LEXSEE 22 CPUC2D 491,AT 566

Order Instituting an Investigation by rulemaking into proposed refinements for new regulatory framework for gas utilities

Decision No. 86-12-010, Rulemaking No. 86-06-006 (Filed June 5, 1986)

California Public Utilities Commission

1986 Cal. PUC LEXIS 754; 22 CPUC2d 491

December 3, 1986

PANEL: [*1] Donald Vial, President; Victor Calvo, Frederick R. Duda, Stanley W. Hulett, Commissioners

OPINION: INTERIM OPINIONI. SummaryThis is one of two Commission decisions issued today which together set forth final policies to restructure natural gas regulation in the State of California. In this decision we adopt rules establishing the general regulatory and industry structures, taking into consideration comments filed by parties in response to a set of proposed rules enunciated in Order Instituting Rulemaking 86-06-006 (hereinafter referred to as the OIR) issued on June 5, 1986. Today's companion decision in Investigation (I.) 86-06-005 addresses the allocation of costs and design of gas transmission and procurement rates in light of the broader policies adopted in this decision.Review of the parties' comments has led us to make several changes in the rules proposed in the OIR. An oft-repeated criticism that the rules were unnecessarily complex and would be a burden for the utilities to implement and for customers to understand has led us to make several changes to simplify the program where appropriate. We have also modified the rules in some respects to make the pricing policies more [*2] cost-based, consistent with our general policy in this regard.In this decision, we slightly modify our earlier proposal to separate the gas market into two classes of customers. The core market will include customers with end-use priorities P-1, P-2A, and P-2B. Customers with priorities P-3 and above are assigned to the noncore market. Noncore customers will be allowed to pick and choose from among a variety of transmission and procurement options. Because of their greater ability to make fuel purchase decisions, core customers with large volume usage are allowed to elect transmission-only service if they desire to do so. Except for these transmission-only customers, core customers will be provided traditional utility service on a bundled basis. We establish default service conditions for those noncore customers which do not sign transmission and/or procurement contracts with the utilities.The adopted rules provide for more flexibility in contract terms and pricing provisions for noncore transmission services than envisioned in the OIR. The distinction between short-term and long-term transmission is eliminated, as is the take-or-pay requirement currently in effect for [*3] long-term transmission contracts. Rather than the four levels of transmission reliability proposed in the OIR, we provide that utilities may negotiate priority levels in noncore contracts; customers with no alternative fuel capability still retain the highest level of transmission service.On the other hand, we decline to allow the utilities as much flexibility as they desire to tailor their procurement services to the specifications of individual noncore customers. We maintain the two basic supply portfolios contemplated in the OIR — a noncore portfolio consisting of spot or short-term gas supplies, and a core portfolio containing a mix of long and short-term gas supplies. Core customers will be served from the core portfolio; noncore customers can choose procurement from either portfolio or from nonutility sources. We reaffirm the proposed rule that gas costs for similar sources of gas must be averaged in computing the commodity prices of the two portfolios, to ensure that the least costly supplies are not diverted to specific customers to the detriment of customers with no fuel alternatives.We conclude that the supply portfolios should be priced at their current market value [*4] for a given level of price stability and supply certainty. Any costs in excess of this value are termed "transition costs" which should be borne by all customer since no customers benefit from excess costs which have resulted from the era of wellhead price regulation.We identify a number of interrelated gas resource planning issues which bear further exploration, and state our intent to initiate further hearings in 1987 to address such topics as the proper mix of gas supplies for the core portfolio, the appropriate level of pricing certainty for the core portfolio, whether the utilities should offer additional supply portfolios to meet possible needs of noncore customers, whether underground storage and interstate transmission capacity can be made available to customers, and the role of out-of-area utility marketing. In the meantime, we adopt general procurement guidelines for the core portfolio which recognize the importance of price security in a competitive supply market.We simplify the terms of core procurement for those noncore customers wishing to participate in the core portfolio and make them more cost-based by elimination of take-or-pay requirements and reduction of [*5] minimum contract periods to one year instead of three years. We provide instead for the eventual implementation of minimum bills and/or longer minimum contract periods if the supply contracts the utilities enter into in the future contain such commitments. To prevent noncore customers from choosing this elected core procurement option only when a market turnaround has occurred, we provide that noncore customers may choose elected core procurement only when the average cost of the core portfolio is greater than the average cost of the noncore portfolio.Finally, we adopt a stipulation entered into by the Public Staff Division (PSD), Toward Utility Rate Normalization (TURN), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and San Diego Gas & Electric Company (SDG&E) which proposed a schedule whereby the policy decisions to be reached in this rulemaking and in I.86-06-005 would be implemented; a partial rather than total elimination of balancing account treatment for noncore fixed costs for two years; and schedules for future cost allocation and gas cost proceedings. There will be implementation hearings in early 1987 with final implementation of [*6] rates planned for mid-1987.II. BackgroundThe Commission opened I.84-04-079, its first investigation into gas transportation issues, in April 1984. Since that time we have issued a number of decisions and instituted two additional proceedings as we have charted the course leading to the two policy decisions issued today. These actions have been investigated as a response to changes in federal regulatory policies and competitive forces in the marketplace.In December 1985 we ordered the regulated California gas utilities to offer long term gas transportation services to customers which wished to purchase nonutility gas supplies (Decision (D.) 85-12-102 in I.84-04-079); short term transportation tariffs were ordered in March 1986 in D.86-03-057. Both long and short-term rates were ordered based on an "equivalent margin recovery" approach intended to maintain ratepayer indifference to whether a customer's gas supplies were bought from the utility or elsewhere. As an exception, enhanced oil recovery customers were allowed to negotiate lower-transportation rates.In the meantime, we were laying the foundations for the present move toward cost-based rates. In October 1985 we [*7] requested comments from interested parties regarding proper regulatory policies in light of changing industry conditions, and an en banc hearing was held in January 1986 in which parties discussed their filed comments. As a result of the comments and hearing, D.86-03-057 set forth a proposed new regulatory policy and asked for further comments from the parties.The regulatory approach proposed in D.86-03-057 was to unbundle gas services so that certain customers could choose separately the types of gas transmission and procurement services they desire. That decision first set forth the concept of core customers without service alternatives and noncore customers which have access to competitive fuel supplies, proposed that utilities develop supply portfolios to match those customers' differing characteristics, and initiated steps toward cost-based rather than value-based or equivalent margin-based prices. It also contemplated that the new regulatory approach would necessitate a basic revamping of current risk-reducing balancing account mechanisms which protect the utilities from fluctuations in gas costs and sales levels, in order to provide incentives to obtain the lowest-priced [*8] gas supplies possible and/or to increase gas usage.After comments were filed in response to D.86-03-057, the two proceedings from which orders emanate today were initiated on June 5, 1986. Order Instituting Investigation (OII) 86-06-005 proposed cost allocation and rate design policies based on long run marginal costs. Evidentiary hearings have been held in that proceeding and the issues are resolved in the companion decision issued today.This OIR, issued at the same time, contained a set of proposed policies regarding the overall industry structure and regulatory approach contemplated. These issues were deemed amenable to rulemaking, and parties were again asked to file written comments.PG&E and SoCal made additional filings on July 7, 1986 as required by the OIR, to publish their policies on the conditions under which they would agree to use their interstate capacity rights on behalf of customers seeking firm interstate transportation. The following parties filed comments due July 20, 1986 regarding the rules proposed in the OIR and the two utility compliance filings:

PSD
PG&E
SoCal
SDG&E
TURN
Southern California Edison Company (SCE)
Department of General Services [*9] (DGS)
City of Long Beach (Long Beach)
City of Palo Alto (Palo Alto)
City of Pasadena (Pasadena)
California Manufacturers Association (CMA)
Industrial Users
California Industrial Group (CIG)

California Hotel & Motel Association and California Restaurant Association (CHMA/CRA)
Canadian Producers Group (CPG)
El Paso Natural Gas Company (El Paso)
Petro–Canada Resources (Petro–Canada)
Champlin Petroleum Company (Champlin)
State of New Mexico (New Mexico)
Pan Alberta Gas Ltd. (Pan Alberta)
Tenneco Oil Company and CONOCO Inc. (Tenneco/CONOCO)
Transwestern Pipeline Company (Transwestern)On October 30, 1986 PSD filed a Motion for Expedited Consideration of a Stipulation for a Transition Period in Natural Gas Regulatory Procedure, presenting a stipulation it had entered into with TURN, PG&E, SoCal, and SDG&E. The following parties filed comments on the stipulation by November 7, 1986, as provided for in an administrative law judge ruling:

SoCal
Long Beach
CMA
CIG
CHMA/CRA
Nabisco Brands, Inc. (Nabisco)III. Market StructureIn the proposed OIR, gas customers were divided into two classes of customers: those which must receive bundled gas service from the utilities [*10] and those which will be allowed to pick and choose from among a variety of transmission and procurement options. In this section, we address this basic demarcation of the two types of customers. Eligibility for the different transmission and procurement options is discussed in Section IV and Section VI, respectively.In the OIR, "captive core" customers were defined as those which use less than 25,000 thousand cubic feet (Mcf) of gas per year. Noncore customers were defined as those customers with usage above that amount. For procurement purposes, noncore customers could choose to become "elected core" customers and have the utility procure a specified quantity of gas for them as part of the core market. At the outset, and unless qualifying customers elect otherwise, all customers in existing end use priorities 1 and 2A would be deemed core, and all in priorities 2B and beyond would be deemed noncore.Positions of the PartiesPSD, TURN and CIG agree with the proposed definition of core market customers.SDG&E argues the definition should specify the period during which the usage for qualification as noncore is to be measured and how often it is to be remeasured. SDG&E believes [*11] there is no reason to allow a customer to qualify once and be assured of noncore status for all time, and suggests that usage be defined as that which has occurred in either of the last two calendar years preceding the year in which a customer seeks such classification.SDG&E also argues the proposed definition is ambiguous regarding whether P–2B and lower priority customers with usage less than 25,000 Mcf/year are to be classified as core or noncore, and recommends that the volumetric requirement should control.SoCal believes the rule should be modified to recognize the fact that an individual customer's load can be served under several priorities (over 500 customers in the SoCal system have loads which fall into more than one priority). SoCal recommends the rule be revised for multiple priority customers, so that all P–1 and P–2A load shall be considered core regardless of the customer's total load.On the other hand, DGS requests that the Commission change the definition to permit aggregation of more than one facility or more than one meter at one facility to produce the minimum level so that an entity with its subsidiaries and affiliates can qualify as noncore. The State [*12] is one of the largest aggregate consumers of gas in California, and DGS contends that the State should be able to avail itself of gas supplies from alternative sources since it pays its appropriately allocated share of fixed costs.CHMA/CRA recommends the rule be revised to specify that all P–1 and P–2A customers, including those with demand over 25,000 Mcf/year, are to be deemed core customers until they take positive action to convert all or a portion of their utility service to noncore. CHMA has members with annual gas requirements that exceed 25,000 Mcf which have no desire to procure gas, and CHMA/CRA argues that they should not be subject to the obligations proposed for elected core customers.CPG suggests that all customers remain core until affirmatively electing to become noncore. Realizing that there must be some assurance that core customers will remain so, CPG suggests that there be a one year window in which core customers may elect to become noncore and that, if after a year the customer does not elect noncore status, it be deemed core for a minimum of three years.PG&E recommends that its utility electric generation (UEG) load be considered a special category, [*13] neither core nor noncore, and that the Commission direct PG&E to adopt a fuel procurement policy for its UEG load which will achieve as beneficial a result in terms of price and reliability as would be achieved if its Electric Department were a separate company. PG&E believes weather fluctuations, load–balancing and cost minimization benefits, and electric reliability needs all support its position for a separate UEG class, as well as full

balancing account treatment for UEG procurement and margin costs. On the other hand, CPG argues that both UEG and residential gas customers would benefit by inclusion of PG&E's UEG load within the core market because this would create a higher overall load factor for that class.DiscussionThe parties' comments in this rulemaking proceeding and our approach to gas rate design adopted in I.86-06-005 make it clear that our proposed rule needs some modification and clarification. First, we recognize that a benchmark tied to therm usage may be more consistent and easier to apply than one based on Mcf usage. While no party requested that this be done, the utilities should convert the 25,000 Mcf/year demarcation to 250,000 therms/yr in any subsequent [*14] tariff filings and for the implementation hearings. Second, we no longer view core customers only as those who receive bundled gas service, and noncore customers as those who can choose among a variety of transmission and procurement options. Instead, we will allocate all customers with Priorities 1, 2A, and 2B to the core market and allow transmission-only service to those core customers who meet the 250,000 therms/yr minimum size requirement.Our reasons for this approach can best be seen by examining the status of Priority 1 and Priority 2A customers. These priorities consist primarily of residential and commercial customers who have no alternate fuel capability. We have always required that utilities provide these customers with the firmest level of service because of their status as captive customers and their end-use characteristics. In fact, there has not been any controversy over our proposal to assign P-1 and P-2A customers with usage less than 250,000 therms/yr to the core market. Parties did raise numerous questions regarding our original proposal to allow large P-1 and P-2A customers with usage over 250,000 therms/yr to elect out of the core in order to receive [*15] transmission-only service. The comments on this issue suggest to us a preferable approach. Rather than requiring large P-1 and P-2A customers to opt out of the core to take advantage of transmission-only service, we will simply provide for this service within the core market. By allowing this type of transmission-only service within the core there remains no reason for P-1 and P-2A customers to elect noncore status. Core customers that meet the minimum size requirements for transportation of customer-owned gas will have the same procurement options as noncore customers; they will, however, be sold gas from the core portfolio unless they choose otherwise. The major difference between large core and noncore customers will be differences in priority and transmission rates resulting from this decision and our decision in I.86-06-005.We are now left with customers in Priority 2B and below. We could rationally place them all into the noncore market since, with minor exception, they all have alternate fuel capability. These customers arguably belong in the noncore market because it is for these customers with competitive alternatives that we want to put the utility at risk (i.e. [*16] through the phasing-out of SAM), and for whom the utilities need rate flexibility. While this approach has appeal, we are reluctant to place P-2B customers in the noncore market at this time. We will, however, place all P-3 customers and below into the noncore market. All noncore customers will be eligible for transmission-only service regardless of their usage.Priority 2-B customers are basically commercial customers with propane as an alternate fuel. They could easily fit into either the core or noncore classes. While they have alternate fuel capability similar to noncore customers, they also have many of the same cost and load characteristics as P-2A commercial customers who have no propane capability and are considered part of the core customer class. Due to their similarities to P-2A customers, we propose to place P-2B into the core class at this time. However, before we make our final decision on this matter, we would like to receive comments from interested parties on whether P-2B customers should be considered part of the core or noncore market. Comments should be submitted within 30 days of the effective date of this order. We recognize that placing P-2B customers [*17] into the core class would impose some minimal risk on other core customers because of P-2B customers' fuel switching capability. However, if we do consider P-2B customers as part of the core class, we will carefully monitor the situation and will not hesitate to put P-2B customers into the noncore class if necessary to protect core customers without alternate fuel capability. We also note that should we decide to place P-2B customers into the noncore class, the embedded cost of serving these customers would have to be assigned to the noncore class under the cost allocation approach adopted in the OII decision.In addition to this basic modification to our proposed rule, we will provide the following clarifications in response to some of the parties' recommendations and comments. Before we begin, we note that there is a need to develop clear definitions for the terms that are used in this decision. We will make a special effort in our adopted rules to define the terms we use and thereafter use them consistently. In some instances, we have recast parties' comments to conform with our adopted terminology.We intend to restrict eligibility for procurement options at this time to [*18] customers who, because of larger size and/or alternate fuel capabilities, are likely to be best equipped to participate in a competitive marketplace and make well-reasoned decisions regarding natural gas service for themselves. Another strictly secondary reason is that such restrictions would ease the utilities' administrative burdens by a reduction in the sheer volume of customers requesting information and contracts. As the marketplace develops, both these factors may become less important, and we may reconsider whether the restrictions should be reduced or eliminated.SDG&E's initial recommendation regarding specification of the period during which usage is measured for core customers to qualify for transmission-only service is sound, and will be adopted. However, we see no benefit in SDG&E's followup recommendation that a customer's usage be remeasured from time to time. Once a customer has met the usage requirements for transmission-only status, it should not be required to requalify based on usage in subsequent years. Such a customer may have signed procurement contracts or made other business commitments which would create an economic hardship if it were forced to purchase [*19] gas from the utility's core portfolio.In a similar vein, we reject SDG&E's request that all customers in all priority designations with usage less than 250,000 therms/year be classified as core and thus ineligible for transmission and self-procurement. The customers in the noncore class are generally large and sophisticated. We see no reason to preclude giving all these customers the option to purchase their own natural gas.We also disagree with SoCal's view that the P-1 and P-2A load of a multiple use customer (i.e. for customers with multiple meters at one facility) should be required to purchase gas from the core portfolio regardless of total usage. If a customer is capable of purchasing natural gas for a portion of its load at one facility, then it should be able to easily extend such purchases to serve its P-1 and P-2A load as well. The critical measure is a customer's size and willingness to make fuel usage decisions. The P-1 and P-2A load of a multiple use customer will still be considered core, but will be eligible for transmission-only service and all utility procurement options.However, we deny DGS's request that it be allowed to aggregate loads from more than [*20] one facility, in order to qualify for self procurement status. While DGS and other similarly situated customers might benefit from such aggregation, it would be difficult if not impossible to restrict such activity to these customers. Until the marketplace is better developed, we conclude that small customers with no alternative fuel capabilities are better served by the utilities as part of the core market.We do find merit in DGS's argument that it be allowed to aggregate loads where it has more than one meter per facility. However, information is needed on what constitutes a customer's facility. We intend to consider this question further in the implementation hearings.We disagree both with PG&E's proposal to treat its UEG load as a separate class and with CPG's recommendation that it be included in the core market. There is a need for consistency of treatment of UEG gas needs of combined and electric-only utilities. PG&E's UEG load should be treated as any other large load. The Electric Department may choose among the same gas procurement options as any other customer with alternate fuel capabilities, and may divide its needs among the options to match load and supply [*21] characteristics if it wishes. The Gas Department should not receive special balancing account treatment for the costs of supplying UEG demands.Adopted RulesThe "core market" shall be comprised of all customers with end-use Priorities 1, 2A, and 2B. Those large core customers with usage in excess of 250,000 therms/yr may choose transmission-only service and may purchase gas from any of the portfolios available to noncore customers.The "noncore market" shall be comprised of all customers with end-use Priority 3 and below. Customers in the noncore market are eligible, regardless of size, to select among a variety of transmission and procurement options. Default service levels will be provided to customers which have not themselves made an affirmative choice among the options.The core and noncore markets are established by definition, and no switching between these two markets will be allowed.A core customer with usage in excess of 250,000 therms/yr may receive eligibility to choose among various procurement options based on its usage in either of the last two calendar years preceding the year in which a customer seeks such classification.A multiple use customer with only [*22] portions of its load falling into end-use Priorities 1, 2A, or 2B will be eligible for transmission-only service for that core portion of its load, regardless of usage.IV. Intrastate TransmissionA. Terms of Intrastate TransmissionThe rules proposed in the OIR would refine the existing two classes of short and long term transmission service. They would shorten the minimum duration of the service contracts to three years for long term transmission and to 30 days for short term transmission service. The existing requirement of a 50 percent take-or-pay provision for long term transportation contracts would be retained under the proposed rules.Positions of the PartiesTURN is the only party which objects to the reduction of the minimum term for long term contracts from five years to three. TURN proposes that if the Commission retains the three year minimum period, it should periodically review the minimum term to determine if revision is called for. TURN also objects to any short term transportation at all and refers to its comments filed in the Investigation and earlier transportation hearings.SoCal and SCE suggest that the thirty day minimum term for short term service [*23] be changed to a calendar month so it conforms with billing and contracting cycles. SoCal would refine this to the greater of thirty days or the calendar month to account for February.CIG, Palo Alto, and Pasadena argue that the distinction between long term and short term should be eliminated and only the short term option retained. CIG reasons that the "long term" is an arbitrary length of time which has no analytical basis and that cost-based rates make the long and short term distinction irrelevant. CIG contends that customers should be allowed to contract for service for as long a period of time as they desire without an artificial barrier.SoCal would limit long term procurement customers to long term transmission contracts as well.SDG&E, SoCal, PSD, and TURN support the take-or-pay provision, with some minor adjustments. PSD and SoCal recommend extending the take-or-pay period from two months to twelve months. PSD would allow force majeure or acts of god to excuse take-or-pay liabilities. TURN would call the provision "use or pay," and requests a clarification that this charge relates to transmission usage and not to demand and/or stand-by charges.SDG&E mentions [*24] that it has yet to work out an arrangement with SoCal regarding the liability for take-or–pay payments of SDG&E's customers which will necessarily transport over SoCal's system. SDG&E has agreed to serve as the point of contact between SoCal and the customers in SDG&E's service territory. However, SDG&E claims that SoCal wishes SDG&E to be responsible for the take–or–pay obligations incurred by customers in SDG&E's territory. SDG&E refuses to do this and requests guidance from the Commission on this issue.PG&E recommends replacing the 50 percent take–or–pay requirement with a payment of the additional firm service margin for any firm contract capacity not used.CIG argues that the 50 percent take–or–pay requirement is best replaced by an appropriate demand charge since the demand charge and the take–or–pay requirement are equivalent in this case. Pasadena argues the take–or–pay provision would make long term transportation unworkable for many customers.DiscussionTURN's arguments against short term transmission contracts are an effort to turn the tide. Our decision to unbundle gas service makes short term contracts a virtual necessity. We find it hard to believe that TURN [*25] seriously expects all alternate fuel customers to be able to confidently predict their gas usage five years in advance. TURN's requests must be rejected.CIG's arguments are more persuasive that there are no cost differences between long term and short term transmission service sufficient to justify a 50 percent take–or–pay requirement for the long term service without a comparable charge for short term service. We also agree with CIG that the intent of a take–or–pay requirement can be met equally well by the demand charge which is contemplated as a separate charge applied to all transmission customers. Elimination of the take–or–pay requirement is consistent with our goal to generally simplify the overall program.We conclude that there should be a continuum of contract lengths available to customers. Although the issue of transmission rates is more fully discussed in our companion decision in I.86–06–005, we note that customers will be allowed to negotiate any combination of contract length and firmness of service, and that the rate for such service will be determined through contract negotiations. As described in our rate design decision, we will establish default transmission [*26] rates and a zone of reasonableness within which negotiations may take place.Absent a signed contract, pricing terms and conditions should be based on a one month contract. Any fixed costs that are assessed to default transmission customers should be determined from either current usage or usage during the most recent comparable period (month, season, or year), depending on the structure of the fixed costs.We agree with SoCal and SCE that the term for a transmission contract should normally coincide with billing and contracting cycles, for ease of implementation. If a customer wishes separate treatment, however, the utility should provide nonstandard contract lengths on a negotiated basis with the pricing provisions reflecting any additional costs that may be incurred.We also agree with SDG&E that it should not be liable for unpaid obligations which its customers incur for transmission on the SoCal system unless it chooses to do so. One alternative would be for SoCal to provide SDG&E reasonable compensation for this collection effort. We direct the two utilities to continue negotiations on this issue.Adopted RulesTransmission service contracts shall be for a minimum period [*27] of thirty days. There shall be a continuum of contract lengths available to customers, with differences in terms among them reflected on differences in costs. No take–or–pay charges shall be assessed. Notice from the customer is required to renew a contract 15 days prior to its expiration.The term of the transmission contract should normally coincide with a calendar month; the utility should provide nonstandard contract lengths on a negotiated basis.The utilities shall provide transmission services to those noncore customers which have not signed transmission contracts with charges and conditions associated with a one–month contract. Any fixed costs assessed to default transmission customers shall be based on either current usage or usage during the most recent comparable period (month, season, or year), depending on the structure of the fixed cost.B. Security of Transmission ServiceThe rulemaking proposed that utilities offer different levels of firmness of transmission service, each level pegged to a level of curtailment. It contemplated four levels of service: Firm Level A available only to core customers which cannot fuel switch, that is, those customers in present [*28] end use priorities 1 and 2A; Firm Level B; Interruptible Level A; and Interruptible Level B. These levels of transmission service reliability would be available to customers choosing either short term or long term transmission service.The proposed rule requires that all customers in priorities 1 and 2A receive the firmest level of transmission service even though some of these customers are large enough to qualify for noncore service options. We concluded that they should not be allowed to elect interruptible transmission service to save money in the short term because they would have no other fuel of any kind available to them in the event of an interruption.Positions of the PartiesPG&E and SoCal recommend that the only service reliability option for long term transmission be firm service, arguing that short term options will be adequate for interruptible customers. TURN also recommends that all long term transportation be firm.PG&E recommends that short term transmission be allowed only on an interruptible basis.SoCal states that customers should specify a percentage of maximum demand to be served at each capacity priority.Palo Alto and Pasadena propose that Firm [*29] Level B be eliminated. There would thus be firm service for only core customers, and interruptible service with varying grades of interruptibility.DiscussionThere first appears to be a need to clarify what is meant by firmness of transmission service. This applies only to transmission within California, not to out–of–state pipelines which are not within our jurisdiction. A capacity–related curtailment would be due only to transmission constraints intrastate. We do not want the utilities or this Commission to have to determine whether the inability of suppliers to deliver sufficient gas to the California border is due to transmission or supply problems.As stated in D.86-03-057 (slip opinion at 12), a critical aspect of our unbundled rate design is the ability of customers to select whatever quality of transportation service they desire through their choice of contribution to the fixed costs of the utility system. This proposal for an economically based reliability system was a major departure from the end-use priority system that is in place today for use in the event of either supply or capacity shortages. As discussed in our decision in I.86-06-005, TURN's persuasive proposal [*30] to base rates on short-run marginal cost including a shortage cost component has given us cause to rethink our original approach, which mandated four distinct levels of service priority. As an alternative, we will allow noncore customers to negotiate a separate "priority charge" in order to improve their transmission reliability.We reaffirm our earlier proposal that Priority 1 and Priority 2A customers receive the firmest intrastate transmission priority, above all other customers. These customers require the firmest level of transmission priority because they have no alternative to utility transmission service. Priority 2B customers will have the next firmest level of transmission priority since we are considering them part of the core customer class, with many of the same characteristics as Priority 2A customers. Beyond this, we recognize that there may be noncore customers who desire transmission reliability levels more secure than other noncore customers, even in the current situation of excess utility capacity. We will, therefore, provide that the utilities may negotiate a transmission priority charge to provide enhanced reliability for those noncore customers based on [*31] their willingness to pay. Curtailment within the noncore customer class will be based on each customer's negotiated priority charge, with those customers paying the highest priority charge being curtailed last. In the event of curtailment among noncore customers paying the same priority charge (e.g. all customers paying no priority charge), curtailment will be conducted based on the end-use priority system.This adopted approach will provide a direct measurement of the value that noncore customers place on reliability, or their shortage cost, which should prove of significant benefit in future system planning. We conclude that willingness to pay is the most appropriate basis for pricing reliability for noncore customers. Customers that perceive a value to additional reliability beyond the already high level that exists today will be able to secure and pay for such enhanced service. Those customers which perceive no value to additional reliability in light of the utilities' current excess capacity situation do not have to negotiate priority charges. We note that realistically, noncore customers should practically, without exception, receive the full amounts of gas which have [*32] been delivered to the California border. To our knowledge, curtailments have been due only to out-of-state system operation, supply, or local distribution constraints, not to intrastate transmission constraints.If transmission capacity becomes constrained in the future, our adopted priority system for noncore customers should result in an economically efficient allocation of scarce capacity. As discussed in more detail in Section IX, if a curtailment situation due to transmission constraints develops, those noncore customers which have not negotiated a priority charge would be curtailed first, according to the existing end use priority system. Then, if necessary, other noncore customers would be curtailed according to the priority charge in their negotiated transmission contracts. Priority 1, 2A, and 2B customers would be curtailed last.Adopted RulePriority 1, Priority 2A, and Priority 2B customers shall receive the firmest transmission service. All other customers (i.e. noncore customers) shall be curtailed in reverse order of their priority charge. Specifically, no noncore customer will be curtailed because of a capacity limitation so long as gas is being transported [*33] or sold for anyone paying a lower (or no) priority charge. n1 Customers which pay the same (or zero) priority charge shall be curtailed according to the current end-use priority system.

n1 This rule is similar to one articulated in a paper published by Arlon R. Tussing and Connie C. Barlow, titled "The Restructuring of the Natural Gas Industry: Implications for Gas Distributors and their Regulators." Natural Gas Industry Restructuring Issues, The National Regulatory Research Institute, September 1986.

C. Changes in Transmission ServiceThe proposed rule provides that customers with short term or interruptible transmission service could change their levels of service, providing that the utility has the desired service level capacity available. These changes could occur no more frequently than once every thirty days. However, it was planned that customers which commit for long term transmission at the firmest service levels would be bound over the life of their transmission service agreements, because they have created an ongoing obligation for the utilities' system planning.Positions of the PartiesSoCal and PG&E share a concern with TURN that customers might elect low [*34] levels of service reliability during periods when capacity is most available, such as spring and fall seasons, and elect for high service reliability levels during peak demand months, if unlimited switching were allowed with no penalties. PG&E would require a thirty day notice before allowing the switching of service levels, and would allow a change of level only once every three years for customers with long term transmission contracts.SoCal and PG&E would allow customers to change service levels before expiration of their contracts only if the customer compensates the utility for all costs imposed by doing so.PSD also supports a one-time termination fee which would allow a customer to buy out of its obligation. TURN, Palo Alto, and Long Beach would prohibit the switching of firm transmission capacity to a lower reliability level. TURN would allow switching of interruptible capacity only to a higher level of service.Pasadena comments that the short term contract renders option switching for such contracts a moot point. TURN agrees that the thirty day minimum allows customers sufficient flexibility so that no switching options are needed for such customers.CIG thinks the [*35] proposed rule is unnecessary, because customers are obligated to fulfill all duties under the service contracts and remain liable for all obligations. However, CIG notes that early termination may allow capacity to be reallocated from a customer which no longer wants a given service level to one which desires that level of service.CMA raises concern about the language allowing a change in service levels whenever "the utility has the desired service level capacity available." CMA states that the context implies that the addition of another customer may reduce the reliability to customers in lower service classes. CMA wishes a clarification or deletion of this clause, and also asks that utilities be obligated to provide the firm level of transmission service.DiscussionSince the primary mode of service to noncore customers will be negotiated service contracts, we agree with the position of CIG that a proposed rule regarding changes in service levels is unnecessary because customers are clearly obligated to fulfill all duties under their service contracts. It goes without saying that customers who want to modify long-term service contracts will be liable for any losses in margin [*36] that would have otherwise been collected under their original contracts. Similarly, customers who want to upgrade their transmission service will be liable for the additional costs associated with their new service.CMA is correct that new transmission customers may reduce the reliability to customers in lower service levels, at least theoretically. We do not expect any transmission-related constraints, so there appears little cause for concern. However, customers which want assured reliability levels are free to negotiate such terms as part of their transmission contracts. It is conceivable, for example, that utilities could negotiate priority charges that vary seasonally depending on changing system constraints or on customers' varying needs for transmission reliability. In any case, we will carefully monitor our adopted curtailment system to assure that it results in an orderly and understandable process that can be relied upon in the event of a capacity curtailment.D. Notice for Maintenance ShutdownsThe OIR provided a 30 day notice period for scheduled maintenance as being more than adequate for long term transmission service. This was a revision to an earlier six [*37] month notice period.No comments were received in opposition to the 30 day maintenance shutdown notice, so we will adopt it as a maximum amount.Adopted RuleUtilities may require notice of no more than 30 days for scheduled maintenance shutdowns of facilities whose gas requirements are covered by transmission contracts.E. Maximum Amount of Short-Term Transmission ServiceThe OIR proposed to eliminate SoCal's restriction in its short term transmission tariff limiting the total amount of short-term transmission service on its system to 500,000 Decatherms per day.CIG supports the elimination of this limitation. Since no party objected to the proposal, we will eliminate this limitation as proposed.F. If Utilities Run Short of Transmission CapacityThe proposed rules provide two methods for dealing with the unlikely event that there would be more demand for firm transmission service than the utilities can provide. The rules would modify current rules that allow the utilities to reduce a customer's contractual volumes if the customer transports less than 80 percent of its daily contractual volumes during any two month period, to allow the utilities instead to reasonably limit [*38] a customer's transmission capacity for anything but the lowest interruptible level to historical demand levels. The proposed rules also provide that, in periods of excess demand, the available service to new customers would be allocated to the highest end use priority customers first. Utilities would maintain waiting lists, by end use priorities, of customers wanting the firmest service.Positions of the PartiesNo party commented that capacity shortages are a likely occurrence, and most commented that a shortage is extremely unlikely at this time. There were many different proposals regarding how to deal with such an occurrence.Regarding the issue of how to limit customers to reasonable firm contract quantities, there were two solutions proposed. PG&E, Transwestern, and CIG agree with the rule's intent in limiting customers to historical usage, but believe consideration should be given to additional information such as an increase in plant size or business trends.SoCal proposes that the 80 percent ratchet be kept, but SoCal would limit its application to situations where the utility has no other available capacity and there is a new customer which has an immediate use for [*39] the capacity.CHMA/CRA does not want contract quantities to be limited to historical use, and further wants the rule to apply only to transmission-only service and not to customers which have contracted for firm procurement service.Industrial Users supports the use of end use priorities in allocating firm transmission capacity. Long Beach and Palo Alto suggest a pro rata allocation method within priority classes.PG&E, SoCal, PSD, El Paso, and TURN all suggest that a bidding system be considered with the highest bidders receiving the scarce capacity. Recommendations regarding the classes of customers allowed to bid varied from SoCal's proposal of bidding only within a given priority class to allowing any party to bid. TURN states that the proposed rule establishing waiting lists appears reasonable if bidding is not allowed.PSD states that intrastate and interstate transmission allocation should be considered at the same time. Pasadena argues that firm capacity, beyond what is available, should not be allocated.DiscussionOur decision to allow a negotiated priority charge in noncore transmission contracts obviates the need for elaborate mechanisms such as the ones proposed [*40] in the OIR for dealing with potential excess demand for firm transmission capacity. The adopted approach of basing priority for noncore customers on willingness to pay essentially creates a self-regulating system.Several parties proposed that a bidding system be considered as a way to allocate firm transmission capacity. This interesting concept has not been developed sufficiently for us to judge its merits. A bidding procedure may be worth further consideration in the future, especially if intrastate capacity becomes constrained. However, it is our hope that the adopted provision for a negotiated capacity priority charge will be effective so that no further mechanisms need be constructed to ensure adequate transmission reliability.V. Interstate TransmissionThe OIR discussed the possible excess capacity which the utilities may have on their supplying interstate pipelines, and concluded that the Commission should wait before reviewing any proposed back-off of the utilities' capacity rights until the gas transmission program within California is established and working smoothly. However, we expressed an interest in SoCal and PG&E allowing customers, particularly wholesale [*41] customers, access to firm interstate capacity by agreeing to use interstate capacity rights on their behalf during an interim period.We required PG&E and SoCal to publish for comment their policies on the conditions under which they would agree to use their interstate capacity rights on behalf of their customers which seek firm interstate transportation, and stated that further action might be taken based on those responses.PG&E and SoCal Compliance FilingsPG&E and SoCal made compliance filings on July 7, 1986 as required by the OIR. In its filing, PG&E states that it presently intends to retain its interstate pipeline rights so long as they continue to provide positive benefits to PG&E's sales customers. PG&E believes that one important consideration bearing on the advisability of retaining or giving up firm interstate capacity is whether such capacity is a less expensive alternative than additional investment in underground storage to assure that the peak needs of high priority customers are protected.PG&E believes that customers currently transporting over interstate pipelines serving California have not found any impediment to service as a result of PG&E's firm capacity [*42] rights. PG&E states that its only choices are to retain or to relinquish its firm capacity rights, since there is not to PG&E's knowledge any mechanism for the selective assignment of interstate capacity rights to other customers.PG&E rejects what it calls a "gray market," where a customer with firm interstate capacity subleases or brokers its assigned capacity rights to other customers. It states that the FERC has characterized such an arrangement as an abuse of the first-come, first-served program it has established.PG&E concludes that it will review its projected need for firm and interruptible capacity on the interstate pipelines serving it, when it becomes appropriate, in the light of changing market conditions including the adoption of open access transportation within California. PG&E would be willing to revise its capacity rights, but only if it is clearly and demonstrably in the best interests of its sales customers.SoCal states that it is committed to the implementation of a successful transportation program on the systems of its two principal interstate suppliers, El Paso and Transwestern. It recognizes that the same balance must be achieved at the interstate [*43] level between the interests of transporters and utility sales customers as SoCal has sought to achieve at the state level. SoCal states that it is therefore willing to consider using its firm capacity rights on the El Paso and Transwestern systems on behalf of its customers which desire firm interstate transportation.SoCal strongly believes that full preservation of its capacity rights on the interstate pipelines is in the public interest and consistent with the intent of FERC Order No. 436. In current FERC proceedings, El Paso and Transwestern have offered to become nondiscriminatory transporters under Order No. 436. Both pipelines and their jurisdictional customers have endorsed settlements which would preserve the historical firm capacity rights of distributors such as SoCal either for firm sales or for firm transportation, after the pipelines become nondiscriminatory transporters.The FERC has approved the El Paso settlement and an order in the Transwestern proceeding is anticipated soon. SoCal states that once the impact of these FERC orders is assessed, it would consider using its capacity rights on behalf of its customers which desire firm interstate transportation, consistent [*44] with FERC orders and regulations and consistent with protecting the interests of SoCal's other customers.SoCal states that it cannot simply reassign its firm capacity rights to third parties, nor can it auction or sell its capacity rights. Any firm capacity rights relinquished by SoCal would most likely be deemed abandoned and reallocated on a first-come, first-served basis, with little or no prospect of reacquiring such rights in the future.SoCal states that it would not be in the best interests of SoCal's customers as a whole for SoCal to relinquish any portion of its firm capacity entitlement. It points out that one of the specific provisions of the Transwestern settlement is that SoCal will not relinquish any of its firm capacity rights on the Transwestern system during the term of the settlement and that the Commission has expressed strong support for this position as recently as in its June 13, 1986 reply comments filed in the Transwestern proceeding.SoCal lists seven conditions which it believes must be met in order for SoCal to offer balanced services to protect the interests of nontransporters. SoCal states that these must be met in order for it to be willing to [*45] consider using its capacity rights on behalf of customers which desire firm interstate transportation:1. There should be an express provision allowing SoCal to terminate use of its capacity on behalf of transportation customers on appropriate notification.2. There should be no impairment of service to higher priority customers; i.e., the end use priority system reaffirmed by the Commission in the OIR must not be jeopardized.3. There should be no transfer of interstate pipeline fixed or variable costs, or any other cost increases, from transporters to other utility customers.4. There should be no adverse impact on utility earnings.5. Any penalties incurred by SoCal under the El Paso or Transwestern tariffs as a result of accommodating transporters should be paid by those customers.6. Transporters accommodated under this program should pay any costs incurred for any failure by third parties to perform.7. The Commission should adopt specific findings and conclusions determining that the use by SoCal of its interstate pipeline capacity to carry out this program is consistent with its public utility obligation under California law.SoCal also states that some operational [*46] limitations may have to be resolved, but concludes that this would preserve the level of service to utility procurement customers at the same time it increases the reliability of transportation arrangements.SoCal points out that the statement in the OIR that SoCal has used its interstate capacity rights to provide transportation on behalf of Shell and Texaco is inaccurate. SoCal states that Shell and Texaco both entered into interruptible transportation contracts directly with El Paso, albeit "on behalf of" SoCal as required by Section 311A of the Natural Gas Policy Act (NGPA).Positions of the PartiesSDG&E, Long Beach, and Palo Alto want SoCal and PG&E to be required to use their firm capacity rights on behalf of transportation customers. Long Beach asks that the utilities be required to bargain in good faith. SDG&E concludes that SoCal's filed conditions on use of its interstate pipeline rights are reasonable on the whole; it requests filed statements and workshops on implementation of a program whereby SoCal's pipeline rights would be shared. SDG&E requests that wholesale customers be granted special treatment and be allowed to receive firm interstate commitments even [*47] if the Commission decides against assignment to other customers.Pasadena states that subleasing of interstate capacity rights may run counter to FERC policies. It cites the June 27, 1986 FERC order regarding El Paso's transportation program proposed pursuant to FERC Order No. 436. It argues, however, that the Commission should give further consideration to ordering SoCal and PG&E to give up demand rights to any excess transportation capacity they may have. It points out that, to the extent the utilities incur interstate pipeline demand charges for excess capacity, costs which potential transporters would be willing to pay are passed to all customers.Industrial Users states that the disposition in the OIR seems reasonable, i.e., that the Commission should wait until the gas transmission program is underway in California before reviewing any backoff of interstate capacity rights. It contends, however, that utilities should be required to share firm capacity rights on reasonable terms and conditions pending final resolution of the matter. It recommends that appropriate steps be taken within a reasonable time frame to effect this. Its position is that this sharing should not [*48] be limited to wholesale customers.CIG supports transactions occurring in compliance with Section 311 of the NGPA, or alternatively the conversion of a portion of the utilities' contract rights to firm transportation service. It states that interstate capacity should be allocated according to the same priorities used to allocate intrastate capacity. Any penalties should be paid by transporters only if a causal relationship is shown.Petro-Canada wants the utilities to be required to use firm capacity rights on behalf of transmission-only customers within 90 days of an order in this rulemaking. It joins with Long Beach in requesting that the utilities be required to bargain in good faith with customers wishing interstate transmission.El Paso endorses the submissions made by SoCal and PG&E. CHMA/CRA supports the use of "studied caution" in evaluating the wisdom of reducing the utilities' interstate rights, and argues that the utilities should not be required to give up rights which may be needed in future years to serve high priority customers.DiscussionThe parties' comments have done little to assuage our concerns expressed in the OIR regarding the need for further information [*49] and experience with California's transmission program before a determination is made regarding the disposition of any excess capacity which SoCal and PG&E may possess on interstate pipelines.This issue is tied closely to other gas resource planning and operational issues, including supply procurement, sequencing, and operation of underground storage. These pieces must be considered in a coordinated fashion to ensure that the utilities' operations are as efficient as possible. We plan to order further gas procurement hearings to examine these linked issues on a consolidated basis during 1987.Further uncertainty is introduced by the fact that the FERC has not yet approved the Transwestern rate case settlement which would complete the transition of Transwestern to an open access transporter in compliance with FERC Order No. 436. The only clear statement from the FERC on the question of sharing or brokering firm interstate capacity rights is to be found in its decision in the El Paso transportation tariff case (Order of June 27, 1986, in FERC Docket No. RP86-45-000, 35 FERC P61,440). In that order, the FERC specifically disapproved of a shipper reserving capacity on the interstate [*50] pipeline with the intent to broker the capacity to an end-user for a fee. The FERC characterized such activities as "an abuse of the first come/first served scheme of allocating capacity." It remains to be seen whether or not the FERC intended its comments in this are to apply to the firm capacity reserved by a distribution company through the payment of demand charges.Accordingly, we believe that the prudent course is to defer any Commission directive on the sharing of interstate capacity until the utilities' gas resource planning goals are made clear in the forthcoming gas procurement hearings and some further direction from the FERC is available regarding its ban on the brokering of capacity and the application of that ban to distributors.We note in passing that interruptible transportation agreements utilizing existing firm capacity held by the distributors and structured under Section 311A of the NGPA remain a viable option for end-users in California. We encourage the pipelines, distributors, and end-users to avail themselves of such arrangements. The current interstate capacity available would suggest that even interruptible transportation arrangements can provide valuable [*51] opportunities for end-users who seek to purchase their own gas supplies.VI. ProcurementA. Market SegmentationIn the OIR, we contemplated that the procurement market would be segmented into three basic components: the core procurement market, the noncore procurement market (both served by the utilities), and the self-procurement market (transmission-only).The core procurement market would be provided long term gas service by the utilities and would consist of core customers, which do not have alternate fuel capabilities, and elected core customers, which voluntarily choose to receive core procurement services from the utilities. Large core customers, with usage over 25,000 Mcf per year, may choose not to receive core procurement, opting instead to purchase gas either from the utility through the noncore portfolio or from other sources. The core market portfolio would include all gas sold to the core procurement customers, and would be a mix of longer term and spot supplies. The price would be the weighted average cost of the core market portfolio.The noncore procurement market would consist of those customers with alternate fuel capabilities (noncore customers), and [*52] those core customers with usage over 250,000 therms per year which desire short term gas procurement from the utilities. The noncore market portfolio would consist primarily of spot or other short term gas. The price would be the weighted average cost of the noncore market portfolio. Noncore procurement would be on a best efforts basis. Further, if there are supply shortfalls, the utilities may use spot gas originally intended for the noncore portfolio to meet the needs of core procurement customers.In general, the noncore portfolio would carry higher risks than the core market portfolio. We noted that customers which elect this level of procurement service would experience the leading edge of the market, whether it goes up or down.In the proposed rules, utilities must file cost-based tariffs for procurement services and apply them in a nondiscriminatory manner. We prohibited utilities from forming subsidiary or affiliate companies in order to procure gas for the noncore customers within their service territories.The requirement of cost-based commodity rates was proposed to ensure that in the near term the utilities will be unable to price in a manner that would exploit [*53] their current market share. We recognized that the need for cost-based tariffs might diminish once we are satisfied that a sufficient number of gas suppliers exist to prevent such activities.We noted that the proposed gas rate structure would make ratepayers as a whole largely indifferent to whether a utility or another entity procures supplies for customers which elect noncore procurement service from the utility.There are two basic directions from the proposed market structure which must be examined: towards more or less market segmentation. We could allow only one portfolio for utility procurement with averaged commodity rates, i.e., no market segmentation for utility procurement services. On the other hand, provision of an increased number of utility portfolios, special rates, rate flexibility, or utility brokerage of gas within its service territory would increase segmentation.In the OIR, we contemplated that there might be a need for some additional market segmentation in order to protect core customers against future increases in short term gas prices. We expressed concerns that there could be excessive switching by noncore customers to the core portfolio if the weighted [*54] average cost of gas for the core portfolio becomes lower than that for the noncore portfolio. The customers which switch would then gain the benefit of the core portfolio without having paid the previous higher costs, and those customers which had paid the higher costs earlier in anticipation of receiving some price security would have this benefit eroded by the switching customers.A proposed rule and an alternative proposed rule aimed at protecting core customers against this event were presented for parties' comments. The proposed rule provides that the utilities should petition to establish a separate core commodity rate for the newly arrived elected core procurement customers if, on an aggregate basis, the price of gas for the core portfolio increases more than five percent within any six month period due to noncore customers switching to elected core procurement service. The alternative rule would require the utilities to establish, from the beginning, a separate supply portfolio for elected core procurement customers.Positions of the PartiesTURN opposes the concept of even two supply portfolios for core and noncore procurement. In its view, this would institutionalize [*55] market segmentation and would inevitably result in most spot gas being targeted at large noncore customers while core customers would be saddled with the long term expensive supplies. TURN's preferred alternative is a continuation of one utility gas supply portfolio for all customers with one uniform average price. TURN states that if the Commission rejects its one portfolio concept, then elected core procurement customers should be required to purchase gas from the core portfolio so as to increase market power and price sensitivity for the core portfolio.CIG supports TURN in arguing for a single gas portfolio for all customers to provide both customers and the utilities with purchasing flexibility. Indeed, CIG argues that the OIR itself contemplates this flexibility by the proposal to use noncore gas for the core and elected core customers when there are supply difficulties. CIG asserts that if the requirement for separate portfolios is eliminated, the Commission can eliminate the proposed restraints on customer service options.SoCal states that it is open to the idea of a separate portfolio for the elected core market due to the significantly different type of service appropriate [*56] for these customers. SoCal portrays the portfolio needed by elected core procurement customers as less reliable and more price-volatile than that desired by core customers, and states that a separate elected core portfolio may protect core customers from these risks.PG&E, SoCal, SDG&E, CIG, and Industrial Users recommend that neither proposal addressing switching to core procurement services be adopted. PG&E argues that a diverse core supply portfolio with sufficient flexibility will serve to protect against core rate increases caused by noncore customers' choosing elected core procurement service. PG&E also presents a proposed alternative: it wants discretion to refuse a core election by a noncore customer if it would be demonstrably detrimental to core customers.SoCal argues that the proposed rule is not workable under certain circumstances and it would be difficult to identify the incremental contracts that should be used to set the vintaged commodity rate. SoCal argues that a rule could better protect core customers if it were designed so that when, on an aggregate basis, the marginal cost to serve a new elected core procurement customer exceeds the elected core commodity [*57] rate, the utility could establish a separate rate for that customer to reflect the difference. Under SoCal's proposal, the special rate would end at the termination of the first service contract signed by the customer.SDG&E, CIG, and Industrial Users state that it would be hard to tell if increases in costs of the core portfolio are due to an influx of noncore customers or due to other reasons. SDG&E and Industrial Users argue that the proposed rule would put an additional administrative burden on the utilities. If necessary, SDG&E and Industrial Users would choose the alternate rule which establishes a separate portfolio for all elected core procurement customers in preference to the proposed rule. Industrial Users urges the Commission not to adopt either alternative and to consider corrective adjustments only if the perceived problems actually materialize over time.CIG argues that neither rule is necessary and that giving elected core procurement customers the option of moving out of the core procurement market provides an incentive for gas suppliers to keep their core market gas prices as low as possible. CIG states that the proper objective is to foster a core procurement [*58] market consisting of a diverse group of customers and that a highly structured regulatory regime, as indicated by the proposed and alternative rules, will not provide an environment within which market forces will work.PSD supports the proposed rule providing for separate vintaged commodity rates on the basis that it provides reasonable protection to deal with any prolonged surges of customers to elected core status as well as any potential abuses. PSD suggests that there should be an absolute ban on switching to elected core procurement whenever the core portfolio is cheaper than the noncore portfolio. Of the two rules, PSD prefers the proposed rule, and opposes the alternative rule establishing separate portfolios on the basis that it would enhance market segmentation and price discrimination problems inherent in the new structure.SCE, Palo Alto, and Long Beach prefer the alternative rule to the proposed rule. SCE agrees with other commenters that it would be difficult to isolate and determine how to measure the cost increases every six months due solely to noncore customers switching to the elected core group. Palo Alto and Long Beach are concerned about the administrative [*59] burdens due to the proposed rule.The utilities and their suppliers generally support segmentation in the noncore market beyond that envisioned in the OIR. PG&E asks that it be allowed to establish a third portfolio for its own UEG load separate from either the core or noncore portfolio, as discussed in Section III of this decision. CPG asks on the other hand that UEG load be served from the core portfolio.PG&E, SoCal, and SDG&E all argue in favor of flexibility in establishing noncore procurement rates. They want the ability to discriminate among noncore customers with regard to all components of gas procurement and transmission services. SoCal also wants to be allowed to form subsidiaries to procure gas for noncore customers within its territory and states that anything less means it will be unfairly handicapped in providing service and competing with the variety of gas and alternate fuel suppliers.PG&E argues that it should be able to serve competitive customers using market-competitive services and supplies, including earmarked supplies for specific customers. PG&E also states that brokering would be a valuable addition to PG&E's offering of unbundled services and would [*60] increase the supply options for customers. Further, PG&E argues that the Commission may be operating under the misperception that PG&E would have an undue advantage in competition for brokerage services, which it states is not so since many brokers are already busy successfully offering such services to PG&E customers. PG&E states that it requires either rate flexibility or authorization to provide brokerage service within its service territory to compete in the new gas world.New Mexico wants utilities to have the opportunity to reserve gas supplies for "vulnerable" noncore customers.TURN supports the utilities in their requests for rate flexibility for noncore procurement, requesting the Commission to allow the volumetric rate to be flexible in both directions around the cost-based rate to assist the utilities to hold specific customers.PSD recommends that the issue of whether noncore procurement should be regulated be revisited after eighteen months. Transwestern goes a step further and finds no public policy reason to regulate noncore gas procurement at this time.SDG&E suggests that the Commission allow the utilities to determine individually whether they would choose [*61] to procure gas for their noncore procurement customers at all. SDG&E questions whether there should be an obligation to provide this service under the newly proposed regulatory concepts. SDG&E argues that a noncore customer can choose to become an elected core procurement customer if it wants a utility to procure gas supplies, or it can procure its own gas supplies.SCE supports the portion of the rules that requires that the tariffed rates be made available in a nondiscriminatory manner, and objects to the preferential rate treatment now afforded enhanced oil recovery customers.Industrial Users worries about the possibility of diversion of gas intended for the noncore procurement market to the core portfolio in times of tight supplies. It asks for assurance of some minimal measure of the utilities' commitment to their "best efforts" obligation to provide noncore procurement.DiscussionMany of the gas utilities, their suppliers, and large users support changes in the proposed rules that would allow the utilities to compete fully for procurement service to large customers with alternate fuel capabilities. At the other extreme, TURN and CIG argue that the utilities should [*62] essentially be required to offer only one service at averaged rates.The discussion surrounding the proposed and alternate rules has helped to focus our attention on two important aspects of procurement service. First and foremost, we share TURN's concern that the policies we adopt with respect to procurement should protect the interests of core ratepayers who lack alternatives to utility procurement service. Second, so long as the objective of protecting core customers is met, we agree with the utilities and the large users that the utilities should be free to offer procurement services to their noncore customers that are competitive with the procurement options available to these customers elsewhere.Although some commenters seem to believe that the gas utilities must be able to discount procurement service to noncore customers or to target low-cost gas supplies to these customers to retain them on the system, we see this option as being a last resort. In our view, protection of the interests of core ratepayers means that we must preclude the utilities from targeting their cheapest supply sources (given equivalent contract terms) to noncore customers, even at the expense of [*63] some loss of noncore load. Some, apparently including TURN, have interpreted this principle to mean that the utilities should use equal proportions of long-term and short-term supplies in serving core and noncore procurement. We disagree. Long-term supply contracts, at least to the extent that they provide price stability and/or supply security, are a separable commodity from short-term or spot gas supply contracts. For a given level of price stability and supply security, we will require utilities to offer procurement service to all customers, core and noncore, at the same price. For example, both core and noncore customers should receive spot gas at the weighted average price of spot bid into the utilities' system.While we will protect core customers by requiring that all gas sold from a given portfolio be priced at that portfolio's weighted average cost of gas (see Section VIII - C for adopted rule), we recognize that this policy limits the utilities' ability to compete with unregulated brokers who have much more flexibility to market gas to noncore customers. We are therefore open to the possibility of allowing utilities to offer noncore customers a different mix of long-term [*64] and short-term supply from that which is provided through the core procurement portfolio. We intend to consider the possibility of establishing multiple portfolios before we consider any individual discounting. By definition, noncore customers have supply options other than natural gas; core customers have no such options. One would expect, therefore, that noncore customers would be willing to tolerate more uncertainty with regard to future price and supply availability than would core customers. Another way of stating this difference is that noncore customers would prefer a gas supply portfolio offering a lower current price combined with greater risk of dramatic price swings and supply interruptions, whereas core customers would prefer a portfolio offering a somewhat higher current price combined with greater certainty regarding price stability and supply availability. A portfolio that meets the needs of the core may not be marketable to many noncore customers, especially since they will be able to obtain a more desirable combination of current price and risk from outside nonutility brokers.Several parties, again most notably TURN, have stressed the desirability of serving [*65] a substantial volume of noncore load through utility procurement service to retain whatever bargaining leverage larger purchase volumes and the inclusion of price-sensitive fuel-switchers gives the utilities in their negotiations with their suppliers. Since we are skeptical that significant volumes of noncore load can be served through the core portfolio, we believe these benefits are most likely to be obtained by allowing the utilities to offer multiple supply portfolios, tailored to the different needs of various customer groups. Again, if we do permit the utilities to offer multiple supply portfolios, we will preclude targeting of low-cost supplies by requiring that the price for gas of a given level of price stability and supply certainty be the same across portfolios. Furthermore, we expect that all gas sales to noncore customers would eventually be below the line. This is in keeping with our desire to minimize the risk to core customers from the business of noncore procurement. For this reason, we have also eliminated PGA treatment for noncore gas sales.We recognize that the concept of multiple supply portfolios outlined above differs significantly from either the proposed [*66] or alternate rule put forth in the OIR. To allow all parties adequate opportunity for comment on the implementation of this approach, we will consider the approval of multiple supply portfolios in our gas procurement hearings.For the time being, we think the utilities have more than enough to handle in implementing the other parts of our new approach to gas ratemaking. Until our procurement hearings can be held and the issue of multiple portfolios can be considered, we will limit the utilities to the provision of two portfolios, the core portfolio and a "best efforts" spot portfolio for noncore customers. However, we recognize that the rules we proposed in the OIR to guard against excess switching were flawed, as many commenters pointed out so well. Another approach is needed.TURN's recommendation that there be a ban on switching to elected core procurement whenever the core portfolio is cheaper than the noncore portfolio appears to be the most sound of the alternatives proposed by the commenters.The beauty of TURN's proposal is its simplicity and ease of implementation. It accomplishes our goal of preventing the overall cost of the core portfolio to increase solely in [*67] response to noncore customers switching into the core portfolio. We will therefore adopt it. Noncore customers may elect core procurement service only when the average noncore market portfolio price is less than the average core market portfolio price. When the reverse is true, the only utility procurement service available to noncore customers beyond that already under contract should be noncore procurement based on short–term gas prices.We reject SDG&E's request for utilities to have discretion regarding whether to provide noncore procurement services at all. We believe that at least one utility supply option should be available to all customers at all times. Since we have placed potential restrictions upon entry into elected core procurement, we conclude that noncore procurement should be available on a best efforts basis as originally proposed.We are also concerned that the unattractiveness of core procurement service for noncore customers is in part attributable to the probable excessive cost for long–term supply in the utilities' current supply portfolios, rather than the balance between long–term and short–term supply. In principle, we view supply costs in excess of [*68] the market value of contracts offering comparable levels of price stability and supply certainty as a "transition cost" that should be spread across all customers, rather than imposed solely on core customers. We discuss this concept more fully in Section VIII, which deals with rate design issues, including the treatment of transition costs.We need to establish the default level of procurement service to be provided to noncore customers who have not signed procurement contracts with the utilities. This default will be gas sales from the noncore portfolio. Some parties might argue that we should require noncore default customers to purchase gas from the core portfolio in order to spread the high cost of long–term supply among as many customers as possible, and to increase the market power and price sensitivity of the core portfolio. We disagree. As mentioned above, we intend to protect core customers from the cost of long–term supply in excess of its current market value by spreading any such excess costs among all customers as a transition cost. We have also previously recognized that potential benefits from the inclusion of price–sensitive fuel–switching load in utility portfolios [*69] can best be realized through the creation of multiple supply portfolios that meet the different needs of various customer groups. Furthermore, as discussed subsequently, noncore customers who elect core procurement will be required to sign procurement contracts for a minimum of one year. The main purpose of such contracts is to assure that utilities recover all unavoidable charges associated with the long–term procurement contracts they enter into on behalf of these core–elect customers. Allowing default customers, who are unwilling to sign procurement contracts, into the core portfolio would defeat the purpose of requiring core–elect procurement contracts. For these reasons, the noncore procurement default will be gas sales from the noncore portfolio.Finally, we reconfirm the proposal in the OIR that utilities should not realize any margin contribution or opportunity for profit through gas procurement rates at this time. We will explore the issue of whether to require utilities to charge brokerage fees for procurement in our future proceeding on gas procurement policy. Ultimately, we would like to unbundle any fixed costs associated with procurement from transmission rates [*70] and have them allocated with commodity rates (i.e. as a brokerage fee).Adopted RulesThe gas utilities shall offer two levels of procurement service to noncore customers: "elected core procurement" and "noncore procurement." A gas utility may not provide any other procurement services to noncore customers at this time.The utilities shall maintain two market portfolios: the "core market portfolio" to serve core customers and those noncore customers which have chosen elected core procurement service, and the "noncore market portfolio" to serve noncore customers which have chosen noncore procurement services.Noncore customers may contract with the utilities for elected core procurement services if and only if the average cost of the core market portfolio is greater than the average cost of the noncore market portfolio. At other times, the only utility procurement service available to such customers shall be noncore procurement. Core–elect customers may enter into a new core–elect contract upon expiration of their old core–elect contract.The utilities shall provide gas from the noncore market portfolios to those customers which have not signed procurement contracts but which [*71] receive utility gas.Noncore procurement shall be on a best efforts basis.B. Core Procurement1. Conditions of Elected Core Procurement ServiceIn the proposed rules, elected core procurement customers would be required to obligate themselves for a minimum of three years and would contractually be subject to a take–or–pay provision for 50 percent of the quantity they elect. The 50 percent take–or–pay provision was intended as a deterrent to customers' contracting for a quantity of core gas as a hedge and later deciding not to take it. The three year minimum was proposed to aid the utilities in forecasting their core market procurement needs.Comments were also sought on an alternative proposed rule, which would make a decision to receive elected core procurement services even more consequential. In addition to the three year commitment and 50 percent take–or–pay provisions, under the alternative proposed rule customers would have a one–time–only opportunity to choose elected core procurement. Any elected core customer which subsequently chose to terminate its core procurement service would not be allowed to regain it at a later date.Positions of the PartiesPSD, SoCal, [*72] Transwestern, Industrial Users, and New Mexico support the proposed three year minimum obligation and 50 percent take–or–pay liability. It is PSD's opinion that this would protect all ratepayers and the utilities from opportunists and without these requirements the elected core procurement customer could opt off core service for short periods when the price is right, coming back with impunity if market conditions change. PSD recommends that the take–or–pay provision should operate such that mitigated damage payments are based on a customer's take over an annual period. PSD suggests the Commission order respondent utilities to confer and devise uniform take-or-pay administrative provisions including force majeure clauses, and file them as tariffs.SoCal proposes that the 50 percent take-or-pay requirement be tempered by allowing elected core procurement customers a once-a-year opportunity to change the annual elected core procurement volume by up to 15 percent relative to existing contract quantities for the remainder of the contract with a reasonable fee imposed for any such changes.Transwestern agrees with the Commission's proposal on the basis that some level of mutuality [*73] of obligation is critical to long term contracts between a utility and its customers. Its position is that the utilities should have the right but not be obligated to provide core procurement service for noncore customers.Industrial Users notes that the three year obligation is consistent with the minimum term proposed for long term transmission service. Industrial Users would like confirmation of the noncore customer's right to request elected core procurement service for only a portion of its gas requirements.PG&E opposes the three year minimum and 50 percent take-or-pay obligation. PG&E argues the 50 percent take-or-pay provision is not an accurate measure of compensation needed to make ratepayers indifferent if a customer decides to terminate its core procurement service. PG&E proposes compensation equal to the commodity rate differences between core and noncore procurement rates times the contract quantities through the end of the contract.TURN argues the three year commitment is too short and suggests that at least five years, or better ten years, would correspond to the duration of the obligations the utilities will incur on their customers' behalf. TURN's opinion [*74] is that the 50 percent take-or-pay obligation is counterproductive, and elected core procurement customers should be free to switch to alternate supplies so long as they pay any resulting costs that would fall on core customers. TURN's proposal for the elected core customer fuel switcher is an unavoidable or minimum charge which includes any take-or-pay costs, minimum bill obligations, or supply reservation charges attached to the displaced gas purchase. TURN recommends this charge be equal to the difference between the average core portfolio cost and the true marginal cost of the supply that is rejected because of the fuel switch.SCE prefers a one year minimum commitment and elimination of take-or-pay obligations. SCE suggests the rule be revised to give affected parties flexibility to enter into arrangements involving minimum obligations of one year if the utility and its customers are willing to do so. Furthermore, SCE states parties should be free to negotiate commitments which are required and agreeable based on current and perceived market conditions, and that elected core procurement customers should assume such obligations only to the extent their election of core procurement [*75] causes the serving utility to incur such obligations to its suppliers.CHMA/CRA opposes the conditions for elected core procurement on the basis that it would be unreasonable discrimination to impose minimum service terms or take-or-pay obligations on customers which have never opted out of the full scope of utility services and have no practical ability to do so, based solely on the volume of their gas usage. CHMA/CRA asks that all P-1 and P-2A customers be treated as core unless they choose otherwise. CHMA/CRA suggests, however, that P-1 and P-2A customers which choose noncore service should only be allowed to rejoin the core procurement market as elected core customers.CMA is of the opinion that there is no basis for the 50 percent take-or-pay requirement unless the utilities guarantee that at least 50 percent of contract quantities for elected core procurement customers will be secured at all times. Furthermore, CMA feels the charge is not justified unless the utility incurs take-or-pay obligations itself. CMA also wants to know how specific the contracted quantity of gas must be and whether it can vary monthly.CIG recommends a single season (or alternatively a one year) [*76] minimum obligation period rather than the proposed three years. CIG argues the three year period will distort price signals and utilities will be making yearly forecasts concerning the number of customers likely to continue in the core market anyway. CIG states that the freedom to elect different service options provides a mechanism by which customers may transmit to utilities economic signals as to the desired quality of gas procurement, and provides a strong incentive for utilities (and in turn pipeline suppliers) to do the best job of acquiring gas.CIG also opposes the 50 percent take-or-pay requirement, and argues that this rule indicates a flawed desire to discourage industrial customers from electing core procurement service. It is CIG's opinion that since elected core procurement customers would also be subject to a transmission demand charge, this should provide adequate incentives to ensure that customers will meet their obligations under their procurement contracts.PG&E, SoCal, SDG&E, SCE, PSD, TURN, Transwestern, Industrial Users, CMA, CPG, and CIG all oppose the alternate rule of a one-time-only election by noncore customers to have the utility procure gas supplies [*77] on their behalf. Most of these parties are of the opinion that this rule is too restrictive.PG&E argues that qualifying customers should have the opportunity to experiment with other procurement options without the threat of losing the option to return to elected core procurement service and that there are clear advantages to promoting core procurement service for these customers. PG&E proposes that elected core procurement customers which wish to break their contracts be obligated to pay the premium that they would otherwise have paid using the rate differentials between the core and noncore portfolios in effect at the termination of elected core procurement service.Likewise, SoCal proposes that the rule be modified to allow eligible customers to move to or from elected core status, as long as they pay a fee that reflects the cost that this may impose on the rest of the utility system.CPG suggests that to the extent which there are costs borne by core customers as a result of elected core customers leaving the core portfolio, these costs should be quantified and assessed to those responsible for them. TURN suggests that the rule should be more stringent: there should be [*78] an absolute ban on switching to elected core procurement whenever the core portfolio is cheaper than the noncore portfolio. On the other hand, TURN states that noncore customers should be allowed to opt into the core portfolio freely any time the noncore procurement portfolio is lower in average price. TURN points out that its preferred alternative of only one portfolio would prevent this problem of "portfolio shopping."PSD argues that the one-time-only election is "overkill" and submits that the safeguards of other proposed rules are adequate to deal with any prolonged surges of customers choosing elected core procurement. SCE's opinion is that the rulemaking should be kept as simple and general as possible to give the California gas utilities and their customers needed flexibility, and the one-time election limitation could be imposed at a later date if needed.Given the substantial commitment of a three year minimum contract length and a 50 percent take-or-pay provision, Industrial Users argues that core market elections by noncore customers will work to the advantage of core customers, and the one-time limit would impede the beneficial effects of gas market competition. [*79] CMA argues that customers should be allowed to move freely from one status to the other as long as the three year contract requirement is maintained. CIG argues the one-time-only election is unduly restrictive and counterproductive, and elimination of customers' ability to choose core procurement at any time would put the utilities in a less attractive bargaining position regarding procurement of gas supplies for core customers.New Mexico supports the restriction against a customer's leaving core procurement service once elected, so that appropriate planning may be conducted by suppliers.DiscussionWe find compelling the arguments of various parties that the proposed restrictions on elected core procurement would be too onerous and would discourage participation in the core procurement efforts of the utilities. We must be mindful that there may be some benefits to core ratepayers to be gained at this time from the creation and retention of an elected core customer group.Consistent with our overall ratemaking policies, restrictions on the ability to choose or terminate elected core procurement service should be based on the economic consequences of such actions. Because existing [*80] utility procurement contracts are in excess of current demand and there is considerable flexibility in the level of takes from these contracts, it is not as critical that the utilities have the advance knowledge of future elected core demand afforded by the three year contract minimum proposed in the OIR. We agree with SCE that a one year minimum is more appropriate at this time. If the nature of the core portfolio changes over time so that utilities are indeed faced with the possibility of entering new financial commitments in excess of one year, then the minimum contract period may need revision at that time. For example, if we move towards the use of multiple portfolios, we would expect that contractual commitments would be tied to the term of the portfolio from which customers elect to purchase.We conclude for similar reasons that a 50 percent take-or-pay provision is unwarranted at this time and could be detrimental to our stated goal of encouraging elected core participation. We agree with TURN that, instead of a take-or-pay obligation, elected core procurement customers which do not use their full contracted quantities on a yearly basis should be liable for unavoidable [*81] or minimum charges which would reflect any take-or-pay costs, demand charges, minimum bills, or supply reservation charges which the utility incurs as a result of that customer's failure to purchase its contracted amount of gas.As discussed elsewhere in this decision, all such charges are now allocated to transmission charges; because of this there is no need for an unavoidable or minimum bill for procurement at this time. However, if new fixed charges are incurred to meet core procurement needs in the future, we contemplate that such a charge would be established at that time.The concept that elected core procurement charges should be based on costs actually incurred is appropriately applied to termination provisions as well. Termination provisions should assess the unavoidable/minimum charge over the remaining life of the procurement contract, based on contract commitments that have been incurred at the time of termination.Regarding CHMA/CRA's requests, we have already clarified that P-1, P-2A, and P-2B customers will be able to receive core transmission-only service if they meet the minimum usage requirement. CHMA/CRA's suggestion that core customers who elect transmission-only [*82] service can only return as elected core procurement customers is a good idea and will be adopted. We note that this rule prohibits core transmission-only customers from getting back into the core portfolio once spot prices rise above the cost of the core portfolio.SoCal's proposal to allow changes in contract volumes of up to 15 percent per year with a reasonable fee is unnecessary in light of the minimal termination fees envisioned at this time. Customers may specify different volumes of gas each year if they do not expect their demands to be maintained at current levels.To respond to CMA's request for clarification, there is no need to specify monthly contract quantities since the contemplated unavoidable or minimum charges would be based on yearly, not monthly, takes. At Industrial Users' request, we also clarify that noncore customers may choose elected core procurement for only a portion of their gas requirements if they wish.Adopted RulesContracts for elected core procurement will be for a minimum of one year. Elected core procurement customers which do not use their full contracted quantities on a yearly basis will be liable for unavoidable or minimum charges to [*83] reflect any costs which the utility incurs as a result, excluding costs allocated to transmission charges. Termination provisions shall assess the unavoidable/minimum charge over the remaining life of the procurement contract, based on utility commitments incurred at the time of termination. These termination fees shall be spelled out in the contract and shall represent estimated unavoidable minimum charges that would be incurred at the time of termination.Core customers which opt out of core procurement service can only return as elected core procurement customers.Elected core procurement contracts shall specify yearly contract amounts. A noncore customer may divide its load among procurement options.2. Core Procurement PoliciesIn the OIR, we proposed a slight modification to PSD's view of howw the utilities should procure supplies for the core market portfolio. Under this approach, the utilities should balance procurement goals of certainty of supply, minimization of costs, and minimization of sudden price swings. We stated that the portfolio should be balanced so that in a normal year some spot or short term gas purchases would be taken, with those purchases increasing [*84] in cold years. We also concluded that supply security is not the driving force in setting procurement policies at this time.The OIR also provided guidelines for the gas utilities to follow in administering their core market portfolios. These guidelines focus on relationships with affiliated entities, the reasonableness of take-or-pay provisions, and flexibility in pricing terms. We asked parties to specifically address the issue of how to define supply security and to comment on what level of security is appropriate for core customers.Positions of the PartiesSoCal, PG&E, and SDG&E are generally in agreement with the stated objectives in constructing gas supply portfolios but all three objected to the proposed specific guidelines regarding both the composition of the portfolios and the contractual terms. The preferred alternative of the gas utilities is freedom to construct gas portfolios according to market conditions. The utilities emphasized that the reasonableness review procedure is the appropriate mechanism for Commission involvement in the utilities' gas contracting strategies.SoCal argues that the objectives stated for portfolio construction (supply certainty, [*85] cost minimization, and price stability) are mutually inconsistent and require a balanced judgment. Specifically, SoCal warns that the Commission should not allow supply security or price stability to become secondary objectives to short term cost minimization. Further SoCal argues that the proposed guidelines improperly focus on contract terms and that evaluation of the core portfolio performance in achieving the objectives is only feasible over the longer term, five years or more.SoCal, PG&E, and SDG&E disagree with the proposal to balance the core portfolio by taking some spot or short term gas in a normal year and more in a cold year. The utilities reason that it is exactly in a cold year that spot gas supplies will be most unreliable and highest priced. SoCal and PG&E point out that their existing long term contracts are already responsive to spot market conditions; hence they believe that the directive to include spot gas in this portfolio is redundant since price responsiveness already exists within the framework of dedicated long term contracts.PG&E contrasts a recent GAC decision, which provides PG&E considerable management discretion in gas purchasing, with the "rigid [*86] core market procurement rules . . . advanced by the Commission in this proceeding." PG&E reasons that specific Commission rules regarding portfolio construction and contractual terms would provide suppliers with advance knowledge and weaken PG&E's negotiating leverage. PG&E, pointing to its long term dedicated supplies that have spot market price responsiveness, argues in favor of only one core gas supply portfolio that has a mix of all supply sources.SDG&E echos SoCal's and PG&E's comments regarding the view that properly structured long term contracts can achieve both supply reliability and the ability to either price some of this supply at spot prices or swing to spot gas alternatives. SDG&E goes into some detail describing contracts and markets to support its beliefs that there are many gas acquisition strategies that can meet the Commission's goals and that Commission specification of supply elements or contractual terms would limit the creativity and flexibility of the utilities in meeting these goals.SDG&E asks the Commission to explain the term "vintaging" as used in the proposed rule regarding guidelines for new core procurement contracts.PSD's specific comments on [*87] these rules are brief, responding to concerns regarding producer take-or-pay charges in the OIR. First, PSD argues that any such take-or-pay payments passed through to ratepayers should be added to the cost of gas from that particular supplier for gas sequencing purposes. Second, PSD anticipates that the FERC will provide a specific additional rule that any take-or-pay terms exceeding 50 percent for gas released under its Order No. 451 are presumptively unreasonable.TURN has no objections to the guidelines set forth for core portfolio construction, but sees little likelihood that such guidelines will endure because it believes that the utilities will exert constant pressure over time to change these policies in favor of guaranteed long term contracts.Transwestern states that its gas portfolio is consistent with the Commission's guidelines. Because of this, it argues, SoCal should use the Transwestern portfolio and should have some responsibility for take-or-pay costs from Transwestern's producers. It also cautions that contract renegotiations involve costs which customers should bear since they are the beneficiaries.Industrial Users and CIG generally agree with the proposed [*88] objectives for gas portfolios. However, CIG argues that it would be a mistake for the Commission to regulate extensively in this area and that the Commission can do little more than provide guidelines and apply those guidelines in reasonableness reviews. CIG states that the Commission should not routinely second guess the utilities' decisions. El Paso asks for public legislative-style hearings on gas procurement policy.Pan Alberta argues against specification of maximum acceptable take-or-pay levels for gas portfolios. It reasons that take-or-pay levels are only one item in gas supply contracts and that the Commission cannot judge the reasonableness of actions without considering all contractual factors.Tenneco/CONOCO urges the

Commission to adopt specific guidelines for the purchase of gas from affiliates, stating that utilities should bear the risk of supplies from affiliated pipelines more expensive than from unaffiliated pipelines.New Mexico argues against restricting the utilities' ability to deal for dedicated acreage by specifying spot gas purchases and 50 percent take-or-pay limits. In a similar vein to El Paso, New Mexico urges the Commission to hold evidentiary [*89] or at least legislative style hearings regarding supply procurement policies.On the issue of supply security, SoCal states that it is unacceptable to curtail core customers, and that utilities must have dedicated long term gas supplies to serve this market. SDG&E states that supply security is the utility's ability to serve its core and elected core loads in a normal year.Transwestern believes that a very high level of security and a conservative approach are appropriate in securing gas supplies for core customers. It contends that noncore gas should not be diverted to the core portfolio when that portfolio runs short. It argues that the two pools of gas should be kept separate; otherwise core customers would get the benefit of extra gas supply during supply difficulties without paying any charge for this gas.Industrial Users also worries about diversion of noncore gas to the core portfolio. It asks for assurance of some minimal measure of the utilities' commitment to their "best efforts" obligation to provide noncore procurement.Long Beach, Pasadena, and Palo Alto all emphasize that there is no single definition of security of supply, and the level of spot gas available [*90] will depend not on this Commission's mandate but on market conditions. They suggest that this topic be further discussed in offset proceedings.CIG states that the only answer to definition of supply security may be the level of security for which one is willing to pay. CMA believes the proposed core procurement policies do not sufficiently emphasize what it views as the complete security required for P-1 and P-2A customers.CHMA/CRA is greatly concerned about the security of supply for core customers and states that the Commission may be paying insufficient attention to this criterion. Accordingly, it argues for sufficient firm supply gas contracts to assure service to all high priority customers during a cold year.CPG states that supply security is the most vexing and crucial issue faced by the Commission. CPG emphasizes its views that there are certain fundamentals in the gas business and that if the Commission ignores these fundamentals by creating a regulatory environment which promotes short term spot purchases, the result will be gas shortages since reserves cannot be developed and maintained on the basis of 30 day contracts. CPG contends that the Commission should [*91] specifically recognize the value of long term supplies in the core market portfolio and find that firm supplies are required sufficient to meet core customers' cold year demands.DiscussionCore procurement policy is a crucial piece of our new gas regulatory structure. With intrastate transportation, noncore customers have the means to procure gas to suit their individual preferences. We are left with the task of providing for gas procurement service in a competitive supply market for the "captive" core - customers who for the most part do not have an economic alternative fuel option and who are too small to purchase their own gas supplies. Until such time in the evolution of the gas industry that core customers, or some other agent acting on their behalf, can reasonably provide for their own procurement needs in a deregulated and potentially volatile supply market, the local distribution utility subject to our oversight must assume this role.In the proposed OIR we described in general terms our procurement goals - balancing certainty of supply, cost minimization and avoidance of sudden price swings. As SoCal notes, implementing these objectives in constructing a core portfolio [*92] involves tradeoffs. Thus, we need to clarify our concerns and define procurement priorities for the core market. Given the importance we attach to this core procurement function in a newly competitive market, it seems appropriate at the outset to set down a few key principles which will guide the development and implementation of our procurement policy.Risk:Many parties have commented on the desirability of reducing "uncertainty" in the core portfolio. In the proposed OIR we shared a concern for core supply security, and we will now try to be more specific in defining what we mean by "uncertainty" of gas supply.As parties discuss uncertainty in the gas supply market, we note that they address a common concern that future market conditions cannot be forecast exactly. In defining our core procurement policy, we prefer to replace the term "uncertainty" with the term "risk" as it applies to measuring variation around some expected value. In a price-deregulated market, we recognize that there exists a probability distribution around any expectation of future gas market conditions. Our use of the term risk captures this common concern with the variation in possible outcomes [*93] around some predicted market condition, whether it be a prediction of price or of supply availability.Price Security:As we stated in the proposed OIR, we believe that natural gas supply availability is not a major concern in a deregulated, competitive supply market. The economic implication of the NGPA and subsequent federal actions indicate that given transmission access buyers will be able to secure whatever quantity of gas they desire at a price sufficient to compensate producers for the cost incurred to develop the resource. In this sense, federal energy policy has replaced price security, accomplished through wellhead price controls, with greater supply availability security.Based upon our view that changes in the market price will determine the quantity of gas supply available in the deregulated, competitive gas supply market, it follows that the risk gas buyers confront is the probability that the market price in the future will vary, both upward and downward, from today's price and from future price predictions. This price risk is the concern which led us to conclude in the OIR that one objective of the core portfolio is the avoidance of sudden price swings.In clarifying [*94] this objective we recognize a fundamental assumption underlying our core procurement policy goals – we assume that the core market is price risk averse and therefore places a value on price stability that can potentially be achieved through long–term contracts. In fact, we believe price risk aversion can usefully define our distinction between the core and the noncore. We perceive that noncore customers, those with access to alternate fuels and/or gas transportation service, are less price risk averse than core customers. This is the key realization that drives our policy of "segmenting" the consumption market and focusing so carefully on crafting a core procurement portfolio while minimizing our role in determining noncore procurement preferences.Although we view the opportunity to exploit downward variation in gas prices as a benefit for the core, we do not anticipate that utilities will be able to secure supply contracts for the core portfolio which permit only downward price adjustments. Given our assumption of core price risk aversion and our belief that a competitive commodity market implies price variation both above and below an expected value, we place a positive value [*95] on reducing market price volatility in the core portfolio. This value in moderating market price swings can be secured in the market at no cost only if the supplier is as equally price risk averse as the core. If, as several parties implicitly conclude, gas producers are less price risk averse than the core, then we expect the core would have to pay a positive risk premium in order to induce the producers to agree to an arrangement which moderated market price swings.The question of whether and how large a premium must be paid by the core to secure a means to moderate swings in the cost of gas over time is an empirical question. No party has yet supplied us with sufficient market evidence which would permit us to decide at this time whether and how much we are willing to pay as a premium over current market price to achieve any degree of price security in the core portfolio. We expect as buyers and sellers with various degrees of price risk aversion begin to shape new supply arrangements, the market will gradually reveal an efficient form and magnitude of risk premium required, if any, for any specified level of price security.Our price risk conclusions for core procurement [*96] policy are as follows:1. core customers are more price risk averse than noncore,2. the cost required, if any, to achieve any given level of price security is unknown at this time,3. how much price security we are willing to buy for the core portfolio depends upon the price premium, if any, associated with achieving that degree of security, and4. until we gain a better understanding of the deregulated supply market we instruct the utilities generally to structure the core portfolio so as to moderate to some extent the upward variation in prices in exchange for likewise foregoing the full magnitude of downward price variation.As a final observation, we recognize that this core portfolio goal of price security is premised on our assumption of core price risk aversion. If in time we are convinced that this assumption is invalid, we will in turn de–emphasize price security as a core portfolio goal.Swing Security:Previously we indicated our belief that gas supply will be available at some price in a price deregulated supply market. Some parties have cautioned that while this may be true, in general, the Commission must be concerned with assuring firm supply deliverability [*97] for the core on peak. These comments address two issues: lags in the supply response to increases in demand on peak (presumably accompanied by price increases), and physical capacity constraints on the interstate pipeline and storage facilities designated to serve the core market. The latter concern is addressed in other sections of this order where we propose to investigate interstate capacity and storage facility operations in a later forum. Here, we address the concern with the lag in the supply response on peak.SoCal and PG&E now meet winter peak load through a combination of storage system withdrawals and increasing volumes of interstate gas supplies. The utilities today have a choice between essentially two types of supplies on the interstate systems. They can increase spot takes or they can increase takes of pipeline system supply, gas dedicated by contract to the pipeline and regulated under the FERC PGA mechanism.In the proposed OIR we established a guideline that the core portfolio should always include some spot gas and in a cold year spot gas takes should increase. We share the concern of some parties that spot gas contracts are on a best efforts basis and that [*98] it is precisely during peak periods when the utilities attempt to increase spot takes that spot supplies nationwide will be most scarce. Certain parties imply that seasonal load variation means that there exists a chance that supply will be insufficient to meet core peak demand. They conclude that to eliminate the risk of peak supply availability the utilities should rely on pipeline system supplies to serve most or all core cold year requirements.We question this policy conclusion for two reasons. First, in our view the utilities generally will be able to buy whatever quantity of spot gas they require on peak although the spot market price may rise quite dramatically to allocate scarce supplies. Second, relying on pipeline system supplies for peaking purposes is not a costless strategy. Provided these supplies are dedicated to the pipeline, we can rely on them to serve core requirements on peak. However, because these supplies normally cannot be marketed to any other buyer at any time during the year, producers demand some form of compensation (traditionally a take or pay agreement) for holding these reserves and the production capability on call when customers require more [*99] gas.What we proposed in the OIR was essentially a policy of buying firm pipeline supplies for baseload needs and rely on short–term supplies for peak needs. It appears today we face a choice of three strategies: a) pay whatever is required in the form of take–or–pay or some other form of producer payment to compensate suppliers for holding dedicated reserves on a year–round basis merely to satisfy cold year peak requirements, b) pay the expected value of taking greater volumes of price risky spot gas on peak, or c) some combination of a) and b) where the utilities swing on a mixture of spot and, pipeline system supplies.Once again, we have insufficient data upon which to specify our core portfolio goal in terms of meeting core peak requirements. In addition to this swing purchasing strategy question, there are the questions of optimizing storage and interstate pipeline capacity, all of which need to be resolved comprehensively to define the supply availability objective of the core procurement policy. Therefore, we defer adopting guidance for utilities on the level of pipeline system supplies appropriate for the core portfolio, but we remind them of their responsibility to [*100] guarantee supply availability for the core at the lowest possible cost.Transitional Strategy:Prudence of the utilities' contracting, sequencing, and storage operations is a moving target, and any implementation rules which we adopt must be reviewed frequently in the existing market conditions. For now, we will adopt procurement rules similar to those in the OIR. We direct the utilities to construct core portfolios which achieve our objectives of guaranteeing some degree of price security relative to spot market prices, an adequate amount of swing security, and of attaining both objectives at the lowest possible cost required by the market.We reject Tenneco/CONOCO's request for specific guidelines for the purchase of gas from affiliates as an unnecessary reiteration of the guideline already proposed in the OIR, which states that affiliated entities will receive the closest scrutiny because of the obvious potential for "self-dealing" at the expense of core obvious potential for "self-dealing" at the expense of core ratepayers and nonaffiliated pipelines. This should forewarn the utilities that any supplies from affiliated pipelines more expensive than other supplies will be [*101] carefully scrutinized and will require justification by the utilities regarding their reasonableness.In response to SDG&E's request for clarification, "vintaging" as used in the proposed rule means the utilities should stagger the termination dates of any fixed price provisions in purchase contracts so that there are not large price shocks as contracts expire or are renegotiated.The question of pricing certainty is central to the evaluation of the extent to which utilities should rely on long-term versus short-term gas supply contracts. In the face of adequate supply (at some price) a primary value of long-term contracts would be to provide some pricing certainty. In fact, given our view that short-term supply will be available at the market price, long-term contracts with short-term pricing adjustments look quite similar to a series of short-term contracts. The floating price terms that apparently determine the sale price in many existing long-term producer contracts mean that these contracts provide the core with very limited pricing security. While this may be in the core's best interests in the current market situation, we are concerned, given core price risk aversion, [*102] that these contracts offer little protection against future upswings in gas prices.We need now to define what we mean by a long-term contract which provides pricing security. We focus on the contractual provision which determines how frequently and by what means the total cost of gas (total price times total quantity) can change. At one extreme we imagine a contract which fixes for the duration of the term the per unit commodity price and fixed gas charge, if any, for a total quantity of gas. At the other extreme we imagine a contract which specifies over the term of the contract a means of moderating the total cost of gas (commodity and/or fixed charges). The latter contract might include a five-year contract with an annual price redetermination provision which adjusts the commodity price to match the current spot price. We suspect that the market will develop a wide range of contractual forms from purely best efforts spot contracts to firm, multi-year fixed price (commodity and fixed charges) deals.In our view the answer to the debate over how much long-term versus short-term supplies belong in the core portfolio really depends upon how much price security long-term contracts [*103] provide relative to short-term sales. This analysis suggests the importance of price in distinguishing short from long-term contracts. Clearly, spot contracts are short term because the contract price remains unchanged for only a month or less. Our definition today of where short-term ends and long-term begins is necessarily artificial given that we expect the market to develop standard contractual forms for buyers and sellers wishing to exchange gas on a fixed price basis for a term greater than one month.However, in order to give the utilities some direction on what supply arrangements they should investigate for the core portfolio, we will define a long-term contract as one offering a fixed gas price for one year or more. An intermediate-term contract offers greater pricing security than a standard spot agreement but does not guarantee a single gas price for at least one year. In the procurement hearings we will initiate, the utilities should research the current supply market and report their views on the cost required to secure various types of long and intermediate-term contracts.As more experience is gained with a competitive gas marketplace, more insight will be gained [*104] regarding the levels and types of contract security which are reasonable for core customers and desired by elected core procurement customers. Elected core will be those noncore customers with a similar price security preference as the core. They will share the mix of gas supplies purchased for the core. As more noncore customers elect to join the core portfolio the utilities will buy more gas in the same mix of spot, intermediate and long-term contract so that the core portfolio generally has the same percentage of spot, intermediate, and long-term supplies.As discussed elsewhere in this decision, we are planning for further hearings next year on several interrelated gas planning and procurement issues. We plan to investigate the appropriate mix of spot, intermediate, and long-term supplies and the types of suppliers willing to offer the core different types of contracts. We decline to adopt sequencing guidelines at this time, but remind the utilities of their responsibility to guarantee supply availability for the core on peak, to provide a measure of price security and to achieve both objectives efficiently.Adopted RulesThere shall be annual reasonableness review of [*105] utilities' gas purchases to serve core procurement needs.Utilities shall undertake to procure for their core procurement customers a supply portfolio which reasonably results in certainty of supply availability to serve core peak requirements, price security greater than can be achieved by relying totally on spot or other market price sensitive supply sources, and which attains these objectives at the lowest possible cost. The core portfolio should generally contain some percentage of spot or short-term market responsive supplies.Utilities must aim for flexibility in obtaining gas with a combination of fixed and variable pricing terms. Until the Commission determines more clearly the cost associated with achieving any given degree of price security, we direct the utilities generally to balance the potential cost of periodic run-ups in price with the potential benefits of periodic soft markets.Supply contracts with provisions for price renegotiation must permit the utilities' core customers a fair opportunity to benefit from falling gas prices. Any contracts purchasing gas supplies under fixed price arrangements should be vintaged to hedge the risk of rising or falling prices. [*106] Gas acquisitions from affiliated entities will receive the closest scrutiny because of the obvious potential for "self dealing" at the expense of core ratepayers.C. Noncore Procurement1. Noncore Procurement PoliciesThe noncore portfolio is intended to consist primarily of spot or short term purchases, with the commodity rate being the average price in the noncore market portfolio. Utilities would be required to exercise best efforts to secure a supply for noncore procurement customers. However, if there are supply shortfalls, then the utilities may use spot gas originally intended for the noncore portfolio to meet the needs of customers which have contracted for core procurement services from the utility.Positions of the PartiesPG&E argues that it should have the freedom to secure gas with whatever characteristics best meet the needs of its noncore procurement customers. PG&E desires the flexibility to purchase supplies under whatever arrangements will allow it to be competitive in the noncore market, including ear-marked supplies for specific customers.PSD believes procurement for noncore customers should be examined after eighteen months, with the aim of deregulating [*107] after two years if core customers can be adequately protected absent noncore regulation.New Mexico states that the statutory obligation to provide service means utilities must obtain some long term supplies for noncore customers, and requests hearings on this matter.CPG and Tenneco/CONOCO argue that the utilities should not be precluded or discouraged from securing long term supplies for noncore customers. CPG states that the Canadians offer pricing flexibility within their dedicated long term supplies so that long term gas contracts can still offer the pricing flexibility desired in the noncore portfolio.Tenneco/CONOCO states that the noncore portfolio could and should contain long term gas and not just spot gas. This step, it argues, would be helpful in maintaining less expensive supply for the core portfolio because it would maintain higher load factors for existing suppliers and lead to greater exploration and development efforts. In its view, a restriction on long term supply to the core market only would not be a sufficient guarantee of the maintenance of such supply since this load is highly seasonal. Because of this, it warns that the utilities could experience supply [*108] shortages if large volumes of the noncore market suddenly choose elected core status when spot supplies decline.DiscussionThe request that utilities be able to secure long term supplies for noncore procurement customers runs counter to our intent in establishing the noncore portfolio. Its purpose is to provide service to those customers which do not want to commit to purchasing gas beyond their immediate needs and which are willing to take the price risk attached to such short term purchases. Customers which want to ensure that exploration and development efforts are undertaken to meet their needs should either buy gas through the core portfolio or enter into their own long term contracts.We disagree with New Mexico's comments regarding the responsibilities attached to the statutory obligation to serve. The utilities will offer customers the option of long term gas supplies through the core portfolio. Customers which choose noncore procurement services are voluntarily accepting a potentially lower level of service in return for the current favorable prices and the lack of long term commitments on their part. These customers have the option of receiving long term procurement [*109] through joining the elected core class if this is what they desire.As discussed earlier, we intend to explore the concept of multiple supply portfolios during procurement hearings in the near future. Multiple supply portfolios would provide the utilities with additional flexibility to meet the diverse procurement needs of noncore customers. Procurement hearings would also offer parties the opportunity to consider the issue of deregulating noncore procurement as recommended by PSD.Adopted RuleUtilities shall undertake on a best efforts basis to procure gas for their noncore procurement customers a portfolio of supply consisting of spot or short-term gas.2. Conditions of Noncore Procurement ServiceSome of the parties have contemplated that customers would sign long term contracts for the utilities to procure gas through the noncore portfolio for them. It is not clear what purpose this would serve given the structure we have adopted for noncore procurement, i.e., best efforts short term gas purchases. The utilities would not incur any different costs in meeting the demands of customers with long term contracts than in serving other noncore procurement customers. By its [*110] nature, the noncore market portfolio would involve no fixed costs for purchases beyond the month at hand.For these reasons, the noncore procurement contract should essentially be month-to-month. Minimum bills and other contract provisions should mirror the utilities' costs in procuring short term gas supplies.Adopted RuleContracts for noncore procurement will have a 30 day notice provision for termination by either party. Minimum bill and other contract provisions will mirror the utilities' costs in procuring gas in the noncore market portfolio.D. Marketing Outside of Utility Service AreaThe OIR set forth proposed rules by which utilities could procure and market gas for sale outside their service territories. Under these rules, the utility and/or its affiliate must account below the line for all expenses and revenues associated with the service; they cannot share resources or information between monopoly transmission and utility procurement operations and the extended area marketing or brokering activities; they must report income as utility income and make their accounting records open to review by our Public Staff Division; their actions must remain subject to reasonableness [*111] review; and core customers must not bear any expense for lawsuits alleging anti-competitive behavior due to such activities.These rules were set forth as proposed safeguards and incentives to reduce the possibility of unfair competition by utilities or affiliates which broker gas outside their service territories and to prevent the subsidizing of nonutility activities by ratepayers. We agreed to permit utilities to compete outside their service areas as brokers to enhance the development of a competitive procurement market, which is one aim of the new regulatory program.Positions of the PartiesSoCal, PG&E, and SDG&E express difficulty understanding the Commission's intent in the proposed rule dealing with the creation of marketing subsidiaries. SoCal and PG&E support marketing of gas services outside their territories, while SDG&E claims it must have protection if this is to be allowed as proposed in the OIR.SoCal states the rule requires clarification. SoCal points to the requirement for income reporting and making accounting records available and asks if this means a marketing subsidiary would be subject to Commission jurisdiction and approval and hence would have cost-based [*112] tariffs. Additionally, SoCal asks if only marketing activities in California would be so regulated. Overall SoCal expresses confusion regarding the Commission's intent and claims that if the Commission wants jurisdiction over such marketing activities, it should so state. It asserts that in no case should the rule extend to utility affiliates located outside California.PG&E stresses that some conditions of the proposed rule are either inconsistent or too onerous. PG&E states that the prohibition on sharing of resources or information between the utility and a marketing subsidiary is too strict and puts PG&E at a competitive disadvantage since any party can call PG&E and obtain such data. PG&E states that the rule is contradictory in ordering that income is to be included in utility revenue even though no utility resources can be provided. PG&E argues that release of cost data to the Commission during a reasonableness review would provide a competitive advantage to other brokers. Finally, PG&E asks why the Commission needs to review the broker's records if brokering is a nonutility activity.SDG&E emphasizes it would be at a competitive disadvantage if it must compete against [*113] a SoCal marketing subsidiary due to SoCal's access to both underground storage and firm interstate transportation. If SDG&E obtains access to such facilities, SDG&E believes it would be able to compete. Without such access SDG&E opposes the overall rule. SDG&E finds the rule confusing and asks whether brokering is anticipated to be regulated or unregulated. SDG&E states that a mixture of regulated and unregulated treatment would not work, and that the expenses and income should be all above or below the line but not a mixture. SDG&E also asks why the Commission proposes reasonableness reviews if the activity is below the line.DiscussionEarlier in this decision we decided that sales to customers within a utility's service territory should be at the average of the gas costs of either of the two portfolios. At this point in time, we see no reason to distinguish between marketing of procurement services by utilities within and outside of their service territories. Accordingly, we will permit utilities to sell gas from both their core and noncore portfolios as long as such sales are at each portfolio's weighted average cost of gas. Out-of-area customers purchasing gas from [*114] another utility's core portfolio would be subject to all of the rules and requirements pertaining to noncore customers within a utility's service territory who choose elected core procurement. This policy should protect the interests of the utilities' primary customers by prohibiting utilities from targeting their cheapest supply sources to customers outside of their service territories.To allow selective discounting of gas for sale of out-of-area customers would raise another problem given the structure we adopt today for gas sales within a utility's service territory. The in-area utility would be at a distinct disadvantage in competing for sales to customers if other utilities were not required to sell gas to out-of-area customers at their average cost of gas. We believe that this policy will promote fair competition between utilities for customers and at the same time protect core customers. ,TWe expect to hear the same criticism with regard to our policy on out-of-area sales as we anticipate with regard to our restrictions on noncore procurement. Prohibiting selective discounting by utilities, whether within or outside of their service territories, could impede their ability [*115] to compete with unregulated brokers who have much more flexibility to market gas. As discussed earlier, we therefore intend to consider establishing multiple supply portfolios in a future proceeding. Such multiple portfolios could assist utilities in marketing gas outside their service territories.As a further safeguard to ensure that in-area customers are not subsidizing gas sales outside of the utilities' service territories, we will direct the utilities to establish a minimum brokerage fee as a charge that reflects the reasonable cost of procuring and marketing out-of-area gas. The minimum brokerage fee, when added to the average cost of gas from the portfolio from which sales are made, will establish a minimum price which a utility can charge an out-of-area customer. The utilities should file their proposed brokerage fee schedules in the implementation hearings for comment by the parties. The brokerage fee will help to ensure that nonutility brokers are not subjected to unfair competition and reduce the possibility that the utilities will face lawsuits alleging anticompetitive conduct.We view the next few months as an interim period. During this time the utilities should [*116] treat outside marketing of gas as a utility service. All brokering income and expenses should be reported above the line. Because of our decision to treat out-of-area marketing as a utility service for an interim period, there is no need to adopt the proposed rules regarding separate accounting or the prohibition against sharing of resources or information. Ultimately such rules may be necessary for it is our intent to eventually treat out-of-area sales as a nonutility function.VII. Underground StorageThe OIR did not discuss the role which the utilities' underground storage operations should play in the new regulatory approach. However, a number of parties raised issues pertaining to the use of storage, and they should be addressed.Positions of the PartiesSDG&E stresses as one of the central themes in its comments that it requires access to underground storage and firm interstate transportation capacity in order to function as a full-fledged player in the new regulatory environment. It states that it cannot compete effectively either within its service territory or without absent the full resources available to SoCal and PG&E.CIG wants storage service to be unbundled [*117] and available on a cost-of-service basis. El Paso states that a separate storage service may be desirable, but that more information is needed before this can occur.DiscussionThe rules proposed in the OIR were aimed at unbundling gas procurement services and intrastate transmission services. We agree with the various parties which comment that a fully unbundled array of services could include underground storage as well. However, we also agree with El Paso that more information is needed before we could decide whether and under what conditions underground storage should be made available on an unbundled basis.The storage system appears to have been sized primarily to meet cold year needs of high priority customers. We would not want to jeopardize the high level of service reliability which has resulted for these customers. On the other hand, it may well be that some amounts of underground storage could be made available to transmission customers, at least for portions of the year, without causing economic harm to core customers. The charges for such services could in fact accrue to the benefit of core customers as the cost of storage is shared with other customers.We [*118] plan to examine this storage aspect of utility operations further in a consolidated proceeding addressing several related issues, to be addressed during the gas procurement hearings.VIII. Rate DesignA. GeneralThe OIR described general rate design principles which were to be explored in the Investigation initiated by Order Instituting Investigation 86-06-005 issued simultaneously. A number of parties addressed certain of these rate design issues in their comments filed in this proceeding. Since that Investigation has proceeded as planned, we will not discuss those areas in this decision. Parties are referred to the Investigation for resolution of these issues.B. Transmission1. Recovery of Fixed Costs and Transition CostsIn the OIR we proposed rules that would allocate fixed pipeline demand charges and certain other fixed costs to transmission services. We concluded that unavoidable "common costs" associated with the transition to a more competitive market and not directly assignable to any particular customer class should be spread equitably among both procurement and transmission-only customers.We concluded that all of today's customers, regardless of the services [*119] they now choose, receive substantial benefit from the fact that a local distribution utility has evolved over the years to the present state. The utilities' structure and contracts evolved because they procured gas for all customers; it follows that all customers should continue to pay unavoidable costs still being incurred as a result of development of the utility structure.Several classes of fixed costs are discussed in the OIR. Pipeline fixed demand charges were proposed to be allocated across the board. The large fixed cost associated with SoCal's PITCO (Pan Alberta) gas supply was proposed to be allocated to the volumetric or usage portion of SoCal's transmission rates, on an equal cents per therm basis.Any take-or-pay costs incurred by the interstate pipelines and passed on to California utilities by the FERC were proposed to be allocated on some pro rata basis to either customers' volumetric transmission rate or demand charge. We also stated that other costs such as the premium paid to purchase relatively expensive pipeline sales gas to avoid potential take-or-pay liabilities or to purchase uneconomic gas to meet minimum operating requirements of the pipelines should [*120] be allocated to all customers.Finally, we discussed the division of utility nongas costs between transmission volumetric and demand charges and concluded that the utilities should experience some risk of fixed cost recovery to provide a real incentive to find gas priced low enough to maintain transmission demand by noncore customers. We proposed that the minimum amount of nongas costs to be included in the volumetric rate should be those incremental costs required to provide the utility its authorized return on equity and associated income taxes, plus PITCO demand charges for SoCal only. This parallels the treatment the FERC has adopted for many of the pipelines it regulates.Positions of the PArtiesPalo Alto, Long Beach, Transwestern, CIG, and Petro-Canada all argue that customers should not be charged for costs that they do not cause or which benefit only other classes of customers. PG&E, Transwestern, Pasadena, Palo Alto, Long Beach, Tenneco/CONOCO, CMA, and CIG argue that pipeline demand charges should only be allocated to those customers which cause these charges to be incurred. In these parties' view, customers which do not receive core procurement services should not [*121] be allocated any of these costs since they do not receive any benefit from the utilities' firm interstate capacity.SoCal feels that pipeline demand costs should be treated like all assignable fixed costs and should be allocated according to its rate design proposal. SoCal also requests flexibility to negotiate special service agreements that might differ from the four part rate design proposed.CHMA/CRA supports allocation of transition costs on an equal cents-per-therm basis or, alternatively, to only interruptible transmission customers.SCE recognizes the need to allocate demand charges to lower service priorities during a transition period, but is against an across-the-board allocation. It states that customers should pay demand-related charges only to the extent they enjoy demand rights. SCE wants refunds of demand charges for any curtailment periods.Industrial Users agrees with SCE that an across-the-board allocation is not appropriate, but states that, at the other extreme, transmission-only customers should not avoid them altogether. Industrial Users asks that the Commission state whether the fixed costs discussed in these sections of the OIR are to be "grandfathered" [*122] as part of the rate structure and not subject to cost-based allocations.TURN strongly supports allocating fixed interstate pipeline demand charges to all customers across the board.Transwestern, El Paso, CIG, Pan Alberta, Tenneco/CONOCO, and CPG all argue that the PITCO demand charge should be treated like any other interstate pipeline demand charge and collected in the monthly transportation demand or stand-by charge. Among them, they argue variously that putting this cost in the volumetric rate (1) would be at odds with the general thrust of the OIR, (2) could cause the demand payment to be paid twice, or (3) would result in putting an extra tax on domestic producers which must take a lower net-back price at the wellhead to compensate for this extra charge. Tenneco/CONOCO concurs with these parties' concerns that the proposed allocation of PITCO demand charges would force a subsidy from El Paso and Transwestern, and argues that it also would result in preferential sequencing of Canadian supplies.New Mexico prefers that PITCO costs be avoided or amortized, and states that at a minimum demand charges of all pipelines should be allocated the same way.TURN would like to see [*123] the PITCO demand charge assigned to UEG customers, as proposed earlier by PSD, but would settle for an equal cents per therm allocation of all fixed interstate pipeline demand charges in either the volumetric transmission rate or demand charge.Producer take-or-pay costs were discussed by SoCal, PSD, TURN, Tenneco/CONOCO, and CIG. PSD and CIG agree that these costs should be spread pro rata to all customers, with PSD stating that these costs should be put into the volumetric transmission rates. Both of these parties argue these costs should be passed on only after they have been found by the FERC and this Commission to be fair.SoCal recommends that take-or-pay costs should be allocated according to its rate design, but states that if this is not acceptable then they should be spread pro rata as proposed by the Commission.Tenneco/CONOCO argues that producer take-or-pay costs and costs such as the premiums for uneconomic gas are costs associated with long term secure supply purchases which benefit the core procurement market only and thus should not be allocated to other customers. It raises questions regarding the legality of the proposed allocation.TURN endorses the Commission [*124] allocation of producer take-or-pay and other transition costs, but goes further and recommends inclusion of certain other common avoidable costs such as remaining unamortized project costs, e.g., LNG or Ten Section, and other nonmarginal nonallocable costs, e.g., marketing expenses, legal and regulatory affairs, and conservation program costs, in the across-the-board allocation.PG&E, PSD, TURN, Transwestern, CMA, CIG, Industrial Users, and DGS all support the proposed rule putting return on equity and associated taxes into the volumetric transmission rate. TURN goes so far as to offer to assign a higher return on equity to the equity associated with noncore customers because it would carry a higher risk. Transwestern requests that the maximum amount of nongas costs at risk be stated, in addition to the minimum highlighted in the proposed rule.SDG&E argues that putting the return on equity and associated taxes into volumetric rates would send inaccurate signals to the ultimate users. It would like to gain working experience with the new rate design before putting return on equity into volumetric rates.DiscussionIn the proposed OIR we enumerated as transition costs the following [*125] items: excess PITCO demand charges, producer take-or-pay costs passed on to the utilities by the FERC and found reasonable by this Commission, and any premiums paid to avoid the accrual of additional take-or-pay liabilities or to meet minimum operating requirements of the pipeline systems.First, we will consider the issue of commodity-related transition costs incurred to avoid the accrual of additional take-or-pay liabilities. Given that FERC has eliminated the utilities' minimum bill obligations with the interstate pipelines and our view that supply security is not of significant concern in a competitive supply market, it is difficult to justify purchasing long-term supply for a given level of price security that is in excess of current market value unless the premiums paid are for the purpose of avoiding the accrual of additional take-or-pay liabilities which are projected to be more costly to ratepayers. We consider such premiums as a transition cost and we disagree strongly with those parties who contend that only core procurement customers should pay for existing long-term supply which may be in excess of current market value.To the extent that long-term supply is priced [*126] in excess of its current market value and it is deemed appropriate to purchase such supply, that excess should not be considered the responsibility of core customers any more than it should be considered the responsibility of noncore customers. Transition costs by definition benefit no particular class of customer. They are the result of our transition to a more competitive procurement market. Our objective is to get these transition costs behind us so that we may move forward with a clean slate into the new, competitive procurement market. We believe that it will be in the best long-run interest of all parties, including the interstate pipelines, if we can first determine the extent to which transition costs have resulted from the era of wellhead price regulation and second, allocate these costs equally among all customers to the extent possible. Since these two issues have not been explored adequately in either this rulemaking or I.86-06-005, we will consider them further in our procurement proceeding which will be initiated as soon as possible and scheduled on an expedited basis.An accurate assessment of the extent to which procurement costs are excessive may be quite difficult. [*127] The best comparison would probably be to new long-term contracts. Absent that, another approach would be to compare them to each other (e.g. to assess any difference among commodity rates in existing long-term contracts as transition costs).Second, with respect to pipeline demand charges we originally proposed to treat PITCO demand costs in excess of current market value as a transition cost. Upon further reflection, we agree with the parties who argue that PITCO fixed costs should be treated like other pipeline demand costs. Inclusion of PITCO costs in the demand charge would be easier to implement and conceivably would encourage increased usage thus increasing overall revenues from the noncore class. As discussed in our decision in I.86-06-005, the allocation factors used to allocate pipeline demand charges recognize the current excess capacity situation by spreading these costs fairly evenly between the core and noncore markets. We do not believe at this point that much would be gained by examining one specific pipeline demand charge such as PITCO to determine the extent to which it exceeds current market value. We will simply recognize the presence of fixed transition [*128] costs in our selection of allocation factors in the OII decision.Therefore, we reaffirm our intent expressed in the OIR to allocate all current pipeline demand charges and FERC-imposed producer take-or-pay liabilities to transmission charges. The method of allocating these charges in setting transmission rates is decided in I.86-06-005. In the procurement hearings parties should propose methods to estimate the extent to which current commodity rates are excessive and should thus be treated as transition costs. They should also propose how such costs should be allocated in transmission rates.We will not adopt TURN's proposal to include unamortized abandoned project costs and other nonmarginal nonallocable costs in transition costs allocated to transmission rates. Before considering such a step further, we would like to see a more detailed proposal including the magnitude of these costs, and would like to see the market responses to the level of fixed costs already allocated to transmission rates.We will adopt the proposed rule including return on equity and associated taxes into the volumetric transmission rate. We will include only these elements of fixed costs in the volumetric [*129] rate for now, until more experience is gained.Adopted RulesPipeline demand costs (including PITCO demand costs) will be allocated to transmission rates as determined in our decision in I.86-06-005.Producer take-or-pay costs passed on to the utilities by the FERC, and any premiums paid to avoid future take-or-pay liabilities or to meet minimum operating requirements of the pipeline system shall be considered transition costs and allocated to transmission demand charges for noncore customers and to bundled gas rates for core customers.The revenue requirements to provide the utility its authorized return on equity and associated taxes shall be allocated to volumetric transmission rates for noncore customers and to bundled gas rates for core customers.2. Flexibility in Pricing Transmission ServicesIn the OIR we recognized that the new regulatory proposal will place the gas utilities directly at risk for the portion of their cost of service collected through volumetric transmission rates. We concluded that it is appropriate to allow pricing flexibility so that the utilities can most effectively react to market developments. The utility would not be able to recover any revenue [*130] lost due to discounting its transmission service, and would be forced to decide whether it would be better off discounting the service, losing customers, or pressuring producers to maintain the competitive viability of gas for large customers.We provided in the proposed rules that the utilities can discount their volumetric transmission rates so long as the service is never provided below its incremental cost. The maximum rate would be set by the Commission through established procedures. The utility would be required to provide any discount offered in a nondiscriminatory manner to all customers of the same level of transmission service. Rates could be changed no more frequently than four times per month.Positions of the PartiesPG&E, SDG&E, SoCal, TURN, Transwestern, and CIG all support discounting in a more flexible manner than the proposed rule provides. The utilities want the ability to discriminate among customers with regard to all components of gas service, including demand charges and commodity rates as well as volumetric transmission rates.The main fear expressed is that, if the discount is required to be given to all customers within a class of transmission service [*131] regardless of their individual situations and needs, the revenue losses would be too great. This might lead the utilities to not discount at all unless the potential load loss is very large. PG&E states that the ultimate losers are the core customers which will subsequently have to contribute the margin that was lost due to a lack of pricing flexibility.SoCal wants pricing flexibility by customer class instead of by service level. SoCal recommends that utilities be encouraged to enter into contracts with special provisions which may be necessary to retain fuel-switchable customers. SoCal comments that this would allow it to resolve unique problems as they arise, and proposes that such contracts would be submitted to the Commission for approval.TURN supports the discounting of transmission demand charges as well as the volumetric transmission charges. It further states that the Commission should allow the volumetric rate to be flexible in both directions around the tariffed rate to assist the utilities in holding specific customers. Similarly, SDG&E

wants to be able to raise as well as lower prices selectively.Most of these commenters also felt that selective discounting [*132] would be consistent with FERC interstate regulations set forth in FERC Order No. 436-A. Transwestern deems the same logic applicable to California gas utilities, and suggests the following rule:"Discounts in transportation rates may be offered on a selective basis when the discount is solely at the utility's expense. A discount to one customer need not be provided to any other customer. Complaints will be entertained as a means of determining whether a particular discount is pernicious."Industrial Users strongly supports nondiscriminatory discounts which are offered to all customers of a particular class. SCE also supports the nondiscriminatory aspect of the rule and objects to the preferential rate treatment now afforded enhanced oil recovery customers.DiscussionThe parties have made convincing arguments that discounting of transmission charges should be allowed in a more flexible manner than that proposed in the OIR. The reasoning behind such discounting is that some margin contribution is better than none. We agree that a requirement of broad discounting could be self-defeating; such discounts could result in the collection of less revenue rather than more. For this [*133] reason, we will also allow discounting of transmission demand charges as well as the volumetric rates. The minimum total transmission charge including demand and volumetric rates should be the short run marginal costs of the service, as discussed in today's companion decision in I.86-06-005.We must be careful, however, to ensure that core customers are not disadvantaged by such discounting. The utilities must be at risk rather than these customers. The proposed elimination of the Supply Adjustment Mechanism (SAM) balancing account for noncore margin would put the risk with the utilities; this is discussed in Section X.We conclude, on the other hand, that the utilities should be required to offer default tariffed transmission rates. Default transmission rates will be set at levels we find to be just and reasonable and will be available for those customers who choose not to negotiate with the utilities. The establishment of default rates is discussed more fully in our decision in I.86-06-005.Adopted RulesThe gas utilities must file tariffs for transmission services consistent with the adopted rules, which will be available to any noncore customer.The utilities will be [*134] permitted to discount their volumetric rates and demand charges for transmission service as long as the service is never provided below the short run marginal costs. Therefore, the minimum and maximum rates will be set by this Commission through its established procedures.Discounts in transmission rates may be offered on a selective basis. A discount to one customer need not be provided to any other customer as long as rates to a particular customer are not unduly discriminatory. Complaints will be entertained as a means of determining whether a particular discount is pernicious.3. Allocation of Costs to Transmission-Only CustomersIn the OIR, we established that customer and demand charges for transmission-only service should equal those imposed for customers receiving procurement services as well, unless the utilities can demonstrate that their costs for metering, account servicing, and billing are greater for customers which receive transmission service than for procurement customers. We instructed SoCal to eliminate the $300 monthly customer charge it had for short term transmission service unless it could demonstrate incrementally higher costs for transmission-only [*135] service.Positions of the PartiesTranswestern, Petro-Canada, Long Beach, and Pasadena agree with the concept that transmission-only customers should pay more if additional costs are imposed on the utility, but argue that the concept should be extended so that rates for transmission-only customers could be lower if it can be shown that transmission-only customers actually impose lower costs, administrative or otherwise, upon the system.Transwestern notes as part of its comments that procurement service costs should be in the procurement/commodity rate, not in the transmission rate.PG&E comments that its transmission tariffs do not include an additional cost for transmission-only customers because it could not demonstrate higher costs for this class of customers. PG&E proposes, however, that it be allowed to charge additional fees, such as brokerage fees, for related services on a case-by-case basis.DiscussionWe agree with the various parties which commented that charges should reflect costs, e.g., that if administrative costs for transmission-only service can be shown to be higher or lower than for other customers, this difference should be reflected in the charges to customers. [*136] This issue of cost causation should be explored further.We further agree with Transwestern that gas procurement costs should be reflected as part of the procurement rate, to the extent of occurrence beyond those costs we have designated as transition costs and allocated to all customers. We have not established a separate procurement charge beyond the commodity rate, but would consider doing so if the costs can be isolated and quantified. We expect that issues such as this will be pursued in future proceedings, as the new regulatory approach is implemented and refined.4. Actual Margin Recovery MethodWe have proposed to eliminate the "actual margin recovery" method of pricing transmission rates for noncore customers, as being of little value now that short term transmission contracts are available.Positions of the PartiesPG&E, CMA, and other parties comment that the current short term transmission option is equivalent to the actual margin recovery method, which is thus not needed as a separate option. TURN would agree to eliminate this schedule if short term transmission is retained, but still remains opposed to short term transmission. If TURN's recommendation that [*137] only long term transmission be allowed is adopted, however, TURN believes that the actual margin recovery method should be kept as an option.Transwestern does not see the connection between the actual margin recovery method and the imposition of cost-based rates, and states that if rates are cost-based then there is no need to retain the actual margin recovery method.Only SoCal supports retention of the actual margin recovery method. SoCal's position is that some customers may wish to elect this option. Because of this, SoCal states that the option should not be terminated until it is clear that customers do not want this option.DiscussionTranswestern is correct that the actual margin recovery method of establishing transmission rates is inconsistent with the cost-based rate approach which we have adopted. Since we have chosen to allow transmission service contracts of a duration as short as one month, there appears to be no value in retaining this option. Our conclusion remains that it should be terminated.C. ProcurementIn the OIR we proposed that the procurement rates for gas sales to core and noncore procurement customers be the average commodity price of the core [*138] market portfolio account or the noncore market portfolio account, respectively. The utilities must file cost-based tariffs for noncore procurement service and apply them in a nondiscriminatory manner. They may revise noncore tariffs upon five days' notice, but no more frequently than twice in any consecutive 30 day period.Most revisions to these pricing proposals put forth by the parties arise from differing views regarding market structure, and are discussed in Section VI. This section addresses residual issues regarding structure of the rates themselves once such underlying issues are determined.Positions of the PartiesPG&E disagrees with the proposal to price gas to the core market at the average core market portfolio cost. It asks that the core commodity rate be adjusted to reflect service options, variable pipeline charges that flow with the gas, and core balancing accounts.Regarding noncore procurement, SCE suggests that the Commission replace the limitation on the number of tariff changes which can occur in a 30 day period with one pegged instead to a calendar month.DiscussionWe recognize that pricing gas to elected core procurement customers at the weighted [*139] average portfolio cost is a bare-bones approach. However, we conclude that no change is needed due to issues addressed in this rulemaking. No service options have been adopted which would affect the procurement rate. It may become reasonable to add other variable costs such as variable pipeline charges and variable acquisition costs to the commodity price in the future, if they can be established. As discussed in Section VI, we also contemplate that components may be added in the future to reflect fixed costs if new ones are incurred. Finally, treatment of current balancing account balances is addressed in I.86-06-005.We will accept SCE's suggestion that the number of tariff changes be measured by calendar month, since that is the time period used by the utilities in scheduling gas purchases.Adopted RulesThe commodity price for core procurement service and noncore procurement service shall be equal to the weighted average cost of the core market portfolio account and the noncore market portfolio account, respectively.Utilities must file cost-based tariffs for core and noncore procurement and apply them in a nondiscriminatory manner. They may revise noncore tariffs upon [*140] five days' notice, but no more frequently than twice in any calendar month.IX. CurtailmentIn the OIR, we proposed separate curtailment mechanisms for application during supply (procurement) shortages and capacity (transmission) shortages.For utility supply shortages, we proposed that the existing end use priority system be used, except that customers receiving noncore procurement service would be curtailed beofre those receiving core procurement service. We provided that utilities could take gas from their transmission-only customers to serve Priority 1 and 2A core procurement customers only if all other utility procurement customers are curtailed and the Commission declares a supply emergency. We concluded that this proposed curtailment program comports with the intent and requirements of PU Code Section 2771 et seq.We concluded that eventually there should be only five end use priority categories, and placed enhanced oil recovery customers in the P-5 priority designation for supply curtailments.The curtailment rules proposed for transmission constraints depart from use of end use designations and instead would order curtailment according to the level of transmission [*141] reliability chosen by the customer. The OIR contemplated that there would be four levels of transmission service: Firm Level A, Firm Level B, Interruptible Level A, and Interruptible Level B. Priority 1 and 2A customers would receive Firm Level A, that is, the firmest level of transmission service; other customers could choose among the remaining three levels of service. Curtailments would occur in reverse order of firmness.We invited comments on the proposed changes, particularly as they affect wholesale customers which serve core customers, and stated that consideration of revisions to end use categories might occur in the longstanding end use proceeding.Positions of the PartiesPG&E argues that the proposed priority mechanisms are too complex. It recommends that the current end use priority system for supply curtailment be replaced by a system which is based on customer choice and economic considerations. PG&E recognizes that noncore procurement customers should be curtailed first in event of utility supply shortages, but recommends that noncore procurement customers willing to commit to long term contracts receive a higher priority than short term noncore procurement [*142] customers, i.e. the longer the contract the higher the priority. Elected core procurement customers would be curtailed next after noncore procurement customers, followed by transmission-only customers, and finally by P-1 and P-2A customers.For capacity curtailments, PG&E argues that customers should be allowed to choose their capacity priority according to the value they place on service reliability. Service for noncore customers which choose the same transmission service level would be curtailed in reverse order of price. PG&E recognizes that its proposals may require revision to PU Code Section 2771 et seq.SoCal supports the proposed rule for supply curtailment, but recommends that transmission rates and procurement rates for sales customers be varied to reflect the level of service reliability that a customer requires. SoCal opposes the proposed transmission capacity curtailment rule and supports instead a transmission curtailment rule that would have short term transmission customers curtailed prior to long term transmission customers, and that would have demand charges and volumetric transmission charges tailored to reflect the level of service reliability required by [*143] the customer.SDG&E's concerns regarding the proposed rules depend on the resolution of other issues. SDG&E states that, if it were permitted access to firm interstate pipeline capacity and storage services, it would no longer be a wholesale customer of SoCal and its concerns would be met. If SDG&E is not permitted firm pipeline capacity and storage services, it would risk the security of supply for its core customers if it elected to become a transmission-only customer and take advantage of opportunities to purchase gas. Because of this, SDG&E states it may have to continue to rely upon SoCal as its agent to secure its gas supply for core customers. Under those circumstances, SDG&E believes that the current parity system would most properly allocate gas supplies. SDG&E believes that the current priority of UEG customers above P-6 to P-8 customers should be maintained.SCE feels that the proposed rules are too complex and difficult for the utilities to administer. It notes in particular difficulties in handling coincident supply and capacity shortages and states that wholesale customers must be woven into the proposed twenty combinations of supply and capacity priorities. [*144] SCE recommends that the Commission hold hearings on the proposed curtailment rules and, if necessary, delay implementation pending the outcome of such hearings so that the new rules are as simple, equitable, and workable as possible. SCE recognizes that this is not in need of immediate resolution.PSD recommends that the wholesale customers' annual demand for Priority 1 and 2 customers be designated to receive the firmest level of transmission service, with no option to switch, and that this load also be assigned core procurement with an option to switch.TURN agrees with the proposed rule for supply priorities. TURN suggests that wholesale customers should designate their gas purchase requirements by priority, specifying quantities at each level to be purchased from the servicing utility as well as from third party sellers. To the extent wholesale customers purchase utility gas supplies, that supply should continue to be served at parity with retail service of the same priority.TURN generally supports the capacity curtailment rule, assuming fixed rates are assessed for differing levels of service. TURN prefers, however, that noncore capacity priority be assigned based on [*145] a bidding system, rather than by customers subscribing to specific pre-set rate levels. TURN argues bidding would be more economically efficient and would provide the utility with clear price signals as to whether demand for capacity would justify expansion of the transmission system.CMA has reservations about the proposed service priorities and the integration of the separate supply and capacity curtailment rules. CMA interprets the proposed rules to mean a customer could have a low priority for supply and a high priority for capacity. It states that such variations are debatable in meeting the requirements of PU Code Sections 2771 et seq.Industrial Users believes the proposed rules improve the curtailment priority element of the new industry structure because they integrate end use priorities with the "price determines priority" concept. Industrial Users states however that the rules leave some unresolved legal issues. Industrial Users prefers the retention of the current end use priorities for the purposes of any future supply-related curtailments, except that it supports the proposed reduction in the number of curtailment priorities to the five originally adopted.CIG [*146] supports continuation of the established curtailment priorities relating to gas supply and the creation of a priority system to allocate capacity based upon price.El Paso states that the proposed curtailment system seems unnecessarily complex, and suggests that customers could choose the level of transmission service they will pay for.Palo Alto, Long Beach and Petro-Canada's concern with these proposed rules relates to curtailment of customers which require utility transmission-only service for a portion of their needs and retain traditional sales service for the remaining portion. They recommend that supply curtailment be limited to only those volumes which represent sales service and that capacity curtailment be limited to only those volumes representing transmission-only service.Champlin recommends the priority level for gas-fired cogenerators remain at a priority level no lower than the current P-3 level. It is concerned because its cogeneration facility as currently designed will not have alternative fuel capability.DiscussionIn Section IV we adopted provisions regarding the reliability of transmission service which will govern the related curtailment rule for capacity [*147] shortages. The adopted rules tie priority to willingness to pay for noncore customers and are consistent with the recommendations of PG&E, CIG, and El Paso. Priority 1, 2A, and 2B customers will receive the firmest level of transmission service and will be curtailed last. Those noncore customers which do not negotiate contracts will pay no priority charge, but will receive the least reliable transmission service in the event capacity constraints develop in the future. Curtailment of these noncore customers without a negotiated priority charge would be based on the current end use priority system. Curtailment of customers with negotiated contracts would be based on each customer's negotiated priority charge, with those customers which pay the highest priority charge being curtailed last.SoCal's arguments that transmission curtailments should be based on the length of contracts runs counter to our policies regarding cost-based rates. A noncore customer should pay more, not sign a longer contract, to get higher service reliability.CMA and Industrial Users have questioned the legality of curtailment mechanisms based on price rather than end use in view of

Public Utilities Code [*148] Section 2771 et seq. This law requires the Commission to establish customer priorities based on a consideration of "[a] determination of the customers and uses of electricity and gas, in descending order or priority, which provide the most important public benefits and serve the greatest public need." We believe that this requirement in the statute can reasonably be construed to allow willingness to pay to serve as a proxy for public benefit and need, at least within the noncore class. The primary argument against the use of willingness to pay applies only to residential customers, for whom inequalities in income may result in the highest priority going to the wealthiest consumers under such a standard. So long as P-1 and P-2A customers are automatically accorded the highest priority, we see no plausible objection to the concept that the willingness of other customers to pay a higher price for transmission priority directly reflects the greater public need and benefit attributable to the receipt by such customers of high transmission reliability.For supply curtailment we still conclude that noncore procurement customers should be curtailed before elected core procurement customers. [*149] This is appropriate because of the nature of the two market portfolios, i.e., elected core customers have chosen to commit to and pay for long term reliable supplies, whereas the noncore portfolio bears a higher risk in return for the current low price. These customers have indicated by their choices their own assessment of the economic value of the utility service they choose. We see this as consistent with PU Code Section 2771 et seq. Supply curtailments within a given procurement service class (i.e., core procurement and noncore procurement) should occur according to end-use priority. As originally proposed in the OIR, we will reduce the number of end-use priorities to five.As discussed elsewhere in this order, we are not in a position to grant the relief SDG&E requests regarding access to interstate pipeline capacity and underground storage at this time. We will, however, allow SDG&E and other wholesale customers to choose among the variety of procurement options available to noncore customers. As discussed in our companion rate design decision, each wholesale customer will be treated as a single noncore customer with respect to procurement. Wholesale customers will [*150] be allowed to elect into the core portfolio for all, none, or any portion of their gas requirements. For transmission service, they will be allowed to negotiate core transmission priority for up to the amount of load represented by their residential and commercial customers. Capacity curtailment will be based on their negotiated transmission service contract.We agree with TURN that wholesale customers should designate their gas purchase requirements by priority and that gas to wholesale customers should be provided at parity with retail service of the same priority.Palo Alto, Long Beach, and Petro-Canada request that supply curtailments be restricted to procurement customers and capacity curtailments be restricted to transmission-only customers. As stated earlier, customers which buy their own gas would be curtailed by the utility during supply constraints only in extreme cases where emergency situations exist and this would be necessary to supply P-1 and P-2A customers. Capacity curtailments should apply to all customers regardless of the source of their gas. We see no reason why a customer's choice of gas source should affect the reliability of transmission service in any [*151] way.Adopted RulesCustomers which are categorized as Priority 1, Priority 2A, and Priority 2B shall have their transmission service curtailed last in the event of a capacity shortage. All other customers shall be curtailed in reverse order of the level of their priority charge. For noncore customers with a zero priority charge, curtailment would occur according to the existing end use priority system.Utility gas service will be curtailed whenever demand for utility procurement exceeds utility supplies. Customers purchasing gas from the noncore market portfolio will always be curtailed before those taking gas from the core market portfolio. Curtailment within a given portfolio will be based on current end-use priorities. Utilities may direct customer-owned gas from transmission-only customers to serve P-1 and P-2A customers receiving gas from the core portfolio only after all other curtailment steps have been taken and the Commission declares a supply emergency.Capacity curtailment for wholesale customers will be based on negotiated transmission service contracts as for other noncore customers. Wholesale customers will, however, be allowed to negotiate firm, core transmission [*152] priority for up to the amount of load represented by their residential and commercial customers (i.e. their P-1, P-2A, and P-2B load). With respect to procurement, wholesale customers will be treated similar to other noncore customers. To the extent wholesale customers purchase utility gas supplies, that supply will be served at parity with retail service of the same priority.X. Ratemaking, Accounting, and ImplementationThe OIR presented a number of ratemaking and accounting changes needed to implement the new regulatory approach. The most substantive change proposed is the elimination of Purchased Gas Adjustment (PGA) balancing account treatment for noncore procurement sales and the elimination of Supply Adjustment Mechanism (SAM) balancing account treatment for fixed costs allocated to noncore customers. Other changes include the establishment of a short term gas purchase account and a long term gas purchase account to gather and average the costs of various gas supplies falling within these two broad categories. Beyond that, the proposed changes are primarily accounting in nature. We also proposed rules regarding notice requirements whereby customers are to be informed [*153] of their choices once the new rate structure is implemented.On October 30, 1986, PSD submitted a stipulation in this proceeding and in I.86-06-005 which has been entered into by PSD, TURN, SoCal, PG&E, and SDG&E. It is attached Appendix A, and contains a package of proposals in the following general areas:a) a partial rather than total elimination of balancing account type treatment for noncore fixed costs for two years;b) allocation of any balances in the utilities' SAM balancing accounts at the time of an implementation decision following further hearings in the two proceedings;c) a schedule to implement the policy decisions to be reached in this rulemaking and in I.86-06-005; andd) schedules for future cost allocation and gas cost proceedings.The assigned administrative law judges in the two proceedings allowed parties to submit written comments on the stipulation by November 7, 1986. Six parties (including SoCal alone of the parties to the stipulation) filed comments by that date.The parties to the stipulation treat the individual items in the package as inseparable. The stipulation states that if the Commission does not adopt the agreement in its entirety, the [*154] parties will not be bound by any provision set forth therein.A threshold issue therefore is whether the stipulation should be adopted as presented. The items in it will be considered together, followed by other issues in these areas not covered by the stipulation.A. Consideration of the Submitted StipulationAs a preliminary issue before the contents of the stipulation can be examined, we must address the question of whether consideration of such a stipulation is even appropriate in this proceeding.1. Appropriateness of the Stipulation ProcessFilings by Nabisco, CMA, and CIG regarding the stipulation stress views that the process by which the stipulation was reached was inappropriate and that the Commission should reject the stipulation without consideration of its contents.One major criticism voiced by all three parties is that the stipulation was reached without consultation with some of the major interests in the proceeding. No representative of any noncore customer interest was informed of the negotiations or asked to participate. CMA finds particularly offensive the inclusion of TURN as a representative of core customers since parties associated with noncore interest [*155] were excluded.These parties stress that the filed stipulation is not a settlement, since parties with obvious interest at stake are not parties to the stipulation. CMA notes that the stipulation, if accepted by the Commission, would inevitably have significant impact on all customers. CIG argues that as a matter of fairness and sound regulatory policy, the Commission should expressly refrain from any consideration of stipulations involving substantive issues unless all parties have had a meaningful opportunity to participate in the stipulation process. Nabisco argues that as a matter of law the stipulation cannot be treated as if it were uncontested or the subject of any meaningful public hearing until other affected parties have been given an adequate opportunity to review and comment upon it. It asserts that seven days is manifestly not such an opportunity.CIG and Nabisco expressed particular dismay at the role of PSD in the negotiations. CIG's position is that PSD is charged with the responsibility of representing the public interest and should not be involved in a process which denies the rights of interested parties. Nabisco argues that in many ways, equal access to [*156] the PSD is as important as to the Commission itself, because the Commission must and does place special trust in its staff. It fears further that the collective position in the stipulation will carry even more weight than a PSD position alone.Nabisco characterizes the stipulation as essentially a late filed position of some of the parties. CIG argues that it is simply unfair to allow other parties less than one week for review and comment, and expresses fear that the stipulation will take advantage of immediate time constraints and stampede the Commission into approving it. CIG states that there is no reason for the Commission to rush to judgment on the issues, which in its opinion should be scrutinized in the implementation hearings.DiscussionThese three parties' primary concern seems to be that we recognize the stipulation for exactly what it is — the position of only some of the parties — and that we give it no more weight than justified. They have made their point well.Only Nabisco argues that there may be legal issues involved in our consideration of the stipulation. We recognize fully that the issues in the stipulation are contested. However, we disagree with [*157] Nabisco's implication that a hearing is necessary before we can consider adoption of the stipulation on its merits.The issues resolved among the parties to the stipulation fall into three categories: those subject to hearing in I.86-06-005, those subject to rulemaking in R.86-06-006, and certain issues regarding procedure and scheduling of cases before the Commission.Interested parties have already had adequate and proper opportunity to express their concerns regarding each of the topics at issue in I.86-06-005 and in this rulemaking. The primary issue covered by the stipulation which was heard in I.86-06-005 is allocation of balancing account balances among the customer classes. As discussed in today's decision in that proceeding, this topic was raised, albeit briefly, in certain utility testimony and discussed through cross-examination. Parties had the opportunity to make their views known on this issue, though few chose to do so.Changes to the SAM balancing account have been considered in D.86-03-057, in the Commission order instituting this proceeding, and in various parties' comments filed in response to the two Commission orders. Resolution of this legislative-type [*158] issue does not require evidentiary hearings. Finally, Commission procedure and schedules are routinely decided internally, sometimes with input from affected parties and sometimes without. There is certainly no vested right to a hearing regarding procedural issues.We conclude that none of the concerns raised by CIG, CMA, and Nabisco are such that they would prevent us from judging the merits of the contents of the stipulation. The individual components are presented in the following four sections, followed by a discussion of whether the stipulation is acceptable and finally by resolution of certain related issues not addressed in the stipulation.2. Changes to SAM and PGA Balancing AccountsBecause the changes to the SAM and PGA balancing accounts proposed in the OIR are integrally linked, the changes to the PGA account will be discussed in this section even though they were not an issue in the stipulation. The proposals in the OIR are presented first, followed by a summary of parties' comments filed in response to the OIR, followed finally by a discussion of the stipulation and parties' responses to the stipulation.The reductions in risk coverage proposed in the OIR were [*159] intended to encourage the gas utilities to promote gas usage and to pressure pipelines and suppliers to keep their commodity prices competitive with oil. Putting the gas utilities at risk for the recovery of some of their fixed costs if they do not maintain gas usage at projected levels while simultaneously allowing them to earn above their authorized returns if they increase gas usage (or alternatively trim their own costs) gives them a greater stake in the competitive market than the current balancing account system, which heavily protects them against changes in gas prices or sales.The rules proposed in the OIR establish three accounts. The Purchased Gas Adjustment (PGA) account would include the cost of all gas bought for the core procurement market, including elected core procurement customers, and the associated revenue from the commodity rate portion of core procurement sales. A separate memorandum account would be maintained to track revenues from the commodity rates for noncore procurement customers, along with gas costs for this supply portfolio; this account would not be subject to balancing account recovery. Finally, a Sales Adjustment Mechanism (SAM) balancing account [*160] would be maintained to track the forecasted margin or fixed costs allocated to core customers and the revenues from this class not associated with gas sales.The OIR also provided that if a utility's noncore procurement and/or transmission service rates result in it exceeding its authorized rate of return on total utility rate base by more than 300 basis points above the authorized return, it would be ordered to reduce rates in view of the excessive profit. This amount of possible excess earnings was allowed to offset risks imposed by elimination of balancing account treatment for noncore fixed costs.In the OIR we declined to propose the Annual Gas Rate (AGR) and Indexed Gas Rate (IGR) mechanisms discussed in D.86-03-057. The AGR was characterized as workable, but an unnecessary additional layer of regulatory complexity in light of the proposed program. We stated that we would be willing to revive it if we are dissatisfied with utility efforts to reduce core portfolio costs or if we decide to maintain a separate portfolio for elected core procurement customers. We concluded that there are not enough specifics about how to construct an IGR mechanism at this time, but that we [*161] would welcome proposals for an IGR to be presented in future proceedings, either as a possible replacement for the AGR or as an adjunct.Positions of the Parties in Response to the OIRIn their filed comments, the three gas utilities voice concern about the proposal to eliminate the SAM balancing account treatment for fixed costs allocated to noncore customers and PGA balancing account treatment for noncore procurement. They all agree that elimination of SAM and PGA should be delayed for at least one year or until the market has been tested under the new rules.PG&E and SoCal warn that the partial elimination of SAM and PGA as proposed could put the utilities' stockholders and ratepayers at risk for millions of dollars. PG&E recommends that SAM include those costs allocated to serving PG&E's UEG load if SAM is retained for only the core class.SoCal warns that the risk could be three times the authorized return on equity, and would largely be due to circumstances beyond the utilities' control.SoCal also objects to what it views as an improper matching of revenue and costs in the proposed balancing and memorandum accounts. It states that the revenue due to fixed pipeline demand [*162] charges should be included in the PGA and not in SAM, so that booked revenues match the gas costs booked to the PGA. Similarly, it recommends that only the portion of transmission revenues and the related projected revenue requirement which are exclusive of pipeline demand charges should be booked into SAM.PG&E, SoCal, SDG&E, and Industrial Users argue that if the Commission wishes to limit the utilities' upside return on equity due to noncore services to 300 basis points then equity requires an identical downside protection, that is, if a utility's rate of return drops 300 basis points below its authorized rate of return, then the utility should be allowed to file an adjustment of its rates to limit this exposure. PG&E recommends further that the basis point cap apply to only that portion of rate base assigned to noncore customers.SoCal proposes either of two alternatives as preferable to the proposed cap: (a) a 200 basis point symmetrical cap on variations in noncore earnings, or (b) 75 percent of any variations in earnings could be debited or credited to the SAM account.SDG&E requests clarification on the earnings cap. SDG&E argues that any rate adjustment should be prospective [*163] only, hence not requiring refunds of excess earnings. This it argues is a quid pro quo for making its return on equity dependent on noncore transmission. SDG&E also urges the Commission to carefully evaluate the criteria by which rates would be adjusted since the factors which could create a 300 basis point return above authorized may be nonrecurring.PG&E and SoCal request that hearings be held as soon as practicable to determine the appropriate level of risk and benefits that should be allowed through an earnings cap. PG&E also requests that the Commission make a policy statement assuring it that the company will be treated fairly in reasonableness review proceedings.TURN supports the proposed elimination of SAM for noncore customers, but supports the partial elimination of PGA only if a separate noncore portfolio is established. TURN states that if two portfolios are established, the Commission should issue guidelines for assignment of gas storage costs and unaccounted-for gas to the two portfolios.CIG supports the elimination of SAM treatment for noncore customers, but suggests that the Commission is being too bold in allowing a 3 percent cap above the authorized rate [*164] of return. CIG recommends a one percent variation on either side of the authorized return as an appropriate step. CIG supports the decision not to pursue an AGR mechanism or an IGR.DGS suggests elimination of the SAM altogether and recommends replacing it with a weather adjustment mechanism for the core customers based on heating degree days.PSD notes that cost allocation issues to be decided in I.86-06-005 may have repercussions on the desirability of elimination of the SAM, since utilities may be encouraged to place a larger share of their fixed costs on the core customers in order to mitigate the impact of scaling back SAM and to put the gas industry collectively in a better position to compete with the alternate fuel industry for fuel switchers.PSD recommends an AGR of 10 percent of gas commodity costs and/or that a separate IGR be put in place. PSD is also in favor of allowing the SAM to guarantee recovery of only 50 percent of the utilities' fixed costs for serving the core market if the core portfolio is to be fragmented.Transwestern states that if utilities are to be at risk for noncore sales by elimination of PGA and SAM treatment for those portions of the utilities' [*165] costs, then fairness dictates that there should be no limit established for profit opportunities. Transwestern would eliminate the proposed cap for this reason.Treatment of the SAM in the StipulationThe stipulation addresses changes in SAM treatment of fixed costs only, and is silent on the issue of the changes to the PGA balancing account proposed in the OIR. According to the stipulation, there would be an implementation phase with hearings following the issuance of this decision and today's companion decision in I.86-06-005. The SAM balancing account treatment for all fixed costs would continue until the rates set by the resulting implementation decision go into effect.Thereafter, the SAM balancing account treatment for the recovery of the portion of "margin," which the stipulation defines to be all utility nongas costs and pipeline demand charges, that have been allocated to the noncore market would terminate. No party to the stipulation would propose any further modifications of SAM balancing account treatment until at least twelve months after the rates set by the implementation decision go into effect.However, as of the date that SAM treatment for the noncore market [*166] is eliminated, a limit on the variation in noncore earnings would be established for each utility during a two year transition period. Each utility would create a tracking account entitled the Negotiated Revenue Stability (NRS) account. If the margin recovered from noncore customers varies from that which has been allocated by the Commission by a magnitude that would change the utility's authorized after-tax return on equity (gas operations only) by more than 150 basis points, then the utility would book amounts representing two thirds of the difference beyond the 150 basis point ceiling or floor to the NRS account until the variation reaches 600 basis points; thereafter all the differences would be booked to the account.The NRS account would bear interest when it has accruals at the same rate as other gas-related balancing accounts. The utilities would file monthly status reports on any NRS account accruals. The NRS account balance would be included in Consolidated Adjustment Mechanism (CAM) proceedings along with the SAM account for margin allocated to core customers. Any balance would be carried forward until it is fully amortized in rates.Positions of Parties Regarding [*167] the StipulationCHMA/CRA alone of the commenting parties (other than SoCal) found the stipulated approach for phasing out SAM treatment for noncore costs to be generally fair and reasonable. At the other extreme, CMA objects to any transitional period. It believes that the competitive marketing of gas sales and transportation services would be best secured without after-the-fact SAM adjustment procedures.CIG complains that the stipulation would preclude parties from proposing any modifications of SAM balancing account treatment for at least twelve months after the new rates go into effect.Nabisco, Long Beach, and CIG recommend that SAM protection be phased out or ended more quickly than provided by the stipulation, and provide other criticisms about the structure of the NRS account. CMA joins these parties in many of their recommendations, though immediate elimination of SAM treatment is its clear preference.CIG states that no more than a six month transition period is needed. It strongly opposes the NRS account proposal, citing lack of evidence regarding the appropriateness of the 150 basis point threshold, the two year life of the mechanism, and the fact that the stipulation [*168] does not categorically provide that at the end of the transition period there shall be no tracking account whatsoever.Long Beach supports an eighteen month gradual phaseout, with the amount of "at risk" margin increasing continually during that period. Nabisco's proposal is similar in effect, with the phaseout occurring over two years through either a stepping up of the basis point threshold of the NRS account or a stepping down of the percentage of undercollections or overcollections which would accrue to the NRS account when the basis point threshold is exceeded. These parties believe that a phaseout of balancing account protection would provide for a smoother transition for the utilities than the sudden termination of the NRS mechanism as provided in the stipulation.In addition to agreeing with other parties that a phaseout of SAM protection with a definite termination date should be required if SAM treatment of noncore costs is not terminated immediately, CMA argues that any undercollections in the NRS account not recoverable within one year after the end of the two year protection period should be written off. It further contends that calculation of NRS account amounts [*169] is not clear from the stipulation. It believes that monthly calculations could be misleading and that a single calculation at the end of each year appears appropriate.CIG states that there is no reason for the Commission to rush to judgment on yet another tracking account such as the proposed NRS account. It contends that if this proposal has any merit, then it should be able to withstand the scrutiny of the parties in implementation hearings.3. Allocation of SAM Account BalancesThe stipulation provides that any under-or overcollections in the utilities' SAM balancing accounts at the time of the implementation decision would be allocated between the core and noncore classes by either the equal cents per therm or equal percent of total rates method. The Commission would choose between these methods in the implementation decision.The portion of the SAM balance allocated to the noncore class would be retained by each utility in a separate interest bearing tracking account, and the utilities could recover it only from noncore customers. The utility could, at their option, recover it through a demand surcharge. The balance in this tracking account would not be considered [*170] in the calculation of each utility's variation in earnings used to determine whether amounts should be booked to the NRS account.Positions of Parties Regarding the StipulationCHMA/CRA urges the Commission to apply the equal cents per therm method for allocation of the under-or overcollection, to reduce the impact of what it expects to be significant undercollections in the SAM balancing accounts on commercial customers.Long Beach contends that either method proposed for allocation of SAM account balances would result in an improper allocation of costs to the noncore classes. It states that the allocation should be consistent with the utility request in the pending offset applications of SoCal and PG&E (A.86-09-030 and A.86-09-055, respectively). For both SoCal and PG&E, this would result in all of the balance being allocated to core customers.CIG states that the stipulation provides no estimate of the total amount of any remaining balances, and that the proposed allocation methods ignore market realities, which could effectively undermine the new rate design at the outset.CIG also opposes the provision that the utilities may at their option recover any portion of the [*171] SAM balances allocated to noncore customers through a demand surcharge. It states that the feasibility of applying such a demand surcharge cannot be determined without some evaluation of the amounts involved and existing market conditions.4. Implementation of Policy DecisionsIn the OIR, we announced our intention that the new regulatory structure and rate design to come out of this proceeding and the companion Investigation would be implemented in the utilities' fall offset proceedings with rates to become effective by January 1, 1987. The parties to the stipulation recommend a longer implementation period with separate hearings.Under the terms of the stipulation, PG&E and SoCal would each submit an implementation filing no later than 45 days after we issue this decision and the companion decision in I.86-06-005. SDG&E would submit its implementation filing no later than 55 days after these decisions. The utility filings would provide rates for various services reflecting the method adopted in the decisions for allocating revenue responsibility to various customer groups.PSD would mail its report responding to each utility filing within 45 days after the utility filing. [*172] Hearings would commence no later than 15 days after PSD's report is mailed. Following the hearings, the Commission would issue a final decision adopting rates which the stipulation refers to as the "implementation decision."Positions of Parties Regarding the StipulationThe commenting parties generally express agreement with the implementation schedule proposed in the stipulation. CIG alone requests additional time to review the PSD report, urging that at least 45 days be provided after the date of the PSD report before the hearing commences.As SoCal's primary comment other than general support for the entire stipulation, SoCal stresses that the period of time during which implementation filings and hearings occur is absolutely vital so that the utilities can accomplish crucial adjustments in their procedures in preparation for implementing the new regulatory program. SoCal describes at length the changes which will be required in the method of billing noncore customers and the manner in which gas demand is forecasted.CMA, CHMA/CRA, Nabisco, and CIG all express concerns regarding the service requirements contained in the stipulation, i.e., that each utility would provide [*173] TURN with one copy and PSD with at least 20 copies of its implementation filing and complete workpapers on the date that the filing is made. These parties contend that the stipulation should have provided for similar service on all other customer representatives requesting such service from the utilities (CMA), all parties to the OII (CIG, CHMA/CRA, and Nabisco), and/or all parties which filed comments in R.86-06-006 (CHMA/CRA and Nabisco). CIG further states that the PSD report and workpapers should also be served upon all parties to the OII.5. Proceedings Following ImplementationThe parties to the stipulation request that there be an annual cost allocation proceeding for each utility in which that utility's margin is allocated between the core and noncore markets. PG&E would file its application on or before September 15 of each year for rates to be effective on January 1 of the following year. SoCal and SDG&E would file no later than March 15 for rates to be effective on July 1 of each year.The utility filings would be based on the adopted cost allocation method and would use the best volume forecasts available to them consistent with the proposed rates. However, if [*174] at any time the earnings variation due to NRS account balances exceeds 600 basis points for a utility during its rate period (annualized as of the filing date), then that utility, PSD, or TURN may propose a different cost allocation methodology in the pending or next annual cost allocation proceeding for that utility.Bundled rates would be set for core customers in the annual cost allocation proceeding. Depending on the extent to which the Commission decides to set rates for noncore customers or to grant the utilities flexibility, noncore rates and/or the range of such rates would also be set in this proceeding.In the utility's annual cost allocation proceeding, the Commission would decide how any under-or overcollection in the NRS account would be allocated between the core and noncore classes. The utilities would have the option of recovering the portion of any undercollection allocated to the noncore class through a demand surcharge. Parties would be allowed to propose methods for passing through the portion of any overcollection in the NRS account allocated by the Commission to noncore customers.The utilities would also file a CAM application with a revision date six [*175] months after the revision date of the allocation cost proceeding if such a filing would produce a change in the average total core rate of at least four percent. Such a proceeding would only change core rates and the elected core procurement rates due to existing or forecasted under–or overcollections in the core SAM and PGA balancing accounts. It would not change the allocation of fixed costs between the core and noncore markets, and would not change rates to noncore customers.The trigger would be determined using the following information:1. An updated forecast of core procurement demand for the next twelve months;2. A twelve month forecast of gas costs based upon the gas purchase mix established for ratemaking purposes in the last annual cost allocation proceeding;3. Dividing the cost of the gas portion of the revenue requirement plus a twelve month amortization of any over–or undercollection for the purchase gas portion of the balancing account by the forecast of core procurement demand; and4. Dividing the core margin plus a twelve month amortization of any over–or undercollection for the SAM portion of the balancing account, by forecasted core customer sales. [*176] Positions of Parties Regarding the StipulationBoth Nabisco and CIG are concerned with the statement in the stipulation that the portion of any undercollection in the NRS account allocated by the Commission to the noncore class may, at the utilities' option, be recovered through a demand surcharge. Nabisco states that there should be a cost–based ceiling on demand surcharges, since noncore customers are no less captive than core customers with regard to demand charges. CIG argues that the feasibility of applying such a surcharge cannot be determined without some evaluation of the amounts involved and existing market conditions.CMA is concerned that the stipulation would bar any proposal to change cost allocation methods unless earnings variations exceed 600 basis points. CMA argues that cost allocation methods may need change quite apart from the utility's ability to collect revenues, due for example to different operating practices or incurrence of new costs.6. Discussion of the Merits of the StipulationWe must determine whether the submitted stipulation represents a reasonable resolution of the issues it addresses. We are quite concerned that implementation of the new [*177] gas regulatory and industry structures occur as quickly yet in as orderly a fashion as possible. A stipulation to major issues could be of significant value in reducing controversy and the resulting hearing time needed to implement today's two decisions.At the same time, we must insure that the interests of parties not signatories to the stipulation are reasonably protected. We will address the concerns expressed by parties commenting on the stipulation.Despite CMA's objections, we find some comfort in the concept of a transition from complete SAM treatment of fixed costs to complete utility exposure for those costs allocated to noncore customers. Both the utilities and this Commission are breaking new ground on untrod soil as the new regulatory approach is implemented. An established safety net could reduce later pressures to adopt quick bandaid fixes if problems arise. There would be more time for customer adjustment to the adopted program and for reasoned consideration of modifications if any appear needed.We agree with CIG and CMA that a definite termination date for any transition measure should be established. However, there is nothing in the stipulation that would [*178] preclude us from adopting a termination date if we choose to do so.The commenting parties also raise concerns regarding the appropriateness of the 150 basis point threshold, whether the transition period should be phased out gradually, and the amortization period of any NRS account balances. We view these as aspects of the stipulation whose reasonableness must be evaluated in toto.CHMA/CRA and Long Beach present opposite views regarding the allocation of SAM balances at the time the implementation decision becomes effective. However, we note that the stipulation leaves the question of which of the two proposed allocation approaches should be used to the implementation hearings. These two methods can be scrutinized at that point.Obviously, Long Beach would prefer that no amount of an undercollection be allocated to noncore customers. CIG and Nabisco are also concerned that the amortization of SAM and NRS account balances might be collected through the demand charge. Our decision today to allow flexibility and negotiations in establishment of noncore transmission rates should provide significant protection to noncore customers. The utilities will have a strong incentive [*179] to ensure that the total transmission charge, including amortization of any SAM undercollection, remain at a level low enough to prevent noncore customers from switching to alternate fuels.The concerns of several of the parties regarding service requirements are unfounded. The stipulation does not address, and therefore would not change, service requirements to other parties. All appearances in I.86–06–005 and all parties which have filed comments in this rulemaking would be served implementation filings as part of the standard procedure.CIG requests 45 days to review PSD implementation filings before the hearing commences. Our standard requirement is that at least a 10 day review period be provided for expert witness testimony before it is addressed in hearings. The stipulation is more than adequate in this respect. Further, we note that utilities typically present their showings prior to PSD; this would give parties time beyond the 15 days in the stipulation in which to review PSD filings.A schedule would be required for submittal of testimony by other interested parties. We anticipate that a prehearing conference would be held some time after the utility filings are [*180] made to address such procedural issues.CIG and CMA assert that the stipulation would preclude parties from proposing changes in SAM balancing account treatment or the allocation mechanism. We disagree. The stipulation states explicitly that the restrictions apply to the parties to the stipulation. Other parties are free to propose any changes they desire at any time.We conclude, on balance, that the submitted stipulation presents a reasonable resolution of the issues addressed. While the NRS balancing account mechanism might not be exactly what we would have adopted absent such a stipulation, it provides adequate protection to both the utility and its customers during the transition period. We would have preferred that the implementation period not be as lengthy as the one set forth in the stipulation; however we recognize that this longer period may produce a better end product that what might result from a more hasty schedule. The proposal for followup proceedings is sound. We appreciate the effort made by the parties to flesh out the details of the proposed schedule.Consistent with CIG's and CMA's recommendations, we conclude that all revenue protection for that portion [*181] of fixed costs allocated to noncore customers should end at the end of the two year transition period. This period should provide ample time to perform any fine tuning which may be needed. We continue to believe that putting the utilities at risk for these costs is necessary to provide proper incentives for them to keep their costs as low as possible.Adopted RulesThe proposals in the attached stipulation shall be adopted to create transitional revenue protection for a two year period.All revenue protection for that portion of fixed costs allocated to noncore customers shall end at the end of the two year transition period established in the stipulation.The allocation of SAM balances shall be decided in the implementation phase of these proceedings, consistent with the attached stipulation.The recommendations in the stipulation regarding procedure and schedule shall be followed.7. Resolution of Other IssuesThe OIR contemplated that there would be SAM balancing account treatment of pipeline demand charges as a fixed nongas cost, contrary to SoCal's assumption that pipeline demand costs would continue to be booked into the PGA. Thus, SoCal's assertions about a mismatch [*182] between booking of revenues and costs are incorrect. However, SoCal's misconceptions show that the issue should be clarified. SoCal's comments also have caused us to rethink whether it is preferable to provide PGA-type (actual versus revenue) or SAM-type (forecasted versus revenue) balancing account treatment to pipeline demand charges and the transition costs identified in Section VIII.Pipeline demand charges and the transition costs adopted in Section VIII are all currently tracked through the PGA account on an as-incurred basis; the treatment of pipeline demand charges proposed in the OIR would switch to recovery of a forecasted amount. The implications of such a change must be examined carefully. Treatment of commodity costs on a recorded basis and pipeline demand charges on a forecasted basis would set up a potential for game-playing on the part of the utilities. This could be done, for example, by the renegotiation of contracts to decrease demand charges but increase commodity rates, or the signing of new contracts that have very low demand charges but high commodity rates. This might be very difficult to detect in reasonableness reviews.TURN has proposed that both [*183] pipeline demand charges and settlement costs be recovered only as they are incurred. We had always contemplated that any take-or-pay liabilities approved by the FERC for recovery from California utilities would only be recovered after they have been assessed by the FERC and found reasonable by this Commission, rather than on a forecasted basis. We also find the arguments in favor of recovery of recorded rather than forecasted treatment of pipeline demand charges persuasive, and will modify the rules to make this change.Forecasted levels of demand charges and transition costs should be used in setting rates, but actual incurred costs should be booked into the core balancing and noncore memorandum accounts. The same allocation factors should be applied to the actual costs to divide them between the core and noncore accounts as are used in allocating the forecasted levels in our adopted rate design methodology.We will not adopt PG&E's proposal that it receive balancing account treatment for the nongas costs allocated to its UEG load. We are concerned, however, about the perverse incentives that will result from this accounting treatment. To protect core customers, we will rely [*184] on traditional reasonableness review and will prohibit combination utilities from negotiating inter-departmental transmission rates for their gas departments as described in our decision in I.86-06-005.As a final matter, an additional account not explicitly mentioned in the OIR should be created for completeness, to track recovery of pipeline demand charges, transition costs, margin costs, and transmission revenues from noncore customers. This would be a memorandum account. We note that it is from this account that variations in earnings would be booked into the NRS account under the terms of the stipulation among PSD, TURN, and the respondent utilities.To summarize, four tracking accounts are needed to make the adopted changes in the PGA and SAM balancing account mechanisms. The existing PGA account would be split into a Noncore Procurement Purchased Gas Account, which will be a memorandum account, and the Core Procurement Purchased Gas Adjustment (PGA) Account, which will be a balancing account. These accounts will track recorded gas costs (excluding pipeline demand charges and transition costs) and procurement revenues. The existing SAM account will be superceded by a [*185] Noncore Customer Fixed Costs Account (memorandum) which is identical to the noncore SAM account discussed in the stipulation, and a Core Customer Fixed Costs Adjustment Account (balancing). These two accounts will track recorded pipeline demand charges and transition costs, forecasted margin costs, and transmission revenues. The cost and revenue accounts feeding into these tracking accounts are illustrated in Figure 1, and are established in the following two sections [SEE ILLUSTRATION IN ORIGINAL].Adopted RulesUtilities shall maintain the following four accounts to track costs and revenues for gas and transmission services:a) Noncore Procurement Purchased Gas Account:

shall include the recorded cost of all gas bought for the noncore procurement market and all revenues from sales of this gas. (Memorandum account.)b) Core Procurement Purchased Gas Account: shall include the recorded cost (excluding pipeline demand charges and transition costs) of all gas bought for the core procurement market and all revenues from sales of this gas. (PGA balancing account.)c) Noncore Customer Fixed Costs Account: shall include recorded pipeline demand charges and transition costs and forecasted [*186] margin costs allocated to the noncore market, and all revenues from transmission services to the noncore market. (Memorandum account.)d) Core Customer Fixed Costs Adjustment Account: shall include recorded pipeline demand charges and transition costs and forecasted margin costs allocated to the core market and all nongas revenues from the core market. (FCA balancing account.)B. Purchased Gas and Nongas CostsIn the OIR, we have proposed that the utilities continue to use the present FERC Uniform System of Accounts (USOA) to record gas purchases and actual operation and maintenance costs. The purchased gas accounts would be subdivided into two source accounts:1. Short Term Gas Purchase Account: the cost of short term gas, excluding any fixed pipeline demand charges, would be booked to this account; this was defined as gas which is priced monthly, purchased under either monthly or longer term contracts with the total price of the gas redetermined at least monthly.2. Long Term Gas Purchase Account: all other purchased gas not eligible for booking to the short term account would be booked to this account.The intent of these two gas purchase accounts is to collect and [*187] average the cost of gas from the two basic types of purchase contracts. A further set of accounts was proposed to track the flow of long term and short term gas into the core and noncore procurement portfolios. We proposed that gas costs would be booked into the following two accounts monthly from the Short Term Gas Purchase Account and the Long Term Gas Purchase Account:1. Noncore Market Portfolio Account: all gas destined for noncore procurement customers (e.g., normally all spot market gas).2. Core Market Portfolio Account: all gas destined for core market procurement customers (e.g., longer term supplies).Our intent was that gas booked into the core market portfolio account would receive balancing account treatment, whereas gas for the noncore market portfolio would not.We also proposed a rule to govern the transfer of gas between gas purchase accounts. Since it engendered some amount of confusion, it is repeated verbatim here:"Transfers from the gas purchase account to the core or non-core portfolio accounts: All gas transferred between the long and short-term gas purchase accounts to the core and non-core portfolio accounts shall be at weighted average cost. If [*188] there are transfers from the long-term source account to the non-core portfolio account during an extremely warm year, because there is such low core demand for the gas and the utility cannot avoid taking the gas even under its flexible contract terms, the gas shall be transferred to the non-core portfolio at the current weighted average cost of the long-term source account."However, any recovery deficiencies in the core portfolio balancing account resulting from sales to the non-core portfolio at a loss shall not be subject to balancing account treatment. The utility may seek recovery of such booked loss in its next annual reasonableness review."Positions of the PartiesAll parties commenting on this issue basically agree with the general thrust of the proposed accounting rules, with some suggested modifications.PG&E suggests that purchases be classified as long term or short term based on contract conditions rather than the periods for price redetermination. It suggests that the Short Term Gas Purchase Account include purchases due to contracts which do not include any expenses or charges for failure to purchase gas beyond the one month period.PSD notes that the proposed [*189] rules are silent on accounting for gas costs in storage. However, it views this as an accounting/ratemaking issue which can be addressed later. SoCal proposes that gas transfers to or from storage and fixed pipeline demand charges be charged to the Long Term Gas Purchase Account. On the other hand, TURN recommends that all fixed pipeline demand charges, including POPCO and PGT, be excluded from both the Long Term Gas Purchase Account and the Short Term Gas Purchase Account, and be tracked in separate accounts.PG&E suggests that a subaccount be added in the Noncore Market Portfolio Account, to reflect specially targeted or earmarked gas such as its Chevron account. It asks that specially targeted gas costs be excluded when calculating weighted average costs for the purpose of transferring gas from the purchase accounts to the portfolio accounts. SoCal suggests subdividing the Core Market Portfolio Account into a core account and an elected core account.TURN requests that the parentheticals in the description of the two portfolio accounts be deleted, because it claims that these could be misleading and the utilities might not properly credit the core market portfolio account [*190] with spot gas. CHMA/CRA similarly asks for clarification regarding the latter of these two parentheticals.PG&E and SoCal oppose the proposed rule regarding transfers between gas purchase accounts. SoCal states that the Commission's concerns regarding "recovery deficiencies" are unclear. It suggests that losses or gains resulting from the transfer of gas receive balancing account treatment at the time of sale subject to reasonableness review.PG&E claims that it is unfair to request the company to seek recovery in the following reasonableness case, as this would impose an initial nonrecovery requirement without a standard which details the requirements to obtain recovery.PG&E also rejects a suggestion in the discussion of these accounts that the gas transfers be booked on a daily basis, because such procedures would require daily meter readings of all customers which would be an extreme administrative burden. PG&E asks that the Commission leave the mechanics of recording transfers up to the utility.DiscussionPG&E's clarifications regarding the Short Term Gas Purchase Account are helpful and will be adopted. Similarly, SoCal's request that the Long Term Gas Purchase Account [*191] include the costs of gas transfers to or from storage addresses a detail which was omitted from the proposed rules. The Long Term Gas Purchase Account is intended to include all variable costs of long term gas procurement; this includes the costs of gas in storage.We agree with TURN that the gas purchase accounts should not include pipeline demand charges; that was not our intent in the OIR. We conclude that these charges and transition costs allocated to transmission charges should be tracked separtely from both gas costs assigned to procurement portfolios and other margin costs, and will provide that a separate Pipeline Demand Charge and Transition Costs Account be established to track these costs. In addition to pipeline demand charges, this account should include any costs imposed by the FERC on the gas utilities for compensation to the pipelines for producer take-or-pay liabilities and the other transition costs adopted in Section VIII. This change will facilitate the adopted change to provide PGA-type balancing account treatment for that portion of these costs allocated to core customers.Since we have decided not to allow targeted gas purchases at this time, PG&E's suggestion [*192] that a subaccount be added to the portfolio accounts is not appropriate. We likewise reject SoCal's proposal to subdivide the core market portfolio account into a core account and an elected core account. Multiple accounts may be appropriate if we decide to move towards the creation of multiple portfolios for serving noncore customers.For clarity, we will delete the two parentheticals as requested by TURN. It certainly was not our intent to imply either that only long term supplies would be allocated to the core portfolio or that all spot gas would be booked to the noncore portfolio.After reviewing the parties' comments, we conclude that the language in the proposed rule regarding transfers between gas purchase accounts that references "recovery deficiencies in the core-portfolio balancing account resulting from sales to the noncore portfolio at a loss" should not be adopted. Of course, we normally would not expect long-term supplies to be directed to the noncore portfolio, since by definition that portfolio provides short-term gas at current spot prices. We would envision long-term gas sales being directed to the noncore account only when the demand for the long-term supply [*193] by core and core-elect customers is insufficient to satisfy the long-term supply obligations. This condition might occur, for example, in particularly warm winters, or during off-peak periods. Since long-term supply is contracted for the benefit of the core and core-elect market, we conclude that in the event long-term gas is sold into the noncore market, the difference between the cost of the gas and the sale price should be credited to the core balancing account. However, if significant amounts of undercollection arise from such transactions, utilities would be closely scrutinized in subsequent reasonableness review proceedings.The phrase referred to by PG&E regarding the booking of gas transfers on a daily basis is also misleading. We certainly did not intend a daily reading of customers' meters. For now, we will leave the details of recording the transfers up to the utilities, subject to reasonableness review. The transfers should occur at least monthly.Adopted RulesThe utilities shall continue to use the present FERC Uniform System of Accounts (USOA) to record gas purchases and operation and maintenance costs.The purchased gas accounts shall be subdivided into three [*194] initial accounts:a) Pipeline Demand Charge and Transition Costs Account: all pipeline fixed demand charges, any take-or-pay costs incurred by interstate pipelines and passed on by the FERC, and any other transition costs approved by this Commission shall be booked to this account.b) Short Term Gas Purchase Account: the cost of short term gas shall be booked to this account; this is gas which is priced monthly and purchased pursuant to contracts which do not include any expenses or charges for failure to purchase gas beyond a one month period.c) Long Term Gas Purchase Account: all other purchased gas costs would be booked to this account, including costs of gas transfers to or from storage.Gas costs shall be booked at least monthly from the Short Term Gas Purchase Account and the Long Term Gas Purchase Account at the weighted average cost of gas in each account to the following two accounts:a) Noncore Market Portfolio Account: all gas destined for noncore procurement customers.b) Core Market Portfolio Account: all gas destined for core market procurement customers.C. RevenuesBecause of the need to track revenues from specific services to various types of customers, [*195] we established in the OIR that the gas utilities should maintain separate revenue accounts for gas sales to noncore procurement customers, gas sales to core procurement customers, gas transmission service to noncore customers and gas transmission service to core customers. These accounts would conform to the USOA, would separate revenues by traditional customer groups (i.e., residential, commercial, industrial, etc.), and would separate transmission revenues generated by short term and long term transmission services.Positions of the PartiesFew parties commented on the proposed accounting rules for revenues. PG&E states that it agrees with the proposed rules.SoCal reiterated its concerns regarding the principle of matching revenue and expense related to fixed pipeline demand charges.DiscussionIn the adopted rate design, core customers may receive a bundled rate or transmission-only service. In any case, the revenues need to be allocated separately to the procurement and transmission components so they can be booked to the proper balancing account. This should be done in proportion to the forecasted amounts of these components used in setting the core rate (i.e. based [*196] on the concept of equivalent margin).Since we do not adopt a distinction between short term and long term transmission services, the comparable distinction mentioned in the proposed rule for revenue accounts is no longer relevant.Adopted RulesGas utilities shall maintain separate revenue accounts that account for revenues generated by gas sales to noncore procurement customers, gas sales to core procurement customers, gas transmission service to noncore customers and gas transmission service to core customers. These accounts shall conform to the USOA and shall separate revenues by traditional customer groups (e.g., residential, commercial, industrial).The separation of the bundled revenues from core customers into procurement and transmission revenues shall be in proportion to the forecasted amounts of these components used in setting the bundled rate.D. UncollectiblesIn the OIR, we concluded that there should be a special incentive for the utilities to collect procurement take-or-pay charges from customers which receive elected core procurement services. For this reason, we provided that the utilities could book and recover in ratemaking a maximum of 50 percent of [*197] incremental uncollectible revenues resulting from customers which do not honor their contractual commitments for procurement services.Positions of the PartiesPG&E opposes the proposed rule, stating that utilities should not be penalized for noncollection in certain circumstances such as when a customer files for bankruptcy or leaves the area.TURN supports the rule, but suggests that this accounting treatment should be extended to cover uncollected amounts resulting from take-or-pay obligations under long term transmission contracts and standby charges for noncore services.DiscussionThe intent of the proposed rule was to strengthen the commitment associated with elected core procurement, in order to reduce the exposure which core ratepayers would have through the PGA balancing account to undercollections resulting from the failure of customers which have chosen elected core procurement to buy gas at contracted levels. Since we have chosen not to adopt take-or-pay requirements for this service at this time, the proposed rule regarding treatment of uncollectibles is no longer applicable.TURN proposed that the rule be expanded to other take-or-pay and standby charges. We [*198] see little value in this. The phasing-out of balancing account treatment for margin costs allocated to noncore customers provides the utilities with greater incentives than before to collect these amounts. As noted in the OIR, their ability to terminate transmission services for nonpaying customers also provides significant leverage with any recalcitrant customer which still desires to use natural gas.E. Customer Notice RequirementsIn the OIR, notice requirements were established whereby customers are to be informed of their choices when the new rate structure is implemented. We required that the utilities send a notice to all noncore customers and those customers which qualify to choose noncore status explaining the options available to them, advising them how to contact customer account representatives who are able to answer questions, and indicating the date for the full cutover to core/noncore unbundling.After the initial notice, once annually the gas utilities would be required to send customers a notice of their service options. The utilities would also be required to tell new customers of their options if they appear likely to qualify for noncore service.The proposed [*199] rule also requires that the utilities switch a customer's service within 20 days after receiving a valid properly executed service contract or election form.Positions of the PartiesSoCal supports the proposed rule, but comments that the Commission should be aware that it will take time and effort to inform customers fully of their options and a substantial amount of time to implement new individual service contracts.PG&E argues that, depending upon the final outcome and complexity of the cost allocation and rate design adopted by the Commission, the 60 day period for notification is not sufficient. PG&E argues that a minimum of 90 days or more will be needed to implement the Commission's proposed rules. SDG&E concurs with PG&E's 90 day request.TURN sees no reason why it should take the utilities 60 days to prepare and mail the necessary information. TURN argues that the notice should be sent within 30 days of the Commission decision to give customers the maximum feasible time to make their choices.Industrial Users concurs with the proposed notice procedure, but suggests that the Commission include a provision for notification of those customers requesting such notice [*200] whenever changes occur in rates and/or the available levels of procurement and transmission service between the annual notices provided for in the proposed rule.CIG believes that the new rate structure should be phased in over a period of up to one year. It recommends that the Commission allow at least 180 days for customers to make their choices after notice is received because of the significant time and effort needed for customers to evaluate their individual circumstances and to decide the type and level of service which they desire.DGS also submits that it would be preferable to phase in these changes over a period not less than six months, so that utility personnel will be available to answer questions, provide and explain contract forms, allow for analysis, and give customers data. It recommends, however, that all customers be advised that they can ask to be cut over prior to the proposed cutover date. DGS suggests that the utilities cut over core and UEG customers immediately, 25 percent of annual sales within 180 days, and then 15 percent more per month to finish the phase-in within one year.CPG also requests a phase-in to allow adequate adjustment time. It suggests [*201] that short term transmission and noncore procurement options could be phased in over a number of years, and notes that FERC chose five years for its contract demand reduction schedule.DiscussionSeveral factors, including the simplification of the regulatory approach adopted in this decision, should ease implementation problems, which rightly concern the commenting parties. The revised approach should be easier to explain to customers and their options should be more clear-cut. Further, the creation of default service options very similar to the current structure should reduce both the pressure on customers to make decisions quickly and the resulting demand for utilities to convert large numbers of customers in a short period of time.

Finally, the time required by the implementation hearings we are ordering should give the utilities more than adequate time to prepare training programs for their personnel, reprogram their computers, and do other planning needed to allow a smooth implementation of the program following the implementation decision.For these reasons, we conclude that the 30 day notice period recommended by TURN is adequate. This period should run from the effective [*202] date of the implementation decision.We see no need to phase in the changes as suggested by CIG, DGS, and CPG. There is no indication that utility resources will be inadequate to handle customer inquiries, particularly given the simplified program and longer implementation period.Industrial Users' concerns regarding notice of program changes between annual changes is well taken. The utilities should provide notice to all potentially affected customers whenever changes occur. The intent of the annual notice required in the proposed rule is to provide a comprehensive summary of all options available; it does not replace the need to inform customers of changes as they occur.Adopted RulesWithin 30 days from the effective date of the implementation decision, the gas utilities shall send by separate mail (not combined with a billing) a notice to all noncore customers and those core customers which qualify to choose noncore status. The notice shall clearly explain the options and levels of service available to them, advise them on how to contact customer account representatives who are able to answer questions, and indicate the date (to be set in the implementation decision) for [*203] the full cutover to core/noncore unbundling. The notice shall also clearly explain the consequences of taking no action within the specified time period."Utilities and their customers shall have 180 days from the effective date of the implementation decision within which to execute service contracts or election forms, during which time customers will continue to be serviced under existing tariffs until such time as they enter into new contracts. After the 180 day period, customers will be served under the default service options until such time as a contract or election form is executed." We admonish all parties not to delay negotiations or implementation.The utilities shall provide notice to all potentially affected customers whenever program changes or rate changes occur. Once annually, the utilities shall send customers a notice summarizing their service options and current rates.Service contract forms need not be sent with the informational notice, but utilities shall make such forms readily available to customers requesting them.Utilities shall switch a customer's service, or part of it if so elected, within 20 days after receiving a valid properly executed service [*204] contract or election form.Findings of Fact1. Large natural gas customers are more likely to be able to make well-reasoned gas purchase decisions than are smaller customers.2. No party disagrees with the proposal to allow large natural gas customers without alternate fuel capability but with usage over 250,000 therms per year access to procurement options.3. Some noncore customers who have not signed transmission or procurement contracts with the gas utilities may desire utility service nonetheless.4. There is a need to treat utility electric generation (UEG) loads of combined utilities different than for electric-only utilities.5. There are no cost differences between long-term and short-term transmission service sufficient to justify a 50 percent take-or-pay requirement for only long-term service.6. Various combinations of transmission contract length and firmness of service can be negotiated to meet the varying needs of utility customers.7. Utility gas purchase contracts are normally tied to calendar months.8. Gas sold through utility procurement contracts must be transported over the transmission system.9. A capacity-related curtailment would be due [*205] only to transmission constraints intrastate.10. In Decision (D.) 86-03-057, the Commission determined that a critical aspect of an unbundled gas rate design is the ability of customers to select whatever quality of transportation service they desire through their choice of contribution to the fixed costs of the utility system.11. There are significant societal benefits to the provisions of the firmest transmission and procurement services to Priority 1 and Priority 2A customers.12. A negotiated priority charge will provide a direct measurement of the value that noncore customers place on transmission reliability.13. No party opposed our proposal in Order Instituting Rulemaking (OIR) 86-06-006 to limit the notice period for scheduled maintenance to 30 days.14. No party opposed our proposal in the OIR to eliminate the volume restriction in the short-term transmission tariff of Southern California Gas Company (SoCal).15. The reasonableness of the level of firm interstate transmission capacity maintained by SoCal and Pacific Gas and Electric Company (PG&E) is tied closely to other gas resource planning and operational issues.16. The Federal Energy Regulatory Commission [*206] has jurisdiction over allocation of firm interstate transmission capacity.17. Natural gas supply availability is not a major concern in a deregulated, competitive supply market.18. In a competitive gas supply market, buyers face the risk of gas price volatility.19. Price security in long-term contracts would offer some protection against future upswings in gas prices.20. Insufficient evidence exists to determine the price premium, if any, required to achieve any given degree of price security.21. Rate averaging for all gas supplies with similar price stability, swing security, and contract lengths (i.e. selling at a portfolio's weighted average cost of gas - WACOG) will ensure that gas is provided to core customers at a fair rate and that the least costly supplies of a given nature are not diverted to other customers.22. The noncore portfolio proposed in the OIR would consist primarily of spot or short-term supplies. The core portfolio would include a mix of long and short-term supplies.23. If customers switch to the core portfolio after its price drops below that of the noncore portfolio, the benefits to customers who had paid higher prices earlier for price [*207] security would be eroded.24. Toward Utility Rate Normalization (TURN) proposed that there be a ban on switching to the core portfolio whenever it is cheaper than the noncore portfolio.25. There is significant societal benefit to be gained from the requirement that utilities offer a noncore portfolio on a best efforts basis.26. The utilities have a large market share for gas procurement.27. Existing utility procurement contracts are in excess of current demand and there is considerable flexibility in the level of taxes from these contracts.28. The utilities do not incur any direct costs at this time as a result of a specific customer's failure to purchase gas.29. A portfolio approach to the purchase of gas supplies allows for a hedging of risks.30. The core portfolio will provide greater swing security and price stability than the noncore portfolio.31. The noncore procurement portfolio will involve no fixed costs for purchases beyond the month at hand.32. The allowance of gas brokering outside a utility's service territory would encourage competition.33. Utility ratepayers currently bear the costs of underground storage facilities and the cost of firm [*208] interstate transmission capacity.34. Requiring a brokerage fee and rate averaging for sales outside a utility's service area would provide protection against the diversion of the least expensive gas supplies outside the service area and the subsidization of marketing operations by utility revenue.35. The term "transition costs" refers to costs in excess of current market value that are not assignable to any particular customer class.36. "Transition costs" include all producer take-or-pay costs passed on to the utilities by the Federal Energy Regulatory Commission and found reasonable by this Commission, and any premiums paid to avoid the accrual of take-or-pay liabilities or to meet minimum operating requirements of the interstate pipeline systems.37. Pipeline demand charges in excess of the amount which would be required under new contracts are transition costs.38. Inclusion of fixed costs in volumetric transmission rates would provide an incentive to utilities to encourage gas transmission.39. Flexibility in pricing transmission services to noncore customers would give utilities the ability to provide price discounts to customers who would otherwise bypass the utilities' [*209] systems due to their competitive alternatives.40. Selective discounting of transmission service would minimize revenue loss due to discounting.41. No utility costs associated with gas procurement other than gas costs have been quantified in this proceeding.42. Public Utilities (PU) Code Section 2771 et seq. provides that curtailment mechanisms must be based on an assessment of public benefits and public need.43. An end-use priority system was developed to comply with PU Code Section 2771 et seq.44. San Diego Gas & Electric Company (SDG&E) does not have access to the firm interstate pipeline capacity and underground storage needed for SDG&E to secure reliable gas supplies.45. Public Staff Division (PSD), TURN, SoCal, and PG&E entered into a stipulation containing a package of proposals regarding balancing account treatment of noncore fixed costs, allocation of existing Supply Adjustment Mechanism (SAM) balances, an implementation schedule for this decision and the companion decision in Investigation (I.) 86-06-005, and schedules for future cost allocation and gas cost proceedings.46. This stipulation represents the views of only some of the parties in the two proceedings. [*210] 47. The allocation of balancing account balances among customer classes was an issue in I.86-06-005.48. Changes to the SAM balancing account have been considered in I.84-04-079 and in this rulemaking.49. The proposals in the OIR to eliminate SAM balancing account treatment for fixed costs allocated to noncore customers and Purchased Gas Adjustment (PGA) balancing account treatment for noncore procurement sales would encourage gas utilities to promote gas usage and to pressure pipelines and suppliers to keep their prices competitive with oil, and would put the utilities at risk for the successful development of the new regulatory structure.50. An established transition period from full SAM treatment to complete utility exposure for those costs allocated to noncore transmission service would provide more time for customer adjustment to the adopted program and for reasoned consideration of modifications if any appear needed.51. The stipulation leaves the question of which of two allocation approaches will be used to allocate SAM balances to the implementation hearings.52. The stipulation does not address service requirements to parties other than those participating [*211] in the stipulation.53. The stipulation provides at least 15 days for review of PSD filings before hearings commence.54. An implementation period longer than that contemplated in the OIR would provide time needed to resolve issues still pending in a well-reasoned fashion.55. Pipeline demand charges and the costs identified as transition costs are currently tracked through the PGA account on an as-incurred basis; the treatment of pipeline demand charges proposed in the OIR would switch to recovery of a forecasted amount.56. Treatment of commodity costs on a recorded basis and pipeline demand charges on a forecasted basis in utility balancing accounts would set up a potential for manipulation by the utilities.57. In the OIR, three accounts were established to track costs and revenues for core procurement, noncore procurement, and fixed costs allocated to core customers.58. The current accounting system does not provide tracking of costs consistent with the new adopted market structure.59. The simplifications in our adopted rules, provision of default options, and institution of separate implementation hearings will ease time pressures on the utilities to prepare for [*212] final implementation of the new market structure and rate design.Conclusions of Law1. All customers with end-use priorities P-3 and below should be classified as noncore customers and should have the opportunity to elect transmission-only service and choose among the utilities' various procurement options.2. Customers with end-use Priorities P-1 and P-2A should be classified as core customers and receive natural gas service on a bundled basis, except that core customers with annual load over 250,000 therms per year should be allowed transmission-only service on an equivalent margin basis.3. Customers with multiple use loads should be allowed transmission-only core service for their high priority loads as well as their alternate fuel loads.4. Customers without alternate fuel capability should not be allowed to aggregate loads from different facilities in order to qualify for procurement options.5. Default levels of transmission and procurement service should be provided to noncore customers which have not signed contracts for utility service.6. UEG gas load should be treated as any other large noncore load.7. There should not be take-or-pay requirements for long-term [*213] transmission service at this time.8. There should be a continuum of transmission contract lengths available to noncore customers, with appropriate terms and conditions established through contract negotiations.9. Default transmission pricing terms and conditions should be based on a one month contract, with any fixed costs determined from either current usage or usage during the most recent comparable period, depending on the structure of fixed costs assessed to customers with signed contracts.10. The term of a transmission contract should normally coincide with a calencar month. Utilities should provide negotiated nonstandard contract lengths at a customer's request, with differences reflecting utility costs.11. Priority 1 and Priority 2A customers should receive the firmest transmission service.12. Comments on whether P-2B customers should be included in the core or noncore market are needed.13. Utilities may negotiate a transmission priority charge to provide enhanced transmission reliability for noncore customers based on their willingness to pay.14. Willingness to pay is the most appropriate basis for pricing transmission reliability for noncore customers. [*214] 15. Utilities should be allowed to require notice of no more than 30 days for schedule maintenance shutdowns of facilities whose gas requirements are covered by transmission contracts.16. The volume restriction in SoCal's short term transmission tariff should be eliminated.17. The issue of sharing or brokering firm interstate capacity should be deferred until further direction from the FERC is available.18. All customers should be required, to the extent possible, to share in compensating the utilities for the cost of existing uneconomic investments and obligations.19. Gas costs in excess of current market value, taking into account the degree of supply certainty and price stability, should be shared among all customers.20. There should be rate averaging for similar components of each utility supply portfolio.21. The establishment of two utility supply portfolios, as proposed in the OIR, provides a reasonable balance of protection to captive customers and provision of service to all customers.22. All utility gas sales should be from one of these two supply portfolios at this time.23. Further procurement hearings should be held to consider the establishment [*215] of multiple supply portfolios.24. TURN's proposal regarding switching to the core portfolio is reasonable and should be adopted.25. Utilities should offer a noncore portfolio on a best efforts basis.26. Noncore customers which do not sign procurement contracts should not be protected from market swings.27. Default procurement service should be priced at the weighted average cost of gas from the noncore portfolio.28. Utilities should not profit from gas sales at this time.29. The utilities' primary procurement responsibility is to customers whose small size and/or lack of alternate fuel capabilities keep them as essentially captive customers of the utilities.30. Restrictions on the ability of noncore customers to choose or terminate elected core procurement service should be based on the economic consequences of such actions.31. A one year minimum for elected core procurement contracts is reasonable at this time.32. No take-or-pay provision for elected core procurement contracts is warranted at this time.33. Elected core procurement customers which do not use their full contracted quantities on a yearly basis should be liable for unavoidable or minimum [*216] charges if the utility incurs costs as a result of their failure to purchase the contracted gas. no such charges are warranted at this time.34. Termination provisions for elected core procurement contracts should assess the unavoidable/minimum charge over the remaining life of the procurement contract.35. Core customers who elect transmission-only core service should only be allowed to return to the core portfolio as elected core procurement customers.36. Noncore customers should be allowed to divide load among procurement options.37. Utilities should assume that core customers are more price risk averse than noncore customers at this time.38. Utilities should undertake to procure for their core procurement customers a supply portfolio which reasonably results in certainty of supply availability to serve core peak requirements, price security greater than can be achieved by relying totally on spot or other market price sensitive supply sources, and which attains these objectives at the lowest possible cost.39. Noncore procurement contracts should have a 30 day termination provision. Minimum bill and other contract provisions should mirror the utilities' costs. [*217] 40. Utilities should not be allowed to use their underground storage facilities or commit their firm interstate transmission capacity on behalf of extended area customers at this time.41. A gas utility's customers within its service area should not bear any costs of marketing or brokering activities outside the service area.42. Utilities should charge brokerage fees for out-of-service area sales so that ratepayers do not subsidize such marketing activities.43. Marketing activities outside a utility's service territory should be considered above-the-line at this time.44. There should be an annual reasonableness review of procurement practices of the gas utilities and any out-of-area marketing activities by the utilities and/or their affiliates.45. All current pipeline demand charges should be allocated to transmission rates.46. Any fixed costs associated with future utility gas purchase contracts should be incorporated into procurement rates.47. All transition costs should be allocated to transmission rates.48. The utilities' return on equity and associated taxes should be recovered through the volumetric transmission rate for default customers.49. Selective [*218] discounting of both transmission demand charges and volumetric rates is reasonable. The minimum charge should be short-run marginal cost including a shortage cost component.50. Differences in administrative costs should be reflected in the charges to customers.51. The actual margin recovery method of establishing transmission rates should be abolished.52. The commodity price for elected core and noncore procurement services should be the weighted average cost of the core portfolio and the noncore portfolio, respectively.53. The number of revisions to noncore procurement tariffs should be measured by calendar month.54. Willingness to pay for transmission reliability is a reasonable proxy for public benefit and need for the noncore class.55. The curtailment order of noncore customers in the event of an intrastate capacity shortage should be in reverse order of the magnitude of their priority charge. For noncore customers with a zero priority charge, curtailment should occur according to the existing end-use priority system.56. The curtailment order for utility gas service in the event of supply shortages should follow the existing end-use priorities.57. Utilities [*219] may divert customer-owned gas from transmission-only customers to serve P-1 and P-2A customers being served from the core portfolio only after all other supply curtailment steps have been taken and the Commission declares a supply emergency.58. Wholesale customers should be treated as noncore customers with core load responsibilities.59. If a wholesale customer elects to purchase gas from their primary utility's supply portfolios, such supply should be provided at parity with retail service of the same priority.60. The adopted curtailment systems for capacity and supply are consistent with PU Code Section 2771 et seq.61. Commission rulemaking proceedings do not ordinarily requires evidentiary hearings in the absence of disputed issues of fact.62. Parties have had adequate and proper opportunity to express their concerns regarding issues in I.86-06-005 and this rulemaking.63. A hearing is not required for procedural issues such as scheduling.64. The stipulation would not change service requirements to parties other than those participating in the stipulation nor restrict their ability to propose changes in the SAM balancing account treatment or the allocation mechanism. [*220] 65. The stipulation more than meets our standard requirement of a 10 day review period for expert witness testimony prior to the commencement of hearings.66. The proposal in the stipulation for future cost allocation and gas cost proceedings is sound.67. Noncore customers have protection against excessive charges for transmission service because of their alternate fuel capability and the transmission rate ceilings adopted in our companion rate design decision in I.86-06-005.68. The submitted stipulation, taken as a whole, presents a reasonable resolution of the issues addressed and reasonably protects all customers' interests.69. All revenue protection for those costs allocated to noncore transmission service should end at the end of the two year transition period contained in the stipulation.70. Pipeline demand charges and transition costs should continue to be treated on an as-recorded basis in utility balancing accounts. The allocation factors used to divide them between core balancing and noncore tracking accounts should be those adopted for the allocation of forecasted levels in rate design.71. No balancing account treatment should be provided for UEG load. [*221] 72. A fourth account should be created to track costs allocated to and revenues from transmission services for noncore customers.73. Pipeline demand charges and transition costs should be tracked separately from either gas costs assigned to procurement portfolios or other margin costs.74. Separate long-term and short-term gas purchase accounts should be established to provide the averaging of gas prices for the two types of purchases. Short-term gas should be defined as gas which is purchased pursuant to contracts which do not include any expenses or changes for failure to purchase gas beyond a one month period.75. Separate revenue accounts should be established for gas sales to noncore procurement customers, gas sales to core procurement customers, gas transmission service to noncore customers, and gas transmission service to core customers.76. A 30 day notice period following the effective date of the implementation decision should be provided for notice to customers which qualify to choose gas transmission and procurement options.INTERIM ORDERIT IS ORDERED that:1. The respondent utilities shall make implementation filings containing further testimony and complete [*222] proposed rates and tariffs consistent with the rules adopted in this order and the companion order issued today in Investigation (I.) 86-06-005. Pacific Gas and Electric Company and Southern California Gas Company shall make their filings no later than 45 days after the effective date of this decision. San Diego Gas & Electric Company shall make its filing no later than 55 days after the effective date of this decision.2. Comments on whether P-2B customers should be included in the core or the noncore market shall be filed in original and 12 copies with the Commission's Docket Office 30 days from today. Copies shall be served on all parties.3. Rulemaking (R.) 86-06-006 and I.86-06-005 are hereby consolidated for the purpose of joint hearings to implement today's orders in the two proceedings.This order is effective today.Dated December 3, 1986, at San Francisco, California.