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Decision 99-11-021 November 4, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Gas Company for Authority to Review its Rates Effective January 1, 1997, in its Biennial Cost Allocation Proceeding	Application 96-03-031 (Filed March 15, 1996)
In the Matter of the Application of San Diego Gas & Electric Company for Authority to Revise its Rates Effective January 1, 1997, in its Biennial Cost Allocation Proceeding.	Application 96-04-030 (Filed April 15, 1996)

(See Attachment 1 for Appearances.)

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FINAL OPINION ON LIMITED REHEARING OF DECISION 97-04-082

1. Summary[1]

The purpose of this limited rehearing is to determine the appropriate cost allocation for Southern California Gas Company's (SoCal) relinquishments (or "step-downs") of interstate natural gas pipeline capacity on both the El Paso and Transwestern pipelines. These relinquishments resulted in a reduction of stranded costs estimated to range from $320 to $525 million in net present value (NPV), based on the record in this proceeding. They also resulted in surcharges, based on settlement agreements among the pipelines and their firm capacity customers. SoCal's share of the surcharges was $161.8 million, including interest.

In Decision (D.) 97-04-082, which is the subject of this rehearing, we determined in error that these were new costs, and allocated them in proportion to the firm capacity reservations of SoCal's core and noncore customers. This resulted in an allocation of $122 million to the core and $39.8 million to the noncore, including interest. All of the benefits of the step-downs, i.e., reduced stranded costs, were allocated to noncore customers.

Today, we find that the surcharges should be treated as Interstate Transition Cost Surcharges (ITCS) costs, except for the portion attributable to the step-downs of Pacific Gas and Electric Company (PG&E) and other shippers on El Paso. We determine the portion attributable to PG&E and other shippers to be $84.8 million, including interest. Accordingly, the portion associated with SoCal's step-downs ($77 million) will be allocated exclusively to the noncore,

[1] Attachment 2 explains each acronym or other abbreviation that appears in this decision.

because the core has met their cap on ITCS costs as of the date we issued D.97-04-082. The portion attributable to the step-downs of PG&E and other shippers on El Paso ($84.8 million) will be allocated between the core and noncore on an equal cents per therm basis, or approximately 40% to the core and 60% to the noncore.

This results in an allocation of SoCal's surcharges as follows: $33.9 million to the core and $127.9 million to the noncore. We make no changes to the allocation of the benefits of the step-downs. Noncore customers will continue to realize the $320 to $525 million in reduced ITCS that have resulted from SoCal's decision to relinquish capacity rights. Today's adopted allocation of benefits and costs from the step-downs, compared to the allocation adopted in D.97-04-062, is as follows:

Allocation of Benefits/Costs of Step-Downs Per D.97-04-082

(in millions of dollars)

	Benefits	Costs
Core	0	122.0
Noncore	320-525 (NPV)	39.8
Total	320-525 (NPV)	161.8

Allocation of Benefits/Costs of Step-Downs Per Rehearing Decision

(in millions of dollars)

	Benefits	Costs
Core	0	33.9
Noncore	320-525 (NPV)	127.9
Total	320-525 (NPV)	161.8

Since noncore customers have already been allocated $39.8 million in surcharge costs, the effect of today's decision is to add $88.1 million to the ITCS balancing account.[2] The Core Fixed Cost Account is reduced by a corresponding amount to reflect the fact that core customers have already paid $122 million in surcharge costs that were allocated to them in error by D.97-04-062. The balancing account adjustments will be implemented in the pending Biennial Cost Adjustment Proceeding (BCAP), Application (A.) 98-10-012 et al. SoCal is directed to submit a late-filed exhibit in that proceeding showing the effect of today's determinations on balancing account amounts. We defer to that proceeding the issue of how and over what period the balancing account amounts will be recovered, including the adjustments adopted in today's decision.

2. Background

In order to understand the debate in this proceeding, it is useful to review some of the basic terminology, ratemaking and regulatory history related to relinquishments by SoCal and others of interstate pipeline capacity. We begin with a brief presentation of basic terminology and ratemaking as they apply to the circumstances surrounding SoCal's step-downs. Next, we discuss the Federal Energy Regulatory Commission (FERC) proceedings that led to the surcharge amounts that are the subject of this rehearing. We then describe the events that led up to the rehearing of Decision (D.) 97-04-082 in our BCAP. Finally, we summarize the procedural history of this rehearing phase of the proceeding and address concerns over late-filed Joint Exhibit (Exh.) 8.

[2] As discussed in this decision, we establish a special ITCS subaccount for this purpose that is allocable only to noncore customers. This allocation does not reflect the adopted treatment for the credits under the El Paso Settlement Agreement. As discussed in this decision, these credits will be allocated between core and noncore customers in the same manner as the El Paso surcharges are allocated.

2.1. Basic Terminology and Ratemaking

Relinquishments or step-downs occur when a utility turns back capacity rights to an interstate pipeline.[3] Prior to the recent step-downs, SoCal held long-term contracts for 2,200 million cubic feet per day (MMcfd) of capacity - 1,450 on El Paso and 750 on Transwestern. SoCal paid "as-billed" rates for the entire 2,200 MMcfd, i.e., maximum rates that are billed to SoCal by the pipeline companies. Of that capacity, 1,044 MMcfd was held by SoCal for core customers per the 1996 BCAP decision, 744 MMcfd on El Paso and 300 MMcfd on Transwestern. (Reporter's Transcript (RT) at 3008.) Core customers paid the as-billed rate for this capacity. The remaining capacity not reserved for the core is made available to the market (e.g., noncore customers) through capacity brokering (aka as capacity releases).[4]

Had there been no step-downs, the entire 1,156 MMcfd remaining after the core reservation amount would have been brokered by SoCal in the secondary market. The difference in value between the as-billed rate for the 1,156 MMcfd and the market price for brokered capacity becomes stranded costs recovered through the ITCS. ITCS costs are allocated among customers by equal cents per therm. However, the core market's liability is capped at 10% of the cost of the core's capacity reservation (referred to as the 10 % cap), in addition to the core's responsibility for 100% of the costs associated with the capacity reserved

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[3] In the area of natural gas, capacity means pipeline space through which natural gas flows.

[4] The noncore market consists of all those customers who, with minor exceptions, have fuel switching capabilities, and thus have competitive alternatives to purchasing natural gas from utilities, such as large industrial companies and utility electric generation companies. The core generally consists of residential and commercial customers who have no alternate fuel capability. (D.86-12-010; (1986) 22 Cal.P.U.C.2d 491, 504-505.)

for its use. Noncore customers are responsible for all ITCS costs above the 10% cap. This allocation of ITCS costs was adopted by the Commission in D.92-07-025.

The step-downs reduced SoCal's reserved capacity by 750 MMcfd-300 on El Paso and 450 on Transwestern. SoCal was left with 1,450 MMcfd of reserved capacity, including the 1,044 MMcfd that was still reserved for the core. SoCal brokers the remaining 406 MMcfd on the secondary market.

In Joint Exhibit 8, parties present their estimates of the benefits of SoCal's step-downs. These benefits, in the form of reduced ITCS, are estimated to range between $320 and $525 million in NPV.

2.2. Step-downs and the FERC

Because SoCal, and others, held more capacity than they needed in the restructured industry, some of that capacity had to be sold into a depressed secondary market, resulting in the stranded costs defined above. By electing to exercise relinquishment rights in their contracts with the pipelines, the utilities could shift the problem of marketing capacity that costs more than its value in the marketplace back to the pipelines. The pipelines attempted to recover these stranded costs in their rates, either by attempting to impose "exit fees" on customers exercising their step-downs rights, or by seeking rate increases to their remaining firm customers.

The exit fee approach was being pursued by El Paso, and being considered by FERC, during the timeframe when SoCal elected to step down its capacity rights from 750 MMcf/d to 300 MMcf/d on Transwestern. On July 26, 1995, FERC denied El Paso's exit fee approach, and made the following statements regarding cost sharing between the pipeline, the exiting customer and remaining customers:

> "The Commission [FERC] recognizes that some cost sharing may be appropriate when a large, historic customer leaves a system that was originally designed to meet its needs. When historic customers terminate service at the end of their contracts it is not appropriate to expect the remaining customers, specifically the EOC customers in this case, to pay for all the remaining costs of the pipeline. The pipeline has some obligation to attempt to develop new business opportunities to make use of its unused capacity. Therefore, a cost sharing mechanism should not diminish the pipeline's incentives to market its unused capacity." (72 FERC ¶ 61, 083, at page 61,441 (1995).)

On July 27, 1995, FERC approved a Transwestern rate case settlement that addressed, among other issues, the allocation of cost responsibility between the pipeline and its firm transportation customers for SoCal's relinquished capacity. (Transwestern Pipeline Company, 72 FERC ¶ 61,085 (1995)). Under the terms of the settlement, Transwestern assumed the risk for approximately 70% of the revenue shortfall caused by SoCal's capacity step-downs during the first five years and 100% thereafter. Transwestern's customers (SoCal, PG&E and others) agreed to pay 30% of the revenue shortfall over a five-year period, for a total of $75 million. SoCal agreed to assume approximately $50 million of that total. The remaining $25 million was allocated to PG&E and other firm customers of Transwestern.

The issue of SoCal's step-downs was again raised at FERC, because SoCal, PG&E and other customers would be relinquishing capacity rights on El Paso in 1996 and thereafter. PG&E relinquished all of its capacity on the pipeline (1140 MMcf/d). SoCal relinquished 300 MMcd/d, and other customers relinquished approximately 175 MMcf/d.[5]

In March 1996, El Paso and its firm transportation customers reached a rate case settlement which addressed the allocation of costs associated with relinquished capacity, among other issues. FERC approved the settlement in April 1997. Under the settlement risk sharing terms, El Paso assumed the risk for 65% of the revenue loss associated with unsubscribed capacity for eight years, and 100% thereafter. El Paso's customers agreed to pay 35% of those costs for eight years in a risk-sharing surcharge. The net present value (NPV) of the customer share was $254.8 million. Of that amount, SoCal's cost responsibility was $98 million (approximately $112 million including interest).

The customer share of step-downs costs were assigned by FERC via a separate charge, which we refer to as "surcharges" throughout this decision.

2.3. Step-downs and the BCAP

In a BCAP proceeding, the Commission allocates the utilities' base revenue requirement among customer classes, and determines the rate design under which the utilities will recover their costs, among other issues. In D.97-04-082 ("BCAP decision"), the Commission adopted rates for the period from January 1, 1997 through July 31, 1999 for customers of SoCal and San Diego Gas and Electric Company (SDG&E).

One of the determinations reached in the BCAP decision involved SoCal's step-downs on Transwestern and El Paso. The Commission determined

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[5] This was actually SoCal's second capacity step-down of 300 MMcf/d on El Paso. The first step-downs was negotiated in 1993 and the capacity was immediately subscribed to by other shippers on the El Paso system, and thus no stranded costs resulted. (Exh. 8, pp. 9-10.)

that the noncore customers would receive the benefits of the relinquishments, and both the core and noncore would bear responsibility for the step-downs surcharges in the same proportion as their pro rata share of SoCal's total pipeline capacity reservations (approximately 75% core/25% noncore). In arriving at this allocation, the Commission treated the surcharges as new costs. Table 1 presents the surcharge amounts allocated to the core and noncore, as adopted in the BCAP decision.

In an application for rehearing, The Utility Reform Network (TURN) challenged the Commission's determination related to the allocation of the costs resulting from the relinquishments. In its rehearing application, TURN argued that the BCAP decision was arbitrary, unduly discriminatory, and unsupported by either the record or past Commission decisions, because the decision resulted in the allocation of most of the surcharges to the core and all the benefits to noncore customers. The Commission's Office of Ratepayer Advocates (ORA) raised similar arguments in a petition for modification.

In disposing of TURN's rehearing application and ORA's petition for modification, the Commission in D.98-07-100 determined that it had erred in the BCAP decision, by treating the surcharges resulting from SoCalGas' relinquishment as new costs. In D.98-07-100, the Commission explained in detail why the surcharges were not new costs, but rather constituted the same transition costs which the noncore customers were made responsible for in the Commission's previous capacity brokering decisions but in a reduced amount as a result of the FERC settlement. (D.98-07-100, mimeo. pp. 8-11.)

In D.98-07-100, the Commission determined that in treating the surcharges incorrectly as new costs and not ITCS costs in D.97-04-082, it had acted inconsistently with its previous decisions by allocating to the core a share of the ITCS beyond the 10 percent cap. It corrected this error in D.98-07-100, and granted a limited rehearing. The purpose of the limited rehearing was to permit parties to present reliable and legally sufficient evidence for the Commission to consider an allocation of the surcharges different from the method adopted in D.92-07-025. In addition, the Commission allowed parties the opportunity to consider a different treatment of any "new costs" associated with the relinquishments of PG&E and others on El Paso, that were included in the surcharges.

2.4. Procedural History

Applications for rehearing of D.98-07-100 were filed by California Industrial Group and California Manufacturers Association (jointly CIG/CMA), SoCal, Southern California Utility Power Pool and Imperial Irrigation District (jointly SCUPP/IID) and Southern California Edison Company (SCE). The challenges raised included: the Commission erred in determining that the surcharges were not new costs, D.98-07-100 is inconsistent with the allocation policies adopted in D.92-07-025 and unsupported by the record; there was no need to grant limited rehearing because there was evidence in the record to support the allocation adopted in the BCAP decision, D.98-07-100 contemplates an unlawful retroactive allocation of the surcharges and D.98-07-100 is inconsistent with the recently enacted Senate Bill (SB) 1602 (Stats. 1998, ch. 401), which was codified as Pub. Util. Code § 328. Responses were filed by TURN, ORA and SCUPP/IID.

By ruling dated August 18, 1998 the assigned Administrative Law Judge (ALJ) noticed a September 16, 1998 prehearing conference (PHC) and requested written PHC conference statements addressing the scope of the rehearing, scheduling and other procedural matters. PHC statements were submitted on September 8, 1998 by CIG/CMA, Dynegy Power Corporation and Dynegy Marketing and Trade, SoCal, SCE, TURN, PG&E and Southern

California Generation Coalition (SCGC). The ALJ issued an oral ruling at the PHC to clarify the scope of the proceeding, based on the issues raised in the PHC statements. The ALJ also requested that parties prepare a Joint Exhibit that would show the dollar-level allocation between core and noncore resulting from parties' positions, as well as the rate impacts with and without any amortization proposals. (RT at 45, PHC 2, September 16, 1998.)

On September 14, 1998, SCUPP/IID filed a motion for stay of the limited rehearing proceedings ordered in D.98-07-100. SCUPP/IDD requested that the Commission delay the establishment of a procedural schedule in this case until the Commission acts on the pending applications for rehearing of D.98-07-100. Responses were filed by SoCal, CIG/CMA and SCE.

On October 16, 1998, SCE, SoCal, SCGC and CIG/CMA (Joint Parties) filed a motion for reconsideration of the PHC ruling of the assigned ALJ. By ruling dated October 21, 1998, the Assigned Commissioner denied both motions. On October 26, the Joint Parties filed an appeal to the full Commission of the assigned ALJ's PHC ruling. TURN submitted a response to this filing. On November 10, 1998, these same parties filed an appeal to the full Commission of the Assigned Commissioner's ruling.

On December 23, 1998, SoCal filed a motion to suspend the procedural schedule for the proceedings ordered in D.98-07-100 because of the December 11, 1998 decision by the United States Court of Appeals. That decision reversed and remanded the FERC order that approved the settlement concerning the ratemaking treatment associated with step-downs on the El Paso system. TURN and ORA filed a joint response opposing the motion. In a ruling issued February 9, 1999, the assigned ALJ denied the motion on the grounds that the surcharges were still being collected and equity required that the proceedings continue.

On March 4, 1999, the Commission issued D.99-03-026, denying the applications for rehearing of D.98-07-100. Also, in this decision, the Commission affirmed the assigned ALJ's rulings on scope of the proceeding as well as her denial of SoCal's motion to suspend the procedural schedule.[6]

Evidentiary hearings were held from March 15-18, 1999. Opening and reply briefs were filed on May 17 and June 1, respectively, by CIG/CMA, ORA, SDG&E, SoCal, SCE, SCGC, SDG&E, TURN and Watson Cogeneration Company (Watson).

SoCal filed Joint Exhibit (Exh.) 8 on May 7, 1999. The purpose of Exh. 8 was to summarize parties' positions on a comparable basis with respect to (1) the quantification of benefits associated with the step-downs and the settlements and (2) the rate impact of parties' cost allocation positions. Although a preliminary comparison was developed prior to hearings, as requested by the assigned ALJ, it became clear during the course of hearings that the comparison was not complete. Therefore, parties were directed to jointly complete the exhibit and file it after evidentiary hearings. SoCal was directed to compile the exhibit with input from all the parties.

Controversy over Exh. 8 appeared in the briefs, where TURN and ORA argue that some of the calculations of benefits to core customers allegedly arising from the settlement agreements were based on assumptions not supported by the record, or based on testimony that was stricken. (See TURN Opening Brief, pp. 23-24, p. 28; ORA Reply Brief, p. 2.)

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[6] On April 5, 1999, SoCal, CMA, CIG, SDG&E and SCUPP/IDD petitioned the California Supreme Court for writ of review of D.98-07-100 and D.99-03-026, which the Court denied on June 23, 1999. (Southern California Gas Company, et. al. v. Public Utilities Commission of State of California (Cal. Supreme Court No. S077858 (June 23, 1999)).

We share TURN's and ORA's concerns, having examined the record and the numbers and assumptions that appear in this portion of Exh. 8. In our discussion below, we will rely only on the benefit numbers that actually appear in parties' testimony, or that were clarified during cross-examination. This is consistent with the direction given by the ALJ. (See RT pp. 2926-2929, 3231-3232.)

In her PHC request for a joint exhibit from the parties, the assigned ALJ specifically requested information on the impacts of parties' proposals on SoCal's core and noncore gas rates. (RT at p. 45, PHC-2, September 16, 1998.) However, this information was not included in late-filed Exh. 8. In their briefs, SoCal and TURN compiled tables illustrating the gas rate impacts associated with an ITCS allocation of the surcharges. By ruling dated July 28, 1999, the assigned ALJ set aside submission for the purpose of clarifying these rate impact calculations and entering them into the record. SoCal, working with TURN, was directed to submit Late-filed Exh. 23 and did so on August 10, 1999, with a supplement submitted on September 10, 1999.

3. Issues To Be Addressed

In D.98-07-100, as clarified by D.99-03-026, the Commission granted a limited rehearing so that interested parties could address the following questions, specifically as they relate to the surcharges resulting from the relinquishments of capacity on El Paso and Transwestern:[7]

1. Should the Commission change the method adopted in D 92-07-025 for assigning the ITCS costs between the core and noncore? If yes, what is the underlying basis for this change? If no, what is the reasoning for not making a change?

[7] D.98-07-100, mimeo., pp. 12-13, as modified by D.99-03-026, Ordering Paragraph 13.

2. If the Commission were to change the method for assigning the ITCS costs, how should the allocation specifically be changed? What is the basis for this new allocation? What are the benefits and burdens, if any, to the core and noncore with this new allocation?

3. Are there economic and business impacts of allocating the ITCS costs to noncore customers? If so, what specifically are these impacts?

4. Whether the Commission decides to reallocate costs or not, should it consider the amortization of the ITCS account balance for both the core and noncore for a period longer than the full BCAP period? In what ways would a longer amortization help core and noncore customers? In what ways would a longer amortization not be of benefit to these customers?

5. If there was a longer amortization period than the full BCAP period, how long should it be? What is the basis for the period recommended?

6. What are the pros and cons of having an amortization period over about four years, with a goal of a zero balance by December 31, 2001? What impacts, if any, would such an amortization period have on the California economy?

The Commission also asked parties to address the following questions with regard to the portion of the surcharges related to the step-downs of capacity of El Paso by PG&E and others:

1. Should the Commission treat the costs related to the relinquishments of capacity on El Paso by PG&E and others in the same way as the costs resulting from SoCal's step-downs on El Paso and Transwestern, which are collected through the ITCS? If yes, what is the basis for this similar treatment? If no, what is the reasoning for a different treatment?

2. If these costs related to the relinquishments by PG&E and others should be treated differently, how should these costs be allocated? Why should these costs be allocated in this manner? What are the benefits and burdens, if any, to the core and noncore with this different allocation?

In addition to the issue areas discussed above, SoCal raised an additional issue during the course of the proceeding, namely, how the one-time $59 million refund from El Paso, arising from the El Paso settlement, should be allocated between SoCal's core and noncore customers.

In the following sections, we summarize parties' positions and present our discussion, by issue. Before turning to those issues, however, we note that this limited rehearing has been highly contested on legal and procedural grounds. As discussed in Section 2.4 above, all of the objections have been addressed, and dismissed without merit. In addition, the Commission has clearly articulated its expectations regarding the scope of the proceeding.

Unfortunately, several parties have persisted in their attempts to relitigate issues that were squarely addressed in D.99-03-026. We mention them briefly here, in order to differentiate between issues we have already decided, and those we will consider in this decision.

The Commission has already ruled on legal issues raised by several parties in their briefs. SoCal, CIG/CMA and SCGC contend that the granting of this limited rehearing results in unlawful retroactive ratemaking. As we stated in D.99-03-026, the law against retroactive ratemaking does not prevent us from correcting mistakes. We have the authority to subject the tariffs that became effective on June 1, 1997 to any adjustment depending on the outcome of this rehearing, and will use that authority as warranted. (D.99-03-026, mimeo., pp. 14-16.) We have also determined that D.98-07-100 is not contrary to SB 1602, which added Public Utilities Code Section 328. In particular, we stated that changing the allocation of costs is unrelated to the unbundling of the services offered by SoCal, and thereby not precluded by SB 1602. (D.99-03-026, mimeo., pp. 17-18.)

In addition, SCE attempts to distinguish surcharges from ITCS costs in a manner that we found to be without merit in D.99-03-026. CMA/CIG supports this distinction. In particular, SCE contends that the surcharges are not really ITCS costs because they are stranded costs of the FERC-regulated interstate pipeline companies. Therefore, SCE advocates that the cost of this unsubscribed capacity should be allocated in the same way pipeline reservation charges are currently allocated, i.e., in proportion to firm capacity reservations held by the core and noncore. Otherwise, SCE argues, noncore customers will be subsidizing core customers. The Commission considered arguments to distinguish surcharges from ITCS and squarely rejected them in D.99-03-026. Our determination in that decision warrants repeating:

> "...these 'surcharges' remain the very same transition costs that the noncore customers were made responsible for in Capacity Brokering Implementation Decision [D.92-07-025], supra, 45 Cal.P.U.C.2d at pp. 59-61, through the ITCS account. Only the amounts have been reduced as a result of the FERC settlements. This Commission has defined ITCS costs as "reasonably incurred transition costs, including costs associated with gas supply contracts and with firm interstate pipeline capacity which cannot be brokered at the rates billed to the utilities by pipeline companies." (Capacity Brokering Decision [D.91-11-025], supra, 41 Cal.P.U.C.2d at p. 705 [Finding of Fact No. 34].) Further, "[t]he ITCS shall be a volumetric surcharge that shall apply to noncore customer services and shall serve to recover various interstate pipeline costs." (Id. at 728.)." (D.99-03-026, mimeo, pp. 6-7.)

We note that SoCal and other parties reargue that adding surcharges to ITCS costs would be inconsistent with the ITCS policy established in D.92-07-025. In that decision, the Commission stated: "[W]e will direct the utilities to eliminate the use of the ITCS for each existing liability on the day that liability is no longer in effect." (D.92-07-025, mimeo., p. 41.) SCGC and others in this proceeding argue that this language can only be understood to hold that the ITCS would not be used to recover the costs of relinquished capacity. In its brief, Watson interprets this language as meaning that the utilities are not allowed to recover through ITCS any costs for the step-downs, and that SoCal's shareholders are responsible for these costs.

In D.99-03-026, the Commission stated:

> "As discussed above, these 'surcharges' were the same transition costs that D.92-07-025 made the noncore responsible for, and they did not transform into new costs or become eliminated when they were termed 'surcharges' . . . .These ITCS costs were not simply eliminated along with SoCal's relinquishments on El Paso and Transwestern. Rather, there was still remaining capacity not relinquished by [SoCal] that was attributable to the noncore, and accordingly, the noncore remained liable for the ITCS related to this capacity." (D.99-03026, mimeo., pp 7- 8.)

With the California Supreme Court's denial of the petition for a writ of review in Southern California Gas Company, et al. v. Public Utilities Commission of State of California (Cal. Supreme Court No. S077858 (June 23, 1999)), the Commission's D.98-07-100 and D.99-03-026 have become final, and the resolution of these issues in these decisions is not subject to collateral attack in this or any other proceeding. (California Pub. Util. Code § 1709.) Therefore, we will not reexamine the Commission's previous determinations that there is no way to distinguish the nature and origin of the costs associated with SoCal's relinquished capacity in the surcharges as different from other ITCS costs. Accordingly, we reject SCE's and other parties' attempts to characterize the surcharges as other than ITCS costs, in order to justify an allocation different from the ITCS allocation adopted in D.92-07-025. CIG/CMA's alternate cost allocation approach, which it characterizes as a method that "recognizes that the risk-sharing surcharges are different from the other stranded costs comprising the ITCS," is rejected for similar reasons.[8] Finally, because Watson's interpretation of the Commission's ITCS policy is inconsistent with the Commission's findings in D.99-03-026, it too is without merit.[9]

We now turn to the issues and arguments that we believe are properly the subject of this limited rehearing.

4. Should the ITCS Allocation Method Adopted in D.92-07-025 Apply to the Pipeline Surcharges?

No party disputes the fact that the capacity step-downs reduced the amount of SoCal's brokered capacity from 1156 to 406 MMcfd, thereby directly reducing the amount of stranded capacity which contributed to ITCS. (See, for example, RT at 3013.) Parties also agree that SoCal's noncore customers have received substantial benefits from the step-downs, in the form of reduced ITCS costs. Although there remains some difference of opinion on how to calculate these benefits, the record provides a range of $320 to $525 million in net present value. (Exh. 8, p. 1.)

What is in dispute is how the $161.8 million in pipeline surcharges should be allocated between SoCal's core and noncore customers. In particular, we allowed a limited rehearing of the BCAP to consider factual or policy reasons

[8] See Exh. 22, pp. 3, 18.

[9] In its comments on the proposed decision, Watson argues that its position was fundamentally misunderstood. This is not the case. Watson's interpretation of Commission policies simply does not comport with the Commission's determinations in D.99-03-026 that the noncore remained liable for the ITCS related to SoCal's step-downs.

that would justify an allocation different from the current ITCS allocation policies established in D.92-07-025. Those policies dictate that SoCal's noncore customers would assume the costs of the step-downs over and above the core's 10% cap.

Below, we summarize the positions of the parties followed by a discussion section that presents our determinations.

4.1. Positions of the Parties

SoCal, CIG/CMA, SCGC, SCE and SDG&E take the position that the Commission should adopt an allocation method that differs from the ITCS allocation method adopted in D.92-07-025. Instead, these parties argue that the Commission should retain the allocation initially adopted in the BCAP decision, i.e., allocate the surcharges based on a pro rata share of SoCal's total pipeline capacity reservations. Under this approach, the core would be responsible for $113.1 million and the noncore would be responsible for $35 million of the surcharge amounts, net of El Paso pipeline credits.[10]

In support of their position, these parties argue that the allocation of pipeline surcharges should take into consideration all aspects of the FERC settlements that resulted in the pipeline surcharges. In their view, the FERC settlements addressed numerous issues in addition to step-downs that had tangible benefits to core customers. In particular, SoCal, CIG/CMA and SCGC argue that the settlements kept the cost of service, and thereby core reservation

[10] Under the El Paso Settlement Agreement, when El Paso is successful in raising revenues by reselling unsubscribed capacity (and those revenues exceed a certain threshold), there is a sharing between El Paso and its customers. These are allocated to SoCal as "credits" to the risk sharing surcharge amounts. To date, SoCal has received approximately $7 million in credits. (RT at 2917-2918, 3027.) There will be credits for a number of years in the future. All parties agree that the credits should be allocated between core and noncore customers in the same manner as the El Paso surcharges are allocated. They estimate the credits at $13.7 million total. (See Exh. 8.)

rates, substantially lower than they would have been under traditional FERC ratemaking procedures. SoCal estimates that the El Paso settlement produced savings of $181 million in core reservation costs relative to what El Paso proposed in its original FERC application. (Exh. 11, p. 13. RT at 3062.)

SoCal and CIG/CMA also contend that, were it not for the FERC settlements, FERC would have reallocated costs resulting from step-downs to the shippers remaining on the pipeline system, which would have resulted in higher core reservation rates. CIG/CMA calculates this savings at $290 million to SoCal's core customers. (Exh. 22, pp. 7-8.) In addition, SoCal and others argue that the settlements addressed other issues, such as base rate freezes and caps on inflationary rate increases, that had beneficial cost consequences to core customers. In sum, these parties argue that because core customers benefited substantially from the settlements, it would be inequitable to allocate all the costs associated with the settlement to the ITCS account.

In further support of their position, SoCal, CIG/CMA, SCGC and SDG&E argue that changing the BCAP allocation of surcharges would have an adverse economic effects. In particular, SoCal contends that noncore rates will increase significantly and these customers will either absorb the costs and thereby reduce profitability, or pass the higher costs along to their customers in the form of higher prices. Moreover, SoCal, and CIG/CMA argue that noncore customers may also look elsewhere for their gas supplies, subjecting remaining customers to higher transportation rates. Absent a detailed economic analysis that evaluates all of the economic development impacts of cost shifting, CIG/CMA argues that the most rational way to minimize adverse economic impacts is to allocate pipeline surcharges to all customers in some fashion.

SDG&E argues that reallocating surcharge costs to SoCal's noncore customers would shift costs from SoCal's residential customer's to SDG&E

residential customers without any offsetting benefit to the San Diego economy.[11] According to SDG&E, allocating surcharge costs to SoCal's noncore customers will result in rate increases of about 2.4% for core and about 17% for noncore customers of SDG&E. (Exh. 14, Att. B.) SCGC and others also argue that allocating all of the surcharge amounts to noncore customers could drive up electric prices for all consumers in California.

Finally, CIG/CMA contends that the benefits associated with the step-downs was the quid pro quo for the noncore bearing most of the ITCS costs. In CIG/CMA's view, the step-downs should not be used a second time as a justification for "dumping" all of the surcharges on the noncore. (CIG/CMA Opening Brief, p. 2.) SCGC supports this position with the additional argument that core customers have realized significant benefits from the advent of capacity brokering, and should therefore bear some of the costs. (Exh. 20, p. 2.)

ORA and TURN, on the other hand, argue that the ITCS allocation method adopted in D.92-07-025 should be applied to the surcharges. Because the 10% cap has been met, this approach would allocate all of the surcharge amounts to the noncore. Taking El Paso pipeline credits into account, ORA and TURN's allocation preference would allocate $148.1 million to the noncore.

TURN and ORA take the position that the FERC settlements themselves should not be considered in determining the appropriate cost allocation of the surcharges. They argue that attempting to define benefits based on the nature of these settlements is speculative and unwarranted. Instead, the

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[11] SDG&E is a noncore (wholesale) customer of SoCal. Under the methodology established by the Commission in its last BCAP, SDG&E allocates its share of SoCal ITCS to customers on an "equal cents per therm" basis (see D.94-12-052). As a result, every SDG&E gas customer, core and noncore, pays an equal rate for these surcharges.

Commission should look only to the benefits and costs flowing to the core and noncore as a result of the step-downs, and allocate those benefits and costs consistent with the existing ITCS allocation method. TURN argues that it is appropriate and possible to look only at the risk-sharing surcharges in this proceeding because the parties to the settlements separately identified those amounts and tied them directly to the step-downs.

TURN and ORA argue that using the traditional ITCS allocation method is equitable and fair because (1) core customers have been responsible for the entire costs associated with the core reservation of capacity at full as-billed rates, while obtaining no direct benefit from the capacity brokering program and (2) noncore customers receive all the benefits of the capacity brokering program and the step-downs of capacity by SoCal in terms of reduced ITCS costs. Whatever assumptions are used to calculate these benefits, ORA and TURN argue that the range presented on the record ($320 to $525 million in net present value over the term of the settlements) far exceed the $160 million in surcharge costs. Therefore, they contend that noncore customers enjoy substantial net benefits from step-downs under current ITCS allocation policies.

With regard to economic impacts, TURN contends that no party to this proceeding submitted any factual evidence demonstrating negative economic impacts of including the surcharges in ITCS. TURN argues that its testimony on this issue demonstrating a lack of any significant economic impacts was undisputed. With regard to allegations about higher electric prices, TURN contends that it is no longer clear how direct the link between gas prices and electric prices really is in the new electric market. Moreover, TURN argues that attempts to alter discrete aspects of gas cost allocation to benefit electric ratepayers would become a policy quagmire. TURN further argues that the rate increases to SDG&E's core and noncore customers are be offset by other factors.

ORA addresses the issue of economic impacts by examining the allocation of interstate-related noncore costs and the interstate component of noncore rates over time. ORA contends that these rates have decreased. From a historical perspective, therefore, ORA concludes that there are no adverse economic and business impacts associated with applying current ITCS allocation policies to the step-downs. Moreover, ORA argues that by amortizing the step-downs surcharges according to the current amortization rate, these costs would be fully recovered prior to December 31, 2001. Therefore, ORA concludes that there would be no negative economic and business impacts on the noncore from a rate increase perspective going forward.

4.2. Discussion

In the following sections, we address the major arguments presented in this proceeding in support of changing our ITCS allocation policies with respect to the pipeline surcharges associated with SoCal's step-downs.[12]

4.2.1. Consideration of FERC Settlements

As discussed above, several parties in this proceeding urge us to consider a different allocation method because the surcharges were negotiated within the context of comprehensive rate case settlements at the FERC. Because core ratepayers allegedly benefited from certain aspects of the settlements, these parties argue that core ratepayers should also share in the costs of the relinquished capacity component of the settlement, i.e., the surcharges.

We reject this argument for several reasons. First, this Commission's long standing policy in support of interstate pipeline settlements

[12] As discussed above, additional arguments were presented by parties that the Commission already considered, and rejected, in D.99-03-026. We do not discuss them any further.

at the FERC has been that such settlements are "black box" agreements. This means that there is no way to impute the rationale for parties agreeing to various components of the settlement, or for imputing any *quid pro quo* tradeoffs in the negotiating process. This also means that the settlements have no precedent with respect to intrastate cost allocation policies or other ratemaking principles that fall under Commission jurisdiction. Further, we support settlements at FERC only with the understanding that the settlement cannot be cited as precedent in any future administrative or court proceeding, except as expressly provided in the terms of the settlement.

This position is clearly articulated in our initial comments on the El Paso settlement, and also contained in the settlement documents themselves. (See Exh. 5, pp. 5-6.) As the FERC itself found in its original order approving the El Paso Settlement, "the cost of service underlying the settlement rates is a 'black box' number..." See El Paso Natural Gas Company, 79 FERC ¶ 61,028 at p. 61, 131 (1997); See also El Paso Natural Gas Company, 82 FERC ¶ 61,337 at p. 62, 340 (1998) ["cost-of-service underlying the settlement is a 'black box' number.... All such comprehensive settlements involve a complex exchange of risks and benefits among the parties."]

Therefore, to ask us to draw conclusions in this proceeding concerning tradeoffs between the level of risk sharing amounts agreed to by the parties and the settlement provisions affecting core reservation rates runs contrary to our position and FERC's position that these settlements are "black box" in nature.

Second, even if we were willing to attempt an examination of the black box, the record in this proceeding clearly demonstrates that the tradeoffs agreed to by settling parties are in the eye of the beholder. On the one hand, SoCal and others argue that the pipelines would have allocated the cost of unsubscribed capacity to remaining shippers on the system in the absence of a settlement. Therefore, these parties conclude that the assumption of El Paso and Transwestern of a portion of these costs was a major concession in the negotiating process that benefited all of SoCal's customers, including the core.

TURN perceives the situation facing the pipelines at the time of the settlement quite differently. In TURN's view, the pipelines were clearly on notice that they would not be able to impose exit fees or allocate the costs of unsubscribed capacity to remaining customers. From this perspective, one could conjecture that pipeline customers did quite well (and El Paso and Transwestern less well) on the surcharge component by negotiating a settlement that allocated approximately one-third of the costs of unsubscribed capacity to the customers, but the pipelines may have done better in negotiating the reservation rate component of the settlement.[13] Similarly, there are diametrically opposite views presented in this case regarding the relationship between the cost-of-service rates in the settlement and the surcharges. On the one hand, TURN argues that the settlement reflects a trade-off between higher cost-of-service reservation rates for the core, going forward, in exchange for lower surcharges. In contrast, SoCal and CIG/CMA and SCGC contend that the reservation rates negotiated in the settlements were substantially lower than they would have been, had the case been litigated before FERC.

We conclude that it is impossible to reconstruct with reasonable accuracy either what core rates would have been in the absence of the settlement, or what tradeoffs were considered by the settling parties in reaching their agreements. Even if we could pose a reasonable hypothesis regarding these

[13] See TURN's Opening Brief, pp. 25-27 and TURN's Reply Brief, pp. 4-5.

matters, the terms of the settlement and our own comments before FERC make clear that such an attempt would have no precedent in terms of our ratemaking policies.

Finally, we believe such attempts are basically irrelevant to the issues at hand. In our view, there is no logical connection between rate case settlements at FERC and our policies regarding the allocation of ITCS costs. If both the core and noncore benefited from the settlement, then the settlement was a good idea. However, if the core never had to pay ITCS beyond the 10% cap anyway, it does not follow that they should pay those costs now just because there was a FERC rate case settlement that may have reduced core and other customers' rates from what the pipeline had proposed. Moreover, the pipeline's proposed rates were subject to refund, so there is no evidence in our record of what the pipeline's actual rates would have been without the settlement.

Several parties in this proceeding argue that the surcharges that resulted from the settlements cannot be viewed in isolation, because they were negotiated as part of a comprehensive settlement agreement. We disagree. While the settlement agreements are silent with respect to the various considerations that led to agreed-upon terms, including any underlying cost allocation principles, they are very explicit in one respect. The settlement attachments clearly relate the surcharges to the capacity that SoCal and others relinquished on the pipelines, as do the FERC tariff sheets. (See Exh. 16, Appendix B.)

As discussed in Section 6 below, these documents present the amount of capacity relinquished by shippers, the revenue loss to El Paso associated with the step-downs of relinquishing shippers and the non-discounted value of the customer portion (35%) of the step-downs of relinquishing shippers. They also present the discounted value of the customer portion of the step-downs and the negotiated surcharge amounts paid by each shipper that add up to this discounted value. Therefore, we find no merit to SCGC and SCE's contention that there is not a direct correlation between the surcharges and the capacity relinquishments, or in Watson's argument that the Commission cannot resolve this case if it is concerned with the "black box" nature of the pipeline settlements.

For the above reasons, we reject the position that cost allocation in this proceeding should consider other aspects of the FERC settlements that affected core and noncore customers.

4.2.2. Rate Impacts

SoCal argues that allocating surcharges based on ITCS policies would produce large rate increases to noncore customers, and for that reason the surcharges should be allocated differently. To support its position, SoCal presents a table in its opening brief comparing a shift of $122 million to the noncore relative to rates proposed in a joint recommendation in the pending BCAP.[14] This comparison yields rate increases of 28% to 55% to noncore customers, assuming a two and one-year amortization period of the surcharges, respectively. As we discuss further below, these calculations are misleading and inaccurate because SoCal ignores most of the rate reductions associated with the step-downs while magnifying the surcharge costs by using short amortization periods.

When considering rate impacts in this case, SoCal and others apparently view rate impacts solely from the perspective of how the surcharges are allocated. Clearly, if noncore customers pay less of the costs associated with

[14] This comparison is also presented in Late-Filed Exhibit 23.

step-downs than more, they will be better off. However, this perspective is as inappropriate as arguing that a customer who installs energy efficiency measures at a cost of $100 and saves a total of $300 (in NPV) in its energy bill is made worse off when the bill comes due. This Commission would not consider that customer worse off just because his bill at the time of payment is higher than the previous bill that already reflected some or all of the energy savings (and other unrelated adjustments to the bill). However, SoCal's analysis presents precisely this type of false perspective. SoCal takes the full cost of the surcharges (or 50% with a 2-year amortization) and compares rates with those costs against a BCAP baseline that already reflects some of the ITCS cost-savings resulting from the step-downs.

The appropriate frame of reference for net rate impacts in our energy efficiency example would be to compare the customer's bill before the energy savings occurred with the bill incorporating both the energy savings and the $100 cost. From this perspective, we see that the customer is clearly $200 ahead of the game. Similarly, the appropriate frame of reference for considering the rate impacts of the surcharges is to compare noncore rates without the step-downs (with higher ITCS costs) to rates after the step-downs (with surcharges).

One difficulty in evaluating rate impacts from this perspective is that the reductions in ITCS costs (step-down benefits) do not occur in a single calendar year, but rather, over approximately a 10-year period. (RT at 2922-2933.) From a NPV basis, these benefits are estimated at between $320 and $525 million. (See Joint Exh. 8.) To put the benefits and costs of the step-downs on an equivalent basis, it is necessary to either (1) assume that both occur in a single year or (2) show the rate benefits over the 10-year period with an equal amortization period for the costs.

We present the first approach in Table 2A. The first column (Alternate 1) presents a 1998 rate scenario where, after step-downs, all the surcharges are allocated to the noncore, per our current ITCS policy (assuming the core cap is met). The second and third columns (Alternates 2 and 3) present a 1998 rate scenario without step-downs (or surcharges). These scenarios illustrate what noncore rates would look like in the 1998 base year if the step-downs never occurred, and the resulting ITCS costs were allocated to the noncore per our current ITCS policy.[15] Alternate 2 assumes the low range of avoided ITCS costs ($320 million) and Alternate 3 assumes the high range ($525 million) in NPV.

Table 2A shows that the net rate impact of the step-downs is to reduce total noncore rates by 29% to 48% and wholesale rates by 32% to 52%, even if all of the surcharges are allocated to them. For the subset of electric generation customers, the net rate impact of the step-downs is a rate reduction of 30% to 50%.

In late-filed Exhibit 23, TURN and SoCal present two additional comparisons of rates that warrant further discussion. First, they present the 1998 BCAP rates with the adopted allocation of surcharge costs ($122 million to the core/$40 million to the noncore). They compare these rates to rates that are expected to result from the pending BCAP, adjusted to reflect a revised ITCS allocation of the surcharge costs. As an estimate of what may result from the pending BCAP (A.98-10-012), SoCal presents the rates contained in the Joint Recommendation in that proceeding, to which a $122 million cost shift to

[15] These scenarios assumes, hypothetically, that all of the ITCS (before step-downs) would be allocated in a single base year to the noncore, just as the Alternate 1 column assumes that surcharges would be allocated to the noncore (after step-downs) in that same base year.

the noncore is added. Table 2B shows that, relative to 1998 rates, all noncore customers (including electric generators) would experience a rate decrease even if all of the $161.8 million in surcharges are allocated to them over a 2-year amortization period. In other words, even if the "bill comes due" to noncore customers after realizing the first couple of years of cost savings from step-downs, they still should not experience any increase in rates on January 1, 2000, all other things being equal.

However, all other things are not equal because noncore rates were reduced substantially on January 1, 1999 while the current BCAP proceeding and this rehearing were pending. This reduction came about as a result of SoCal's Advice Letter 2751 to reduce projected overcollections in their gas balancing accounts. SoCal's request was approved in Resolution G-3247. Such adjustments are often approved by the Commission in order to return overcollections to ratepayers as expeditiously as possible. However, in this instance, the resulting reduction in noncore rates has created a false baseline for the purpose of evaluating the rate impact of surcharges. As discussed above, noncore customer rates are substantially lower than they would have been, without any step-downs, even if all surcharges are allocated to the noncore.. Moreover, had the January 1, 1999 reduction in rates not occurred (or occurred at a lower level of reduction), noncore customers would still have seen rate reductions relative to "current" (1998 BCAP) rates, even if all surcharges are allocated to the noncore. Therefore, we believe that it is misleading to argue that reallocating surcharges to the noncore will make the noncore worse off from a rate impact perspective because current rates will go up. Moreover, even if that argument were acceptable, we note that the rate increases to noncore customers relative to the rates put into effect by Resolution G-3247 are minimal even if a short (e.g., 2-year) amortization period is assumed.

These calculations are also presented in Table 2 B. Assuming that all surcharge costs are allocated to the noncore over a 2-year period, the table indicates that electric generators would see a rate increase of about 1%, and total retail noncore customers would see a rate increase of 4% relative to the rates put into effect by Resolution G-3247. As TURN points out in its Opening Brief, however, these numbers do not incorporate the California Alternative Rates For Energy (CARE) rate component that decreases from 0.721 to 0.611 cents per therm. Hence, the total noncore transportation rate will not increase as much. (Turn Opening Brief, p. 9.) Moreover, these impacts assume that 100% of the surcharges are allocated to the noncore. As discussed below, we do not adopt such an outcome, and hence, the actual impact of this decision on current rates is lower. (See Section 6 below.) We note that the rate impacts discussed above are directly a function of the amortization period chosen for recovering the surcharges from noncore customers.

In sum, in considering the overall rate impact of the step-downs including the avoided ITCS benefits, we find that noncore customers have been made better off from a rate impact standpoint, even if the surcharges are allocated exclusively to the noncore.

Some parties urge us to reconsider current ITCS allocation polices in light of potential impacts on electric rates in California and, in the case of SDG&E, on the rates of residential and commercial customers who are served by SoCal's wholesale customers. As discussed above, all of SoCal's noncore customers, including electric generators, are better off from a rate impact perspective because of the step-downs. Even if we accept the narrow view of looking at current rate changes, electric generators will see no more than about a 1% increase in rates if surcharges are reallocated to the noncore and amortized over 2 years. This increase is eliminated with a longer amortization period.

Moreover, while higher gas costs may affect electric prices some of the time, we find TURN's testimony persuasive that the linkage between such minor marginal gas rate increases and market clearing prices in the electric power exchange may no longer be direct or clear. (Exh. 7, p. 9; RT at 2906-07, 2909-10.)

With respect to SDG&E's concerns about the rate impacts of ITCS allocation on its customers, we note that cost allocation issues for SoCal will always affect SDG&E's core and noncore customers, whichever way those costs are allocated. This is because SDG&E is a wholesale (noncore) customer of SoCal, and thus pays ITCS in the same way as other noncore customers. By SDG&E's logic, any allocation of ITCS costs to SoCal's noncore customers is inequitable because it would benefit SoCal's core customers at the expense of SDG&E's core and noncore customers. Moreover, it appears that SDG&E's specific concerns over shifting costs among residential customers are one directional: SDG&E did not raise this issue when the cost allocation adopted in the BCAP would make SDG&E's residential customers better off at the expense of SoCal's residential customers.

We reject SDG&E's definition of equity for the purpose of allocating SoCal's ITCS costs. As a noncore customer of SoCal, SDG&E (and all of its customers) have benefited from SoCal's step-downs in the form of reduced ITCS costs. Prior to the step-downs, SDG&E would have been allocated a portion of the cost of capacity before the step-downs, approximately $300 million. Once the step-downs occurred, SDG&E is paying approximately one-third of that amount in the form of surcharges. (RT at 2939.) It is a self-serving argument to now claim that SDG&E should not pay the remaining ITCS costs just because of the particular composition of its customer base.

4.2.2. Economic and Business Impacts

In D.98-07-100, we specifically requested parties to present testimony on the economic and business impacts of allocating the surcharges to the noncore. We did so in order to consider whether those impacts would warrant a policy change with respect to our ITCS allocation method, as it would apply to step-down costs. We were surprised, therefore, that most parties who addressed economic impacts in their direct testimony did so in a very cursory or limited manner.

For example, SoCal devoted less than a page to this issue, simply stating that the impacts would be "higher energy costs to noncore and wholesale customers, including the prospect of manufacturing industry job losses." (Exh. 11, p. 15.) In support of this statement, SoCal referred to testimony in A.97-12-048, where the SoCal witness in that proceeding made calculations concerning the impact of gas cost increases on manufacturing jobs and area income. SCGC did not specifically address economic or business impacts in its direct testimony, but alluded briefly to the potential for higher electricity costs when discussing the impact on core customers of allocating surcharges to the noncore. (Exh. 11, p. 15; Exh. 19, pp. 7-8.)[16] SDG&E presented testimony that focused exclusively on the impacts of cost allocation on its residential and commercial customers, without consideration of the impacts on SoCal's customers or the economy as a whole. (Exh. 14.) Only ORA and TURN responded in an extensive manner to this question in their direct testimony, albeit from different perspectives.

In considering the issue of economic and business impacts, we take the perspective that when one customer group is allocated less gas costs,

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[16] We note that some parties attempted to introduce new analysis and testimony on this issue into their rebuttal testimony, which was properly stricken by the assigned ALJ. (See RT at 48-49, 2846-2852, 3165-3166.)

another customer group is allocated more costs by the same amount. Therefore, for there to be any measurable net impact on the economy, there must be a significant difference in how the gas costs of different customer groups will affect overall economic development. As TURN states, "If the benefits of one group's lower gas costs are similar in magnitude to the disbenefits of another group's higher gas costs, there will be no overall impact on the economy." (Exh. 9, pp. 4-5.)

In support of its position that allocating surcharges to the noncore would have negative economic impacts, SoCal references a study it performed in the unbundling proceeding, (A.97-12-048.) In that proceeding, SoCal claimed that increasing gas costs by 1.1 cents per therm would result in 900 less manufacturing jobs and $54 million less in area income. However, we find several flaws in SoCal's conclusions, particularly as they relate to the cost allocation issues in this proceeding.

First, SoCal's conclusions regarding job impacts overstate effects on manufacturing and understate offsetting effects on other sectors. As pointed out by TURN, the job losses estimated by SoCal are not all in the manufacturing sector. In fact, many of the jobs that would be lost (owing to higher noncore rates) are the types of jobs that would be created by the corresponding decrease in core gas rates and increased spending by residential and commercial customers. (Exh. 9, p. 12.) The fact that SoCal's study does not attempt to quantify any of the job gains associated with lower core gas rates renders it inconclusive regarding overall economic impacts. Moreover, SoCal's analysis of impacts on industry are based on assumed cost shifts that bear little relationship to those that would actually result from the cost allocations under consideration in this proceeding. SoCal's estimates are based on an increase in industrial sector gas costs. In fact, the industrial sector represents only about a quarter of noncore load. (Exh. 9, pp. 14-15.)

Second, an accurate consideration of core and noncore customer makeup shows that allocating costs to the core does little to reduce the overall cost of gas to SoCal's commercial and industrial users. Similarly, allocating costs to the noncore does not significantly advantage these customers. Both core and noncore are a mix of customer classes, and neither group is clear-cut in terms of underlying customer characteristics. This is because the majority of SoCal's commercial and industrial customers are part of the core class. (RT at 3029-3030.)

As TURN illustrates in its testimony, allocating surcharge costs to noncore customers actually reduces gas costs to commercial customers by $14 million. EOR customers experience no change in costs because they are exempt from transition costs. Industrial customers would see an increase in their gas costs of approximately $25 million, which is only a fraction of the amount shifted to noncore ($125 million) and a very small amount compared to their total gas bill. (Exh. 9, Attachment E.)

Third, even if shifting surcharges to the noncore did significantly increase gas costs to commercial and industrial users, it does not necessarily follow that this increase leads to a degradation in jobs and income in the economy. One must consider the relative impact of a dollar in one group of society's participants versus a dollar in another group of society's participants. The evidence presented in this proceeding is simply not persuasive that there are relevant distinctions between core and noncore customers with regard to spending, savings and profits and multiplier effects. As TURN's witness Mr. Goodman points out:

> "...to the extent that there are relevant distinctions between core and noncore customers, these differences may actually tend to contradict the Company's position

> in this proceeding. Given their greater size and energy-intensity, the businesses assigned to noncore may be more reliant on goods/services produced outside California than core's smaller, more labor intensive, business and residential customers. The Company's own study notes that:
>
> > 'From the perspective of core customers,...reduction in price can be viewed as a reduction in the cost of living or as a change that releases income to be spent on items other than energy. A large fraction of this income will be spent in California which will have a positive direct impact and ensuing multiplier effects....'" (Exh. 9, pp. 13-14.)

In addition, we must consider the potential economic impacts of any cost allocation in the context of the overall regional or statewide economy. We find that the potential cost shifts in this proceeding are quite small in relation to the Southern California economy. As one witness put it, the level of gas costs related to surcharges "is roughly equivalent to the profit on one movie." (RT at 2986.) On average gas represents less than 0.7% of the total value of shipments averaged across all California manufacturing industries. (Id., p. 23.) Even taking SoCal's study at face value, applying it to this proceeding yields calculations of increased manufacturing costs in only the hundredths of a percent. (Exh. 9, p. 10.)

To put this issue further in perspective, we refer to ORA's testimony concerning the impact of current ITCS allocation policies from a historical perspective. ORA compares the pipeline demand charge component of noncore rates since the onset of capacity brokering and as projected through 2002, including ORA's proposed allocation of surcharges to the noncore. ORA's summary shows that, prior to capacity brokering, the pipeline demand charge component of noncore rates was 3.573 cents per therm. In the post-capacity brokering period, that component (now ITCS and PITCO/POPCO) has averaged 2.66 cents per therm and is expected to decrease to 0.417 cents per therm by January 1, 2002. Hence, noncore customers will continue to experience a significant reduction in SoCal's interstate rate components under existing ITCS allocation policies. (Exh. 16, pp. 12-13; RT at 3129-3130.)

Based on the above, we conclude that the net economic impacts of allocating surcharges to noncore customers are likely to be very small, and do not warrant a change to our current ITCS allocation policies.

4.2.3. Equity of Core/Noncore Allocation of ITCS Costs

CIG/CMA and SCGC take the perspective that allocating the step-downs costs to noncore customers would be inequitable, because noncore customers have borne most of the ITCS costs, and core customers have realized significant benefits from the advent of capacity brokering. SCE argues that reallocation of pipeline surcharges to the noncore would result in noncore customers subsidizing the core.

We do not find merit to these arguments. First, as the Commission made clear in its capacity brokering decision, a limit on the core's responsibility for ITCS is appropriate, given the magnitude of benefits to the noncore that arise from capacity brokering:

> "Because no specific class of customers is responsible for stranded costs, we will allocate some of those costs to all customers. In light of the substantial benefits to the noncore which arise from the implementation of capacity brokering and other related actions we take today...we will direct the utilities to allocated stranded interstate costs to all customers on an equal-cents-per-therm basis. The limit of the core class liability for these stranded costs is the cost of 10% of existing capacity held for the core class on each pipeline." (D.92-07-025; (1992) 45 Cal. P.U.C.2d 47, 61.)

While core customers may have benefited from gas-on-gas competition and from firm capacity over the years, as SCGC argues, they have also contributed a significant amount to cover stranded costs within the 10% cap. This amount has averaged $9 to $12 million per year since 1994. (Exh. 1, Appendix A; RT at 2940-2942.) Moreover, when the difference between the as-billed rate and the market value of capacity reserved for the core is considered, it can be argued that core customers have actually paid more in stranded costs than the noncore. (Exh. 1, Appendix A, SoCal's Response To TURN's Data Request Question 9; Exh. 2, pp. 9-10; RT at 2940-2942.)

With respect to the surcharges, we note that the step-downs by SoCal reduced only excess noncore capacity. Thus the surcharges reflect that portion of the stranded cost payment originating with the noncore, and no "core subsidization" is involved.[17] Moreover, the reduction in excess capacity is valued at a minimum of three times the level of the surcharges. Hence, even if all of the surcharges are allocated to the noncore, this customer group will still experience significant benefits from the reduction in cost responsibility that it would otherwise have to bear.

In sum, we find that there is nothing inequitable about allocating the surcharges to the noncore, consistent with our ITCS allocation policy. All parties agree that the credits accruing to El Paso when it is successful in reselling unsubscribed capacity should be allocated between core and noncore in the same manner as the El Paso surcharges are allocated. Accordingly, all credits received

[17] If SoCal had relinquished core gas capacity, core customers could have benefited from the discounted transportation rates in the secondary market. However, since none of the core capacity was relinquished, core customers are still responsible for 100% of the maximum rates for the interstate pipeline capacity reserved for the core. Meanwhile, the noncore customers benefit from the discounts in the secondary market associated with this relinquished capacity.

to date (approximately $7 million) and those that will accrue in the future shall be allocated to the noncore.

5. How Should Refunds Be Treated?

When a pipeline files a rate case at FERC, the pipeline's proposed reservation charges ("rates") are immediately put into effect subject to refund. After the rate case is litigated or settled, then the rates are adjusted based on the outcome. When El Paso filed its rate case at FERC, it put rates into effect that were higher than the rates adopted as the result of the settlement. SoCal's share of the resulting refunds was $59 million. SoCal allocated the refund to its core and noncore customers based on their relative share of capacity reservations. (RT at 3024-3025, 3028.)

SoCal recommends that the $59 million refund should be re-allocated in the same manner as the allocation of surcharges. SoCal argues that to allocate the refunds primarily to core customers (based on core reservation capacity) but to allocate the surcharges to noncore customers would be inequitable. SCGC, SCE and SDG&E support this position. To the extent that we reallocate surcharges to noncore customers in this decision, these parties would recommend that we reallocate the refunds to noncore customers in the same manner.

We agree with ORA and TURN that this recommendation is inconsistent with the origin of the refund described above and the manner in which the refund was determined. As described above, the refund was associated with past overpayment of El Paso interstate reservation costs made by SoCal (and its customers). SoCal's core and noncore customers, in proportion to their capacity reservation amounts, were charged rates that were too high for the period of time when there was no step-down surcharge, i.e., when El Paso's proposed rates were on file.

Changing the allocation of the refunds, as SoCal proposes, would penalize core customers who paid those higher rates (subject to refund) while the FERC case was pending. Moreover, we believe that this proposal would be inconsistent with the requirements of Pub. Util. Code Section 453.5, which states that rate refunds should be distributed "to all current utility customers, and, when practicable, to prior customers, on an equitable pro rata basis", i.e., "in proportion to the amount originally paid for the utility service involved."

We also find no merit to CIG/CMA's argument that the magnitude of the refund would have been much smaller if surcharges had been included as part of the reservation rate. This argument is purely hypothetical and based on the premise that the surcharges and other components of the rate case (including the final level of reservation rates that are used to calculate refunds) were traded-off and thus fungible. As we discuss above, we do not share this perspective. Therefore, we do not agree with CIG/CMA's assumption that one could add the rates and surcharges to compare an alternate refund outcome. Even if an alternate refund outcome were credible, it does not follow that the refund should flow to noncore and core customers in proportion to the adopted surcharge allocation. Again, this approach ignores the fact that core customers shared in the cost of higher reservation charges to a greater extent while the FERC case was pending, and the FERC had made those higher reservation charges subject to refund.

For the above reasons, we do not modify the allocation of refunds in today's decision. However, as discussed above, the revenues SoCal receives under the revenue crediting mechanism in the El Paso Settlement (i.e., the "credits") should be refunded to SoCal's customers as a credit to risk sharing amounts or in a way that tracks SoCal's allocation among its customers for its risk sharing surcharges from El Paso.

6. How Much Of The El Paso Surcharge Is Attributable To The Relinquishments By PG&E And Others, And How Should These Costs Be Allocated?

This issue only applies to El Paso's risk sharing surcharges. Transwestern's risk sharing surcharges were entirely due to SoCal's step-downs on Transwestern[18] and, therefore, we previously found that they were not new costs. The Transwestern risk sharing amounts to SoCal should be recovered solely through the ITCS for the reasons discussed above.

However, in D.98-07-026, the Commission recognized that other shippers besides SoCal relinquished capacity and entered into a settlement with El Paso regarding the allocation of revenue shortfalls that translated into surcharges. In considering the issues for this limited rehearing, the Commission stated:

> "With respect to the portion of the surcharges related to the step-downs of capacity on El Paso by PG&E and others, we acknowledge that these are arguably new costs. These specific costs were mainly the result of PG&E's relinquishment of a substantial amount of capacity on the El Paso system (71 percent of the capacity step-downs). In D.97-04-082, we lumped these particular costs with the other step-downs costs related to SoCal's relinquishments of capacity on El Paso and Transwestern. Because we are granting a limited rehearing on the other step-downs costs, we believe it would be reasonable to include, as part of this rehearing, the issues concerning how these new costs should be allocated." (D.98-07-100, mimeo., p. 13.)

In their testimony, parties present their positions on how much of the $98 million in risk sharing amounts allocated to SoCal by El Paso represent these new costs, i.e., can be attributed to the step-downs of PG&E and others.[19] To the

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[18] See 72 FERC ¶ 61,083 at pp. 61,447-48 (1995).

[19] The $112.3 million of El Paso surcharges in Table 1 corresponds to this $98 million, but includes interest.

extent that these new costs are identified and allocated to core customers, the ITCS allocation of surcharges to noncore customers discussed above will be reduced. Core's cost responsibility would, in turn, be increased by a corresponding amount.

The parties' positions are summarized below, followed by our determinations regarding this issue.

6.1. Positions of the Parties

The El Paso settlement documents provide several sets of numbers used by parties to address this issue (see Attachment 3):

- The value of the step-downs of relinquishing shippers i.e., the value of billing determinants (Tab 3, Sheet 4, II. 1-9)
- The non-discounted value of the customer portion (35%) of the step-downs of relinquishing shippers (Tab 3, Sheet 4, II. 10-18)
- The discounted value of the customer portion (35%) of the step-downs of relinquishing shippers (Tab 3, Sheet 4, II. 19-27); and
- The actual surcharge amounts paid by remaining shippers (Tab 3, Sheets 2-3.)

The numbers derived from these documents are summarized for convenience in the table below:

Summary of El Paso Settlement Numbers

	Relinquished Capacity (MMcfd)	Value of Billing Determinants ($M)	Non-discounted Risk Sharing Value ($M)	Discounted Risk Sharing Value ($M)	Amount of Surcharge ($M)
SoCalGas	300	257.3	90.8	66.9	98.6
Total	1614	1114.6	393.5	273	273.3
SoCalGas Share	18.6%	23.1%	23.1%	24.5%	36.1%

SCGC and CIG/CMA use the total billing determinant column (i.e., the revenue losses to El Paso associated with the relinquishments) in support of their recommendation to use the 23.1% ratio. This ratio is then applied to the actual surcharge payment of $112.3 million to determine the portion attributable to SoCal's step-downs, i.e., $25.9 million. The remaining portion, $86.4 million, is attributable to PG&E and others.

SoCal proposes to use the 24.5% figure from Table 3 to calculate SoCal's share, based on the ratio between the discounted risk-sharing amount attributed to SoCal's step-downs relative to total step-downs on El Paso. SCE supports SoCal's proposal. This yields a calculation of $27.4 million (including interest) attributable to SoCal's step-downs and $84.8 million attributable to PG&E and others.

Like SoCal, ORA looks at the discounted risk-sharing amount attributed to SoCal's step-downs, which is $66.9 million. ORA then compares this figure directly to SoCal's actual payment of $98.6 million to determine the portion of agreed upon surcharges attributable to SoCal's step-downs. By ORA's calculation, that leaves $31.1 million ($36.1 with interest) or approximately one-third of the surcharges attributable to the step-downs of PG&E and others.

TURN argues that there is no principled basis upon which to assign the various dollar amounts resulting from the several relinquishments to the amounts paid by the various customers of El Paso. Moreover, TURN takes the position that PG&E's large step-downs exerted enormous negotiating leverage on El Paso which, in turn, benefited other shippers. In TURN's view, El Paso may have been less willing to bear 65% of the total risk for the relinquished capacity without the presence of PG&E. Therefore, TURN argues that attempts to differentiate a portion of the surcharges as "new costs" ignores the fundamental fact that the financial burden to SoCal resulting from stranded interstate capacity has been substantially reduced.

If such an exercise is undertaken, TURN suggests that the ORA approach is the most rational method of apportioning responsibility. If the Commission chooses to deduct some portion of SoCal's surcharge payment which represents a contribution for the step-downs of PG&E (and others), TURN argues that it should consider the fact that PG&E and other shippers contributed to the surcharge on Transwestern, which was caused solely by SoCal.

In terms of allocating the surcharge costs attributable to the relinquishments by PG&E and others, ORA recommends that these costs be allocated between core and noncore customers based on equal cents per therm. This results in an allocation of approximately 40% to the core and 60% to the noncore. TURN supports this approach, should the Commission determine that such costs can be differentiated from SoCal's step-downs. ORA and TURN argue that the equal cents per therm approach is reasonable because it is consistent with how other transition costs have been allocated in the gas industry. (ORA Opening Brief, p. 7; TURN Opening Brief, p. 40.)

SCGC would allocate these costs based on reservation capacity, as D.97-04-082 originally provided for all the surcharge costs. SCGC argues that this is reasonable because these costs are part of the cost of the capacity reservation on the pipelines and are equivalent to normal reservation charges. (Exh. 19, p. 13; SCGC Opening Brief, p. 28.) This approach results in an allocation of approximately 65% to the core and 35% to the noncore. SCE supports this capacity reservation method.

SoCal's and CIG/CMA's positions on how to allocate the surcharge costs attributable to PG&E and others are unclear. In its opening brief, SoCal recommends the capacity reservation method. However, this contradicts SoCal's recommendation as presented in Exh. 8, where SoCal recommends an equal cents per therm allocation. CIG/CMA's position in Exh. 8 is that these costs should be allocated on an equal cents per therm basis, whereas in its brief it supports either this approach or the capacity reservations method.

6.2. Discussion

The settlement documents are silent with regard to how the relinquishment amounts and revenue losses to El Paso were translated into an allocation of surcharges to relinquishing and non-relinquishing customers. What is clear from the calculations presented in the settlement documents, however, is that someone other than PG&E picked up a sizable portion of costs associated with the PG&E step-downs. This is evidenced by the fact that PG&E was assigned a surcharge of only $58.4 million while the total value of the risk of revenue loss to El Paso from PG&E's relinquishments was $740.6 million and the customer share of that loss was $176.6 million in NPV. To a much lesser extent, the same can be said for most of the other relinquishing shippers, except for SoCal and Public Service of New Mexico ("PNM"). (See Attachment 3.)

TURN's position would, in effect, ignore this information. Moreover, TURN's argument that the customer share of revenue losses would have been greater, if PG&E was not at the negotiating table, is pure speculation and not pertinent to the issue at hand. The fact that the total risk sharing amount allocated to El Paso's customers could have been higher has no bearing on the fact that SoCal did pay more in surcharges than the customer share of the revenue losses associated with its own step-downs. In order to determine how much more, we need to make some assumptions.

ORA's calculations implicitly assumes that SoCal's surcharge payment first covered all of its own step-down responsibility ($66.9 million in NPV). Any additional payment beyond this amount covered step-downs by

PG&E (and other) shippers. We do not believe that this is a credible assumption. It would mean that the settling parties isolated the risk-sharing amount associated with only SoCal's relinquishments and allocated all of that amount to SoCal first, before considering the allocation of the rest of the risk-sharing costs. In other words, ORA's calculations assume that the other settling parties, including those that did not relinquish capacity, paid for all of the other capacity relinquishments except for SoCal's. Moreover, as SCGC's Witness Catherine Yap points out:

> "...if you look at the long list of billing determinants, most of the folks that toss in money aren't stepping down in capacity. So why should we say that they are only paying for PG&E's capacity? What basis would we have for that? They are paying for a share of that [$273 million] pot...[b]ecause this is in lieu of facing litigation that would require them to potentially absorb that cost of service.... And you've got lots and lots of customers who are saying, okay, we're willing to pay 35 percent of this obligation. And this obligation is the whole package. It's the whole 273 million. It's not we're going to pay a portion of $273 minus 66 million because SoCal's paying it all for themselves." (RT at 3176-3177.)

We believe that the more credible assumption is that all of the settling parties picked up the risk-sharing costs in a manner that spread all of the costs of relinquishments among all of El Paso's firm capacity customers. To determine the proportion associated specifically with SoCal's step-downs, we adopt SoCal's position that we should use the ratio of the risk-sharing value of SoCal's relinquishments ($66.9 million) to the risk-sharing value of all relinquishments ($273 million), on a discounted basis. In our view, this calculation is preferable to the one proposed by SCGC and CMA/CIG because it utilizes a numerator and denominator that are on the same discounted basis as the total amount of surcharges allocated to the settling parties. The resulting ratio (24.5%), when applied to the total El Paso surcharge (including interest) yields an amount attributable to SoCal's step-downs of $27.4 million.

The rest of the El Paso surcharge ($84.8 million) is attributable to the step-downs of PG&E and others. TURN argues that this amount should be reduced by $27.5 million to reflect the payment of other shippers in the Transwestern settlement. (Exh. 1, p. 10; Exh. 8, Permutation #2; RT at 2869-2870.) We disagree. All that is indicated from the Transwestern settlement documents is that the surcharge assigned to SoCal for its relinquishments on Transwestern may have been higher if PG&E and others had not also shared in the cost of those relinquishments. This is irrelevant, however, to the issue of what portion of the El Paso surcharge assigned to SoCal is attributable to SoCal's step-downs on El Paso. We see no trade-off here, as TURN implies. The overall level of the Transwestern surcharge assigned to SoCal is one thing; the individual components making up the El Paso surcharge assigned to SoCal is quite another.

We now turn to the issue of how to allocate the $84.8 million in surcharges attributable to the relinquishments of PG&E and others. First, we emphasize that our determinations on how to allocate these costs in the initial BCAP decision is not precedential. We specifically granted rehearing on this issue, as evidenced by the second question we posed in D.98-07-100 concerning the relinquishments of PG&E and others. (See Section 3 above.) Therefore, we reject any notion that a differentiation between "old" and "new" cost components of the El Paso surcharge presupposes an allocation of the new costs based on capacity reservations.

In considering this issue, we must look at the nature of these costs. We recognize that they are not directly related to capacity that SoCal itself would be responsible for brokering in the secondary market. However, we do not believe that they arise as " a normal consequence of FERC ratemaking" for the allocation of a pipeline's revenue requirement, as SCGC contends. (Exh. 19, p. 12.) This is not a simple case of the normal, ongoing changes in pipeline revenue requirements. Rather, these costs arise from major relinquishments under long-term gas contracts that herald the transition to a highly competitive gas transportation industry.

While we have never encountered precisely this cost allocation circumstance before, we have considered the allocation of other costs that pipelines have allocated to SoCal as its customer in analogous transitional circumstances. In D.90-01-015, we addressed the allocation of direct billed take-or-pay costs. These costs were the amounts billed to SoCal from interstate pipelines as a result of FERC's allocation of take-or-pay costs arising from uneconomic contracts between interstate pipeline companies and gas producers. We gave SoCal the option of allocating these costs on a volumetric basis (with no balancing account treatment) or sharing the risk between shareholders (25%) and customers (75%) via a direct-billed demand charge (with balancing account treatment). SoCal elected to recover the costs on a volumetric (equal cents per therm) basis. (See D.90-01-015; 35 Cal. P.U.C2d 3, 32-37 (1990); Advice Letter 1929.)

Hence, there is precedent for using an equal cents per therm allocation of the costs allocated to SoCal because of circumstances related to the competitive transition of other entities in the gas industry.[20] Moreover, aside

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[20] In its comments on the proposed decision, SCGC argues that the direct billed take-or-pay costs were SoCal's transition costs, and therefore not analogous to the surcharge costs attributable to the step-downs of PG&E and others. We disagree. In both circumstances, these are *pipeline* transition costs that were allocated to SoCal as the pipelines' customer. In the case of direct billed take-or-pay costs, the pipelines were transitioning into commodity competition, whereas with surcharges they were

Footnote continued on next page

from the issue of precedent, we find that an equal cents per therm allocation is appealing from an equity perspective because it allocates costs to all customers in proportion to how they are using the system. (RT at 3220.)

For the above reasons, we will allocate the portion of surcharges associated with the relinquishments of PG&E and others ($84.8 million including interest) on an equal cents per therm basis, or approximately 40% to the core and 60% to the noncore.

7. Amortization and Other Adjustments To Implement Adopted Allocation

Today's determinations allocate the surcharge amount ($161.8 million including interest) as follows: $33.9 million to the core and $127.9 million to the noncore. The issue now is how to implement this allocation, i.e., what vehicle to use to adjust the allocation we adopted in error in D.97-04-082 and over what period of time should the allocation be amortized.

TURN recommends that we implement account balancing adjustments to allocate the surcharges, and no parties object to this approach. TURN also raises an important implementation issue that we must address in establishing this balancing account treatment:

> "If the Commission's current ITCS allocation policies (D.92-07-025) had been applied to the step-down surcharges in D.97-04-082, with rate effective June 1, 1997, the vast majority of those costs (about $145 of the total $160 million) would have been recovered in rates by the end of the current BCAP period, which will occur on or after August 1, 1999. (Exh. 1, p.7.) Because the core's ITCS assignment has been at the cap through out this period, all of the incremental ITCS costs related to the surcharges would have been recovered from the noncore

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experiencing a market with unprecedented quantities of turn-back capacity. Either way, we are talking about pipeline transition costs, not those of SoCal.

> market. Once the new BCAP rates are implemented, however, the cap is no longer expected to be binding and the core will therefore pay an allocation based on equal cents per therm. (Ex. 1, p. 8.) Therefore, if this rehearing results in a decision to remove the previously designated "core" portion of the surcharges from the Core Fixed Cost Account (CFCA) and simply add them to the then-current ITCS balance, core customers would end up paying more of those costs than they would have if D.97-04-082 had correctly classified them in the first place." (TURN Opening Brief, pp. 49-50.)

Accordingly, we will adjust the balancing accounts to reflect today's determinations as follows: We will transfer the recorded surcharge payments that must be removed from the CFCA to a special ITCS subaccount that is allocable only to noncore customers. Core customers have paid to date approximately $108 out of the allocated $122 million in surcharges, and we have determined today that only $33.9 million should have been paid by the core. The difference (approximately $74.1 million) should be transferred in this manner. Amounts not yet collected (approximately $14 million) will be collected in the regular ITCS account without transferring it to the special sub-account.

In terms of amortization, SoCal recommends a period of no more than a year, so as to minimize the interest component of the charges and potential bypass. ORA recommends that the current ITCS amortization rate be retained until the costs are completely amortized, which ORA estimates would be accomplished by the end of 2000. In the alternative, ORA supports TURN's recommendation of a two year amortization period.

SCE supports a four-year amortization period, i.e., one ending around the end of 2003. In SCE's view, this period is fairly consistent with the remaining period over which surcharges will be paid by El Paso's customers. CIG/CMA supports a three or four-year amortization period, depending on other rate impacts stemming from the pending BCAP in A.98-10-012. Watson supports a four-year amortization period. California Cogeneration Council (CCC) supports a 10-year period.

We believe that the best course of action is to implement account balancing adjustments to properly allocate the surcharges, but defer to the pending BCAP proceeding the amortization period over which balancing account amounts will be recovered.

Therefore, we direct SoCal to submit a late-filed exhibit in the BCAP proceeding (A.98-10-012 et. al.) showing the effects of today's determinations on balancing account amounts. The revenues that SoCal receives under the revenue crediting mechanism in the El Paso settlement should be refunded to SoCal's customers as a credit to risk sharing amounts or in a way that tracks SoCal's allocation among its customers for its El Paso risk sharing surcharges.

Today's determinations complete our limited rehearing of D.97-04-082, and we will close this proceeding. The discussion of surcharges on pages 74-75 of D.97-04-082, as modified by D.98-07-100 and D.99-03-026[21], are superceded to the extent inconsistent with this decision.

8. Response to Comments on ALJs Proposed Decision and Petition of the Electric Generator Alliance to Intervene

Pursuant to Pub. Util. Code § 311 and to our governing Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the proposed decision of ALJ Gottstein was issued before today's decision. CCC, CIG/CMA, ORA, SCE, SCGC, SDG&E, SoCal, TURN and Watson filed timely comments to the proposed decision. Reply comments were filed by SoCal, ORA, TURN, SCE, SCGC, CCC, CIG/CMA, and Watson.

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[21] D.99-03-026 modified D.98-07-100 to make changes to the decision language in D.97-04-082. See Ordering Paragraph 2 of D.99-03-026.

We have carefully considered the comments and do not make any substantive changes to the determination of contested issues in the proposed decision, except to defer the issue of amortization period to the pending BCAP.

One area of comment, however, warrants further discussion. SCGC contends that the Commission's discussion of Pub. Util Code § 328 and retroactive ratemaking in D.98-07-100 and D.99-03-026 is "mere dicta", and therefore, the Commission must address these issues in this rehearing. (SCGC Opening Comments, p.5.) SoCal argues that the proposed decision erred in dismissing without comment numerous legal issues that were raised by the parties in this proceeding, and states that it "reserves its rights" to pursue these issues when the Commission's order becomes final. (SoCal Opening Comments, p. 3.)

Calling our discussion of these issues mere "dicta" is inconsistent with the fact that SoCal and others filed a petition for writ of review with the California Supreme Court on these issues. It is also inconsistent with the substantive discussions of these issues in D.98-07-100 and D.99-03-026. Besides the fact that the parties are precluded from relitigating these issues under the doctrine of res judicata, under Pub. Util. Code § 1709, the Commission decisions on these issues, having become final, are now conclusive. As the proposed decision stated, we have chosen not to revisit these issues because we have definitively ruled on them.

The Electric Generator Alliance (EGA) filed a Petition to Intervene in this proceeding, along with timely comments on the proposed decision. EGA describes itself as an *ad hoc* organization formed for the specific purpose of intervening in the 1999 BCAP. EGA is not a party to this proceeding, although two out of its three members filed appearances in the 1996 BCAP. In large part, EGA's comments attempt to introduce elements of EGA's and others parties' testimony from the 1999 BCAP into this proceeding. EGA's comments also refers to a study that is not on the record in this proceeding, and EGA presents calculations from testimony that was stricken during evidentiary hearings. For these reasons, we deny EGA's Petition and do not consider EGA's comments in today's decision.

Findings of Fact

1. The Commission's determinations in D.98-07-100 and D.99-03-026 have become final. Among other things, the Commission determined that there is no way to distinguish the nature and origin of costs associated with SoCal's relinquished capacity in the surcharges as different from other ITCS costs.

2. Capacity step-downs reduced the amount of SoCal's brokered capacity from 1156 to 406 MMcfd, thereby directly reducing the amount of stranded capacity which contributed to ITCS. None of the core reservation capacity was relinquished with SoCal's step-downs.

3. The step-downs gave rise to negotiated pipeline surcharges, which were allocated to SoCal under risk sharing agreements approved by FERC. SoCal's share of surcharges on El Paso and Transwestern totals $161.8 million, including interest.

4. The reduction in stranded cost from the step-downs is valued at a minimum of three times the level of the surcharges.

5. Estimates of the benefits to noncore customers from the step-downs, in the form of reduced stranded costs, range from $320 to $525 million in NPV. These benefits accrue to noncore customers over approximately a 10-year period.

6. The FERC-approved settlement agreements that established the risk sharing surcharges also addressed other issues, such as pipeline cost-of-service and capacity reservation rates.

7. Under the El Paso settlement agreement, there is a sharing of the revenues raised by El Paso when it resells unsubscribed capacity above a certain threshold. These are allocated to SoCal as "credits" to the risk sharing surcharge amounts.

8. FERC settlements are "black box" agreements, i.e., there is no way to impute the rationale for parties agreeing to various components of the settlement, or for imputing any *quid pro quo* tradeoffs in the negotiating process.

9. FERC settlements have no precedential effect on intrastate cost allocation policies or other ratemaking principles that fall under Commission jurisdiction.

10. FERC settlements are not precedent in any future administrative or court proceeding, except as expressly provided in the terms of the settlement.

11. There is no logical nexus between rate case settlements at FERC and Commission policies regarding the allocation of ITCS costs.

12. There is no evidence in our record of what the pipeline's actual rates would have been without the settlement.

13. The FERC-approved settlement agreements were silent with respect to the various considerations that led to agreed-upon terms, including any underlying cost allocation principles. However, the settlement documents clearly related the surcharges to the capacity that SoCal and others relinquished on the pipelines, as do the FERC tariff sheets.

14. The appropriate perspective for considering rate impacts associated with the surcharges is to compare rates before step-downs (with higher ITCS costs) to rates after the step-downs, with the surcharges.

15. SoCal's calculations of rate impacts ignore most of the rate reductions associated with the step-downs and magnify the surcharge costs by using short amortization periods.

16. Because the step-down benefits (reduction in ITCS costs) occur over approximately a 10-year period, to evaluate the net rate impacts associated with

step-downs it is necessary to put both the benefits and costs (surcharges) on an equivalent basis. One approach is to assume that both the rate reduction benefits and the surcharge costs accrue in a single year to SoCal's customers. Another approach is to present the rate impact analysis over 10 years, showing the rate benefits net of surcharges amortized over that same period. Evaluating the rate impacts of the step-downs, including the surcharges, using the first approach yields average rate reductions to SoCal's noncore and wholesale customers in the 30% to 50% range.

17. Relative to the rates that noncore customers faced in 1998 (when the original BCAP decision was issued), these customers would still have experienced a rate decrease even if all of the $161.8 million in surcharges were allocated to them over a 2-year amortization period, all other things being equal. However, noncore rates were reduced substantially on January 1, 1999 in order to reduce projected overcollections in gas balancing accounts, while the current BCAP and this rehearing proceeding were pending. This has created an artificially low baseline against which to compare the impact of allocating surcharges to the noncore. As a result, instead of seeing rate reductions relative to the last BCAP decision, these customers would see some minor rate increases if surcharges are reallocated to noncore customers and amortized over a 2-year period.

18. An amortization period that is longer than 2-3 years would eliminate any rate increases to noncore customers from allocating all surcharges to the noncore, relative to current rates.

19. As a noncore customer of SoCal, SDG&E and all of its customers have benefited from SoCal's step-downs in the form of reduced ITCS.

20. For gas cost allocation policy to have any measurable net impact on the economy, there must be a significant difference in how the gas costs of different customer groups will affect overall economic development.

21. SoCal's conclusions concerning the negative economic impact of allocating surcharges to the noncore are flawed because they: (1) overstate effects on manufacturing and understate offsetting effects on other sectors; (2) do not reflect the fact that the majority of SoCal's commercial and industrial customers are part of the core class; and (3) ignore the relative impact of a dollar available to core versus noncore customers.

22. Allocating surcharge costs to noncore customers actually reduces gas costs to commercial customers by $14 million. EOR customers experience no change in costs because they are exempt from transition costs. Industrial customers would see an increase of approximately $25 million, which is only a fraction of the amount shifted to noncore ($125 million) and a very small amount compared to their total gas bill.

23. The record does not produce relevant distinctions between core and noncore customers with regard to spending, savings and profits and multiplier effects.

24. The potential cost shifts in this proceeding are quite small in relation to the Southern California economy. On average, gas represents less than 0.7% of the total value of shipments averaged across all California manufacturing. Even taking SoCal's study at face value, applying it to this proceeding yields calculations of increased manufacturing costs in only the hundredths of a percent.

25. Noncore customers will continue to experience a significant reduction in SoCal's interstate rate components under existing ITCS allocation policies.

26. Core customers have contributed $9 to $12 million per year since 1994, on average, to cover stranded costs within the 10% cap. In addition, core customers have paid for the difference between the as-billed rate and the market value of capacity reserved for the core.

27. Reallocating the $59 million in El Paso refunds to noncore customers is inconsistent with the origin of the refunds and the manner in which the refunds were determined, would penalize core customers who paid higher reservation charges (subject to refund) while the FERC case was pending, and is inconsistent with the requirements of Pub. Util. Code Section 453.5.

28. Because FERC settlements are "black box" in nature, there is no way to determine what the refunds would have been if other aspects of the FERC settlement had been resolved in a different manner.

29. The FERC settlement documents that someone other than PG&E picked up a sizable portion of costs associated with PG&E step-downs on El Paso, and that SoCal paid more in surcharges than the risk sharing amount of losses associated with its step-downs.

30. The surcharges associated with step-downs on Transwestern are fully attributable to SoCal's step-downs because SoCal was the only customer relinquishing capacity rights at that time.

31. ORA's proposed calculations of how much of the El Paso surcharge is attributable to the step-downs of PG&E and others unrealistically assumes that the other settling parties, including those that did not relinquish capacity, paid for all of the other capacity relinquishments except for SoCal's. It is more likely that all of the settling parties picked up the risk-sharing costs in a manner that spread all of the costs of relinquishments among all of El Paso's firm capacity customers. The calculations presented by SoCal, SCGC and CMA/CIG reflect this assumption.

32. SCGC and CMA/CIG's calculation of the percentage of SoCal's surcharge attributable to the relinquishments of PG&E (and others on El Paso) utilizes a ratio based on a numerator and denominator that are undiscounted. SoCal's calculation utilizes a numerator and denominator that are on the same discounted basis as the total amount of surcharges allocated to the settling parties.

33. The fact that the surcharge assigned to SoCal under the Transwestern settlement agreement may have been higher if PG&E and others had not also shared in the cost of SoCal's step-downs on Transwestern is irrelevant to the issue of what portion of the El Paso surcharge assigned to SoCal is attributable to SoCal's step-downs on El Paso.

34. The costs that SoCal incurred as a result of the relinquishments of PG&E and others on El Paso pipeline did not arise as a normal consequence of FERC ratemaking for the allocation of a pipeline's revenue requirement. Rather, they arose from major relinquishments under long-term gas contracts that herald the transition to a highly competitive gas transportation industry.

35. In analogous circumstances, where a pipeline experienced transition costs that it billed to SoCal as its customer, SoCal has allocated costs on an equal cents per therm basis.

36. An equal cents per therm allocation allocates costs to all customers in proportion to how they are using the system.

37. Removing the previously designated core portion of surcharges from the CFCA and simply adding them to the current ITCS balance would result in the core paying more of those costs than they would have if D.97-04-082 had correctly classified them in the first place. This is because the 10% cap would have been in effect at the time D.97-04-082 was issued, but is not expected to stay in effect once the new BCAP rates are implemented.

38. The use of balancing account adjustments to implement the reallocation adopted by today's decision was uncontested.

39. The amortization periods for balancing accounts is at issue in the pending BCAP proceeding, A.98-10-012 et al.

40. Finding of Fact 58 in D.97-04-082, as modified by D.98-07-100 (which was modified to make this change in D.99-03-026) is still accurate, based on this rehearing.

41. Finding of Fact 61 in D.97-04-082, as modified by D.98-07-100 (which was modified to make this change in D.99-03-026) is superceded by the findings in this decision.

42. In large part, EGA's comments attempt to introduce elements of EGA's and others' testimony from the pending BCAP into this proceeding. EGA's comments also refers to a study that is not on the record in this proceeding, and EGA presents calculations from testimony that was stricken during evidentiary hearings.

43. EGA is not a party to this proceeding, even though two of its members did file as appearances.

Conclusions of Law

1. This limited rehearing should not reexamine the Commission's determinations in D.98-07-100 and D.99-03-026. Accordingly, SCE's and other parties' attempts to characterize surcharges as other than ITCS costs, in order to justify an allocation different from the ITCS allocation adopted in D.92-07-025, should be rejected.

2. Because Watson's interpretation of the Commission's ITCS policy is inconsistent with the Commission's findings in D.99-03-026, it should be rejected.

3. Cost allocation in this proceeding should not consider other aspects of the FERC settlements that affected core and noncore customers.

4. All of SoCal's noncore customers benefit from the step-downs from a rate impact perspective, even if all of the surcharge costs are allocated to them.

5. The net economic impacts of shifting surcharge costs from core customers to noncore customers are likely to be very small, and do not warrant a change to our current ITCS allocation policies.

6. It is unreasonable for SDG&E to claim that it should not pay the surcharges, after benefiting from SoCal's step-downs, just because of the particular composition of its customer base.

7. Allocating pipeline surcharges to the noncore would not result in noncore customers subsidizing the core.

8. It would be unreasonable to modify the allocation of El Paso refunds in this proceeding.

9. Pipeline surcharges that are attributable to SoCal's step-downs should be allocated based on the ITCS policy adopted in D.92-07-025.

10. The revenues that SoCal receives under the revenue crediting mechanism in the El Paso settlement should be refunded to SoCal's customers as a credit to risk sharing amounts or in a way that tracks SoCal's allocation among its customers for its El Paso risk sharing surcharges.

11. SoCal's calculation of the amount of SoCal's surcharges attributable to the step-downs of PG&E and others on El Paso pipeline is reasonable and should be adopted. TURN's proposal to reduce this amount by the payment of other shippers in the Transwestern settlement is unreasonable and should be denied.

12. An equal cents per therm allocation of the amount of SoCal's surcharges attributable to the step-downs of PG&E and others is reasonable, and should be adopted.

13. It is reasonable to defer to the pending BCAP proceeding (A.98-10-012 et al.) the amortization period over which balancing account amounts should be

recovered. SoCal should submit a late-filed exhibit in the BCAP decision showing the effect of today's determinations on balancing account amounts.

14. It is reasonable to transfer the recorded surcharge payments that must be removed from the CFCA to a special ITCS subaccount that is allocable only to noncore customers. Surcharge amounts that were allocated to the core by D.97-04-082 but remain uncollected should now be collected in the regular ITCS.

15. It is reasonable to adopt a 4-year amortization period for the surcharges reallocated to the noncore by this decision. SoCal should submit a late-filed exhibit in the BCAP proceeding (A.98-10-012 et. al) showing the effect of today's determinations on account balances.

16. Conclusion of Law 12, added by D.98-07-100 (which was modified by D.99-03-026 to make this addition) is superceded by the conclusions of law in this decision.

17. EGA's petition to intervene should be denied.

18. In order to implement the reallocation of surcharges adopted today, this order should be effective immediately.

FINAL ORDER

IT IS ORDERED that:

1. Southern California Gas Company (SoCal) shall allocate pipeline surcharges (including interest) as follows:

   a. 24.5% of the surcharges associated with step-downs on El Paso pipeline shall be allocated to SoCal's noncore customers.

   b. 75.5% of the surcharges associated with step-downs on El Paso pipeline shall be allocated to SoCal's core and noncore customers on an equal cents per therm basis.

c. 100% of the surcharges associated with step-downs on Transwestern pipeline shall be allocated to SoCal's noncore customers.

d. The revenues that SoCal has received and may receive in the future under the revenue crediting mechanism in the El Paso settlement shall be refunded to SoCal's customers as a credit to surcharge amounts in the manner that we allocate surcharges arising from the El Paso step-downs in sub-paragraphs (a) and (b) above. Future revenues under this crediting mechanism shall be allocated among core and noncore customers in a way that tracks today's allocation of these surcharge amounts, even if the surcharges have been fully collected in rates.

e. The difference between the surcharge amounts allocated to core customers by Decision (D.) 97-04-082 (and already collected) and the amounts allocated to the core by this decision shall be removed from the Core Fixed Cost Account and transferred to a special Interstate Transition Cost Surcharge (ITCS) subaccount that is allocable only to noncore customers. Amounts allocated to the core by D.97-04-082 that have not already been collected from the core should be collected in the regular ITCS account.

f. The amortization period for the amounts referenced above that will be transferred to the ITCS subaccount or collected in the regular ITCS account shall be determined in the pending Biennial Cost Adjustment Proceeding (BCAP), Application (A.) 98-10-012 et al.

2. The transfer of amounts from the Core Fixed Cost Account to the ITCS subaccount or collected in the regular ITCS account, and amortization thereof pursuant to Ordering Paragraph 1, shall be implemented in the BCAP, A.98-10-012 et al. Within 10 days from the effective date of this decision, SoCal shall submit a late-filed exhibit in the BCAP, A.98-10-012 et al., showing the effect of today's determinations on account balances.

3. Electric Generator Alliance's Petition to Intervene, dated October 6, 1999, is denied.

4. A.96-03-031 and A.96-04-030 are closed.

This order is effective today.

Dated November 4, 1999, at San Francisco, California.

HENRY M. DUQUE
JOEL Z. HYATT
CARL W. WOOD
Commissioners

I dissent.

/s/ RICHARD A. BILAS
President

I dissent.

/s/ JOSIAH L. NEEPER
Commissioner

TABLE 1

1996 BCAP Rehearing
(A.96-03-031/96-04-030)
El Paso and Transwestern Surcharges from Capacity Relinquishments

($ Millions)	EP		TW		TOTAL
Total Surcharges from Capacity Relinquishments	112.3		49.5		161.8
	Core	Noncore	Core	Noncore	
1996 BCAP Allocation (D.97-04-082)	73.1	39.2	48.9	0.6	

	Core	Noncore	Total
Total	122.0	39.8	161.8

TABLE 2A
Net Rate Impacts of Step-downs (Benefits and Costs)

All Rates in Cents per Therm	Alternate 1 – Allocates Surcharges Exclusively to Noncore Customers[1]	Alternate 2 – Rate Impact of allocating $320MM of Stepdown Benefits to Noncore Customers and Excluding All Surcharges on 1998 Rates[2 4]	Alternate 3 – Rate Impact of allocating $525MM of Stepdown Benefits to Noncore Customers and Excluding all Surcharges on 1998 Rates[3 4]
Residential[5]	44.388	44.388	44.388
NonResidential[6]	32.469	32.469	32.469
Total Core	41.392	41.392	41.392
CARE surcharge[7]	0.994	0.994	0.994
NonCore C/I	9.055	12.131	16.096
Electric Generation	7.059	10.134	14.100
Total Retail Noncore	7.722	10.798	14.763
Wholesale[8]	6.532	9.592	13.539
DGN (Mexican Affiliate)	N/A	N/A	3.713

[1] It is assumed that the 1998 rates presented in Exhibit 23 includes $161MM of surcharges. The rates presented here shifts the $122MM allocated to core customers to noncore customers. The adjustment was solely to the ITCS account and CFCA. This tables assumes that the full $122MM costs shift was amortized in the base year 1998.

[2] Using Alternate 1 as the starting point, all the surcharges totalling $16MM were excluded and $320MM of step-down benefits was added to the noncore rates. The net impact is a revenue requirement increase of $159MM ($320MM-$161MM). The core rates remain unchanged.

[3] Using Alternate 1 as the starting point, all the surcharge totalling $161MM were excluded and $525MM of stepdown benefits was added to the noncore rates. The net impact is a revenue requirement increase of $364MM ($525MM-$161MM). The core rates remain unchanged.

[4] This table assumes that the rate impact from the stepdown benefits will be recognized in the 1998 base year. In practice, the rate impact from the stepdown benefits would be recognized over the ten-year pipeline settlement period.

[5] Residential includes single family, multi family, small master meter, and large master meter customers.

[6] Nonresidential includes core commercial and industrial, Gas A/C, and gas engine customers.

[7] The CARE surcharge is chargeable to residential non-CARE, core nonresidential, and noncore C&I customers.

[8] The wholesale rates exclude Vernon.

TABLE 2A (continued)

All Rates in Cents per Therm	Percentage Change from Alternate 2 to Alternate 1 ($320MM of Step-down Benefits vs. All Surcharges Allocated to Noncore Customers	Percentage Change from Alternate 3 to Alternate 1 ($525MM of Step-down Benefits vs. All Surcharges Allocated to Noncore Customers)
Residential[1]	0.0%	0.0%
NonResidential[2]	0.0%	0.0%
Total Core	0.0%	0.0%
CARE surcharge[3]	0.0%	0.0%
NonCore C/I	-25.4%	-43.7%
Electric Generation	-30.3%	-49.9%
Total Retail Noncore	-28.5%	-47.7%
Wholesale[4]	-31.9%	-51.8%
DGN (Mexican Affiliate)	N/A	N/A

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[1] Residential includes single family, multi family, small master meter, and large master meter customers.

[2] NonResidential includes core commercial and industrial, Gas A/C, and gas engine customers.

[3] The CARE surcharge is chargeable to residential non-Care, core nonresidential, and noncore C&I customers.

[4] The wholesale rates exclude Vernon.

Table 2B
Illustrative Rate Impacts of ITCS
Allocation to Noncore of Step-Down Surcharges

All Rates in Cents per Therm	1998 Rates	1999 Rates	Rate Impact of ORA & TURN proposal to shift to $122MM to Noncore Customers[5]	Percentage Change from 1998	Percentage Change from 1999
				2-year Amortization	
Residential[1]	47.858	44.222	41.748	-12.8%	-5.6%
NonResidential[2]	35.939	32.690	28.284	-21.3%	-13.5%
Total Core	44.863	41.324	38.365	-14.5%	-7.2%
CARE surcharge[3]	0.994	0.721	0.611	-38.5%	-15.3%
Noncore C/I	6.695	6.081	6.544	-2.3%	7.6%
Electric Generation	4.699	4.053	4.100	-12.7%	1.2%
Total Retail Noncore	5.362	4.727	4.915	-8.3%	4.0%
Wholesale[4]	4.183	3.572	3.445	-17.6%	-3.6%
DGN (Mexican Affiliate)	N/A	N/A	3.713	N/A	N/A

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[1] Residential includes single family, multi family, small master meter, and large master meter customers.

[2] NonResidential includes core commercial and industrial, Gas A/C, and gas engine customers.

[3] The CARE surcharge is chargeable to residential non-CARE, core nonresidential, and noncore C&I customers.

[4] 1998 and 1999 rates exclude Vernon.

[5] The $122MM cost shift to noncore was additive to the Joint Recommendation rates in the pending BCAP proceeding (A.98-10-012). The adjustment was solely to the ITCS account and CFCA. A two-year amortization assumes that $61MM is amortized in year 2000 and 2001.

Table 2B (continued)

All Rates in Cents per Therm	Rate Impact of Shifting $88.1MM to Noncore Customers[6]	Percentage Change from 1998 Rates	Percentage Change from 1999 Rates	Rate Impact of Shifting $88.1MM to Noncore Customers[7]	Percentage Change from 1998 Rates	Percentage Change from 1999 Rates
		3-year Amortization			4-year Amortization	
Residential[1]	42.697	-10.8%	-3.4%	42.917	-10.3%	-3.0%
NonResidential[2]	29.233	-18.7%	-10.6%	29.453	-18.0%	-9.9%
Total Core	39.313	-12.4%	-4.9%	39.533	-11.9%	-4.3%
CARE surcharge[3]	0.611	-38.5%	-15.3%	0.611	-38.5%	-15.3%
Noncore C/I	6.003	-10.3%	-1.3%	5.875	-12.2%	-3.4%
Electric Generation	3.548	-24.5%	-12.5%	3.420	-27.2%	-15.6%
Total Retail Noncore	4.364	-18.6%	-7.7%	4.236	-21.0%	-10.4%
Wholesale[4]	2.896	-30.8%	-18.9%	2.769	-33.8%	-22.5%
DGN (Mexican Affiliate)	3.165	N/A	N/A	3.037	N/A	N/A

[6] The $88.1MM cost shift to noncore was additive to the Joint Recommendation rates in the pending BCAP proceeding (A.98-10-012). The adjustment was solely to the ITCS account and CFCA.

[7] The $88.1MM cost shift to noncore was additive to the Joint Recommendation rates in the pending BCAP proceeding (A.98-10-012). The adjustment was solely to the ITCS account and CFCA. A four-year amortization assumes that $22MM is amortized in year 2000, 2001, 2002, and 2003.

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(END OF ATTACHMENT 1)

ATTACHMENT 2
ACRONYMS

Abbreviation	Meaning
BCAP	Biennial Cost Adjustment Proceeding
CARE	California Alternate Rates For Energy
CCC	California Cogeneration Council
CFCA	Core Fixed Cost Account
CIG	California Industrial Group
CMA	California Manufacturers Association
D.	Decision
EOR	Enhanced Oil Recovery
Exh.	Exhibit
FERC	Federal Energy Regulatory Commission
IID	Imperial Irrigation District
ITCS	Interstate Transition Cost Surcharge
MMcfd	Million cubic feet per day
NPV	Net Present Value
ORA	Office of Ratepayer Advocates
PG&E	Pacific Gas and Electric Company
PHC	Prehearing Conference
RT	Reporter's Transcript
SB	Senate Bill
SCE	Southern California Edison Company
SCGC	Southern California Generation Coalition
SCUPP	Southern California Utility Power Pool
SDG&E	San Diego Gas and Electric company
SoCal	Southern California Gas Company
TURN	The Utility Reform Network

ATTACHMENT 3

EL PASO NATURAL GAS COMPANY

Offer of Settlement and Request for
Approval of Stipulation and Agreement
Docket Nos. RP95-363-000, RP95-363-002
and CP94-183-002
March 15, 1996

PIPELINE
OF CHOICE
El Paso

ATTACHMENT 3
Page 1

EL PASO NATURAL GAS COMPANY
SETTLEMENT RESERVATION AMOUNT ALLOCATION
BY CUSTOMER
RESERVATION COMPONENT

Tab 3
Docket No. RP95-363
Settlement
Sheet 2 of 9

Line No.			Settlement Allocation Reservation Amount	Line No.
1	Big Lake, City of	$	13,300	1
2	Denver City, City of		25,487	2
3	PNM (formerly GCNM)		63,909	3
4	Goldsmith, City of		1,776	4
5	Grandfalls, City of		1,267	5
6	Zia Natural Gas (formerly Jal Gas)		11,373	6
7	McLean, City of		8,936	7
8	Morton, City of		13,282	8
9	Navajo Tribal		232,082	9
10	North Bailey Co-op		4,119	10
11	Plains, City of		7,822	11
12	CPEX (formerly Rimrock)		3,532	12
13	Southern Union		88,567	13
14	Spur, City of		5,422	14
15	Sterling		2,758	15
16	Town of Texola		302	16
17	West Texas Gas		23,339	17
18	Whiteface, City of		2,815	18
19	Total Zone 1 (Production Area)	$	510,088	19
20	Asarco	$	268,197	20
21	Dumas, City of		168,614	21
22	El Paso Electric		1,804,448	22
23	Nat Gas Processing		197,318	23
24	Southdown (SW Portland)		77	24
25	Southern Union		3,343,070	25
26	Total Zone 2 (Texas)	$	5,781,724	26
27	Capitan-Carrizozo	$	38,599	27
28	Corona, Village of		1,857	28
29	Deming, City of		89,948	29
30	EMW		100,304	30
31	PNM (formerly GCNM)		1,528,395	31
32	Las Cruces, City of		539,694	32
33	Lordsburg, City of		29,685	33
34	Mountainair, Town of		11,462	34
35	Phelps Dodge		767,716	35
36	Rio Grande		249,206	36
37	Socorro, City of		55,741	37
38	Total Zone 3 (New Mexico)	$	3,412,607	38

ATTACHMENT 3
Page 2

EL PASO NATURAL GAS COMPANY
SETTLEMENT RESERVATION AMOUNT ALLOCATION
BY CUSTOMER
RESERVATION COMPONENT

Tab 3
Docket No. RP95-363
Settlement
Sheet 3 of 9

Line No.		Settlement Allocation Reservation Amount	Line No.
1	Ajo Improvement	$ 9,572	1
2	Apache Nitrogen	90,078	2
3	AEPCO	913,704	3
4	APS	4,673,624	4
5	Asarco	210,727	5
6	Benson, City of	40,764	6
7	Black Mountain	64,523	7
8	Chemical Lime (Chemstar)	110,160	8
9	Citizens Utilities	2,218,168	9
10	Cyprus Miami	295,763	10
11	Duncan Rural	16,616	11
12	Graham County	93,772	12
13	Magma Copper	929,800	13
14	Mesa, City of	840,324	14
15	Navajo Tribal	135,532	15
16	Pemex	82,446	16
17	Phelps Dodge	349,774	17
18	Safford, City of	93,140	18
19	Salt River Project	3,420,972	19
20	Southwest Gas	17,794,031	20
21	Willcox, City of	44,116	21
22	Total Zone 4 (Arizona)	$ 32,427,606	22
23	Southwest Gas Zone 4 (Nevada)	$ 9,636,991	23
24	Total EOC	$ 51,769,016	24
25	LADWP (W)	$ 2,723,837	25
26	Meridian Oil Mktg (W)	7,566,216	26
27	Meridian Oil Mktg	6,279,961	27
28	Mission Energy	529,633	28
29	PG&E	58,416,615	29
30	Saguaro (W)	1,513,244	30
31	San Diego Gas & Electric	756,621	31
32	Socal Edison	12,021,406	32
33	SoCalGas	98,584,081	33
34	Texaco Inc. (W)	13,240,876	34
35	US Borax & Chemical (W)	1,437,579	35
36	Total Zone 5 (California)	$ 203,070,069	36
37	Customer Allocation	$ 254,839,085	37
38	El Paso Allocation	18,161,002	38
39	Total RESERVATION	$ 273,000,087	39

EL PASO NATURAL GAS COMPANY
RISK SHARING CALCULATIONS
RESERVATION COMPONENT

Tab 3
Docket No. RP95-363
Settlement
Sheet 4 of 9

LINE NO.		Billing Determinant	Rate	Total	1996	1997	1998	1999	2000	2001	2002	2003	LINE NO.
	Stepdown Value @ 100%												
1	SoCal	306,900	$8.73309	257,297,791	32,162,224	32,162,224	32,162,224	32,162,224	32,162,224	32,162,224	32,162,224	32,162,224	1
2	Sunrise	30,690	$8.73309	25,729,779	3,216,222	3,216,222	3,216,222	3,216,222	3,216,222	3,216,222	3,216,222	3,216,222	2
3	PNM-PA	16,695	$3.20845	4,981,552	482,086	642,781	642,781	642,781	642,781	642,781	642,781	642,781	3
4	PNM-NM	24,225	$5.41751	12,205,244	1,181,153	1,574,870	1,574,870	1,574,870	1,574,870	1,574,870	1,574,870	1,574,870	4
5	SWG	30,000	$7.44719	19,660,582	893,663	2,680,988	2,680,988	2,680,988	2,680,988	2,680,988	2,680,988	2,680,988	5
6	PEMEX	4,617	$7.35012	2,850,582	0	407,226	407,226	407,226	407,226	407,226	407,226	407,226	6
7	SCE	71,610	$8.73309	51,280,879	0	6,253,766	7,504,519	7,504,519	7,504,519	7,504,519	7,504,519	7,504,519	7
8	PG&E	1,166,220	$8.82042	740,631,615	0	0	123,438,603	123,438,603	123,438,603	123,438,603	123,438,603	123,438,603	8
9				1,114,638,024	37,935,347	46,938,077	171,627,433	171,627,433	171,627,433	171,627,433	171,627,433	171,627,433	9
	Non-Discounted Risk Sharing Per Settlement												
10	SoCal			90,838,144	11,354,768	11,354,768	11,354,768	11,354,768	11,354,768	11,354,768	11,354,768	11,354,768	10
11	Sunrise			9,083,814	1,135,477	1,135,477	1,135,477	1,135,477	1,135,477	1,135,477	1,135,477	1,135,477	11
12	PNM-PA			1,758,721	170,199	226,932	226,932	226,932	226,932	226,932	226,932	226,932	12
13	PNM-NM			4,309,021	417,002	556,003	556,003	556,003	556,003	556,003	556,003	556,003	13
14	SWG			6,941,104	315,505	946,514	946,514	946,514	946,514	946,514	946,514	946,514	14
15	PEMEX			1,006,389	0	143,770	143,770	143,770	143,770	143,770	143,770	143,770	15
16	SCE			18,104,547	0	2,207,872	2,649,446	2,649,446	2,649,446	2,649,446	2,649,446	2,649,446	16
17	PG&E			261,477,570	0	0	43,579,595	43,579,595	43,579,595	43,579,595	43,579,595	43,579,595	17
18				393,519,310	13,392,950	16,571,335	60,592,504	60,592,504	60,592,504	60,592,504	60,592,504	60,592,504	18
	Present Value - Discounted Risk Sharing Per Settlement												
19	SoCal			66,934,437	10,877,661	10,044,013	9,274,255	8,563,489	7,907,196	7,301,200	6,741,647	6,224,977	19
20	Sunrise			6,693,444	1,087,766	1,004,401	927,425	856,349	790,720	730,120	674,165	622,498	20
21	PNM-PA			1,281,739	161,412	200,735	185,351	171,146	158,030	145,919	134,736	124,410	21
22	PNM-NM			3,140,374	395,473	491,820	454,127	419,324	387,187	357,514	330,115	304,815	22
23	SWG			4,967,049	294,251	837,252	773,086	713,838	659,130	608,616	561,972	518,903	23
24	PEMEX			709,770	0	127,174	117,427	108,428	100,118	92,445	85,360	78,818	24
25	SCE			12,676,223	0	1,939,912	2,163,993	1,998,147	1,845,012	1,703,613	1,573,051	1,452,495	25
26	PG&E			176,596,964	0	0	35,594,585	32,866,668	30,347,814	28,022,002	25,874,437	23,891,457	26
27				273,000,000	12,816,563	14,645,307	49,490,250	45,697,389	42,195,208	38,961,429	35,975,481	33,218,373	27
	El Paso Amounts Added to the Revenue Sharing Deductible												
28	Nominal Dollars			26,178,404	890,950	1,102,388	4,030,844	4,030,844	4,030,844	4,030,844	4,030,844	4,030,844	28
29	NPV Dollars			18,161,000	852,607	974,262	3,292,280	3,039,964	2,806,986	2,591,863	2,393,226	2,209,813	29

(END OF ATTACHMENT 3)