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Decision 92-02-075 February 20, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Rulemaking on the Commission's own motion to establish rules and procedures governing utility demand-side management.	R.91-08-003 (Filed August 7, 1991)
Order Instituting Investigation on the Commission's own motion to establish procedures governing demand-side management and the competitive procurement thereof.	I.91-08-002

(See Attachment 4 for appearances.)

INTERIM OPINION ON RULES GOVERNING UTILITY DEMAND-SIDE MANAGEMENT PROGRAMS

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INTERIM OPINION ON RULES GOVERNING UTILITY DEMAND-SIDE MANAGEMENT PROGRAMS

I. Summary

By this order, we issue rules governing the evaluation, funding and implementation of demand-side management (DSM) programs and associated shareholder incentives. In developing these rules, we establish basic policy principles designed to tap DSM's potential for meeting our overall resource procurement goal, namely, to provide California ratepayers with reliable, least cost, environmentally sensitive energy service:[1]

- o <u>Resource Planning</u>. We are committed to having the utility integrate supply- and demand-side resource planning to produce the least-cost, environmentally sensitive resource plan. To this end, we must continue to improve our analytical approaches for evaluating demand-side resources.

  We need to move ahead on the measurement and evaluation of DSM savings, in order to ensure that DSM savings forecasts are as accurate as possible. To the extent that utilities use ratepayer-supplied funds to procure and maintain DSM resources, measurement and evaluation allows us to ensure that ratepayers receive the resources that they are paying for. We aim to make all aspects of our resource procurement process, including the evaluation and implementation of DSM, as predictable as possible.

- o <u>Resource Acquisition</u>. Introducing competition into the utility's acquisition

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1 The text that follows represents a brief summary of the general principles established in the body of the order and appended rules. See Sections III, IV and Attachment 1.

of demand-side resources offers great potential for achieving our goal of reliable, least cost, environmentally sensitive energy service. We will explore competitive bidding for DSM resources, pursuant to Public Utilities Code § 747, in order to assess the role of DSM bidding in providing least-cost energy services to ratepayers.

- Program Emphasis. Utilities' DSM activities should focus on programs that serve as viable alternatives to supply-side resource options, i.e., energy efficiency programs and load management programs which promote energy efficiency.

- Cost-Effectiveness Testing. Methods to test the cost-effectiveness of DSM programs should be consistent with our least-cost planning principles and our policy of emphasizing DSM programs that serve as alternatives to supply. Therefore, the primary indicator of DSM cost-effectiveness should consider the total resource costs and benefits of DSM, including nonprice factors.

- Shareholder Incentives. The role of shareholder incentives is to offset any regulatory biases against DSM that the utility might have in procuring least-cost energy resources. Shareholder incentives should be designed to encourage energy efficiency and load management programs that promote energy efficiency.

  For shared-savings incentive mechanisms, ratepayers should share their DSM investment earnings (in the form of lower resource costs) with shareholders at the agreed upon percentage. We therefore reaffirm our commitment to shift from prespecified savings to ex post verified savings, for the purpose of calculating shareholder incentives.

- Improved Consistency. We must continue to improve consistency across the various regulatory proceedings that address DSM-related issues. The determinations made in

> this Rulemaking and companion Investigation should be used in any subsequent utility-specific proceedings.

As described in this order, certain aspects of our adopted rules are interim, pending the receipt and consideration of comments, workshop reports, and program evaluations. We also establish a separate phase in these proceedings for reviewing respondents' measurement and evaluation activities.

The rules adopted by this order are presented in Attachment 1. Attachment 2 explains each technical acronym or other abbreviation that appears in this decision.[2]

II. Background

In Investigation (I.) 86-10-001, our generic examination of ratemaking, we identified the need to take a fresh look at demand-side management of utility resources.[3] Demand-side management (DSM) programs focus on the customer side of the utility meter and have included programs for load management and energy efficiency, among others.

On July 20, 1989, we convened an en banc hearing to reexamine the role of DSM in utility resource procurement. As described below, the events and decisions that followed the en banc hearing led to the issuance of this Order Instituting Rulemaking (OIR), and companion Order Instituting Investigation (OII).[4]

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2 As part of this proceeding, Pacific Gas & Electric Company submitted a pilot DSM bidding proposal for our consideration. We will address this proposal in a separate opinion.

3 See Decision (D.) 89-05-067 (32 CPUC 2nd, 79, 80-81).

4 In subsequent sections we refer to these two proceedings collectively as the DSM OIR/OII (or OIR/OII) proceeding.

A. The California Collaborative

During the July 20, 1989 en banc hearing, several participants recommended that interested parties collaborate on a blueprint for the revitalization of DSM activity in California. We agreed, with the hope that a collaborative approach could help facilitate that goal.

The California Collaborative working group (Collaborative) set its own agenda and membership. Its stakeholders were a wide array of interested groups: California's four major investor-owned energy utilities, representatives of various California state agencies, environmentalists, ratepayers of all types, energy service companies, and independent energy producers.

The Collaborative's achievements are reflected in its January 1990 report to the Commission, An Energy Efficiency Blueprint for California (the Blueprint). In their report, the Collaborative's stakeholders proposed a new regulatory mechanism designed to allow utility shareholders to participate in the benefits of DSM. They also created new and expanded DSM programs, and identified key characteristics of DSM programs which must be considered in order to provide lasting energy efficiency savings. Finally, they recommended policies to govern the regulatory treatment of utility DSM programs.

B. Adoption of Experimental DSM Shareholder Incentive Programs

As promised in the Blueprint, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Gas Company (SoCal) filed applications requesting Commission authorization for expanded DSM programs and shareholder incentive mechanisms. The parties to the proceeding subsequently entered into settlement agreements, and in D.90-08-068 and D.90-12-071, we approved, with some modifications, the terms of the respective settlements. Pursuant to the settlement agreements, each utility convened Advisory Committees to assist them in the implementation of the approved programs.

The shareholder incentive programs adopted in D.90-08-068 and D.90-12-071 were experimental, and were authorized through 1991 for SCE and SDG&E and through 1992 for PG&E and SoCal.[5] As we stated in D.90-08-068, "...these mechanisms should be considered experimental only and not necessarily the blueprint for the next generation of DSM programs."[6] In approving these experiments, we identified the need for an OIR to provide a forum for "comparing the different DSM models...and to assess the relative success of the different approaches." We also stated that this OIR could lead to "the development of statewide standards and benchmarks by which to measure energy efficiency and to measure the appropriate levels of incentives." To aid us in this evaluation, we directed our Commission Advisory and Compliance Division (CACD) to submit a report, by December 31, 1992, on the effectiveness of the adopted incentive mechanisms.

C. <u>Issuance of the DSM OIR/OII</u>

The issuance of our DSM OIR/OII on August 7, 1991 allows us to take up where the Collaborative left off. As we state in the OIR/OII, this proceeding will examine: (1) Collaborative positions agreed to by consensus but which are not yet formal Commission policy; (2) policy areas where the stakeholders failed to reach consensus and where resolution is critical to secure a sustained role for DSM in future utility resource procurement strategies; and

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5 SCE's incentive program was reevaluated, and modified on an interim basis, in its recent general rate case decision, D.91-12-076; SDG&E's experimental incentive mechanism was extended through 1992 as part of its 1992 modified attrition (see D.91-12-074 in Application 91-03-001).

6 D.90-08-068 (37 CPUC 2d 347,362).

(3) other important policy or technical areas not explicitly addressed in the Collaborative.[7]

Our DSM OIR/OII includes 29 proposed rules (Rules) related to utility gas and electric DSM programs. Rules 1-4 articulate policy principles for considering DSM programs as viable alternatives to traditional supply-side resource options, and present common terms and definitions. Rules 5-13 provide guidelines for the cost-effectiveness testing of DSM, and establish priorities among different types of DSM programs. Rules 14-19 adopt interim principles governing future shareholder incentives, pending CACD's report. Rules 20-25 address the role of measurement and evaluation in DSM program development. They also discuss the need for consistent treatment of DSM programs across utilities and across regulatory forums. In Rule 25 we propose establishing a single forum where all utilities' DSM activities can be reviewed, and ask for comments on that proposal. Rules 26-29 provide guidance on the development of DSM pilot bidding programs. A copy of the Rules, as originally proposed, is appended to this order. (See Attachment 3.)

Comments on the Rules were filed on September 23, 1991 by PG&E, SCE, SDG&E, SoCal, Southwest Gas Corporation (Southwest), Division of Ratepayer Advocates (DRA), California Energy Commission (CEC), South Coast Air Quality Management District (SCAQMD), California Department of General Services (DGS), United States Department of Defense (DOD), Natural Resources Defense Council (NRDC), Toward Utility Rate Normalization (TURN), Utility Consumers' Action Network (UCAN), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA),

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7 OIR/OII, August 7, 1991, p. 7.

National Association of Energy Service Companies (NAESCO), SYCOM Enterprises (SYCOM), and Transphase Systems, Inc. (Transphase).[8]

After comments were filed, various parties decided to meet informally to discuss the proposed rules and their comments to those rules. By letter to the assigned administrative law judge (ALJ), dated December 10, 1991, representatives from SCE, PG&E, SDG&E, SoCal, DRA, CEC, CLECA, DGS, NAESCO, and NRDC presented their consensus recommendations for amending the Rules, and identified areas where no consensus could be reached. A copy of this letter was served on all parties to this proceeding.

III. Utility Resource Procurement: Where We Are Heading

Utility resource procurement involves both planning and acquisition. Resource planning determines whether the utility needs to acquire new resources, in order to maintain reliability and/or to improve the efficiency of the utility system. This determination is made by comparing the total costs of the utility's resource plan before and after adding supply- or demand-side resource options. Resource acquisition, on the other hand, determines how the utility will acquire the new resources that are needed, as identified in the planning process. The utility can construct new plants, purchase power from other utilities, offer DSM programs to its customers, or purchase power (or DSM services) from unregulated third parties. Competitive bidding enables utilities and third parties to compete in the resource acquisition

8 Kenetech Energy Management, Inc. (Kenetech) also filed comments, but they were late-filed (October 8), and did not include a certificate of service or service list. While we do not explicitly consider Kenetech's comments in this order, we note that the comments of several other parties reflect similar views.

process, for the purpose of putting downward pressure on the costs of energy services.

As stated in our Rules, our overall objective for utility resource procurement is reliable, least-cost, environmentally sensitive energy service.[9] All parties support this objective. However, they offer different views on how to achieve that objective. In particular, parties' comments highlight two fundamentally different views on how DSM should fit into the planning stage of utility resource procurement.

The first view is that utility DSM programs should be funded whenever they reduce the total costs of the system (defined to include environmental impacts). For example, NRDC argues that the way to achieve our resource procurement goals is to "favor demand-side measures over supply-side alternatives whenever life-cycle costs, including environmental costs, can be reduced in the process." Similarly, SoCal suggests that the reference point for DSM program funding be the level of cost-effective DSM that can be achieved on a utility's system. In practice, this approach establishes a DSM "set-aside," where a utility's need for resource additions would first be reduced by implementing all potential cost-effective DSM.

Under this approach, any remaining need for resource additions is met through a least-cost planning and acquisition process for supply-side resources only. This includes bidding by qualifying facilities (QFs) and other non-utility generators (NUGs)

9 As DRA and others point out in their comments, Rule 1, as originally proposed, refers only to "electricity service." (See Attachment 3.) We correct the language of Rule 1 to read "energy service" in our adopted rules. (See Attachment 1.)

for the supply-side resources identified in the process.[10] DSM bidding could also take place, but only within the set-aside framework, i.e., energy service companies (ESCOs) would bid for a portion of the DSM set-aside, either to replace or augment utility DSM efforts.

The second view is that demand- and supply-side resources should be compared head-to-head for cost-effectiveness, including relative environmental impacts. Once the optimal mix of utility DSM and supply-side options is identified in the planning process, some or all of those options would then be put out for bid by third parties. In their comments, some parties indicate a preference for an acquisition process that segregates the bidding arena, allowing ESCOs to bid only for DSM options and NUGs only for supply-side options. Others prefer an "integrated" bidding process, with ESCOs and NUGs competing together for all resource needs.

The first view describes our current resource procurement framework. In our Biennial Resource Plan Update proceeding (Update), we essentially develop a DSM set-aside, based on the California Energy Commission's forecast of cost-effective DSM activities that are not currently included in utility DSM funding authorization. Once the demand forecast is adjusted for this amount of "uncommitted DSM," we proceed to test all utility supply-side options, side-by-side and year-by-year, to see if the total costs of the system can be reduced further. We refer to this testing process for supply-side resources as the Iterative Cost-Effectiveness Method (ICEM). Using ICEM, the quantity and price of supply-side resource additions are identified in the

10 QFs are the subset of NUGs that satisfies various efficiency and technology criteria established under the Public Utility Regulatory Policies Act (PURPA) of 1978.

planning process. The resulting resource plan creates the baseline for long-run marginal costs of electricity.[11]

As we've acknowledged in the past, our current planning process is somewhat limited in its ability to produce an optimal mix of resources in the system, for it does not include DSM programs in the iterative analysis of cost-effectiveness. Our current approach does not necessarily allow us to determine whether ratepayers might receive greater benefits from, for example, a renewable resource than from additional DSM programs, and vice versa. In addition, the current approach does not accommodate the optimal sequencing of investments in demand- and supply-side resources. By achieving our goal of comparing supply- and demand-side options on an equal footing, we hope to ensure such optimization. As we stated in D.91-06-022, and reiterated in our OIR, "we are committed to head-to-head comparison of DSM and supply options in the planning process, and perhaps ultimately in the bidding process as well."[12]

We are moving in this direction in several ways. First, we are testing the capabilities of analytic tools to directly integrate DSM programs into our current planning process for supply-side resources. In the current phase of the Update, SDG&E has used ICEM to integrate DSM into its resource plan. Demonstrations for PG&E and SCE are underway. These efforts should illuminate what factors are involved in directly comparing DSM and electric supply options, and the advantages and limitations of ICEM in making that comparison. On the gas side, we are committed to

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11 To date, we have only developed a general methodology for estimating natural gas long-run marginal costs. Implementation hearings in I.86-06-005 will begin in late summer/early fall of 1992.

12 See D.91-06-022, mimeo., pp. 10-11.

moving forward with our objectives in as many ways as practicable, as we await the outcome of implementation hearings in our marginal cost proceeding (I.86-06-005).

Second, we have made considerable progress in the way we account for nonprice factors associated with both demand- and supply-side resources. Our recent decision in Phase 1B of the Update established preliminary values for residual emissions of air pollutants. (See D.91-06-002.) As part of our transmission Investigation (I.90-09-050), we are examining ways to incorporate transmission and distribution costs into the planning process. By explicitly valuing these factors, we can better appreciate the full range of costs and benefits associated with supply- and demand-side resources.

Third, on the acquisition side, we have steadily introduced competitive bidding in order to put downward pressure on the costs of energy services. We already have a competitive bidding process in place for QFs, and are currently working towards widening the bidding arena to include other NUGs in the Update and transmission Investigation.[13] On the supply side, QFs compete with the utility for the least-cost resource additions, as identified in the planning process. If the QF's bid is lower than the utility's planned cost-effective addition, then the QF wins the bid and builds its own project. If QFs cannot beat the utility's costs, then the utility builds the addition identified in the planning process.

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13 For the purpose of this OIR/OII, we use the term "all-source bid" to refer to a bidding arena where all types of NUGs (not just QFs) can bid against utility supply-side resources, as identified in the planning process. We use the term "integrated bid" to refer to a bidding arena where providers of DSM services and NUGs can bid against utility demand- and supply-side resources alike.

As part of this OIR/OII, we are also initiating pilot DSM bidding programs to test the potential for achieving energy savings through a competitive market. Pursuant to Public Utility (PU) Code § 747, we will experiment with DSM-only bidding pilots, as well as integrated bidding, where demand- and supply-side options compete in a single arena. These bidding experiments will help us learn more about alternative DSM delivery mechanisms, and assess the role of DSM bidding to provide least-cost DSM services to ratepayers.

Finally, as stated in our OIR, we are working towards a procurement framework that gives the utility comparable incentives to meet its least-cost resource needs through demand- or supply-side resources. We want to ensure that neither our regulatory framework nor procedures contain any inherent biases that inhibit utility management from actively pursuing the optimal mix of demand- and supply-side resources. To this end, we established a pilot program of shareholder incentives for gas and electric DSM programs in D.90-08-068. We are in the process of evaluating the various shareholder incentive mechanisms now in place, and will report our findings to the Legislature by the end of 1992. In the meantime, we will continue to examine implementation issues related to these incentive programs, as they arise in these and other ongoing proceedings.

The above discussion serves as a backdrop to our consideration of comments filed in this proceeding. Not all parties share our vision of where we are heading in resource procurement: towards head-to-head comparison of demand- and supply-side options in the planning process and workable competition in resource acquisition. As a result, many of the comments to the specific rules reflect a different vision of the future. At the same time, some commenters agree with where we are heading in resource procurement, but suggest that we move faster in making changes to our current framework. As described above, we are committed to achieving our objectives in a careful, deliberate manner. Without losing sight of our goals, we will structure our rules to accommodate new information, as we gain experience with shareholder incentives, DSM bidding, and other aspects of integrated resource planning and acquisition. We aim to make all aspects of our resource procurement process, including the evaluation and implementation of DSM, as predictable as possible.

IV. Major Issues

We turn now to the major issues raised in parties' comments to our proposed rules. This summary highlights the range of debate and proposed modifications. It is not intended to be a comprehensive description of all points raised by commenters. We believe that the saving of space and the gain in clarity justify using an overview. For reference, we present the full text of our proposed Rules in Attachment 3.

A. Measurement and Evaluation

We begin with the issue of measurement and evaluation (M&E) of DSM savings because it represents, in our view, the threshold issue for our regulatory oversight of DSM programs. All parties agree, in principle, that M&E must be emphasized as a priority. However, parties differ on how to establish this priority, what specific M&E activities should be required, and how M&E activities should be linked to shareholder incentives. (See Rules 20 to 22 in Attachment 3.)

1. Two General Observations

In addressing parties' comments, we make two general observations. First, parties raise concerns about M&E-related issues in response to all aspects of our proposed rules, not just the rules specific to M&E. For example, SDG&E, NRDC, and others react to our proposal for an earnings cap (as a method of reducing ratepayer risk) by recommending that we instead reduce ratepayer risk "at the source" through improved M&E activities. In response to our stated preference for a shared savings approach to shareholder incentives, SoCal argues that other approaches that do not rely as heavily on savings estimates might be preferable, given the uncertainty over the reliability of those savings.

Concerns over M&E are also raised in response to our proposed rules on cost-effectiveness testing for DSM programs. For example, CMA argues that our preference for the Total Resource Cost (TRC) test requires a "leap of faith" that future savings in supply-related costs will justify today's expenditures. On the topic of incentive payments, several parties recommend that those payments be based on the results of M&E activities, rather than on advance engineering estimates, in view of the uncertainties associated with future savings. Parties also raise the issue of M&E in conjunction with DSM bidding pilots: DGS and others recommend that M&E requirements for bidders apply equally to the utilities. Finally, several parties comment on the importance of M&E activities in improving long-term forecasts of DSM savings. In sum, parties identify M&E as a critical element in all aspects of the rulemaking.

Our second observation is that we currently lack an identified regulatory forum for evaluating M&E protocols, reviewing the results of M&E activities and considering methods for incorporating M&E results into the next generation of DSM programs and forecasted savings. To date, these types of M&E activities have been conducted informally, starting with the Collaborative process. During the Collaborative, a technical subcommittee developed proposed M&E protocols for the utilities' experimental incentive mechanisms, and submitted them as part of the Blueprint. Protocols similar to these were included in the settlement agreements, and adopted in D.90-08-068. In compliance with the settlement agreements, utilities hold statewide M&E Advisory Committee meetings every six months to present and discuss the status, plans and results of their M&E activities. However, none of this information has been reviewed formally at the Commission.[14]

2. Establishing a Forum for Measurement and Evaluation

What emerges from these general observations is our recognition that (1) M&E is the pivotal issue in this rulemaking and (2) this Commission needs a regulatory forum for examining ongoing M&E activities and results. With or without shareholder incentives, we must be confident that forecasts of DSM savings are reliable in meeting energy needs. Without this confidence, we cannot achieve our goal of directly comparing all resource options. Nor can we feel comfortable with major expansions of DSM commitments, as long as they are based on unverified savings estimates. To the extent that utilities use ratepayer-supplied funds to procure and maintain DSM resources, measurement and evaluation allows us to ensure that ratepayers receive the resources that they are paying for. Including shareholder incentives in DSM funding heightens the need for assurances that estimated resource savings will be forthcoming.

The Collaborative, and subsequent Advisory Committees on M&E, have shown the usefulness of providing interested parties with opportunities to informally review the results of M&E studies, share technical expertise, and discuss possible improvements in M&E activities. We encourage this informal process to continue. However, we also need a process for formally considering the results of these activities and incorporating them into DSM program

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14 We have reviewed general funding proposals for M&E activities in recent Energy Cost Adjustment Clause (ECAC) and General Rate Case (GRC) proceedings. However, none of these reviews has attempted to examine the reasonableness of the M&E protocols for future applications, or considered how the results of M&E should be used in adjusting savings estimates.

design and forecasts of DSM savings. At least initially, we will establish a separate M&E phase in these proceedings to serve as the forum for addressing the following types of M&E-related issues:

- <u>Pre-Implementation Measurement</u>. The acceptable methods and procedures for estimating, prior to program implementation, the various program impact parameters for DSM programs. These include the load impacts (and its components), participation level, utility costs, total costs and useful lives of DSM measures.

- <u>Post-Implementation Measurement</u>. The acceptable methods and procedures for measuring DSM program impacts after program implementation. This includes developing guidelines for M&E activities beyond current activities.

- <u>Incorporating the Results of Measurement Studies</u>. Using the results of M&E activities to (1) refine pre- and post-implementation measurement protocols, (2) adjust forecasts of DSM program savings, and (3) adjust shareholder earnings under a shared-savings mechanism.

We think that addressing M&E issues in this OIR/OII is the most administratively feasible approach at this time. As we discuss in Section IV.F below, we may consider alternative procedural approaches for addressing DSM-related issues, once we have completed our generic gas and electric ratemaking proceeding (R.90-02-008/I.90-08-006).

Most of the issues raised in parties' comments to Rules 20-22 will be addressed in the M&E phase of these proceedings. For example, SDG&E, NRDC, and DGS ask us for more guidance on what we expect to see in "comprehensive and aggressive" measurement plans (Rule 22). As indicated above, we will develop more specific guidelines for M&E activities in the M&E phase, thereby clarifying our expectations under Rule 22. Similarly, PG&E's recommendation that we establish ex post measurement methods for each key program fits nicely into this procedural forum. We expect to adopt acceptable ex post measurement methods in the M&E phase, with future refinements as the "state-of-the-art" improves.[15] However, we will not defer to this phase the issue of <u>how</u> to link the results of measurement studies to shareholder earnings, as some parties suggest. Rather, we reaffirm our commitment to shift to an ex post measurement approach in today's order, and will use the M&E phase of these proceedings to address implementation issues associated with this approach. (See Section IV.A.3 below.)

With regard to the timing of the M&E phase, we believe that it should begin as soon as possible. We direct the assigned ALJ to notice a prehearing conference (PHC) to coordinate the scheduling of the M&E phase as soon as practicable after issuance of this order. We would also like additional comments from respondents and interested parties regarding (1) the types of information that will be needed to address the M&E-related issues outlined above and (2) scheduling recommendations for the M&E phase, including detailed timetables for prehearing workshops (if appropriate), the filing of testimony, evidentiary hearings and briefs. Comments should be filed at our Docket Office and served on all appearances and the state service list no later than 30 days from the effective date of this order.

3. Linking the Results of Measurement and Evaluation to Shareholder Incentives

Rule 21 states our intention to shift from basing shareholder incentives on prespecified savings estimates to basing them on ex post measurement, that is, estimates made after program implementation.

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15 As part of the M&E phase, we will consider procedural options for making such refinements, on an ongoing basis.

PG&E and SCE agree with the intent of Rule 21, but argue that establishing acceptable ex post measurement methods is a precondition for the shift. CEC, TURN, UCAN, Transphase, CMA, and DGS strongly recommend that the Commission move on implementing Rule 21 immediately. NRDC suggests that the Commission leave this issue open, and not insist on the shift to ex post measurement at this time.

DRA and SDG&E object to Rule 21, and recommend that we instead use ex post results to adjust savings estimates <u>prospectively</u> for future program activities. DRA is concerned that a shift toward ex post measurement will produce a "narrow" focus on actual impacts of last year's programs, rather than establishing reliable estimates for future savings. In addition, DRA believes that this shift could result in "cream skimming," e.g., the utilities downplaying certain market or geographic segments, and favoring the most cost-effective applications.

SDG&E argues that the ex post approach creates too much uncertainty regarding the outcomes of utilities' DSM efforts and would delay recovery of potential earnings. SDG&E asserts that this uncertainty would reduce the productivity and efficiency of its field operations. In SDG&E's view, this uncertainty would require higher potential returns, resulting in higher ratepayer costs.

We are not persuaded by DRA's and SDG&E's arguments. With regard to DRA's comments, we do not believe that basing incentives on ex post measurement results will undermine efforts for improving forward-looking estimates. In fact, we see the ex post approach as a marked improvement to the current scheme, where forward-looking estimates are the sole basis for incentive payments. By de-linking the forecasting process from monetary returns, we expect that process to become more objective, not less. We also note that there is currently little incentive for utilities to aggressively implement their ex post measurement studies, as there will be under a scheme that links shareholder earnings to those results.

We do not share DRA's concern that there will be "gaming" in an ex post approach. We intend to carefully review the ex post measurement methods in the M&E phase, in order to ensure that they are methodologically sound. In addition, the results of ex post measurement activities will also be reviewed in the M&E phase. Moreover, as stated above, we will use the M&E phase, and its successor, to address the longer term issues of how and why last year's results might be different from measures installed in future years. With this process, we are confident that Rule 21 will yield improvements in both verifying past savings, as well as projecting savings from measures installed in future years.

As to DRA's concerns over cream skimming, we fail to see how they are unique to an approach where incentive payments are based on ex post measurement. As DRA states elsewhere in its comments, cream skimming can occur whenever more cost-effective measures are promoted at the expense of other measures or sectors where less cost-effective opportunities are available. This is equally true for an incentive mechanism based on prespecified savings. While ex post measurement may change the relative cost-effectiveness of measures or programs over time (and hence the types of measures or sectors that are more cost-effective than others), we do not believe it is more prone to cream skimming than prespecified savings. As discussed in Section IV.E. below, we will address the issue of cream skimming/lost opportunities through the establishment of minimum performance levels and reporting requirements.

With regard to SDG&E's comments, it is understandable that SDG&E prefers upfront payments, based on a fixed forecast of DSM savings, rather than payments linked to actual measured performance. However, SDG&E's comments appear to overlook the fact that, under the shareholder incentive mechanisms currently in place, investments in DSM are financed entirely by ratepayers through rate increases (i.e., DSM program costs are expensed).

Under a shared-savings incentive mechanism, ratepayers essentially give a percentage of their investment "earnings" (in the form of DSM savings) to shareholders. In effect, the utility is managing ratepayer funds in return for a share of the estimated earnings. Hence, changing to ex post verification of savings does not add uncertainty to the <u>shareholders'</u> return on investment. Rather, it ensures that ratepayers are not sharing too much (or too little) of <u>their</u> investment earnings with shareholders, relative to the percentage originally agreed to under the shared-savings mechanism. In effect, it provides a true-up protection for ratepayers' investment in DSM.[16] We consider such protection to be entirely appropriate.[17]

Moreover, we find it appropriate to place utility-delivered DSM savings on the same footing as ESCO-delivered savings, in terms of performance risks and rewards. Throughout the country, ESCO payments are based on ex post measurement of delivered savings, not on prespecified estimates. Similarly, for its DSM pilot bidding program, PG&E proposes to pay ESCOs across

16 The fact that SDG&E argues so strongly for "offsetting higher potential earnings" indicates to us that actual DSM savings (and hence shareholder earnings) are likely to be lower than those forecasted in the settlement agreements. We would not expect to hear such arguments if there were an equal (or better) chance that ex post verification would improve earnings.

17 It is important to keep in mind that ex post verification of savings does not protect ratepayers from forecasting uncertainty, since the overall level of savings assumed in justifying their expenditures in DSM is still subject to error. Ex post verification merely ensures that the agreed-upon percentage split of savings between shareholders and ratepayers is maintained; i.e., that a "deal is a deal."

all market sectors based entirely on ex post measurements of program savings. Clearly, the state-of-the art of ex post measurement is beyond its infancy. Therefore, we see no reason to continue with a dual standard for utility- versus ESCO- delivered savings beyond the original Collaborative experiment.

For the reasons stated above, we will retain Rule 21 essentially as proposed. Future shareholder incentives will be based on verified savings, whether that verification is in the form of metered results, sample bill analysis, or other post-installation measurement methods that we deem appropriate. We intend to implement this policy for all DSM programs. However, if there are specific measures for which post-installation measurement is either technically infeasible or overly impractical to implement, we will consider case-by-case exceptions in the M&E phase. We will also consider how to incorporate the shift to ex post savings verification into specific shareholder incentive mechanisms, as part of the M&E phase.

We agree with DGS and others that we should establish a timetable for making the shift to ex post verification of savings, for the purpose of calculating shareholder earnings. Although we wish to make this shift as swiftly as possible, we recognize that it will involve a significant learning curve and commitment of resources, at least for the initial transition. Therefore, to provide for a reasonable transition period, we will continue to base shareholder incentives on prespecified savings until 1994. We intend to shift to ex post verification for all shared-savings programs authorized as of January 1, 1994.[18] These programs will

18 SCE will operate under the shared-savings method adopted in its recent general rate case for its 1992 and 1993 programs. Beginning in 1994, SCE will shift to the ex post approach described

(Footnote continues on next page)

be eligible for shareholder earnings the following year. Parties developing proposed schedules for the M&E phase should keep this timetable in mind.

B. Program Emphasis, Eligibility for Incentives, and Common Definitions

Our Rules also address the issues of DSM funding priority and eligibility for shareholder incentives. Rule 6 states that DSM activities should focus on programs that serve as alternatives to supply-side resource options, and defines these programs as "energy efficiency and load management programs which promote energy efficiency." Appendix B of the Rules defines energy efficiency as programs which "reduce energy use for a comparable level of service." Rule 16 limits eligibility for shareholder incentives to these program categories. Rules 12 and 13 generally discourage the promotion of load building, load retention, and any fuel substitution programs with those characteristics, but still permit the utility to justify expenditures for those activities. (See Attachment 3.)

1. Position of the Parties

As described above, our Rules place heavy emphasis on the definition of "energy efficiency" in establishing DSM funding priorities and eligibility for shareholder incentives. Several parties propose to broaden the definition of energy efficiency to include fuel substitution programs, under specific circumstances. For example, PG&E would categorize a fuel substitution program under energy efficiency (making it eligible for shareholder

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above. Similarly, for shared-savings programs in PG&E's and SDG&E's test year 1993 general rate cases, the shift to ex post verification will apply to programs continuing in 1994.

incentives) if it has a conservation impact from a source Btu perspective, with a total resource benefit/cost ratio greater than 1.0. Similarly, SoCal recommends that a fuel substitution demonstrate a total resource benefit/cost ratio of at least 1.0, when comparing the best available gas and electric equipment. CEC and NRDC also recommend cost-effectiveness criteria for fuel substitution programs, if they are to be included under energy efficiency, as well as requirements that these programs improve air quality.

PG&E and SCE argue that reliance on the efficiency criteria is overly restrictive. In their view, load retention and load building programs benefit ratepayers in other ways (e.g., customer retention, cleaner air), and should therefore be funded by ratepayers and, in some cases, be eligible for shareholder incentives. Others parties (NRDC, TURN) strongly support the rule's exclusion of load retention and load building programs from shareholder incentives, and recommend that ratepayers not fund load building programs, with or without incentives.

2. <u>Discussion</u>

We believe that the proposed rules appropriately articulate the DSM funding priorities we have established over the last few years. In particular, we have encouraged utilities to treat energy efficiency improvements and energy conservation as viable alternatives to traditional supply-side resource options.[19] To this end, we look to demand-side options that <u>reduce</u> the costs of energy service by avoiding (or deferring) the cost of more expensive supply-side options. As we have stated in the past, programs that result in an incremental increase in customer and

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19 See D.89-05-067 (32 CPUC 2d 77), D.89-12-057 (34 CPUC 2d, 199), and D.90-01-016 (35 CPUC 2d 81).

system load do not achieve this result.[20] We also agree with TURN's observation that it is difficult to design and implement a load building program which builds load only at the time of day (and duration) when the utility has excess capacity. Load retention programs do not generally reduce energy use; rather they induce customers to delay or avoid bypassing utility service. As discussed in our OIR/OII, fuel substitution programs can also be designed to predominately retain load, build load, or both.[21]

In D.88-03-008, as modified by D.88-07-058, we authorized utilities to negotiate special bypass deferral contracts in the form of rate discounts and/or conservation incentives. The purpose of these contracts was to avoid uneconomic bypass of the utility system. Uneconomic bypass results when a customer chooses to leave the utility system (e.g., generate its own power or use an alternative fuel supply) at a cost that is less than its average rates, but greater than the utility's marginal costs. We specifically limited the application of these DSM incentives to

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20 See, for example, our discussion of load building versus load retention/load management in D.87-12-066 (SCE's test year 1988 General Rate Case; 26 CPUC 2d 475), and D.88-07-027 (28 CPUC 2d 542, 545 and Conclusion of Law 6).

21 For example, suppose a customer was considering replacing an existing gas heating system with an electric heat pump. The replacement would promote energy efficiency if the program causes the customer to install a high efficiency heat pump, instead of a minimum efficiency heat pump. However, if the customer did not use the gas heating system very much (e.g., instead used a lot of wood), it could be argued that the electric fuel substitution program had a predominately electric load building effect. As another example, suppose a customer was considering replacing gas-fired ovens in a commercial bakery with electric microwave ovens. If that customer was facing closure or relocation due to air quality restrictions on the use of gas ovens, and replacement of gas ovens with microwave ovens meant they could remain in operation, it could be argued that the program has predominately a load retention effect.

load retention programs, and excluded load building from consideration. We will continue to evaluate load retention programs designed to avoid uneconomic bypass as part of utility applications for special contracts.[22]

More recently, the concept of load retention has been expanded to encompass "economic development" activities, e.g., DSM incentives designed to retain businesses that would otherwise leave a utility service territory or California because of the cost of environmental regulations. On October 11, 1991, Assembly Bill (AB) 2054 added Section 740.4 to the PU Code, which would allow rate recovery of expenses supporting economic development programs, to the extent that ratepayers benefit from those programs.

While our Rules state that DSM activities should focus on energy efficiency programs and load management programs which promote energy efficiency, they also recognize that load retention and load building programs may serve other policy objectives. (See Rule 12.) However, we agree with NRDC that proponents of these programs should carry the burden of proof to quantify the social or ratepayer benefits, and justify ratepayer funding for these programs. We also agree with CEC that any general conclusions about the net benefits of load building or load retention programs should be backed up by program-specific analysis. In particular, for load building programs, utilities should quantify the programs' net effect on air emissions, including increased emissions from the increased load on the system. We will modify proposed Rules 12 and 13 to clarify these expectations. We intend to establish more

22 We have been reviewing the terms of special bypass contracts, including any negotiated load retention programs, in an expedited application docket and subsequent reasonableness reviews. Only the implementation and administrative costs of negotiating these contracts are authorized in the DSM budget. The costs of the rate discounts or conservation rebates are recovered through the sales forecasting and ratemaking process.

specific guidelines for evaluating and funding load building and economic development activities, in a later phase of these proceedings.

We turn now to the related issue of which DSM programs should be eligible for shareholder incentives. As part of the Collaborative Agreement, the ability for shareholders to earn on DSM was limited to energy efficiency programs, i.e., programs that serve to reduce energy use for a comparable level of service. Our Rules expand eligibility to include load management programs "that promote energy efficiency." In other words, our Rules limit shareholder incentives to DSM programs designed to defer or avoid utility supply-side requirements. We refer to these types of programs as "DSM resource programs."

This limitation is appropriate. Shareholder incentives for DSM were adopted in D.90-08-068 to address the different regulatory treatment of DSM vis-a-vis supply-side options, namely, the potential for shareholders to earn if the utility builds needed plant, but not to earn if the utility reduces that need via cost-effective DSM. Providing shareholder incentives for load retention or load-building programs goes beyond this objective. In effect, it provides shareholders with the opportunity to earn twice--first with the implementation of load retention or load building programs, and second, with the utility investment in supply-side resources that remain undeferred or unavoided. It is therefore inappropriate for ratepayers to provide shareholder earnings for programs that retain or increase customer or system load, even if the retention or increases are accomplished with the installation of energy efficient measures.

In their comments, several parties recommend modifications or clarifications to the DSM terms and definitions presented in Appendix B of our proposed Rules.[23] These recommendations should now be considered with the above policy guidance in mind. We direct CACD to hold workshops to discuss parties' specific recommendations for modifying DSM program terms and definitions, including:[24]

- o Recommended criteria for categorizing fuel substitution programs as energy efficiency programs, including recommended sources of assumptions for testing their cost-effectiveness. (PG&E, CEC, NRDC, SoCal)

- o Further refinements/enhancements to M&E definitions and program sub-categories, including DRA's recommendation to shift utility end-use Research, Development and Demonstration (RD&D) activities to the DSM side of the companies. (DRA, CEC)

- o Recommended definitions and/or criteria to distinguish load management programs which promote energy efficiency from load building or load retention programs. (SDG&E, Transphase)

- o Identification of specific energy efficiency programs that should be considered alternatives to supply-side resources. (DRA)

We caution parties that the workshops described above should not become a forum for relitigating the basic principles we've established in today's order. Workshop participants and CACD should carefully scrutinize all proposed modifications to the DSM program terms and definitions presented in Attachment 1 to ensure that they are consistent with these principles. With the policy

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23 Appendix B of our proposed rules is reproduced as an Appendix to our adopted rules (see Attachment 1).

24 As discussed in Section IV.C.2.b. below, these workshops should also explore the cost-effectiveness issues raised by DRA, SDG&E, and SoCal with regard to New Construction Programs.

guidance provided in this order, we expect that parties can reach consensus on most recommended changes.

In its workshop report, CACD should describe all proposed modifications to DSM program terms and definitions, indicate which are agreed to by all workshop participants, and describe any outstanding issues. CACD's workshop report shall be filed with the Commission's Docket Office and served on all parties within 120 days of the effective date of this order. As stated in Rule 4, the <u>Reporting Requirements Manual</u> will be modified to reflect the final version of DSM program terms and definitions. The assigned ALJ will direct these efforts after receiving CACD's report.

C. Cost-Effectiveness Indicators for DSM Programs

The Rules on DSM cost-effectiveness indicators are closely related to the Rules on DSM funding priorities, described above. In particular, Rule 6 directs utilities to rely on the Total Resource Cost (TRC) test as the primary indicator of DSM program cost-effectiveness because that test "reflects our view that utility DSM activities should focus on programs that serve as alternatives to supply-side resource options." At the same time, Rule 11 acknowledges that the usefulness of the TRC test is limited for direct assistance, information, and energy management services programs. For these programs, our Rule 11 states that the TRC test should be an important, but not the sole, factor used to determine funding levels.

The Rules also speak to the mechanics of conducting cost-effectiveness tests for DSM programs. Rule 5 directs utilities to use the methods and indicators included in the <u>Standard Practice Manual</u> (<u>SPM</u>), until a methodology is established that allows for the side-by-side comparison of demand- and supply-side resources. Rule 7 states that utilities should include nonprice factors along with price factors in considering DSM programs, and directs utilities to use any nonprice factors developed in the Update proceeding that are applicable to DSM evaluation. Rule 8 also directs utilities to use resource values (i.e., avoided supply costs) in their DSM cost-effectiveness tests that are consistent with the values adopted in the Update. Rule 9 states that utilities should not be required to include any indirect costs of DSM in their analyses at this time, given the speculative nature of attempts to quantify those costs. Rule 10 directs utilities to include the costs of shareholder incentives in each of the SPM tests of cost-effectiveness. (See Attachment 3.)

1. Position of the Parties

Parties generally agree that the SPM methods and indicators are appropriate for the cost-effectiveness testing of DSM programs, at least in the short-run.[25] This is not surprising, given the long history of using these tests in various proceedings at this Commission and the CEC. Only CMA argues that the SPM tests of cost-effectiveness are inappropriate. In CMA's view, none of those tests adequately account for the impact of DSM programs on rates.

With regard to our primary reliance on the TRC test, most parties agree that this emphasis is appropriate for DSM resource programs (i.e., programs designed to avoid or defer supply-side resources). However, NRDC urges the Commission to use the societal test instead, because it accommodates the inclusion of environmental costs. Transphase believes that the Utility Cost test is preferable, since it excludes customer costs from the cost-effectiveness evaluation. CMA argues that the TRC is inadequate because it ignores near-term rate impacts. TURN and DOD urge the Commission to continue to assess the rate impacts of all DSM programs, and take those impacts into account when considering

25 See Section III above regarding parties' differences on where we are heading in the longer term.

DSM program funding. SDG&E, DRA, and SoCal recommend that the TRC test be relaxed for New Construction programs, in addition to the direct assistance, information and energy management services programs mentioned in Rule 11.

On the topic of nonprice factors, most parties agree that these factors should be incorporated in the cost-effectiveness analysis of DSM, and should be consistent with the values developed in our Update proceeding.[26] Similarly, parties agree that the resource value associated with DSM programs should be consistent with the avoided costs adopted in the Update proceeding. PG&E, CEC, and Transphase recommend, however, that deferred transmission and distribution costs be included as part of that resource value.

All parties agree with the current framework which allows, but does not require, inclusion of DSM indirect costs in cost-effectiveness testing. SCE and CEC suggest that the SPM working group revisit this issue in the future.[27] SDG&E would have the SPM working group also address whether or not utility shareholder incentives should be included in the Societal Test.

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26 The CEC argues that the nonprice factors we use for DSM planning purposes should be consistent with the values it is developing in its Electricity Report (ER) proceedings. We have addressed coordination issues between the CEC's ER process and our Update proceeding on several occasions. We expect that coordination to continue. (See, for example, D.90-03-060 (36 CPUC 2d, 2) and D.91-06-022). However, it is in our Update proceeding that the final resource plan scenarios for each electric utility are adopted and used as the basis for supply-side acquisition decisions. Hence, we expect consistency between the resource values and nonprice factors used in the Update and those used in our evaluation of DSM programs.

27 The SPM working group consists of CEC and California Public Utilities Commission (CPUC) staff, utilities and interested parties. It is convened, as needed, by the staffs of the CPUC and CEC. See Section 2.d. below.

All other parties agree with Rule 10, which includes shareholder incentives as costs in all SPM tests.

2. Discussion

Before addressing the specific issues raised in parties' comments, we present a brief background on the SPM manual and various tests of cost-effectiveness.

a. SPM Tests of Cost-Effectiveness

The SPM is a joint CEC/CPUC staff publication that presents a cost-benefit methodology for the evaluation of DSM programs. It is the product of workshops among the staffs of the CEC and this Commission, the major utilities, and interested parties. Originally published in Febuary, 1983, the SPM was modified in December 1987.[28]

The SPM outlines cost-benefit equations for four major perspectives: the program participant (Participant Cost, or PC), the utility, in terms of its revenue requirements (Utility Cost Test, or UC), the total costs of the program, including utility and participant costs (Total Resource Cost, or TRC) and the change in rate levels (Rate Impact Measure, or RIM). The Societal Test, or ST, is a variation of the TRC that considers total costs and benefits from society's perspective as a whole, rather than just the utility and its ratepayers.

The SPM cost-benefit equations are considered static (as compared to dynamic or iterative) tests of cost-effectiveness. This is because they compare each DSM program against the utility's resource situation at a single point in time. Static tests of cost-effectiveness will indicate whether a resource option is cost-effective (i.e., lowers system costs), assuming all other things remain equal. In contrast, an iterative approach chooses from

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28 The December 1987 version is entitled: Standard Practice Manual: Economic Analysis of Demand-Side Management Programs.

among cost-effective options to determine which are the most cost-effective to add to the utility system, taking into account the type, size, and timing of potential additions. As we discuss in Section III above, we are examining methods to iteratively assess both demand- and supply-side resources. In the meantime, we will use the SPM tests of cost-effectiveness in ways that are the most consistent with our resource procurement goals. Each of the SPM tests is described in greater detail below.

(1) Participant Cost Test (PC)

Analysts use the PC test to measure the benefits and costs of a program to a customer. This test compares the reduction in the customer's utility bill, plus any incentive paid by the utility, with the customer's out-of-pocket expenses. It gives a good "first cut" of the desirability of the program, and is used as an indication of potential participation rates.

(2) Utility Cost Test (UC)

The UC test measures the net change in a utility's revenue requirements resulting from a DSM program. The SPM describes the benefits for this test as "the avoided supply costs of energy and demand--the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost--for the periods when there is a load reduction." The costs for the UC test are the program costs incurred by the utility, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Since the test is designed to focus on revenue requirements, it does not include any net costs incurred by program participants.

(3) Total Resource Cost Test (TRC)

The TRC test measures the net costs of a DSM program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The benefits side of the equation is the same as the UC test, described above. The costs in this test are the total equipment or measure costs, including installation, operation, and maintenance and administration, no matter who pays for them. In addition, costs for this test include the increase in supply costs for the periods in which load is increased. The ST variation is structurally similar to the TRC, but includes broader societal impacts, such as the externality costs of power generation not captured in the market system.

(4) <u>Rate Impact Measure Test (RIM)</u>

The RIM test indicates the direction and magnitude of the expected change in customer bills or rate levels. On the benefits side, the RIM test calculates the savings from avoided supply costs, similar to the UC and TRC tests described above. On the cost side, the RIM test includes the costs incurred by the utility (including incentives paid to the participant). Up to this point, the RIM test looks identical to the UC test.

However, the RIM test also includes a rate effect that is unique to DSM programs. Unlike supply-side resources, DSM programs cause a direct shift in revenues. In other words, when DSM programs reduce energy sales, a utility's fixed costs must be spread over a smaller sales volume (or a larger sales volume in the case of load building programs). This revenue shift does not affect total revenue requirements (as measured in the UC test), but does raise utility rates on a cents per kwh basis. The revenue shift effect may be offset by the cost savings that ratepayers realize in avoiding supply-side options. The net effect depends on the relationship between average costs and marginal (or avoided) costs. As a general rule, if average costs are expected to exceed marginal costs into the future, then the program is likely to increase utility rates. This is generally the case when a utility system has excess capacity, e.g., it has recently ratebased a "lumpy" plant investment. If, however, marginal costs are expected to exceed average costs (e.g., the utility needs to build new resources), the net effect is likely to be a reduction in utility rates. The overall effect on a customer's bill depends on whether or not they are past, current or future participants in energy efficiency programs.[29]

b. Which Test to Favor?

We remain committed to using the TRC as the primary indicator of cost-effectiveness for DSM programs. This is consistent with our stated policy of emphasizing DSM programs that serve as long-term alternatives to supply-side resources. It is also consistent with the least-cost planning principles that we apply to supply-side resources. In that context, we compare the total resource costs of the supply system, with and without the incremental resource addition. If inclusion of the new resource lowers total costs more than any other supply-side option, then it is considered cost-effective, and added to the resource plan. The TRC test does the same thing, although in a static sense, for DSM programs. As described above, the TRC test is the only SPM test of cost-effectiveness that looks at the total resource costs of DSM, regardless of who pays for the measure or equipment.

The UC test, on the other hand, only considers the portion of the DSM measure or equipment cost that is paid for by the utility. For most DSM programs, the utility cost is significantly less than the full resource cost. In contrast, all of the costs of supply-side resources are traditionally paid for by the utility, on behalf of its ratepayers.[30] Hence, funding DSM

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29 Contrary to CMA's assertions, the RIM test does indeed take account of the revenue shift and rate effects discussed in its comments.

30 In other words, we do not identify individual ratepayers who, because they "caused" the need for new generating resources, should pay a greater portion of the incremental plant than other ratepayers. For electric utilities, the costs of new plant are

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programs on the basis of the UC test would lead to the inefficient allocation of resources, since investments would be based on an evaluation of only a portion of total costs. It would also bias resource planning decisions in favor of DSM, relative to supply-side resources. Both of these results are contrary to our resource procurement objectives. For these reasons, we reject Transphase's recommendation that the UC test be favored.

For similar reasons, we find the RIM test inappropriate as the primary indicator of DSM cost-effectiveness. Like the UC test, the RIM test only looks at a portion of the total costs of DSM programs, i.e., the portion reflected in utility revenue requirements. Therefore, the RIM test does not identify least-cost resource options, from an economic efficiency perspective.

Moreover, the results of the RIM test are affected by the <u>ratemaking</u> treatment for DSM programs, that is, the way in which program costs are recovered in rates. For example, a DSM program that lowers total costs over the program life could still increase rates initially because the costs associated with that program are recovered relatively quickly, e.g., over the first few years of the program. At the same time, a more expensive DSM program could have a lower rate impact just because cost recovery is stretched over a longer period of time. While the RIM test gives us useful information about the overall rate impact of

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spread to all ratepayers, old and new. By definition, there are only utility costs (and no participant costs) for supply-side options. This is also true for the bulk of a gas-utility's customers (i.e., core or core-subscription), where the utility pays for all the costs of supply-side resources on behalf of its ratepayers.

resource procurement decisions, or the effect of various ratemaking approaches on rates, it does not accurately compare the economic costs of resource options.

For the above reasons, we do not compare the rate impacts of various supply options in deciding which is the least-cost resource to add in a given year. If we did, we would probably favor all supply options for which the ratemaking treatment was less front-loaded than utility-constructed plants. Moreover, if we only funded cost-effective supply-side resources that also reduced utility rates in the short term, we probably wouldn't fund a single one. Just like DSM programs, almost all investments in supply-side resources increase rates initially, as those costs are recovered at a rate that is higher than avoided costs during the early years of the project.[31] Ranking resource options primarily on the basis of relative rate impacts rather than total costs, whether those options are supply-side options or DSM programs, would be contrary to our least-cost planning principles.

We also note that, because of the revenue shifting characteristic of DSM, primary reliance on the RIM test would tend to promote programs that increase (or retain) electric and gas sales. While this may result in slightly lower rates in the short to medium term, it will not reduce the costs of the supply system (and customer bills) in the longer term. This is particularly true for utilities that will require resource additions over the next decade. Based on the base case filings in our Update proceeding, this appears to be the case for the three major electric utilities, PG&E, SCE, and SDG&E.

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31 Exceptions include payments to QFs under "as available" standard offer contracts and out-of-state power purchase agreements that similarly track avoided costs over their contract lives.

For the reasons stated above, we retain the use of the TRC test as the primary indicator of cost-effectiveness in ranking and funding DSM programs, as we proposed in our Rules. We direct utilities and other parties to our proceedings to use the TRC test for this purpose. NRDC's concerns about using the TRC, rather than the ST variation, are addressed by our clear direction to include nonprice factors, such as environmental externalities, in developing avoided supply costs. Moreover, the ST variation treats certain cost components as transfers (e.g., tax credits and interest payments). We prefer to treat those components as explicit resource costs, as we do in evaluating supply-side options.

While we clearly favor the TRC test for ranking and funding DSM programs, strict TRC adherence is not required for direct assistance programs, information programs and energy management services (see Rule 11). The workshops on DSM program terms and definitions, described in Section IV.B. above, should also explore the cost-effectiveness issues raised by DRA, SDG&E, and SoCal with regard to New Construction Programs.[32]

As we stated in the Order Instituting this Rulemaking, our preference for the TRC test does not diminish the importance of the information provided by the other indicators included in the <u>SPM</u>.[33] We plan to use these other indicators in considering the appropriate level of DSM funding in a given period, e.g., in deciding how far down the TRC-ranked program list to go in establishing an overall DSM budget. We also note that the rate impact of DSM programs, as measured by the RIM test, is affected by

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32 New Construction Programs are designed to encourage the installation of new efficiency measures that go beyond existing CEC efficiency standards for new building.

33 OIR/OII, August 7, 1991, p. 16.

the size of the utility incentive to participants, the level of utility administration costs (including shareholder incentives), and the overall timing of rate recovery for those costs. We will consider the effect of these design parameters on rates, as we evaluate respondents' specific DSM program proposals. Accordingly, we retain the language in Rules 5 and 23 that requires utilities to provide information on the other SPM tests and, in particular, on the rate effects of DSM programs.

c. Avoided Cost Assumptions

As described above, Rules 7 and 8 require that, in applying the SPM tests of cost-effectiveness, parties use avoided supply costs (or "resource values") and nonprice factors that are consistent with the values adopted in our Update proceeding.

(1) Consistency with the Update

By ruling dated September 12, 1991, the assigned ALJ requested further comment on how to implement these principles. Supplemental comments were filed on October 21, 1991 by SCE, SDG&E, PG&E, SoCal, DRA, and Henwood Energy Services, Inc. (HESI). HESI's comments were filed on behalf of the Geothermal Resources Association and the Independent Energy Producers.

In their supplemental comments, parties offer a wide range of methods for using Update planning or modeling outputs to derive the long-run avoided costs required for the SPM tests. We agree with SDG&E and others that specific proposals for ensuring consistency should first be explored in workshops. We therefore direct CACD to conduct workshops for the purpose of (1) discussing the specifics, similarities, and differences of each party's proposal and (2) narrowing the issues for further Commission consideration in these proceedings.

In addition, as discussed in Section IV.F. below, parties should address the relationship between the DSM elements of our current resource planning framework and the subsequent funding of DSM programs.[34] These workshops should follow shortly after our issuance of a decision on deferrable resources in the resource plan phase of I.89-07-004. CACD's workshop report should be filed and served on all parties to this proceeding and the Update on or before November 1, 1992. As SoCal points out, the avoided cost of electric generation (developed in the Update proceeding) does not apply to a gas-only utility. We will continue to rely on approximations of long-run marginal gas costs as we await the outcome of implementation hearings in I.86-06-005.

(2) Transmission and Distribution (T&D) Costs

We agree with PG&E, CEC, and Transphase that avoided T&D costs should be accounted for in evaluating DSM cost-effectiveness, just as similar avoided costs should be considered in comparing supply-side options. However, this raises the fundamental issue of how to quantify the avoided (or increased) T&D costs associated with resource options. We do not explicitly include avoided transmission costs in our determination of avoided supply costs in the Update, because we do not yet have adequate information to assess the impact of QFs on the utility's transmission system.

However, as we describe in D.91-10-048, we are setting up a process whereby this type of information will be readily available. More specifically, utilities will compile and publish transmission information on a two-year cycle, as part of the ER/Update process. This information will include current and anticipated loads, line losses, transmission capacity considered to be available now and in the future, plans for upgrades, and estimated cost of upgrades. As stated in D.91-10-048, utilities

34 See also the next Section.

will be required to use the same projections, costs, analytical techniques, etc., in planning for their own supply-side resources.[35]

The use of consistent, published data is equally appropriate for DSM resource procurement. We expect utilities to use the published transmission information described above for the purpose of quantifying any avoided T&D costs associated with specific DSM programs. As part of the workshops on avoided cost consistency, parties should identify the types and sources of distribution cost data that will also be needed for this purpose. We will continue to define "resource value" as stated in Rule 8, until we have established a track record of incorporating T&D information into the Update process.

d. SPM Working Group

In developing the original and revised versions of the SPM, the staffs of the CPUC and CEC formed an informal working group that included most of the major utilities in California and other interested parties. In their comments, parties generally agree that the SPM working group is an appropriate forum for technical issues related to the SPM cost-effectiveness tests, such as the quantification of indirect costs. We would like to see the SPM working group continue, and encourage parties to use this forum for informally addressing these types of ongoing technical issues. We agree with SDG&E that the appropriate treatment of shareholder incentives in the Societal test should also be considered by the SPM working group. All future updates or modifications to the SPM, based on these ongoing meetings, should be filed in this docket and served on all parties.

35 See D.91-10-048, mimeo., pp. 9-10 and 32-35.

D. Shareholder Incentives

Shareholder incentives for utility DSM activities are addressed in Rules 14 through 19. Rule 14 states that the utility should be provided a "comparable" opportunity for earnings from prudent investments in both demand- and supply-side resources, and that shareholder incentives can help ensure this comparability.[36] Rule 15 acknowledges that CACD will be reviewing the experimental incentive mechanisms that were adopted in D.90-08-068 for the 1990-1992 period. Until the results of that study can be reviewed, Rule 15 proposes that a limited number of principles be adopted to govern future shareholder incentives. Rule 15 also states that we expect the shareholder incentive mechanisms to eventually converge toward a more uniform, statewide approach.

Rules 16 through 19 outline general principles for governing shareholder incentive mechanisms, pending CACD's report on shareholder incentives. These principles can be summarized as follows:

- Load building and load retention programs should not be eligible for shareholder incentives. Fuel substitution programs should also be ineligible until technical issues associated with assessing ratepayer benefits are resolved.[37] (Rule 16)

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36 Rule 14 also states that the introduction of balancing account treatment for electric sales and gas throughput has removed the disincentive for utilities to invest in DSM. In its comments, SoCal argues that disincentives due to gas throughput fluctuations still exist on the gas side, for both the core and noncore markets. We will explore this issue in a later phase of this proceeding, once CACD's overall evaluation of DSM incentives has been completed. In the meantime, we will acknowledge that disincentives may still exist on the gas side by modifying the language in Rule 14.

37 We discuss this Rule in Section IV.B. above.

- Any proposed shareholder incentive mechanism should include minimum performance requirements and accompanying penalty features. (Rule 17)

- Shareholder incentive mechanisms should be based on a shared-savings approach for programs whose savings can be reasonably estimated. (Rule 18)

- A mechanism should be established to limit the level of potential shareholder earnings from DSM, keeping in mind the "comparable earnings" guideline. (Rule 19)

In their comments, parties presented a wide range of views regarding Rules 15 through 19, both in terms of the general role of shareholder incentives, as well as the specific form of those incentives. We discuss these views, by issue, in the following sections.

1. The Role of Shareholder Incentives

TURN, DOD, and UCAN urge the Commission to await CACD's report, before concluding that shareholder incentives are necessary or appropriate on a permanent basis. In their view, CACD's review of the various shareholder incentive mechanisms should include an examination of the underlying assumption that shareholder incentives are required to stimulate DSM. In particular, UCAN suggests that CACD examine, among other things, the development of a private marketplace in energy efficiency, which may replace the need for incentives for those services.

Neither the Collaborative process nor our consideration of the incentive programs adopted in D.90-08-068 yields conclusions concerning the longer-term role of DSM shareholder incentives. As acknowledged in the Blueprint, Collaborative stakeholders were split on this issue.[38] Similarly, in adopting the settlement agreements on shareholders incentives, we stated only that we would "test the efficacy of such mechanisms on an experimental basis."[39] Because of the experimental nature of these procedures, we directed CACD to prepare and submit, by December 31, 1992, a report "on the effectiveness of the procedures we are adopting together with recommendations for improvements."[40] We therefore agree with TURN, DOD, and UCAN that CACD's evaluation should also consider the longer-term role of DSM shareholder incentives. This is consistent with our mandate under PU Code 746(d), which requires that the Commission report to the Legislature on "whether incentives are preferable to a regulatory scheme which mandates utility energy efficiency programs and load management programs that promote energy efficiency." We will then consider CACD's findings and recommendations in this proceeding. The language in Rule 14 is modified to clarify our intent to examine the longer-term role of shareholder incentives, after CACD's report is submitted.

2. Comparable Opportunity for Earnings

Parties' comments reflect divergent views on why and how to create "comparable opportunities for earnings" for demand- and supply-side investments. SoCal, for example, believes that comparability should be measured in terms of the risk of DSM to utility shareholders, relative to supply-side options. In SoCal's view, this risk is higher (justifying a higher return) because of the added risk of bypass and/or reduced business growth associated with DSM programs. Similarly, PG&E recommends that the relative

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38 See <u>Blueprint</u>, p. 9.

39 D.90-08-068, Finding of Fact 4 (37 CPUC 2d 346).

40 Ibid, Ordering Paragraph 1.h.

risk of demand- and supply-side alternatives should factor into a determination of comparable earnings.

NRDC and SCE apparently believe that resources that provide comparable net benefits should yield comparable earnings, but resource options that provide greater net benefits should yield a higher return to shareholders. More specifically, NRDC argues that shareholders' returns from DSM expenditures should be higher than those from supply-side resources, as long as DSM is more cost-effective (including environmental impacts). Similarly, SCE argues that shareholder incentives for DSM should do more than remove disincentives to DSM investment, because DSM provides environmental and customer service benefits in addition to resource benefits.

CMA, on the other hand, challenges the premise that earnings comparability is meaningful when different entities are making the investment. In CMA's view, a utility shareholder incentive is not really comparable to the supply-side returns on investment unless shareholder funds are risked.

Given the broad range of interpretation, there may be some uncertainty regarding what we mean by "comparable" opportunity for earnings, and we provide further guidance in this order.

First, we do not agree with NRDC and SCE that shareholder incentives should go beyond removing disincentives to least-cost resource procurement. NRDC's and SCE's view of comparability implicitly assumes that nonprice factors, such as environmental impacts, are not incorporated into the utilities' resource planning framework, and therefore an extra "reward" must be factored into the process to ensure that these relative net benefits are recognized.[41] While that may have been the case during the Collaborative process, we have made progress in explicity quantifying nonprice factors (e.g., air emissions) since the adoption of D.90-08-068, and intend to continue with these efforts in this OIR/OII, the Update and the Transmission OII. Moreover, our efforts in this proceeding to improve the integration of DSM and supply-side planning assumptions should also help ensure that the environmental benefits of DSM are explicitly recognized in cost-effectiveness testing. (See Section IV.C.2.c. above.)

In our view, the role of shareholder incentives is to offset any regulatory or financial biases against DSM (or in favor of supply-side resources) the utility might have in procuring least-cost resources.[42] This is the type of "parity" or "comparability" that the creation of DSM earnings incentives was designed to achieve. For example, we do not want to identify least-cost DSM programs in the planning process, and then have the utilities consistently underspend their DSM budgets in favor of investing in supply-side resources (where they earn a return). Nor do we want utilities to be motivated by higher returns to pursue DSM programs that, even when environmental benefits are considered, are more costly than certain supply-side options.

Until further consideration in these proceedings, we agree with SoCal and PG&E that relative risk should be a factor in

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41 We are not sure what "customer service" benefits SCE is referring to in its comments. As we discuss in Section IV.B. above, however, we will examine on a program-specific basis the appropriateness of using ratepayer expenditures on DSM to retain customers that would otherwise go out of business or locate in another service territory or state.

42 This does not ignore the fundamental issue of whether there are such biases and if so, whether DSM shareholder incentives are the most effective way to address them in the long run. We leave that for further consideration after CACD's report is completed.

determining what shareholders need to earn to offset those biases. However, CMA highlights a fundamental difference in risk that others appear to overlook. As we discussed in Section IV.A.3. above, shareholders do not invest funds in DSM, as they do in utility-constructed plants. Rather, investments in DSM are generally financed by ratepayers through rate increases (i.e., DSM program costs are expensed). Hence, shareholders do not incur the financial risk associated with tying up their funds in a particular investment. For utility-constructed supply-side resources, we establish a rate of return that will, among other things, compensate investors for this risk. In other words, one of the primary considerations in establishing the rate of return is the "opportunity cost" of investors, e.g., what rate of return could they make in investing in other stocks or bonds of comparable risk.

For DSM, on the other hand, utility shareholders generally do not incur any investment opportunity costs for which they need compensation in the form of a rate of return that is comparable to other investments of similar risk. Instead, the utility is managing ratepayer funds, in return for a share of the ratepayer yield or earnings, which come in the form of lower resource costs. It is therefore inappropriate to assume that one should compare the relative risks of DSM and supply-side resources as if shareholders were investing in both equally, and equally incurring the financial risk. Instead, one should ask the question: 'What level of management fees for DSM programs would be comparable to shareholders' earnings on supply-side investments, given the relative risks of each?" Phrasing the comparability issue in this way clearly highlights the "apples and oranges" aspect of considering the relative risks of DSM and supply-side resources to shareholders.

SoCal argues that there are certain aspects of DSM programs that pose higher risks to shareholders than supply-side options. That may be true, particularly for gas utilities, where our balancing account treatment may not have completely eliminated the impact of DSM on the utility's recovery of fixed costs. However, we find it difficult to believe that those increases in risk would more than offset the decrease in financial risk associated with DSM programs, as described above. In other words, we are not convinced that, on balance, to pursue cost-effective DSM shareholders require management fees that are effectively higher than their required rate of return on invested funds. Moreover, we note that many supply-side options are being pursued without any shareholder investment or associated earnings opportunites, e.g., contracts with nonaffiliated QFs and inter-utility power purchase agreements. In comparison to these resource options, DSM could look attractive to shareholders even with a relatively low return.

The above discussion on relative risk is not intended to be a definitive discourse on the subject. We expect to revisit this issue in depth at a later date, after CACD's report has been completed. However, we do use the above observations to provide interim guidance on the issue of relative risk and comparable earnings potential. On balance, in view of the factors described above, we conclude that shareholders' rate of return on DSM programs should be <u>no greater</u> than shareholders' rate of return on utility-constructed plants facing traditional ratemaking. This policy should be applied to current shareholder incentive mechanisms, as follows:

- For incentive mechanisms based on program expenditures, such as SoCal Gas' current variable rate of return mechanism, the earnings rate on program costs should not exceed (and could be lower than) the authorized rate of return on utility constructed plants;

- For shared-savings mechanisms using an "S-curve" function, such as the mechanism adopted for SCE in its recent GRC, the incentive payment target should be calculated using forecasted utility expenses at 100% of forecasted net savings, times a rate that is no higher (and could be lower) than the authorized rate of return on utility constructed plants;[43]

o For "flat rate" shared-savings mechanisms, such as the ones adopted for SDG&E and PG&E in D.90-08-068, the shared-savings rate should not exceed (and could be lower than) the authorized rate of return on utility constructed plants.

We recognize that the application of a comparable earnings policy to specific shared-savings mechanisms is a complex process. Therefore, we stress that our directives today on comparable earnings will serve as an interim policy, until we have further opportunity to examine the role of incentives in general, and the issue of relative risk in particular, in a later phase of this proceeding.

In D.91-12-076, we based SCE's incentive payment target on SCE's authorized rate of return. Therefore, SCE's current incentive mechanism is in compliance with the above policy, and no further filings are necessary. However, SDG&E and PG&E should file revised testimony in their test year 1993 GRCs, in conformance with the directives in today's order. We will establish the specific shared savings rates for SDG&E's and PG&E's shared-savings mechanisms in those proceedings, consistent with the policy established above.

SoCal Gas' experimental shareholder incentive mechanism, as adopted in D.90-08-068, will expire at the end of 1992. Because

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43 The incentive payment target represents the level of shareholder earnings at 100% of forecasted net benefits. It is used to help define the S-curve shared savings function, i.e., determine the "height" of the function. (See D.91-12-076, pp. 160-161, Appendix G.)

of the recent changes in the rate case plan, SoCal's next GRC is for test year 1994. That leaves a procedural gap for incorporating today's directives into SoCal Gas' shared-savings mechanism. We invite interested parties to develop procedural proposals for incorporating today's directives into SoCal Gas' shared-savings mechanisms. Parties should present their proposals to the assigned ALJ for consideration at the M&E phase prehearing conference.

3. Convergence to a Uniform Approach

Several parties urge us to await CACD's report before concluding that statewide uniformity in incentive mechanisms is needed. In particular, SoCal argues that it should not be required to shift to a shared-savings mechanism for its resource programs. Under a shared-savings approach, shareholder earnings are calculated as a percentage of the net resource benefits of DSM programs. In SoCal's view, its current incentive program, which is not based on shared savings, is better suited to a gas-only utility, and accomplishes the Commission's stated goals with regard to cream skimming and lost opportunities.[44]

In D.90-08-068, we accepted the degree of diversity in the experimental incentive programs because we expected to learn some valuable lessons from such diversity. However, we clearly stated our expectation that "in the long run as we apply those lessons we expect to see the convergence of much of this variety

44 For its resource programs, SoCal has in place what it terms a variable rate of return incentive. Under this incentive structure, SoCal would earn 14% of the program cost, provided that actual program cost does not exceed planned program cost, and the planned number of units are installed. SoCal will break even for each program if the program reaches 70% to 80% of planned goals, and for every dollar that program costs exceed planned costs, the shareholder incentive is reduced by a dollar. In addition, SoCal would receive 14% of the planned unit variable cost for every unit installed over the program planned goal.

into a uniform, proven DSM energy efficiency program.[45] This does not mean that the incentive structure will be identical across utilities. For example, it may make sense to establish different comparability standards for DSM earnings, when utilities have different rates of return. Or, the absolute level of target savings for each utility may vary, depending on the nature and combination of each utility's cost-effective programs. Clearly the value of energy efficiency savings (which factors into the calculation of shared savings) also differs among utility systems.

On the other hand, there are certain aspects of any shared-savings mechanism that should, in our view, become uniform in the longer run. In particular, the method of calculating net resource benefits (to which the earnings percentage is applied) should be consistent across utilities. Similarly, the relationship between achieved savings and shareholder incentive payments should become consistent across utilities (e.g., the use of deadbands, performance minimums, penalty rates, etc). To date, there are significant differences in these aspects of the shared-savings mechanisms for PG&E, SDG&E, and SCE.[46] We expect to fully explore the pros and cons of various approaches to shared savings during our consideration of CACD's findings. Similarly, we will examine the various cost-plus mechanisms in place for DSM programs where

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45 D.90-08-068 (37 CPUC 2d 346, 366).

46 As adopted in D.90-08-068, SCE's incentive mechanism was based on an amortization approach where certain DSM program costs were amortized in rates over a five-year period, with the unamortized balance allowed to earn at SCE's authorized rate of return. In SCE's test year 1992 general rate case, however, SCE stipulated to continuing its shareholder incentive program under a shared-savings mechanism. By D.91-12-076, we adopted a shared-savings mechanism for SCE that took the form of an "S-curve" function, rather than the "flat-curve" (fixed percentage) approach adopted in D.90-08-068 for PG&E and SDG&E.

the link between programs and savings is less clear, such as direct assistance programs and energy management services. Finally, we will consider the appropriateness of the various experimental incentive approaches in place for New Construction Programs.[47]

With our recent adoption of a shared-savings approach for SCE, SoCal is now the only utility with an incentive mechanism for DSM resource programs that links shareholder earnings directly to DSM program expenditures, rather than energy savings. SoCal apparently interprets Rule 18 to mean that SoCal is required to implement a shared-savings approach at this time. This is not our intent. As SoCal points out, and we acknowledge, the lack of gas long-run marginal costs makes it difficult to estimate the current value of energy savings on SoCal's system. Rule 18 explicitly states that a shared savings approach is appropriate for programs "whose savings can be reasonably estimated." In view of the fact that gas marginal costs will not be adopted until late 1992, we will defer the issue of shared savings for SoCal until that time. This will also enable SoCal to complete its experimental program, which was authorized in D.90-08-068 to continue through 1992.

With regard to SoCal's preference for its experimental program, we note that CACD has been directed to conduct a comparative analysis of all the incentive experiments in its 1992 report. We will revisit the issue of SoCal's incentive mechanism when CACD's report is completed. As we have stated in Rule 18, we must also await the adoption of gas marginal costs in I.86-06-005 before applying shared savings to SoCal's programs. In the

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47 Appendix B of D.90-08-068 presents a full comparison of the experimental incentive mechanisms adopted through 1991 for SCE and SDG&E, and through 1992 for PG&E and SoCal. A description of SCE's recently approved shared-savings mechanism can be found in D.91-12-076.

meantime, we adopt the guiding principle articulated in Rule 18 for all utility DSM programs whose savings can be reasonably estimated.

4. Performance Minimums and Penalties

Rule 17 echos the language of PU Code § 746(a), which states that our DSM incentives program shall:

> "...require utilities to achieve reasonable minimum performance requirements as a condition for receiving incentive benefits, and shall hold utilities accountable for not achieving reasonable minimum performance requirements through loss of incentive benefits and the imposition of penalties."

We will examine ways to implement this directive, on a consistent basis across all utilities, in a later phase of this proceeding.

5. Earnings Limits/Caps

In their comments, parties strongly disagree over the issue of whether or not to impose earnings limits or caps on shareholder earnings. On the one hand, DRA, TURN, and DOD support some form of limitation to the earnings potential of shareholders under a shared-savings incentive mechanism. DRA argues that such limits are necessary to protect ratepayers from overlooked deficiencies in the mechanism, as well as from utility "gaming" in its savings forecasts. DRA recommends a cap in the form of absolute dollar earnings and spending limits. For similar reasons, TURN recommends that the current budget cap that limits shareholders' earnings potential (e.g., PG&E's 130% limit) be retained. DOD would go even further, and require a convincing demonstration of DSM savings before any additional shareholder incentives were approved.

PG&E, SCE, SDG&E, NRDC, and CEC strongly oppose imposing any further earning caps or limits on shareholder earnings. PG&E argues that earnings potential is already effectively limited by the size of the program and the adopted savings estimates. These parties suggest that the appropriate response to reducing the risks associated with prespecified savings is to improve the quality of measurement and evaluation. NRDC and others also argue that earnings caps promote cream skimming, unless the ceiling is set well above established goals.

We agree with CEC and others that the ratepayer risks associated with prespecified savings should be reduced at the source, and not by limiting earnings at the end of the process. As described in Section IV.A. above, we intend to do just that by requiring post-implementation verification of savings for all shared-savings mechanisms. This should address the primary concern that motivated us to propose Rule 19. Having now established a schedule to move to ex post measurement, we believe it is appropppriate not to require a mechanism to restrict shareholder earnings over and above the indirect limitation imposed by funding authorizations.

E. Cream Skimming/Lost Opportunities

Rules 2 and 3 address the issue of cream skimming, along with its corollary, lost opportunities. As defined by the Collaborative, cream skimming results in the pursuit of only the lowest cost energy efficiency and load management measures, leaving behind other cost-effective opportunities. Rule 2 directs utilities to place "special emphasis" on lost opportunities, that is, energy efficiency options that offer long-lived cost-effective savings and which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. Rule 3 asks for comments on whether cream skimming continues to be a concern and, if so, how to minimize potential cream skimming and lost opportunities.

1. Position of the Parties

In their comments, parties present differing views on what constitutes cream skimming. PG&E, SCE, and others stress that pursuing less cost-effective or less expensive measures first is not necessarily cream skimming. According to PG&E, cream skimming occurs only if the cost of these additional measures would increase by deferring them. Similarly, SCE argues that cream skimming occurs only if those less cost-effective measures become "lost opportunities." CEC questions whether lost opportunities really occur if the customer would not have been motivated (because of longer pay-back) to purchase them in the first place. DRA and CLECA, on the other hand, believe that cream skimming raises distributional equity issues as well as the lost opportunities concern raised in the OIR/OII.

There is also little consensus on a solution to cream skimming. PG&E, SoCal, and others suggest that cream skimming can be minimized by providing utilities with flexibility to shift funding between programs and sufficient funding levels over the long term.[48] DRA, on the other hand, recommends that "excessive" shifting of funds between programs be prohibited. SDG&E and others argue that cream skimming can be minimized by establishing annual minimum performance requirements for each major sector or program. NAESCO, SYCOM, and Transphase believe that adopting competitive bidding will prevent cream skimming. Other parties (e.g., NRDC and DGS) recommend that utilities provide detailed reports on how their programs are designed to minimize cream skimming and capture lost opportunities.

2. Discussion

We agree with PG&E and others that the pursuit of the most cost-effective measures first does not, per se, constitute

48 SoCal also argues that the problem of cream skimming can be mitigated by abandoning the shared-savings mechanism in favor of its variable rate of return approach. As we discuss in Section IV.D.3. above, we will await CACD's report on shareholder incentives, before passing final judgment on SoCal's experimental program.

cream skimming. As several commenters point out, this approach becomes a problem when lost opportunities are created in the process. With regard to equity and distributional issues, we prefer to address those concerns by funding programs designed to provide low-income assistance, e.g., our Direct Assistance Programs. For DSM resource programs, we see no reason to constrain a utility from first pursuing the most cost-effective program in one sector (over a less cost-effective program in a another sector), if doing so does not create lost opportunities in either sector. Constraints of that nature would inappropriately reduce the potential net resource benefits that all ratepayers realize from cost-effective DSM.

As noted above, parties recommend several different approaches for minimizing the cream skimming/lost opportunties problem described in our Rules. Rule 17 already requires utilities to achieve minimum performance requirements as a condition for receiving incentive benefits, and to focus those requirements on potential lost opportunities. We will also require, as stated in Rule 2, that utilities provide a detailed account of strategies to avoid creating lost opportunities. We may consider additional methods for minimizing lost opportunities at a future date. For now, these two approaches should provide a reasonable level of protection against potential harm from cream skimming.

In their comments, SDG&E and others ask for further guidance on how to reconcile our cost-effectiveness criteria with the objective of capturing lost opportunities. As a general rule, the objective of minimizing lost opportunities should not be elevated above our primary cost-effectiveness criteria for DSM, namely, passing the TRC test. Instead, capturing lost opportunities should serve as an additional ranking criterion for programs with TRC benefit-cost ratios greater than 1.0--e.g., as a rationale for prefering a program with a TRC benefit-cost ratio of 1.2 over a program with a ratio of 1.6. Several parties suggest that certain types of programs designed to capture lost opportunities (e.g., New Construction Programs) should be exempt from the TRC criteria. We will explore this issue further, after parties have completed the workshops directed in Section IV.B. above.

F. <u>Regulatory Forum/Consistency Issues</u>

Rule 25 identifies the need to improve consistency with which DSM programs are treated across utilities and across regulatory forums. Rule 25 also asks for comments on a proposal to establish a single forum in which utility DSM activities would be reviewed, approved, and funded every two years.

We received a wide range of comments on procedural options for addressing consistency issues. The suggestions include:

1. Initiate a consolidated biennial proceeding for reviewing and funding utility DSM programs, as proposed in the OIR/OII.

2. Use the OIR/OII to resolve general policy and methodology issues, but keep DSM funding, program implementation and incentive levels in GRC and fuel offset proceedings.

3. Remove DSM issues from the GRCs and fuel offset proceedings. Initiate annual proceedings for each utility to review the previous year's program results and shareholder incentives. Applications would be filed in May, with a Commission decision in December.

4. Keep DSM funding issues in the GRCs and fuel offset proceedings, but initiate a separate consolidated proceeding to address savings measurement and verification for all utilities, on an annual basis.

5. Keep DSM funding issues in the GRCs and fuel offset proceedings, but develop a tighter link between our resource planning determinations in the Update and subsequent authorizations to acquire DSM resources.

We originally proposed a single forum for all DSM issues because, in our experience, DSM program evaluation and funding raise as many generic policy and methodological issues as utility-specific considerations. Until the issuance of this OIR/OII, all DSM-related issues were considered in different utility-specific proceedings, such as the GRC and fuel offset proceedings. As a result, many of the generic issues were litigated over and over again in utility-specific proceedings, making it difficult for us to establish clear, consistent policy on DSM funding priorities, evaluation methods and other generic issues.

Consistency on DSM policy and methodology is particularly important today, as we embark on a new generation of DSM programs and work towards the effective integration of DSM into our resource procurement framework. Under this integrated framework, least-cost planning criteria will need to be consistent across utilities and resource options. Similarly, we will need to apply consistent methods for evaluating DSM program expenditures and for measuring DSM savings. Moreover, workable competition in resource acquisition requires clear and consistent "rules of the game" for all participants.

The use of consolidated, generic proceedings for establishing consistency is by no means new at the Commission. Over the last decade, we have removed and consolidated several areas of utility activities that were previously considered in utility-specific proceedings, including the cost of capital and electric and gas long-run marginal costs. As indicated above, all parties acknowledge the advantages of a consolidated proceeding to address at least some of the major DSM issues.

As we described in Section IV.A., we will address DSM savings measurement and evaluation issues across all utilities in a separate M&E phase of this OIR/OII. The results of this phase should feed directly into subsequent cost-effectiveness evaluations of DSM for all utilities. Moreover, the M&E phase will serve as a consolidated forum for examining the results of post-installation measurement across all utilities, forming the basis for incentive payments. In addition, by initiating this OIR/OII, we have created a consolidated forum for addressing other DSM policy and methodological issues. These changes should significantly improve the consistency with which DSM programs, including shareholder incentives, are evaluated and funded, and remove many of the contentious issues that are currently litigated in GRCs and fuel offset proceedings (e.g., verification of savings estimates, cost-effectiveness testing procedures, funding priorities).

Ultimately, we believe that it may make more sense to address all DSM procurement issues in a consolidated forum, perhaps in conjunction with our Update proceeding. However, we recognize that our ratemaking procedures may change as a result of our generic gas and electric ratemaking proceeding (R.90-02-008/ I.90-08-006). Therefore, we will await the outcome of that proceeding before considering any further consolidation of GRC or fuel offset activities. In the meantime, we will improve consistency by addressing generic policy and methodological issues in this OIR/OII, and by initiating an M&E phase as quickly as possible. We expect our determinations in this OIR/OII to be used in any subsequent utility-specific proceedings. We also intend to keep the GRCs and fuel offset proceedings free from litigation over issues that are more properly reserved for this OIR/OII. Accordingly, pursuant to the order which follows, SDG&E and PG&E should revise their test year 1993 proposals for DSM funding to conform to these adopted policies and directives.

We agree with DRA and others that the issue of consistency between resource planning determinations and DSM funding authorizations also needs to be addressed. On November 18, 1991, DRA filed supplemental comments on how to 1) assess utility forecasts of long-term DSM program costs and impacts in our current resource planning framework and 2) link those forecasts to DSM program funding. Now that we have articulated our goals, funding priorities, and evaluation criteria for various types of DSM programs, those policies should carry over into the consideration of uncommitted DSM in our Update planning framework. We direct parties to address DRA's proposal as part of the workshops on avoided cost consistency issues. (See Section IV.C.1.c.)

G. DSM Bidding

Rule 26 states that integrated bidding offers great potential for achieving our goal of reliable, least-cost, environmentally sensitive energy service.[49] Rule 27 directs the utilities to develop and implement several DSM pilot bids, consistent with PU Code § 747, and Rule 28 establishes four general guidelines for bid design. Rule 29 states that each of the pilots will be addressed in this OIR/OII.

Several parties question the policy principle stated in Rule 26. In their view, the effectiveness of integrated bidding has not yet been established. We agree, and modify the language of Rule 26 to refer to DSM bidding in general, without prejudging the appropriate form of bidding. We also agree with SDG&E that PU Code § 747 does not specifically require a "replacement bid," (i.e., a bid for DSM services to replace current or planned utility DSM programs) but we would like to see one developed in the pilot bids. As we state in Section III, we have introduced competition into the supply acquisition process to put downward pressure on utility resource costs. A replacement bid fulfills this objective for DSM

49 Rule 26 actually uses the term "all source" bidding. However, as we discuss in Section III above, we will use the term "all source" to describe supply-side bid where all types of NUGS, not just QFs' can compete. We use the term "integrated bidding" to refer to a bidding process in which providers of DSM services and NUGs compete to meet utility supply- and demand-side resource needs.

resources. We modify Rule 27 to distinguish between our own directives and the requirements of PU Code § 747.[50]

PU Code § 747(c) also directs the Commission, in consultation with the CEC, to report the results of the pilot bid projects to the Legislature by January 1, 1993. In order to facilitate this process, we direct CACD to appoint a Project Coordinator to manage the evaluation. This evaluation may be performed by an independent consultant who will be selected by the Commission in consultation with the CEC. The Project Coordinator should approve the request for proposals/bid package, bidder list, contractor selection criteria, contractor selection and contract document.

Funding for the evaluation will be provided by the subject utilities. It is our intent to allow the utilities to recover in rates the costs of the evaluation, similar to the treatment of costs associated with management audits. The costs of the evaluation should be allocated according to the average of each utility's percentage of total authorized DSM expenditures for the years 1990, 1991 and 1992. One utility may be designated contract administrator, to assist with billing and payment details.

The Project Coordinator should both direct consultant efforts and approve consultant invoices for payment. It is important that the utilities participate in the evaluations in a spirit of cooperation. Consultant personnel should be afforded the same access to company documents and personnel that the Commission

50 We do not agree with SDG&E, however, in its interpretation of PU Code § 747 regarding integrated bidding. Contrary to SDG&E's assertion, we do not believe that a study of integrated bids outside of California meets the code requirements. Rather, we expect at least one California utility to conduct its own integrated bidding pilot, which we will evaluate in consultation with the CEC.

staff would have. These proceedings will remain open to consider the evaluation report and its recommendations.

With regard to our guidelines in Rule 29, several parties commented that bid pilots should be eligible for shareholder incentives. Since the appropriateness of shareholder incentives may depend on the specific form or design of the bid, we will address that issue as we review specific pilot bid proposals. The longer-term issue of what bidding forms and features are most compatible with our resource procurement policies will be addressed in a later phase of these proceedings, after CACD's report is submitted.

H. <u>Advisory Committees</u>

Rule 24 encourages respondents to continue the Advisory Committees established as part of the settlement agreements on shareholder incentives. (See Section II.B., above.) In their comments, several parties presented their views on the expected role of Advisory Committees and on how the Committees could function more smoothly and effectively.

We agree with PG&E and others that the primary purpose of Advisory Committees is to provide utilities with informal advisory input on program design issues. However, as we stated in the Order Instituting this Rulemaking, "...the Advisory Committees do not dilute the utility's responsibility to develop a wide range of cost-effective DSM programs, nor do they supercede the Commission's role in approving and overseeing programs".[51]

To improve the effectiveness of Advisory Committee activities, we will require the four major energy utilities to establish a single clearinghouse for all Advisory Committee noticing and scheduling. The utilities should identify a single contact person or office that coordinates the various Advisory

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51 OIR/OII, August 7, 1991, p. 37.

Committee activities. As DGS suggests, the utilities should avoid, whenever possible, concurrent Advisory Committee meetings. We expect the utilities, via this clearinghouse, to provide appropriate notice of all meetings, complete with advance agendas. The utilities can decide among themselves how to provide these services (e.g., nominate one utility to coordinate, rotate responsibilities every year, etc.). Within 90 days from the effective date of this order, respondents should file a joint report with the Commission's Docket Office, describing the clearinghouse procedures established in compliance with today's order. Copies of the report shall be served on all parties to these proceedings.

V. What Comes Next

The Rules proposed in our OIR/OII address a broad range of DSM policy and implementation issues. In providing clarifications and making certain modifications to those Rules, we attempt today to bring closure to some of the major areas of controversy. Nonetheless, as described throughout this order, there are certain issues that require further exploration prior to our final consideration. Our expectations of "what comes next" are summarized below.

A. The M&E Phase

In Section IV.A.2, we establish a separate phase in these proceedings to review M&E activities across the four major energy utilities. As we describe in this order, this M&E phase will be the forum for establishing the M&E protocols for verifying, via post-installation measurement, the basis for shared-savings incentive calculations. We intend to shift to ex post verification for all shared-savings programs authorized as of January 1, 1994. Therefore, the M&E phase should move forward as expeditiously as possible.

To this end, we have directed respondents and interested parties to file and serve comments regarding the type of information that needs to be submitted in the M&E phase, along with scheduling recommendations. Following these filings, which are due within 30 days from the effective date of this order, the assigned ALJ will conduct a PHC to address scheduling and other procedural issues.

B. <u>CACD Workshops</u>

As described in this order, CACD will conduct two sets of workshops on unresolved issues related to our Rules. (See Sections IV.B.2 and IV.C.2.c.) The first set will address parties' recommendations on modifying the terms and definitions presented in the Appendix to our adopted Rules, and consider cost-effectiveness criteria for Fuel Substitution Programs and New Construction Programs. CACD will file and serve its report on these workshops within 120 days of the effective date of this order.

The second set of workshops will address DSM/Update consistency issues. These workshops will examine parties' recommendations on how to use the Update planning or modeling outputs consistently for the <u>SPM</u> tests of cost-effectiveness. As part of these workshops, parties should also identify the types and sources of distribution cost data that will need to be published, as part of the process for identifying the T&D impacts of all resource options. Finally, these workshops will also consider recommendations, such as DRA's, on how to 1) assess utility forecasts of long-term DSM program costs and impacts under our current resource planning framework and 2) link those forecasts to DSM program funding. CACD's report on this set of workshops is due on or before November 1, 1992.

CACD's reports should describe each recommendation or option and present the pros and cons of each, as identified in the workshop process. CACD's draft reports should first be circulated to workshop participants for their comments before final submission. We intend to issue CACD's final workshop reports for a further round of comments, before addressing these issues in our Rules. We strongly encourage parties to use these workshops as a forum for narrowing the issues and, hopefully, finding some common ground.

C. <u>Later Phases of These Proceedings</u>

CACD's report on the effectiveness of shareholder incentives, due by December 31, 1992, will serve as the starting point for our consideration of the next generation of DSM programs. In a later phase of this proceeding, once CACD's report has been completed and filed, we will examine the longer term role of shareholder incentives, as well as the specifics of various incentive mechanisms. As we state in Section IV.D.3, if we continue shareholder incentives for DSM in the long run, we expect to develop uniformity across utilities on many aspects of the programs. We will also revisit the issue of comparable earnings and earnings limits/caps after CACD's report has been submitted.

We've identified two additional issues that will require further consideration in later phases of these proceedings. As we state in Section IV.B., we will establish more specific guidelines for evaluating and funding load building and load retention programs, in particular, economic development activities. We will also examine alternatives for implementing performance minimums and penalty features, on a consistent basis across all utilities, in compliance with PU Code §746(a). (See Section IV.D.4.) We leave it to the assigned ALJ to establish a schedule for considering these issues, after the M&E phase has been completed.

Findings of Fact

1. On July 20, 1989, the Commission convened an en banc hearing to reexamine the role of DSM in utility resource procurement.

2. Following the July 20, 1989 en banc hearing, a California Collaborative working group developed a blueprint for the revitalization of DSM activity in California.

3. In response to the Collaborative's Blueprint, respondents filed applications requesting authorization for expanded DSM programs and shareholder incentive mechanisms.

4. Parties to the proceeding entered into settlement agreements, and in D.90-08-068 and D.90-12-071 we approved, with some modifications, the terms of the respective settlements.

5. The shareholder incentive programs adopted in D.90-08-068 and D.90-12-071 were experimental, and were authorized through 1991 for SCE and SDG&E and through 1992 for PG&E and SoCal.

6. Pursuant to the settlement agreements, each utility convened Advisory Committees to assist them in the implementation of the approved DSM programs.

7. In approving the shareholder incentive programs, we identified the need for a rulemaking proceeding, in which we could compare the different DSM models, evaluate the longer-term role of shareholder incentives, and develop statewide standards and benchmarks for measuring energy efficiency.

8. In D.90-08-068, we directed CACD to submit a report, by December 31, 1992, on the effectiveness of the adopted incentive mechanisms.

9. On August 7, 1991, we initiated this Rulemaking and companion Investigation, by proposing rules governing the evaluation, funding, and implementation of DSM programs and associated shareholder incentives.

10. The comments of Kenetech on our proposed rules were not timely filed. The consensus recommendations from SCE, PG&E, SDG&E,

SoCal, DRA, CEC, CLECA, DGS, NAESCO, and NRDC, as presented in a December 10, 1991 letter to the assigned ALJ, were also not timely filed.

11. As stated in our proposed rules, the Commission's overall objective for utility resource procurement is reliable, least-cost, environmentally sensitive energy service.

12. Utility resource procurement involves both planning and acquisition. Resource planning determines whether or not the utility needs to acquire new resources, in order to maintain reliability and/or to improve the efficiency of the utility system. Resource acquisition determines how the utility will acquire the new resources that are needed, as identified in the planning process.

13. We are committed to head-to-head comparison of DSM and supply options in the planning process, including the consideration of relative environmental impacts.

14. Under the current resource planning process, the utility's need for resource additions is first reduced by implementing all potential cost-effective DSM, as identified using the Standard Practice Manual tests of cost-effectiveness. Any remaining need for resource additions is identified through a least-cost planning process, which compares supply-side options using the Iterative Cost Effectiveness Method.

15. The differing methods for evaluating DSM and supply-side resources limit our efforts to directly compare resource options and optimize the utility system.

16. Competitive bidding enables utilities and third parties to compete in the resource acquisition process, for the purpose of putting downward pressure on the costs of energy services.

17. On the supply side, our competitive bidding process puts downward pressure on utility resource costs.

18. PU Code $ 747 requires the testing and evaluation of utility DSM bidding pilots, including integrated bidding.

19. DSM shareholder incentive programs have recently been extended, on an interim basis, for SCE (in its general rate case) and SDG&E (in its modified attrition), pending the outcome of this Rulemaking.

20. In their filed comments, parties raise concerns about M&E-related issues in response to all aspects of our proposed rules.

21. In order to directly compare all resource options, we must be confident that forecasts of DSM savings are reliable in meeting energy needs.

22. DSM funding commitments and shareholder incentive calculations are currently based on prespecified savings estimates.

23. We currently lack an identified regulatory forum for evaluating M&E protocols, reviewing the results of M&E activities, and considering methods for incorporating M&E results into the next generation of DSM programs and forecasted savings.

24. Basing shareholder incentives on ex post measurement results would de-link the forecasting process from monetary returns, thereby making the process more objective.

25. Under the shareholder incentive mechanisms currently in place, utility ratepayers, not shareholders, finance DSM through rate increases.

26. Shareholders do not receive a return on investment under a shared-savings incentive mechanism. Rather, in exchange for managing their funds, ratepayers give shareholders a percentage of their investment earnings (in the form of DSM savings).

27. ESCO payments are typically based on ex post measurement of delivered savings, not on prespecified estimates.

28. Shifting to ex post verification of DSM savings requires a transition period, to allow for the initial learning curve process in addressing measurement and evaluation issues.

29. Our proposed rules and recent orders direct utilities to focus DSM activities on programs that serve as viable alternatives to supply-side resource options.

30. DSM programs that retain or incrementally increase customer and system load do not avoid or defer the cost of supply-side options.

31. Fuel substitution programs can be designed to predominately retain load, build load, or both.

32. In D.88-03-008, as modified by D.88-07-058, we authorized load retention programs designed to avoid uneconomic bypass of the utility system.

33. Uneconomic bypass results when a customer chooses to generate its own power or use an alternative fuel supply at a cost that is less than its average rates, but greater than the utility's marginal costs.

34. Assembly Bill 2054, which adds § 740.4 to the PU Code, expands the concept of load retention to include economic development programs, to the extent that ratepayers benefit from those programs.

35. Providing shareholder incentives for load retention or load-building program provides shareholders with the opportunity to earn twice--first with the implementation of load retention or load building programs, and second, with the utility investment in supply-side resources that remain undeferred or unavoided.

36. In their comments, parties proposed modifications/ clarifications to the DSM program terms and definitions contained our proposed rules.

37. Establishing a single clearinghouse for all Advisory Committee noticing and scheduling would improve the effectiveness of the Advisory Committee.

38. In evaluating supply-side resources, we compare the total resource cost of the supply option with resource benefits, including environmental impacts.

39. In evaluating DSM programs, we use the Standard Practice Manual tests of cost-effectiveness, developed jointly by the staffs of this Commission and CEC.

40. The Standard Practice Manual presents methods for evaluating DSM programs using four tests of cost-effectiveness: the participant cost test, the utility cost test, the total resource cost test, and the rate impact measure.

41. The participant cost test measures the benefits and costs of a DSM program to a participating customer.

42. The total resource cost test compares the total resource cost of DSM, including participant's costs, with resource benefits.

43. The societal cost test is a variation of the total resource cost test, which looks at costs and benefits from the perspective of society, not just the utility and its ratepayers. This variation includes the impact of externalities on costs and benefits, and treats tax credits and interest payments as transfers.

44. The utility cost test compares the utility's cost of DSM, excluding participant's cost, with resource benefits.

45. The UC and RIM tests look at only a portion of the total costs of DSM programs, i.e., the portion reflected in utility revenue requirements.

46. The UC and RIM tests do not identify least cost resource options, from an economic efficiency perspective.

47. The rate impact measure test compares DSM programs on the basis of their relative rate impacts.

48. The results of the RIM test are affected by the ratemaking treatment for DSM programs, i.e., the way in which program costs are recovered in rates.

49. Reliance on the rate impact measure for program ranking and funding would tend to promote DSM programs that increase or retain electric and gas sales.

50. The total resource cost test, when modified to include nonprice factors such as environmental externalities, is the most consistent with our resource procurement policies and least-cost planning principles.

51. The usefulness of the total resource cost test as a primary indicator of cost-effectiveness is limited for direct assistance programs, which address equity concerns, and for information programs and energy management services, where the link between programs and savings is difficult to discern.

52. Quantification of the indirect costs of DSM and determining the appropriate treatment of shareholder incentives in the societal test are technical aspects of the Standard Practice Manual.

53. In their comments, several parties raised issues concerning the appropriate cost-effectiveness criteria to be used in evaluating New Construction Programs and Fuel Substitution Programs.

54. Electric utility long-run avoided or marginal costs, including nonprice factors such as environmental externalities, are developed in our Biennial Resource Plan Update Proceeding (I.89-07-004).

55. On October 21, 1991, parties filed supplemental comments on how to use Update planning or modeling outputs to derive the long-run avoided costs required for the Standard Practice Manual tests of cost-effectiveness.

56. Long-run avoided or marginal costs for natural gas are currently being developed in I.86-06-005.

57. The lack of natural gas long-run marginal costs makes it difficult to estimate the current value of energy savings on SoCal's system.

58. As we describe in D.91-10-048 in I.90-09-050, electric utilities will compile and publish transmission information on a two-year cycle, as part of the Electricity Report/Update process.

59. The Standard Practice Manual working group, which is convened by the staffs of this Commission and CEC, informally addresses ongoing technical issues related to the Standard Practice Manual tests of cost-effectiveness.

60. Neither the Collaborative process nor our consideration of the experimental incentive programs yields conclusion concerning the longer-term role of DSM shareholder incentives.

61. Quantification of nonprice factors is our preferred means of ensuring that the relative net benefits of resource options are recognized in utility resource planning.

62. The DSM shareholder incentives adopted in D.90-08-068 were designed to offset any regulatory or financial biases against DSM (or in favor of supply-side resources) the utility might have in procuring least-cost resources.

63. With utility supply-side investments, the shareholder is putting up equity in return for an expected yield that is comparable to investments in other stocks or bonds of comparable risk. In contrast, with utility DSM programs, the utility is managing ratepayer funds in return for a share of the ratepayer yield or earnings.

64. Utilities currently pursue many supply-side options without any shareholder investment or associated earnings opportunities, such as contracts with unaffiliated QFs and interutility power purchase agreements.

65. DSM programs may cause some increased risks to the shareholders of gas utilities, relative to supply-side options, because our balancing account treatment may not have completely eliminated the impact of DSM on the utility's recovery of fixed costs.

66. On balance, it does not appear that shareholders require fees for managing ratepayers' investment in DSM that are effectively higher than the required rate of return on shareholders' invested funds.

67. In D.91-12-076, we adopted an "S-curve" function for SCE's shared-savings mechanism, where shareholder earnings at 100% of forecasted net benefits (i.e., the incentive payment target) were set at forecasted utility expenses on eligible programs times SCE's pre-tax rate of return.

68. There appears to be a procedural gap for incorporating today's policy directives into SoCal's incentive program, since SoCal's next general rate case is not until 1994.

69. In D.90-08-068, we adopted a diverse set of pilot shareholder incentive programs, with the expectation that much of this variety would converge into a uniform approach in the long run.

70. SoCal is currently the only utility with an incentive mechanism for DSM resource programs that links shareholder earnings directly to DSM program expenditures, rather than energy savings.

71. The lack of gas long-run marginal costs makes it difficult to estimate the current value of energy savings on SoCal's system.

72. PU Code § 746(a) requires that our DSM incentive programs include performance minimums and penalty provisions.

73. The earnings potential for current shared-savings incentive programs is limited by the size of the program and the adopted savings estimates.

74. In our adopted rules, we reduce the ratepayer risks associated with prespecified savings by requiring ex post verification of savings for all shared-savings mechanisms, effective January 1, 1994.

75. Imposing additional restrictions on the dollar level of shareholder earnings may encourage cream skimming and the creation of lost opportunities.

76. Cream skimming results in the pursuit of only the lowest cost energy efficiency options, leaving behind other cost-effective opportunities.

77. Lost opportunities are energy efficiency options that offer long-lived cost-effective savings and which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve.

78. Cream skimming becomes a problem when lost opportunities are created in the process.

79. Requiring a utility to pursue less cost-effective programs in one sector, which are not lost opportunities, would reduce the potential net resource benefits that all ratepayers realize from cost-effective DSM.

80. Equity and distributional issues can be addressed directly by funding programs designed to provide low-income assistance, such as our Direct Assistance Programs.

81. DSM program evaluation, funding and implementation raise as many generic policy and methodological issues as utility-specific considerations.

82. Consistency on DSM policy and methodology is needed as we embark on a new generation of DSM programs and work towards the effective integration of DSM into our resource procurement framework.

83. The use of consolidated generic proceedings has been used by the Commission in several areas, including the cost of capital and electric and gas long-run marginal costs.

84. Our ratemaking procedures may change as a result of our generic gas and electric ratemaking proceeding (R.90-02-008/ I.90-08-006).

85. On November 19, 1991, DRA filed supplemental comments on how to treat DSM as an energy resource option for planning purposes.

86. PU Code $ 747(c) directs respondents to develop and implement several DSM pilot bids, including an integrated bid.

87. PU Code § 747(c) directs the Commission, in consultation with the CEC, to report the results of the pilot bid projects to the Legislature by January 1, 1993.

Conclusions of Law

1. To meet our resource procurement goals, we should continue to explore analytical approaches that integrate DSM programs with supply-side options in the resource planning process.

2. The bidding experiments performed pursuant to PU Code § 747 should help us learn more about alternative DSM delivery mechanisms, and assess the role of DSM bidding to provide least-cost DSM services to ratepayers.

3. The Commission should regularly review and evaluate respondents' M&E activities in a consolidated forum. At least initially, a separate phase of this Rulemaking/Investigation is well suited for this purpose.

4. It is reasonable to true-up energy savings so that ratepayers are not sharing too much (or too little) of their investment earnings with shareholders, relative to the percentage originally agreed to under the shared-savings incentive mechanism.

5. It is reasonable to shift to ex post verification of DSM savings for all shared-savings programs authorized as of January 1, 1994.

6. Utility DSM activities should focus on programs that serve as alternatives to supply-side resource options.

7. Ratepayers should not provide shareholder incentives for programs that retain or increase customer or system load, even if the retention or increases are accomplished with the installation of energy efficient measures.

8. Specific guidelines for evaluating and funding load building and economic development activities should be developed in a later phase of these proceedings.

9. Proponents of load building and load retention programs (or fuel substitution programs with those elements) carry the

burden of proof to quantify the social or ratepayer benefits, and justify ratepayer funding for these programs.

10. Utility requests for load retention programs as part of special bypass deferral contracts should continue to be made by separate application.

11. Until we adopt improvements to our analytical methods, we should continue to use the Standard Practice Manual tests of cost-effectiveness in ways that are the most consistent with our resource procurement objectives.

12. The total resource cost test should be the primary indicator of cost-effectiveness in ranking and funding DSM programs.

13. Strict adherence to the total resource cost test should not be required for direct assistance, information programs, and energy management services.

14. The rate effects of cost-effective DSM should be considered in determining the overall funding level of utility DSM programs in a given period.

15. In applying the Standard Practice Manual test of cost-effectiveness and when calculating shareholder incentives, electric utilities should use the avoided supply costs and nonprice factors that are consistent with the values developed in our Biennial Resource Plan Update proceeding.

16. Electric utilities should use the forum described in D.91-10-048 to publish information on transmission and distribution costs. This information should be used consistently across all resource options for the purpose of quantifying avoided transmission and/or distribution costs.

17. We should examine the longer-term role of DSM shareholder incentives, the pros and cons of various approaches to incentive mechanisms, and the issue of earnings comparability and limits/caps in a later phase of this proceeding, after CACD's report is submitted.

18. As an interim policy on earnings comparability, it is reasonable to adopt the principle that shareholders' rate of return on DSM programs should be no higher (and could be lower) than shareholders' rate of return on utility-constructed plants, facing traditional ratemaking.

19. On an interim basis, it is reasonable to apply today's adopted policy on comparable earnings to specific incentive mechanisms, as follows:

- For incentive mechanisms based on program expenditures, such as SoCal Gas' current variable rate of return mechanism, the earnings rate on program costs should not exceed (and could be lower than) the authorized rate of return on utility constructed plants;

- For shared-savings mechanisms using an "S-curve" function, such as the mechanism adopted for SCE in its recent GRC, the incentive payment target should be calculated using forecasted utility expenses at 100% of forecasted net savings, times a rate that is no higher (and could be lower) than the authorized rate of return on utility constructed plants;

- For "flat rate" shared-savings mechanisms, such as the ones adopted for SDG&E and PG&E in D.90-08-068, the shared savings rate should not exceed (and could be lower than) the authorized rate of return on utility constructed plants.

20. SCE's current shared-savings mechanism, as adopted in D.91-12-076, is in compliance with the interim policy on comparable earnings adopted by this order.

21. It is reasonable to defer the issue of shared savings for SoCal's resource programs until gas marginal costs are adopted in I.86-06-005.

22. The issue of comparable earnings and earnings caps should be revisited in a later phase of this proceeding, after CACD's report has been submitted.

23. Utilities should pursue the most cost-effective DSM program in one sector (over a less cost-effective program in another sector), if doing so does not create lost opportunities in either sector.

24. Utilities should focus the performance minimums required by PU Code § 746(a) on efforts to achieve cost-effective energy efficiency opportunities and, in particular, on those which represent lost opportunities.

25. Utilities should provide a detailed account of strategies to avoid creating lost opportunities with any proposal for shareholder incentives, or increases in funding levels for DSM programs which are eligible for incentives.

26. It may ultimately make sense to address all DSM procurement issues in a consolidated forum, perhaps in conjunction with our Biennial Resource Plan Update proceeding. However, as we await the outcome of R.90-02-008/I.90-08-006, it makes sense to limit procedural changes to initiating a consolidated M&E phase in these proceedings.

27. All generic policy and methodological issues related to DSM should be addressed in this rulemaking and companion investigation. The determinations made in these proceedings should be used in any subsequent utility-specific proceedings. SDG&E and PG&E should revise their test year 1993 DSM funding proposals to conform to the policies and directives adopted in this order.

28. As described in Section IV.G of this order, CACD should appoint a Project Coordinator to manage the pilot bid evaluation required by PU Code § 747(c).

29. Since the appropriateness of shareholder incentives may depend on the specific form or design of the bid pilot, we should address that issue as we review specific DSM pilot bid proposals.

30. The longer-term issue of what bidding forms and features are most compatible with our resource procurement policies should be addressed in a later phase of this proceeding, after CACD's report is submitted.

31. The rules and policy principles governing the evaluation, funding, and implementation of DSM programs and associated shareholder incentives, as presented in Attachment 1 to this order, are reasonable and should be adopted.

32. In order to proceed expeditiously with the M&E phase of this proceeding and CACD workshops, this order should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. The rules governing the evaluation, funding, and implementation of DSM programs and associated shareholder incentives, as revised by this order and presented in Attachment 1, are adopted.

2. Until further order of the Commission, a separate, concurrent phase of these proceedings shall serve as the forum for addressing the measurement and evaluation (M&E) issues described in this order. These include reviewing and evaluating methods for ex post measurement of demand-side management (DSM) program impacts, adjusting forecasts of DSM program savings, and adjusting shareholder earnings under a shared-savings mechanism.

3. Rulemaking (R.) 91-08-003 and accompanying Investigation (I.) 91-08-002 shall remain open to consider the comments, workshop reports, and program evaluation reports described in this order.

4. Respondents and interested parties may file comments regarding (1) the types of information that will be needed for the M&E phase ordered above, and (2) scheduling recommendations, including detailed timetables for prehearing workshops

(if appropriate), the filing of testimony, evidentiary hearings, and briefs. Comments shall be filed at our Docket Office and served on all appearances and the state service list in these proceedings, no later than 30 days from the effective date of this order.

5. For all shared-savings programs authorized as of January 1, 1994, payments of shareholder incentives shall be based on post-installation verified savings. Exceptions to this policy for specific DSM measures shall be addressed in the M&E phase of these proceedings.

6. The assigned administrative law judge (ALJ) shall notice a prehearing conference to coordinate the scheduling of the M&E phase as soon as practicable after comments are filed. At the PHC, interested parties shall also present procedural proposals for incorporating the policies adopted in today's order to Southern California Gas Company's shareholder incentive mechanism.

7. As described in Sections IV.B and V.B of this order, the Commission Advisory and Compliance Division (CACD) shall conduct workshops to discuss parties' specific recommendations for modifying DSM terms and definitions presented in the Appendix to our adopted rules. (See Attachment 1.) In addition, these workshops shall also address the cost-effectiveness issues raised in parties' comments with regard to Fuel Substitution and New Construction Programs. Within 120 days of the effective date of this order, CACD shall file its report on these workshops with the Commission's Docket Office and serve the report on all appearances and the state service list in these proceedings.

8. Respondents shall establish a single clearinghouse for all Advisory Committee noticing and scheduling, as described in Section IV.H of this order. Within 90 days from the effective date of this order, respondents shall file a joint report with the Commission's Docket Office describing the clearinghouse procedures established in compliance with our orders. Copies of the report

shall be served on all appearances and the state service list in these proceedings.

9. As described in Sections IV.C and V.B of this order, CACD shall conduct workshops for the purpose of discussing parties' proposals on:

1. Using the Biennial Resource Plan Update planning or modeling outputs to derive long-run avoided costs required for the <u>Standard Practice Manual</u> tests;

2. Treating DSM as an energy resource for planning purposes in the Update; and

3. Identifying the types and sources of distribution cost data that will be published, as part of the process proposed in I.90-09-050 for identifying the transmission and distribution impacts of all resource options.

On or before November 1, 1992, CACD shall file a report on these workshops with the Commission's Docket Office, and serve copies of the report on all appearances and the state service list in I.89-07-004 and in these proceedings.

10. The <u>Standard Practice Manual</u> working group, which is convened by the staffs of this Commission and the California Energy Commission, shall file future updates or modifications to the <u>Standard Practice Manual</u> with the Commission's Docket Office, under the docket for these proceedings or any successor proceedings, and serve the updates or modifications on all parties.

11. As described in Section IV.G of this order, CACD shall manage the evaluation of DSM pilot bids required by Public Utilities (PU) Code § 747(c).

12. San Diego Gas and Electric Company and Pacific Gas and Electric Company shall revise their test year 1993 proposals for DSM funding and shareholder incentives to conform to the policies

and directives adopted in this order. The administrative law judges assigned to the test year 1993 general rate cases shall establish filing dates for these revisions.

This order is effective today.

Dated February 20, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
NORMAN D. SHUMWAY
Commissioners

Commissioner Patricia M. Eckert, being necessarily absent, did not participate.

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

pB

ATTACHMENT 1
Page 1

ADOPTED RULES AND POLICY STATEMENTS FOR DEMAND-SIDE MANAGEMENT PROGRAMS*

I. Resource Planning and DSM Program Definitions

1. This Commission's goal for utility resource procurement is reliable, least cost, environmentally sensitive ~~electricity~~ energy service. Using energy more efficiently constitutes an important means of achieving this goal. The utilities should treat energy efficiency improvements and energy conservation as viable alternatives to ~~traditional~~ supply-side resource options.

2. Lost opportunities are those energy efficiency options which offer long-lived, cost-effective savings and which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. In developing funding priorities for cost-effective DSM activities, the utilities should ~~place special emphasis on DSM activities which capture~~ consider capturing lost opportunities as an additional ranking criterion for programs with Total Resource Cost benefit-cost ratios greater than 1.0. The utilities should submit a detailed account of strategies designed to capture lost opportunities with any request for shareholder incentive mechanisms and/or for increases in DSM program funding.

* Additions to the proposed rules and policy statements, issued on August , 1991, are underlined. Deletions are ~~struck out~~.

Manual should be ~~modified~~ updated to include the final version of the terms and definitions included in the Appendix B. This OIR will remain open to accommodate any future requests to modify the terms or definitions proposed herein or to add new terms or definitions.

II. Cost-Effectiveness Indicators

5. The tests in the Standard Practice Manual (SPM) help assess the variety of effects associated with new or expanded DSM programs. The tests in the SPM will serve as the standard for determining DSM program cost-effectiveness until a methodology is established that allows for the side-by-side comparison of demand- and supply-side resources. The utilities should perform cost-effectiveness analyses for any proposed DSM program consistent with the indicators and methodologies included in the SPM. The utility should, to the extent practicable, perform each of the tests included in the SPM for any proposed DSM program.

6. This Commission relies on the Total Resource Cost Test (TRC) as the primary indicator of DSM program cost effectiveness. This reflects our view that utility DSM activities should focus on programs that serve as alternatives to supply-side resource options. Energy efficiency programs and load management programs which promote energy efficiency serve as such alternatives because they reliably reduce a utility's fuel and/or capacity needs.

7. To the extent practicable, nonprice factors should be considered along with price factors in utility resource procurement. Insofar as nonprice factors developed in the Biennial Resource Plan Update (Update) for supply-side resources

CORRECTION

THIS DOCUMENT HAS
BEEN REPHOTOGRAPHED
TO ASSURE
LEGIBILITY

ATTACHMENT 1
Page 1

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* Additions to the proposed rules and policy statements, issued on August 7, 1991, are underlined. Deletions are ~~struck out~~.

3. As defined by the Collaborative, "cream skimming" results in the pursuit of only the lowest cost conservation and load management measures, leaving behind other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process. Utilities should pursue the most cost-effective DSM resource programs first, if doing so does not create lost opportunities. ~~To reduce the potential for cream skimming, the stakeholders agreed that any proposed incentive mechanism should include strategies explicitly designed to avoid such activities. Parties are invited to provide comments on whether cream skimming as described by the Collaborative continues to be a concern, and whether the utilities should continue to provide a detailed account of strategies to avoid cream skimming with any proposal for shareholder incentives, or increases in funding levels for DSM programs which are eligible for incentives.~~

4. To ensure optimal funding of DSM activities requires consistent treatment of programs across utilities and across regulatory forums. Common terms and program definitions help ensure consistent treatment. On an interim basis, the utilities should use the definitions included in the Appendix ~~B of this rulemaking~~ to these rules when characterizing any proposed program. The burden is on the utility to justify any departure from them. We will consider modifying these terms and definitions after we receive the workshop report described in Sections IV.B and V.B of this order. The Reporting Requirements

Manual should be ~~modified~~ updated to include the final version of the terms and definitions included in the Appendix B. This OIR will remain open to accommodate any future requests to modify the terms or definitions proposed herein or to add new terms or definitions.

II. Cost-Effectiveness Indicators

5. The tests in the Standard Practice Manual (SPM) help assess the variety of effects associated with new or expanded DSM programs. The tests in the SPM will serve as the standard for determining DSM program cost-effectiveness until a methodology is established that allows for the side-by-side comparison of demand- and supply-side resources. The utilities should perform cost-effectiveness analyses for any proposed DSM program consistent with the indicators and methodologies included in the SPM. The utility should, to the extent practicable, perform each of the tests included in the SPM for any proposed DSM program.

6. This Commission relies on the Total Resource Cost Test (TRC) as the primary indicator of DSM program cost effectiveness. This reflects our view that utility DSM activities should focus on programs that serve as alternatives to supply-side resource options. Energy efficiency programs and load management programs which promote energy efficiency serve as such alternatives because they reliably reduce a utility's fuel and/or capacity needs.

7. To the extent practicable, nonprice factors should be considered along with price factors in utility resource procurement. Insofar as nonprice factors developed in the Biennial Resource Plan Update (Update) for supply-side resources

affect DSM programs, the utility should include them in cost-effectiveness analyses consistent with their development in the Update. Electric utilities should use the forum described in Decision 91-10-048 to publish information on transmission and distribution costs. This information should be used consistently across all resource options for the purpose of quantifying avoided transmission and/or distribution costs.

8. Resource value refers to the ability of a DSM program to reliably reduce utilities' fuel and/or capacity needs. For DSM programs designed to defer or avoid these requirements, the resource value associated with such programs should be consistent with the ~~utilities'~~ avoided costs of electric service adopted in the Update and, when completed, the avoided costs of natural gas service adopted in Investigation 86-06-005. These values should be used in applicable cost-effectiveness analyses and when calculating shareholder incentives. We will address the issue of consistency between resource planning determinations and DSM funding authorizations in this OIR/OII, after CACD's workshop report is submitted (see Sections IV.F and V.B of this order.)

9. Insofar as a DSM program results in indirect costs, they should be considered. The speculative nature of any attempts to quantify indirect costs significantly reduces their applicability as an analytic tool at this time. These costs should therefore not be required in any of the cost-effectiveness tests included in the SPM. The issues related to indirect costs of DSM programs are technical in nature. The SPM working group, which is convened by the CPUC and the CEC, represents the appropriate forum for considering indirect costs as they apply to DSM programs.

ATTACHMENT 1
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10. Shareholder incentives represent a true economic cost in the production of utility DSM programs and should be included <u>as a direct cost</u> in the TRC test, ~~the Societal test,~~ the Rate Impact Measures, and the Utility Cost test. <u>The SPM working group should consider the appropriate treatment of shareholder incentives in the societal test variation, i.e., as a transfer payment or direct cost.</u>

11. The usefulness of the TRC test as a primary indicator of cost-effectiveness is limited for certain programs <u>which do not necessarily focus on the timing or type of resource needs of the utility</u>. Direct Assistance programs address equity concerns; as such, positive cost-effectiveness shall be an important, but not the sole, factor used to determine funding levels for these programs. Cost-efficiency is also important in the conduct of Direct Assistance programs. For Information Programs and Energy Management Services, the link between programs and savings is difficult to discern. Strict adherence to the TRC should not be required for these programs. <u>We will consider addressing the applicability of the TRC test to New Construction Programs in these Rules after we receive the workshop report described in Sections IV.B and V.B of this order.</u>

12. Load Building <u>and load retention</u> programs lack resource value, and the TRC does not apply to these programs. Though utility DSM activities should focus on energy efficiency programs and load management programs which promote energy efficiency, the pursuit of certain load building <u>or load retention</u> programs may achieve other policy goals. <u>Proponents of these programs carry the burden of proof to quantify the social or ratepayer benefits, and justify any ratepayer funding for these programs. General conclusions about the net benefits of these types of</u>

programs should be backed by program specific analysis. In particular, for load building programs utilities should quantify the programs' net effect on air emissions, including increased emissions from the increased load on the system. The utility should design any load building or load retention program so as to avoid frustrating this Commission's goal of encouraging energy efficiency and energy conservation. We intend to adopt more specific evaluation and funding guidelines for these types of programs in a later phase of these proceedings.

13. Fuel substitution programs may offer resource value and environmental benefits. We currently lack a framework to assess the tradeoffs between gas and electric DSM programs that compete to provide the same service. ~~The tests included in the SPM do not capture these tradeoffs.~~ Fuel-substitution programs should reduce the ~~utilities~~ need for ~~electric generation~~ supply without degrading environmental quality. The TRC test should be the primary indicator of cost-effectiveness for fuel-substitution programs that meet these criteria. We will consider adopting more specific evaluation criteria for fuel substitution programs in these Rules after we receive the workshop report described in Sections IV.B and V.B of this order.

We discourage utilities from pursuing fuel substitution programs with a predominantly load building or load retention character. For ~~fuel-substitution programs designed to retain~~

~~load~~, these types of programs, the utility ~~should~~ carries the burden of proof to demonstrate that the benefits of the program justify relaxing our focus on energy efficiency programs.

V. Shareholder Incentives

14. The Electric Revenue Adjustment Mechanism and Core Fixed Cost Account remove ~~the~~ significant ratemaking disincentives for utilities to invest in demand-side management. To further ensure that demand-side management programs which result in, or promote, energy efficiency are not disadvantaged in utility resource procurement decisions, we initiated a pilot program of shareholder incentives in D.90-08-068. Shareholder incentives can help ensure that the utility ~~should be provided~~ is motivated to procure the least-cost resources by providing a comparable opportunity for earnings from prudent investments in both demand- and supply-side alternatives. ~~Shareholder incentives can help ensure that these opportunities are comparable.~~ We will examine the effectiveness of the specific incentive mechanisms adopted in D.90-08-068, the longer term role of shareholder incentives in resource procurement and revisit the issue of earnings comparability after CACD's report to the Legislature is submitted in late 1992.

15. The differences among utility shareholder incentive mechanisms approved in D.90-08-068 should eventually converge toward a more uniform, statewide approach. Pending CACD's report on shareholder incentives, it is appropriate to establish a limited number of guiding principles governing future shareholder

incentives. These principles should apply to shareholder incentive mechanisms proposed after the final adoption of this rulemaking.

16. Shareholder incentive mechanisms should be designed to encourage energy efficiency and load management programs that promote energy efficiency. Load building and load retention programs should not be eligible for shareholder incentives. Fuel substitution programs should also be ineligible pending resolution of the technical issues associated with assessing the benefits to ratepayers of these programs.

17. Shareholder incentive mechanisms should balance risk and reward. Coupling rewards for good performance with penalties for poor performance represents a reasonable way of achieving that balance. Any proposed shareholder incentive mechanism should therefore include minimum performance requirements and accompanying penalty features. The utilities should focus minimum performance requirements on efforts to achieve cost-effective energy efficiency opportunities, and in particular, on those which represent potential lost opportunities.

18. Shareholder earnings derived from a shared-savings approach to incentives reflect the value of the energy saved. Incentive mechanisms that determine earnings based solely on program expenditures are unrelated to that value. Thus, for programs whose savings can be reasonably estimated, a shared-savings approach is superior. Shareholder incentive mechanisms

should be based on a shared-savings approach for programs whose savings can be reasonably estimated. We will defer the application of shared savings to SoCal's programs until after gas marginal costs are adopted in I.86-06-005.

19. As an interim policy, shareholders' rate of return on DSM programs should be no greater (and could be lower) than shareholders' rate of return on utility-constructed plants. On an interim basis, this policy should be applied to specific shareholder incentive mechanisms, as follows:

- o For incentive mechanisms based on program expenditures, such as SoCal Gas' current variable rate of return mechanism, the earnings rate on program costs should not exceed (and could be lower than) the authorized rate of return on utility constructed plants;
- o For shared-savings mechanisms using an "S-curve" function, such as the mechanism adopted for SCE in its recent GRC, the incentive payment target should be calculated using forecasted utility expenses at 100% of forecasted net savings, times a rate that is no higher (and could be lower) than the authorized rate of return on utility constructed plants; and
- o For "flat rate" shared-savings mechanisms, such as the ones adopted for SDG&E and PG&E in D.90-08-068, the shared savings rate should not exceed (and could be lower than) the authorized rate of return on utility constructed plants.

We will revisit the issue of comparable earnings and earnings limits/caps in a later phase of this proceeding, after CACD's report has been submitted.

~~Reliance on energy savings estimates made prior to progra mimplementation to determine shareholder incentives increases risk to ratepayers. This risk should be minimized while still providing a comparable opportunity for earnings from prudent expenditures in both demand- and supply-side resources. A mechanism which~~

~~limits the level of potential shareholder earnings meets these goals. This mechanism should be designed keeping in mind the need to establish comparable earnings opportunities between prudent demand- and supply-side expenditures.~~

VI. Measurement, Evaluation, and Accounting

20. The stable development of DSM programs that deliver reliable energy savings for California's ratepayers depends on well-designed methods of program measurement and evaluation. Thoughtful measurement and evaluation practices are required to gauge utility performance, verify energy savings, and improve the design and success of future DSM programs. The utilities should make program measurement and evaluation a priority.

21. It is reasonable to base shareholder incentives on prespecified savings ~~estimates at this time. The~~ until we can implement a shift from prespecified savings estimates to ~~estimates~~ ex post verification made after program implementation ~~should occur as swiftly as practicable~~. Though prespecified savings estimates increase risks to ratepayers, the measurement protocols developed as part of the Blueprint help mitigate these risks. To implement the shift to ex post verification, we will conduct a consolidated measurement and evaluation (M&E) phase in this Rulemaking and Companion Investigation. This M&E phase will serve as the forum for addressing the following types of measurement-related issues:

- o Pre-Implementation Measurement. The acceptable methods and procedures for estimating, prior to program implementation, the various program impact parameters for DSM programs. These include the load impacts (and its components), participation level, utility costs, total costs and useful lives of DSM measures.

- o Post-Implementation Measurement. The acceptable methods and procedures for measuring DSM program impacts after program implementation. This includes developing guidelines for M&E activities beyond current activities.

- o Incorporating the Results of Measurement Studies. Using the results of M&E activities to (1) refine pre- and post-implementation measurement protocols, (2) adjust forecasts of DSM program savings, and (3) adjust shareholder earnings under a shared-savings mechanism.

We intend to base payments of shareholder incentives on post-installation verified savings, for all shared-savings programs authorized as of January 1, 1994, using the protocols adopted in the M&E phase. Verification may be in the form of metered results, sample bill analysis, or other post-installation measurement methods that we deem appropriate. As part of the M&E phase, we will consider procedural options for refining and updating M&E protocols on an on-going basis.

22. It is important that forecasts of DSM savings be as reliable ~~as forecasts of supply-side options~~ in meeting California's energy needs. Rigorous measurement and evaluation enhances the reliability of these forecasts. The utility will include a comprehensive and aggressive measurement plan with any

request for DSM funding which includes shareholder incentives. For programs authorized for 1992 and 1993, this plan should be consistent, at a minimum, with the protocols ~~included as Appendix C of this rulemaking.~~ contained in Appendix A of the Collaborative Blueprint. For programs authorized for 1994 and beyond, this plan should be consisted with the protocols adopted in the M&E phase of these proceedings. ~~Proposed changes to these protocols should be filed as part of this rulemaking.~~

23. The utility should explicitly quantify the following for any proposed shareholder mechanism:

- o The rate effects of both the program incentive and programs costs to which the incentive will apply;
- o The program's net resource savings; and
- o The timing of both rate effects and resource savings.

24. The DSM Advisory Committees provide an informal forum for parties to review utility programs and to work with the utility on any proposed changes to its programs. These activities can augment effective program implementation. The utilities should continue the Advisory Committees. For the Committees to be effective, the utilities should clearly define the role of the Committee and the input it seeks; provide the Committee with comprehensive information on program implementation activities; notify Committee members in a timely fashion of proposed program

changes; provide adequate information supporting such changes; and coordinate Committee activities with current and anticipated regulatory proceedings and other review procedures. To this end, respondents should establish a single clearinghouse for all Advisory Committee noticing and scheduling, as described in Section IV.H of this order.

25. We intend to improve the consistency with which DSM programs are treated across utilities and across regulatory forums by initiating the consolidated M&E phase described in Rule 21 and by addressing generic policy and methodological issues in this Rulemaking and Companion Investigation. Determinations made in these proceedings should be used in any subsequent utility-specific proceedings. We may also consider further consolidation of DSM-related issues at a later stage of these proceedings, after our generic investigation on ratemaking (R.90-02-008/ I.90-08-006) is completed. ~~Decisions governing utility DSM activities currently take place in several different proceedings. Establishing a single forum where the utilities' DSM activities can be reviewed simultaneously may further enhance consistent treatment. We propose to establish a single forum in which utility DSM activities would be reviewed, approved, and funded every two years. Parties are invited to comment on this proposal or to provide detailed alternatives to the proposal.~~

VII. Bidding

26. ~~All-source bidding, in which demand- and supply-side options compete on an equal footing for a place in the utility resource plan,~~ Introducing competition into the utility's acquisition of demand-side resources offers great potential for achieving our goal of reliable, least cost, environmentally sensitive energy service.

27. The utilities will work with the Division of Strategic Planning (DSP) to develop and implement several DSM pilot bids. PG&E has volunteered to conduct a pilot bid based on a partnership approach. Public Utilities Code §747 requires this Commission to test at least one ~~replacement~~ DSM-only bid, ~~and~~ an integrated resource bidding pilot, and a DSM bidding pilot for gas utilities. As one of their DSM-only bid pilots, respondents should test at least one replacement bid. CACD will perform an evaluation of the pilots, in consulation with the California Energy Commission. This Commission will submit its report, with any recommendations, to the Legislature by January 1, 1993.

28. The bid pilots should be designed to ensure that 1) the procurement process is fair, 2) contract terms equitably share risks, and 3) utility market power is mitigated. To the extent practicable, the bidding pilots should incorporate both price- and non-price factors for all DSM programs.

29. Each of the pilots, including PG&E's, will be addressed in the investigation opened in conjunction with this rulemaking.

(END OF ATTACHMENT 1)

ATTACHMENT 2
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TABLE OF ACRONYMS AND ABBREVIATIONS

ALJ	Administrative Law Judge
Blueprint	An Energy Efficiency Blueprint for California
CACD	Commission Advisory and Compliance Division
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
CMA	California Manufacturers Association
Collaborative	California Collaborative
CPUC	California Public Utilities Commission
D.	Decision
DGS	California Department of General Services
DOD	Department of Defense
DRA	Division of Ratepayer Advocates
DSM	demand-side management
ECAC	Energy Cost Adjustment Clause
ER	Electricity Report
ESCOs	energy service companies
GRC	General Rate Case
HESI	Henwood Energy Services, Inc.
I.	Investigation
ICEM	Iterative Cost-Effectiveness Method
Kenetech	Kenetech Energy Management, Inc.
M&E	measurement and evaluation
NAESCO	National Association of Energy Service Companies
NRDC	Natural Resources Defense Council
NUGs	non-utility generators
OII	Order Instituting Investigation
OIR	Order Instituting Rulemaking
PC	Participant Cost
PG&E	Pacific Gas and Electric Company

ATTACHMENT 2
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PHC	prehearing conference
PU Code	Public Utilities Code
PURPA	Public Utilities Regulatory Policies Act
QFs	Qualifying Facilities
RD&D	Research, Development & Demonstration
RIM	Rate Impact Measure
Rules	proposed rules
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SoCal	Southern California Gas Company
Southwest	Southwest Gas Corporation
SPM	Standard Practice Manual
ST	Societal Test
SYCOM	SYCOM Enterprises
T&D	Transmission and Distribution
Transphase	Transphase Systems, Inc.
TRC	Total Resource Cost
TURN	Toward Utility Rate Normalization
UC	Utility Cost
UCAN	Utility Consumers' Action Network Association
Update	Biennial Resource Plan Update Proceeding

(END OF ATTACHMENT 2)

SUMMARY OF RULES AND POLICY STATEMENTS PROPOSED IN THE OIR/OII (AUGUST 7, 1991)

I. Resource Planning and DSM Program Definitions

1. This Commission's goal for utility resource procurement is reliable, least cost, environmentally sensitive electricity service. Using energy more efficiently constitutes an important means of achieving this goal. The utilities should treat energy efficiency improvements and energy conservation as viable alternatives to traditional supply-side resource options.

2. Lost opportunities are those energy efficiency options which offer long-lived, cost-effective savings and which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. The utilities should place special emphasis on DSM activities which capture potential lost opportunities. The utilities should submit a detailed account of strategies designed to capture lost opportunities with any request for shareholder incentive mechanisms and/or for increases in DSM program funding.

3. As defined by the Collaborative, "cream skimming" results in the pursuit of only the lowest cost conservation and load management measures, leaving behind other cost-effective opportunities. To reduce the potential for cream skimming, the stakeholders agreed that any proposed incentive mechanism should include strategies explicitly designed to avoid such activities. Parties are invited to provide comments on whether cream skimming as described by the Collaborative continues to be a concern, and whether the utilities should continue to provide a detailed account of strategies to avoid cream skimming with any proposal for shareholder incentives, or increases in funding levels for DSM programs which are eligible for incentives.

4. To ensure optimal funding of DSM activities requires consistent treatment of programs across utilities and across regulatory forums. Common terms and program definitions help ensure consistent treatment. The utilities should use the definitions included in Appendix B of this rulemaking when characterizing any proposed program. The burden is on the utility to justify any departure from them. The Reporting Requirements Manual should be modified to include the terms and definitions included in Appendix B. This OIR will remain open to accommodate any request to modify the terms or definitions proposed herein or to add new terms or definitions.

II. Cost-Effectiveness Indicators

5. The tests in the Standard Practice Manual (SPM) help assess the variety of effects associated with new or expanded DSM programs. The tests in the SPM will serve as the standard for determining DSM program cost-effectiveness until a methodology is established that allows for the side-by-side comparison of demand- and supply-side resources. The utilities should perform cost-effectiveness analyses for any proposed DSM program consistent with the indicators and methodologies included in the SPM. The utility should, to the extent practicable, perform each of the tests included in the SPM for any proposed DSM program.

6. This Commission relies on the Total Resource Cost Test (TRC) as the primary indicator of DSM program cost effectiveness. This reflects our view that utility DSM activities should focus on programs that serve as alternatives to supply-side resource options. Energy efficiency programs and load management programs which promote energy efficiency serve as such alternatives because they reliably reduce a utility's fuel and/or capacity needs.

7. To the extent practicable, nonprice factors should be considered along with price factors in utility resource procurement. Insofar as nonprice factors developed in the Biennial Resource Plan Update (Update) for supply-side resources affect DSM programs, the utility should include them in cost-effectiveness analyses consistent with their development in the Update.

8. Resource value refers to the ability of a DSM program to reliably reduce utilities' fuel and/or capacity needs. For DSM programs designed to defer or avoid these requirements, the resource value associated with such programs should be consistent with the utilities' avoided cost adopted in the Update. These values should be used in applicable cost-effectiveness analyses and when calculating shareholder incentives.

9. Insofar as a DSM program results in indirect costs, they should be considered. The speculative nature of any attempts to quantify indirect costs significantly reduces their applicability as an analytic tool at this time. These costs should therefore not be required in any of the cost-effectiveness tests included in the SPM. The issues related to indirect costs of DSM programs are technical in nature. The SPM working group, which is convened by the CPUC and the CEC, represents the appropriate forum for considering indirect costs as they apply to DSM programs.

10. Shareholder incentives represent a true economic cost in the production of utility DSM programs and should be included in the TRC test, the Societal test, the Rate Impact Measures, and the Utility Cost test.

11. The usefulness of the TRC test as a primary indicator of cost-effectiveness is limited for certain programs. Direct Assistance programs address equity concerns; as such, positive cost-effectiveness shall be an important, but not the sole, factor used to determine funding levels for these programs. Cost-efficiency is also important in the conduct of Direct Assistance programs. For Information Programs and Energy Management Services, the link between programs and savings is difficult to discern. Strict adherence to the TRC should not be required for these programs.

12. Load Building programs lack resource value, and the TRC does not apply to these programs. Though utility DSM activities should focus on energy efficiency programs and load management programs which promote energy efficiency, the pursuit of certain load building programs may achieve other policy goals. The utility should design any load building program so as to avoid frustrating this Commission's goal of encouraging energy efficiency and energy conservation.

13. Fuel substitution programs may offer resource value and environmental benefits. We currently lack a framework to assess the tradeoffs between gas and electric DSM programs that compete to provide the same service. The tests included in the SPM do not capture these tradeoffs. Fuel-substitution programs should reduce the utilities need for electric generation without degrading environmental quality. The TRC test should be the primary indicator of cost-effectiveness for fuel-substitution programs that meet these criteria. We discourage utilities from pursuing fuel substitution programs with a predominantly load building character. For fuel-substitution programs designed to

retain load, the utility should demonstrate that the benefits of the program justify relaxing our focus on energy efficiency programs.

V. Shareholder Incentives

14. The Electric Revenue Adjustment Mechanism and Core Fixed Cost Account remove the disincentive for utilities to invest in demand-side management. To ensure that demand-side management programs which result in, or promote, energy efficiency are not disadvantaged in utility resource procurement decisions, the utility should be provided a comparable opportunity for earnings from prudent investments in both demand- and supply-side alternatives. Shareholder incentives can help ensure that these opportunities are comparable.

15. The differences among utility shareholder incentive mechanisms approved in D.90-08-068 should eventually converge toward a more uniform, statewide approach. Pending CACD's report on shareholder incentives, it is appropriate to establish a limited number of guiding principles governing future shareholder incentives. These principles should apply to shareholder incentive mechanisms proposed after the final adoption of this rulemaking.

16. Shareholder incentive mechanisms should be designed to encourage energy efficiency and load management programs that promote energy efficiency. Load building and load retention programs should not be eligible for shareholder incentives. Fuel substitution programs should also be ineligible pending resolution of the technical issues associated with assessing the benefits to ratepayers of these programs.

17. Shareholder incentive mechanisms should balance risk and reward. Coupling rewards for good performance with penalties for poor performance represents a reasonable way of achieving that balance. Any proposed shareholder incentive mechanism should therefore include minimum performance requirements and accompanying penalty features. The utilities should focus minimum performance requirements on efforts to achieve energy efficiency opportunities, and in particular, on those which represent potential lost opportunities.

18. Shareholder earnings derived from a shared-savings approach to incentives reflect the value of the energy saved. Incentive mechanisms that determine earnings based solely on program expenditures are unrelated to that value. Thus, for programs whose savings can be reasonably estimated, a shared-savings approach is superior. Shareholder incentive mechanisms should be based on a shared-savings approach for programs whose savings can be reasonably estimated.

19. Reliance on energy savings estimates made prior to program implementation to determine shareholder incentives increases risk to ratepayers. This risk should be minimized while still providing a comparable opportunity for earnings from prudent expenditures in both demand- and supply-side resources. A mechanism which limits the level of potential shareholder earnings meets these goals. This mechanism should be designed keeping in mind the need to establish comparable earnings opportunities between prudent demand- and supply-side expenditures.

VI. Measurement, Evaluation, and Accounting

20. The stable development of DSM programs that deliver reliable energy savings for California's ratepayers depends on well-designed methods of program measurement and evaluation. Thoughtful measurement and evaluation practices are required to gauge utility performance, verify energy savings, and improve the design and success of future DSM programs. The utilities should make program measurement and evaluation a priority.

21. It is reasonable to base shareholder incentives on prespecified savings estimates at this time. The shift from prespecified savings estimates to estimates made after program implementation should occur as swiftly as practicable. Though prespecified savings estimates increase risks to ratepayers, the measurement protocols developed as part of the Blueprint help mitigate these risks.

22. It is important that forecasts of DSM savings be as reliable as forecasts of supply-side options in meeting California's energy needs. Rigorous measurement and evaluation enhances the reliability of these forecasts. The utility will include a comprehensive and aggressive measurement plan with any request for DSM funding which includes shareholder incentives. This plan should be consistent with the protocols included as Appendix C of this rulemaking. Proposed changes to these protocols should be filed as part of this rulemaking.

23. The utility should explicitly quantify the following for any proposed shareholder mechanism:

- The rate effects of both the program incentive and programs costs to which the incentive will apply;
- The program's net resource savings; and
- The timing of both rate effects and resource savings.

24. The DSM Advisory Committees provide an informal forum for parties to review utility programs and to work with the utility on any proposed changes to its programs. These activities can augment effective program implementation. The utilities should continue the Advisory Committees. For the Committees to be effective, the utilities should clearly define the role of the Committee and the input it seeks; provide the Committee with comprehensive information on program implementation activities; notify Committee members in a timely fashion of proposed program changes; provide adequate information supporting such changes; and coordinate Committee activities with current and anticipated regulatory proceedings and other review procedures.

25. We intend to improve the consistency with which DSM programs are treated across utilities and across regulatory forums. Decisions governing utility DSM activities currently take place in several different proceedings. Establishing a single forum where the utilities' DSM activities can be reviewed simultaneously may further enhance consistent treatment. We propose to establish a single forum in which utility DSM activities would be reviewed, approved, and funded every two years. Parties are invited to comment on this proposal or to provide detailed alternatives to the proposal.

VII. Bidding

26. All-source bidding, in which demand- and supply-side options compete on an equal footing for a place in the utility resource plan, offers great potential for achieving our goal of reliable, least cost, environmentally sensitive electric service.

27. The utilities will work with the Division of Strategic Planning (DSP) to develop and implement several DSM pilot bids. PG&E has volunteered to conduct a pilot bid based on a partnership approach. Public Utilities Code §747 requires this Commission to test at least one replacement bid, and an integrated resource pilot, and a DSM bidding pilot for gas utilities. CACD will perform an evaluation of the pilots. This Commission will submit its report, with any recommendations, to the Legislature by January 1, 1993.

28. The bid pilots should be designed to ensure that 1) the procurement process is fair, 2) contract terms equitably share risks, and 3) utility market power is mitigated. To the extent practicable, the bidding pilots should incorporate both price- and non-price factors for all DSM programs.

29. Each of the pilots, including PG&E's, will be addressed in the investigation opened in conjunction with this rulemaking.

(END OF ATTACHMENT 3)

ATTACHMENT 4

List of Appearances

Respondents: David R. Clark and J. F. Walsh, Attorneys at Law, and Y. A. Whiting, for San Diego Gas & Electric Company; Robert B. Keeler, Attorney at Law, for Southern California Gas Company; Robert B. McLennan, Attorney at Law, for Pacific Gas and Electric Company; and Stephen E. Pickett, Frank J. Cooley, and Gene E. Rodrigues, Attorneys at Law, for Southern California Edison Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barbara Barkovich, for Barkovich and Yap; Ralph Cavanagh, Attorney at Law, for Natural Resource Defense Counsel; Steven F. Greenwald and Andrea B. Colace, Attorneys at Law, for Skadden, Arps, Slate, Meagher & Flom; Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services and South Coast Air Quality Management District; James Hodges, for The East Los Angeles Community Union; Caryn Hough, Attorney at Law, for California Energy Commission; Lon W. House, for Henwood Energy Services; Phyllis Huckabee, for El Paso Natural Gas Company; Douglas K. Kerner, Attorney at Law, for Roberts & Kerner; Audrie Krause, K. Justin Reidhead, Michel Peter Florio, and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Martin A. Mattes and Diane I. Fellman, Attorneys at Law, for Graham & James; Melissa Metzler, for Barakat & Chamberlin; David L. Modisette, for Edson & Modisette; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Bronson, Bronson & Mc Kinnon, by Scott W. Pink, Attorney at Law, for Transphase Systems, Inc.; John D. Quinley, for Cogeneration Service Bureau; John W. Witt, City Attorney, by William S. Shaffran and Deborah Berger, Deputy City Attorneys, for the City of San Diego; Andrew Brown and Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers Association; Jackson, Tufts, Cole & Black, by William H. Booth, Joseph Faber and Allan Thompson, Attorneys at Law, for California Large Energy Consumers Association; James Adams, for Energy & Resource Associates; Robert I. Burt, for California Manufacturers Association; and Charles Goldman and Patrick L. Splitt, for themselves.

Division of Ratepayer Advocates: Irene K. Moosen, Attorney at Law.

(END OF ATTACHMENT 4)