasadena; Morse, Richard, Weisenmiller & Associates, Inc., by Robert B. Weisenmiller, for MRW & Associates; Kevin D. Woodruff, for Henwood Energy Services, Inc.; Barkovich & Yap, by Catherine Yap, for Barkovich and Yap; Adrian Hudson, for California Gas Producers Association; David J. Schultz, for Pacific Gas Transmission; Timothy J. Battaglia, and Jeffrey M. Holloman for Access Energy Corporation; Messrs. Brady & Berliner, by John W. Jimison, Attorney at Law, for City of Vernon; Messrs. Fulbright & Jaworski, by Patrick J. Keeley, Attorney at Law, for Canadian Petroleum Association; Patrick J. Power, Attorney at Law, for City of Long Beach; Dennis Prince, for Independent Petroleum Association of Canada; Eric Wills, for Luz Partnership Management; Grueneich, Ellison & Schneider, [*89] by Christopher Ellison; and Edson & Modisette, by Karen Edson, for herself.Division of Ratepayers Advocates: Patrick L. Gileau, Attorney at Law, Natalie Walsh, and Robert Mark Pocta.Commission Advisory and Compliance Division: Richard Dobson, Anne Premo, and Phyllis White.APPENDIX BImplementation of Capacity Brokering Over Part of a Utility's Pipeline System

The rules and services adopted in D.90–09–089, as modified, shall be retained with the exceptions set forth herein which pertain to services over pipelines for which capacity is brokered. Customers who do not wish to participate in capacity brokering retain their existing service options, and will be subject to the rules set forth in D.90–09–089, except as set forth below.

The utility shall unbundle its noncore transportation rates for customers who commit to the utility's brokered interstate capacity. The rate for these customers shall include all costs associated with intrastate service, including any transition or stranded costs allocated to noncore transportation rates but shall not include interstate demand charges. Cost allocation principles adopted herein will also take effect. [*90]

Customers who do not participate in capacity brokering will be billed according to rules adopted in D.90–09–089.Customers who successfully bid for brokered capacity or who can demonstrate a contractual commitment to a marketer, producer, or broker who has successfully bid for brokered capacity may abrogate outstanding commitments for bundled transportation services adopted in D.90–09–089. The contractual commitment must be for capacity brokered by the serving utility and for a period no less than the customer's remaining commitment to the utility for bundled service. Such customers may purchase intrastate service under any of the existing service levels which are to be unbundled, as set forth above.

"Buy–sell" arrangements adopted in D.90–09–089 will be eliminated over pipelines for which capacity brokering is in place.

The rules adopted in D.90-09-089, as modified, will be eliminated for SoCalGas when capacity brokering is available over El Paso and Transwestern or when SoCalGas has relinquished all interstate pipeline capacity in excess of its core requirements, whichever comes first.

The rules adopted in D.90-09-089, as modified, will be eliminated for PG&E when [*91] capacity brokering is available over El Paso and PGT or when PG&E has relinquished all interstate pipeline capacity in excess of its core requirements, whichever comes first.

Norman D. Shumway, Commissioner, concurring:Today I join in the decision of the Commission; however, I wish to qualify my support for capping core responsibility for the cost of stranded interstate capacity at 110%.It is the policy of this Commission to set rates which reflect the marginal costs of serving a given customer class. I agree with this policy and believe it is one which we should continue to strive to achieve. In this context, my concerns with the 110% cap we place on the allocation to the core of stranded costs are several. First, I believe it may be premature to set such a cap when our Long-Run Marginal Cost (LRMC) proceeding, in docket I.86-06-005/R.86-06-006, is pending. It is my hope that the LRMC proceeding will provide the Commission with better information than is available at present so that we may indeed be confident that we are establishing rates which minimize inappropriate cross-subsidies of one class by another. Absent a final decision in the LRMC proceeding, which we do not [*92] expect before the end of this year, we cannot really know that we have "got it right" in setting a cap at 110% — or at any level. We cannot really know whether the 110% cap moves us closer to or further away from our goal of marginal cost rates.Second, our decision to set a cap at 110% relies upon evidence developed for another purpose in another docket, I.88-12-027, commonly called the "Pipeline OII." In Decision 90-02-016 in that docket, the Commission found that a 10% short-term excess interstate capacity or "slack" factor was desirable to enable the operational flexibility needed to promote price competition for the sale and transportation of natural gas. The figure was developed for that specific purpose, and is taken out of context here. While the existence of a 10% "slack" factor may be the best evidence developed in the present record on the issue of allocating core responsibility for stranded investment, I feel that it is nonetheless an arbitrary figure. Specifically, I fear we may be ascribing more precision to the 10% "slack" factor than is appropriate.Third, we do not know now what the ultimate cost of stranded interstate capacity will be, and consequently cannot [*93] assess the rate impact of any allocation. I believe this fact is important because movement toward marginal cost rates has traditionally been tempered to avoid rate shock. At the present time, however, the Commission cannot fully assess the impact of the 110% cap from this perspective either.The concerns outlined above all cause me to believe that when more complete information becomes available we would be wise to look again at our decision to allocate 110% of the costs of stranded investment to the core.

July 1, 1992 San Francisco, California