Decision **DRAFT DECISION OF ALJ GOTTSTEIN** (Mailed 5/23/2006)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-Run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004)

INTERIM OPINION: 2006 UPDATE OF AVOIDED COSTS AND RELATED ISSUES PERTAINING TO ENERGY EFFICIENCY RESOURCES

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INTERIM OPINION: 2006 UPDATE OF AVOIDED COSTS AND RELATED ISSUES PERTAINING TO ENERGY EFFICIENCY RESOURCES

1. Introduction and Summary[1]

By today's decision, we address the "2006 Update" of avoided costs and related issues that were identified in Decision (D.) 05-09-043 and subsequent scoping rulings. Avoided cost refers to the incremental costs avoided by the investor-owned utility when it purchases power from qualifying facilities (QFs), implements demand-side management, such as energy efficiency or demand-response programs, or otherwise defers or avoids generation from existing/new utility supply-side investments or energy purchases in the market. Avoided costs also encompass the deferral or avoidance of transmission and distribution-related costs. In D.05-04-024, we adopted an avoided cost methodology for the purpose of evaluating the 2006-2008 energy efficiency portfolio plans of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), which were filed on June 1, 2006.[2]

By this decision, we refine the interim avoided costs adopted in D.05-04-024 in two ways. First, we adopt correction factors for residential and small commercial air conditioning (a/c) unit installations,[3] to account for the

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1 Attachment 1 describes the abbreviations and acronyms used in this decision.

2 We refer collectively to PG&E, SCE, SDG&E and SoCalGas throughout this decision as "the utilities."

3 As discussed in this decision, "small commercial" unit installations refers to direct-expansion packaged or split-system a/c units installed in the commercial sector.

undervaluation of avoided costs when hourly avoided costs are averaged for these measures by time-of-use (TOU) periods. TOU-based averaging of the adopted hourly avoided costs occurs when there is insufficient data to create a corresponding load shape (kilowatt (kW) and kilowatt hour (kWh) impacts in each hour) for a particular measure. For residential a/c units, the correction factors are: PG&E-1.171, SCE-1.202 and SDG&E, 1.276. For commercial sector installations the correction factors are: PG&E—1.085, SCE—1.105 and SDG&E—1.145. These correction factors will be applied to the total avoided cost valuation for the installations, excluding transmission and distribution avoided costs. For example, if the ratio is 1.17, and the TOU avoided cost is $100, we will multiply $100 by 1.17 (or increases $100 by 17%) to correct the TOU-weighted avoided cost to the hourly equivalent ($117).

Second, we update the natural gas and generation avoided costs to reflect more recent market realities for natural gas prices. These updates are based on recent market data and updated gas price forecasts, as discussed in this decision. They result in significant increases to avoided costs through 2014. Attachment 3 presents the updated values for natural gas and electric generation avoided costs.

Several parties also recommend that we modify the interim avoided cost methodology at this time to incorporate an adder during peak hours, based on the costs of a combustion turbine (CT). This adder would be in addition to the TOU-averaging correction factors described above. Parties supporting a CT-based adder contend that the current hourly price profile in the interim avoided costs fails to value avoided costs properly for low load-factor energy efficiency measures during peak hours, and therefore, an adder during these hours is appropriate. There was, however, no consensus on this issue.

Moreover, there was no consensus on the methodology or input assumptions for calculating the CT-based adder. The record indicates that the value of a CT-based adder could range from approximately $28 to $44 per kilowatt-year (kW-yr), depending the methodology and input assumptions.

We find that consideration of a CT-adder requires the resolution of complex theoretical issues, assumptions and methodological issues that are beyond the scope of the 2006 Update, and should instead be addressed in Phase 3 of this rulemaking. Some parties recommend that the Commission adopt a simple capacity adder until these complexities can be further examined; namely, a capacity adder of 10 percent for residential a/c and 5 percent for commercial cooling measures. However, this approach still assumes that the current hourly price profile fails to value avoided costs properly during peak hours. We are unwilling to accept this assumption until we can further examine the underlying theoretical and methodological issues discussed in this decision. We will do so in Phase 3.

In sum, the two refinements we make today to the interim avoided costs adopted in D.05-04-024 are to: (1) adopt TOU-averaging correction factors and (2) update natural gas and electric avoided costs based on recent gas price forecasts and market data, as described above. These refinements are specific to energy efficiency resources, and do not address pricing for QFs or other applications of avoided or marginal costs.[4] However, in Phase 3 of this

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[4] As we recognized in opening this rulemaking, marginal costs used for revenue allocation and rate design in Commission proceedings are a "close derivative" of avoided cost calculations. Although "marginal costs" and "avoided costs" are not precisely identical in all contexts, for the purpose of today's decision we use these two terms interchangeably.

proceeding, we will consider the permanent adoption of the interim avoided cost methodology with today's refinements for energy efficiency resource evaluation, as well as consider the potential application of this methodology to other resource options, such as distributed generation and demand response. In the meantime, as discussed in this decision, we will continue to coordinate our consideration of avoided-cost related issues across Commission proceedings to ensure that avoided cost methodology is debated and resolved in this rulemaking, rather than in multiple proceedings where the methods and inputs for specific applications of avoided or marginal costs are applied.

We also address today several additional issues related to the valuation of energy efficiency resources that were identified for this phase of this proceeding. In particular, we adopt a common definition for energy efficiency peak kW reductions based on the Database for Energy Efficient Resources (DEER) definition of peak load reductions, as follows:[5]

- Peak is defined as the average grid level impact for the measure from 2 p.m. to 5 p.m. during the three consecutive weekday period containing the weekday with the hottest temperature of the year.
- DEER identifies these three contiguous peak kW days for each of the 16 California climate zones, based on the weather data sets developed for the California Title 24 Building Energy Efficiency Standards.
- DEER also defines a secondary peak demand period for educational facilities and other buildings that tend to operate at greatly reduced use during the peak demand period defined

[5] DEER is a database developed jointly by this Commission and the California Energy Commission (CEC), and funded by ratepayers.

> above. For this purpose, DEER uses the next highest peak during a period in which the facility is operated in full use mode.

Until further notice, the Commission will use this definition of peak kW for the purpose of verifying energy efficiency program and portfolio performance *ex post* (i.e., after measure installation/program implementation). In addition, the utilities are required to apply this definition to energy efficiency uses during the 2006-2008 program cycle, including any necessary portfolio rebalancing. An appropriate long-term definition for energy efficiency peak kW impacts will need to be considered in the context of available load shape data for individual energy efficiency measures.

We clarify today what *ex ante* estimates of peak kW impacts the utilities should use for rebalancing their portfolios and reporting program accomplishments during the 2006-2008 program cycle, and the schedule for updating *ex ante* estimates of kW and kWh savings for customized rebate programs as they proceed with implementation.[6] We also establish the calculator platform to be used for the *ex ante* evaluations and submissions of portfolio plans in preparation for the 2009-2011 program cycle.

In addition, we take steps to facilitate the ongoing exchange of peak load impact information among the utilities, Joint Staff and members of the utilities'

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[6] In this context, *"ex ante"* refers to estimates of load impacts that are made prior to measure installation/program implementation. As noted above, *"ex post"* refers to load impacts that are verified after-the-fact, i.e., after measure installation/program implementation. This verification can be based on a combination of site inspections of installed measures, engineering studies using site-specific data, regression analyses of billing data or other approaches. We have established protocols for *ex post* verification of load impacts in Rulemaking (R.) 06-04-010 and its predecessor proceeding, R.01-08-028.

program advisory/peer review groups, as the utilities consider rebalancing their portfolios during the program cycle. To this end, we direct the utilities to provide information to Joint Staff and their program advisory/peer review groups within 15 days of this decision that will enable them to review the estimates they are currently using for peak kW reduction load factors.[7]

We also adopt an action plan for moving forward with the requisite load shape updating that all parties urge us to undertake in order to improve program evaluation and resource planning efforts in the future. As discussed in Section 8, this "Load Shape Update Initiative" is designed to assist Energy Division in identifying problems in existing load shape data and in establishing priorities and study scopes for load shape improvements by end uses/measures over the next 18 months. It is modeled after the process we have undertaken to obtain public input and technical expertise for this 2006 Update, which we have found to be very effective.

As discussed in Section 8, the Commission will not take formal action on this matter by issuing a decision or ruling on what specific improvements to load shape data should be undertaken or the associated budget level and schedule for these efforts. These specific determinations should be made by Energy Division, per our discussion in D.05-01-055 of Energy Division's functions under the administrative structure for energy efficiency in 2006 and beyond.[8]

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[7] Joint Staff refers to Energy Division and CEC staff assigned to work on energy efficiency issues in the collaborative process set forth in R.01-08-028 and Application (A.) 05-06-004 et al.

[8] As we stated in that decision, and reiterate in today's decision: "we anticipate that the CEC staff can be called upon to provide Energy Division with technical input and, if needed, staffing support for these functions." D.05-01-055, *mimeo.*, p. 51.

Accordingly, Energy Division will consider the information obtained through the Load Shape Updating Initiative as it proceeds to develop the study scopes, specific work tasks, schedules and budgets for load shape improvements as part of its ongoing evaluation, measurement and verification (EM&V) responsibilities. Funding for the Load Shape Update Initiative and load shape studies to be conducted during 2006-2008 will come out of authorized 2006-2008 EM&V funding levels. Energy Division will determine the specific EM&V budget category for funding these efforts in consultation with the utilities.

Today's decision also addresses several anomalies that were observed during the 2006-2008 planning process for energy efficiency with respect to cost-effectiveness calculations. In particular, we find that anomalies with respect to the treatment of costs in the total resource cost (TRC) test need to be corrected, and provide direction for this purpose. We reiterate that the TRC must capture all participant and non-participant costs of the program. In addition, we direct the utilities to develop a joint request to modify the reporting requirements in order to correct the overhead double-counting problem discussed in this decision.

Finally, we discuss potential improvements to the quality control and oversight of data assumptions and inputs used to perform cost-effectiveness calculations in the future. We direct the utilities to collaboratively explore these and other approaches with Joint Staff, interested parties and the public through workshops noticed to the service list in R.06-04-010 and to the utility program advisory and peer review group members. By December 15, 2006, the utilities are required to report back to the assigned Administrative Law Judge (ALJ) and assigned Commissioner in R.06-04-010 on consensus and non-consensus recommendations presented at the workshops. For this effort, the utilities are directed to jointly hire technical expertise to ensure that options for improvements and implementation requirements associated with them are fully explored and presented in the report.

We direct the assigned Commissioner and ALJ to consider these recommendations in consultation with Joint Staff and take the necessary steps to implement any quality control improvements that they determine are reasonable and practicable. For this purpose, the assigned Commissioner, ALJ and/or Energy Division may hold further workshops, solicit written comments, obtain technical expertise or take other steps that they deem necessary to further consider and implement quality control improvements to the data assumptions and inputs used to perform cost-effectiveness calculations.

Compliance with today's decision will require updates to the model and model inputs used to perform energy efficiency cost-effectiveness calculations. We direct the utilities to jointly contract with the appropriate expertise to perform these tasks. As discussed in Section 9, these model and model input updates will be reviewed by the utilities' program advisory and peer review groups in statewide public meetings prior to submission to the Commission.[9]

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[9] The utility program advisory and peer review groups are part of the administrative structure for post-2005 energy efficiency established in D.05-01-055 (Section 5.2.2). The utilities' program advisory groups draw from the energy efficiency expertise of both market and non-market expertise across the full spectrum of program areas and strategies. The program advisory groups: (1) provide guidance to the utilities regarding region-specific customer and program needs, (2) provide a forum for input and collaboration with the local interests and stakeholders served by the program, and (3) meet on a statewide basis to address statewide design and consistency issues across service territories. The peer review groups are a subgroup of non-financially interested members with extensive energy efficiency expertise that serve as peer reviewers in the competitive solicitation process, implementation and planning process, as described in

Footnote continued on next page

The compliance submission is due by September 8, 2006. The utilities are directed to file a Notice of Availability and serve that notice on the service list in R.06-04-010.

All interested individuals or organizations who are not already parties (appearances) to R.06-04-010, and who wish to have the opportunity to comment on the compliance submittal described above should file a motion to intervene for this purpose in R.06-04-010 without delay. Parties to R.06-04-010 may file opening comments on the compliance submittal by September 22, 2006 and reply comments by September 29, 2006. After considering written comments, and in consultation with Joint Staff, the assigned ALJ in R.06-04-010 will address the compliance submittal by ruling, or take other steps as necessary to ensure compliance with today's decision.

2. Procedural Background

In Phase 1 of this rulemaking, the Commission adopted an avoided cost methodology on an interim basis for the evaluation of energy efficiency programs during the 2006-2008 program cycle. In doing so, the Commission stated its intent to consider potential revisions to this methodology in Phase 3 of this rulemaking. Phase 3 was also designated as the forum for considering the potential application of the interim avoided cost methodology to other resource options, such as distributed generation and demand response programs.[10]

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that decision. Joint Staff are members of both the program advisory and peer review groups, and Energy Division chairs the latter.

[10] D.05-04-024, p. 1. Phase 2 of this rulemaking is addressing QF pricing issues, to be addressed in a separate decision.

On September 22, 2005, the Commission issued D.05-09-043 in the energy efficiency rulemaking, R.01-08-028. In that decision, the Commission determined that specific improvements to the interim avoided cost methodology with respect to the valuation of peak/critical peak demand reductions should be considered during 2006, prior to the initiation of Phase 3. As part of this "2006 Update," the Commission directed that staff and interested parties work to develop a common definition of peak/critical peak demand reductions for energy efficiency planning and evaluation purposes.

In addition, the Commission identified the need to refine/make consistent across the utilities certain aspects of the calculator model used to map the Commission-adopted avoided costs to energy efficiency programs for cost-effectiveness calculations. This model is referred to as the "E3 calculator," named after the consultants (Energy and Environmental Economics, or E3) that developed the interim avoided methodology adopted by the Commission and the calculator model for use by the utilities.

Finally, D.05-09-043 identified the need to improve the consistency in underlying load shape data and the methods by which energy savings from energy efficiency measures are translated into peak savings estimates.

Consistent with the approach taken in Phase 1 of this proceeding, the Commission directed the utilities to contract with the appropriate expertise to develop recommendations on these avoided cost updating issues, after obtaining public input. The Commission also articulated its goal to "issue a decision on these issues during the first half of 2006, or as soon thereafter as practicable."[11]

[11] D.05-09-043, *mimeo.*, p. 141.

The utilities contracted with E3 for this work. The utilities and E3 held informational workshops in October 2005, consistent with D.05-09-043, to explain how the calculator produces peak savings estimates for the portfolio as a whole and for specific types of measures, and to provide information on the underlying load shape data. As discussed in that decision, the primary purpose of the workshops was informational—they were not intended to be the forum for debating or resolving disagreements about the E3 calculator or inputs at this juncture. However, the Commission asked workshop participants to assist in identifying what E3 calculator (model or input) "quick fixes" would be relatively easy to implement and where consensus could be reached, and areas where longer term refinements/improvements should be considered with respect to the valuation of peak load reductions and related issues. The utilities submitted this information in a joint November 1, 2005 workshop report (Joint Report).[12]

By ruling dated December 7, 2005, the Assigned Commissioner solicited written comments on that report "to assist in scoping the issues for the 2006 updating process," as directed by the Commission.[13] The Assigned Commissioner also presented a list of issues and proposed schedule for the 2006 Update, based on the discussion in D.05-09-043 and the workshop report, and invited the utilities and interested parties to comment on that proposal. In addition, parties were asked to comment on how the avoided cost/E3 calculator

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[12] See *Joint Utility Report Summarizing Workshops on Avoided Costs Inputs and The E3 Calculator*, November 1, 2005 (A.05-06-004 et al.). The report includes a description of the "quick fixes" to the E3 calculator made based on the consensus that emerged during the workshop process. See pp. 9-11.

[13] D.05-09-043, *mimeo.*, p. 113.

updating issues discussed in D.05-09-043 relate to Phase 3 of this proceeding, and whether they should be addressed through the 2006 Update process or in a later Phase 3.

After considering the Joint Report and subsequent comments, on December 27, 2005, the assigned ALJ issued a ruling setting forth the scope for the 2006 Update and established the due date for E3's report and recommendations.

On January 24, 2006, E3 held a public workshop to discuss each of the issue areas identified in the December 27, 2005 Assigned Commissioner's ruling. Pre-workshop written comments were also submitted to E3. Taking into consideration the written comments and workshop feedback, on February 20, 2006, E3 issued a draft report summarizing the positions of the parties and presenting preliminary recommendations for each issue area.[14]

Pre-workshop comments were filed on March 9, 2006 by the Division of Ratepayer Advocates (DRA), PG&E, SCE, The Utility Reform Network (TURN) and jointly by SDG&E and SoCalGas. A two-day workshop was held on March 14 and 15, 2006 in San Francisco. It was led by E3 with assistance from James J. Hirsch and Associates (collectively referred to as "2006 Update consultants") and also attended by the assigned ALJ. In addition to the utilities and Joint Staff, representatives from the following organizations participated in person or via conference call access: DRA, Freeman Sullivan, JBS Energy, TURN, Coast Economic Consulting, Van Horn Consulting and Quantum

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[14] Draft Report on 2006 Update to Avoided Costs and E3 Calculator, Prepared for the California Public Utilities Commission by Energy and Environmental Economics, Inc., February 20, 2006.

Consulting. We refer to those participating at the workshop collectively as "workshop participants" or "participants" throughout this decision.

Based on the comments and workshop discussion, on March 21, 2006, the 2006 Update consultants submitted a final report summarizing consensus and non-consensus positions on the 2006 Update issues, and presented final recommendations for Commission consideration (Final Report).[15]

At the direction of the ALJ, parties were given a further opportunity to comment on the 2006 Update issues and Final Report. Opening comments were filed on March 27, 2006 by DRA, TURN, PG&E, SCE and jointly by SDG&E and SoCalGas. Reply comments were filed by DRA, TURN, PG&E, SCE and SDG&E.

Based on the input from parties, the ALJ directed the 2006 Update consultants to supplement the report with an alternative set of weighting factors for the tables in Attachment 2 (Supplement).[16] The Supplement was submitted on April 10, 2006. TURN and DRA jointly filed comments on the recalculated weighting factors on April 14, 2006.

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[15] *Report on 2006 Update to Avoided Costs and E3 Calculator*, prepared for the California Public Utilities Commission by Energy and Environmental Economics, Inc. with assistance from James J. Hirsch and Associates, March 21, 2006. This report can be viewed on the Commission's website at http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/eeevaluation.htm.

[16] *Administrative Law Judge's Ruling Requesting Additional Information for 2006 Update*, April 3, 2006. The Supplement is also posted at http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/eeevaluation.htm.

3. Purpose and Scope of the 2006 Update

As set forth in the ALJ's December 27, 2005 ruling, the purpose and scope of the 2006 Update is to:[17]

- Develop a common definition of peak/critical peak to use in evaluating energy efficiency across proceedings. In doing so, consider whether different definitions of peak demand reductions for EE are needed for:
  - Cost-effectiveness evaluation
  - Establishing peak reduction goals
  - Evaluating achievement of those goals
  - Critical peak pricing
  - Resource adequacy counting.
- Update interim avoided costs methodology/E3 calculator to more accurately reflect impact of energy efficiency and other resources on peak/critical peak loads (according to the scope restrictions below).
- Improve consistency in underlying load shapes, including specifying the type of load shapes to be developed, sources of data and how demand will be measured *ex post*.
- Determine the most appropriate application (calculation) platform for program evaluations.
- Correct calculation anomalies in the E3 calculator with respect to Standard Practice Manual cost-effectiveness indicators and/or methodologies.
- Update natural gas prices in E3 calculator based on current forecasts and consider whether Commission should revise *ex ante* assumptions.

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[17] *Administrative Law Judge's Ruling on Scope and Schedule for the 2006 Update to Avoided Costs and E3 Calculator Directed by Decision 05-09-043,* December 27, 2005.

- Consider where further refinement of the E3 calculator is needed to create common calculator, and
- Convert annual savings to peak savings in the E3 calculator for all measures using consistent counting periods.

The December 27, 2005 ALJ ruling also clarified the distinction between the near-term (2006) updates to be considered in this phase of the proceeding, and the more comprehensive reassessment of avoided cost methodology to be addressed in Phase 3:

> "…Phase 3 of this proceeding will be the forum for developing a complete record on issues related to the adoption a common methodology, consistent input assumptions and updating procedures needed to quantify all elements of long-run avoided costs across the various Commission proceedings. The Commission's decision in Phase 3 will also adopt avoided cost calculations and forecasts that conform to those determinations. This process is likely to take a great deal of time and effort as we coordinate the inputs used in multiple proceedings and address methodological issues in order to develop an avoided costs 'yardstick' for valuing the resource benefits of various supply and demand-side options."[18]

As further discussed in that ruling, the 2006 Update is *not* the forum for the following:

- Considering proposals that fundamentally reject or represent a major change to E3 method.
- Modifying the Commission's established energy efficiency goals for 2006-2008 program cycle, or
- Addressing transmission and distribution valuation issues.[19]

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[18] *Ibid.*, p. 5.

[19] *Ibid.*, pp. 6-7.

In the following sections, we address the 2006 Update issues identified in the ALJ's scoping ruling.[20] In doing so, we describe general areas of agreement among parties, the range of views where there is non-consensus, and present the recommendations included in the Final Report.

4. Peak Definition

By D.05-09-043 in A.05-06-004 et al., we addressed the utilities proposed energy efficiency portfolio plans for the 2006-2008 program cycle. As discussed in that decision, part of the controversy over whether these portfolios were likely to meet the Commission-adopted peak demand (kilowatt or kW) reduction goals stemmed from differences in opinion over what definition of peak demand should be used when estimating portfolio savings. For a variety of reasons, including limitations to load shape data for specific measures, the utilities used a mix of metrics in the E3 calculators to prepare their portfolio plan estimates of peak kW demand reductions.

We discussed at some length in D.05-09-043 the need to develop the record further in the 2006 Update with respect to the appropriate definition of peak kW for energy efficiency planning and evaluation purposes.[21] In particular, one of our tasks today is to adopt a definition that will be used for the *ex post* evaluation of program and portfolio accomplishments during the 2006-2008 program cycle. This evaluation will be used to assess (1) whether the utilities have met the savings goals established by D.04-09-060 for this program cycle and (2) whether

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[20] This last issue on the list (consistent counting periods), however, has already been addressed and resolved as one of the "quick fixes" to the E3 calculator discussed in Section 2. Therefore, we do not address it further in today's.

[21] See D.04-09-060, pp. 101-114.

the minimum performance threshold is met under the risk/reward incentive mechanism being developed in R.06-04-010. The Commission has directed that the minimum performance threshold be tied to the Commission-adopted savings kWh, peak kW and therm savings goals, in a manner to be developed in R.06-04-010.

As discussed during the workshops, there are various options for defining peak demand reductions for these purposes. Currently, there are four measurements of peak kW reduction used in the E3 Calculator. The first measurement is based on the definition of peak used in the Database for Energy Efficiency Resources (DEER), a database developed jointly by the CEC and this Commission and funded by ratepayers. The second is a "load factor" based definition, whereby annual energy reductions are multiplied by a fixed conversion factor.[22] The third measurement is based on prior TOU studies of kW reductions, which conform to utility TOU period definitions that vary by utility. The fourth measurement is coincident peak kW reductions based on hourly load shapes/end-use data, where that data is available.[23] As discussed in the E3 report, the mix of peak metrics is driven by the available load data information and represents a "best effort" to estimate the summer on-peak impacts of the various energy efficiency measures.

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[22] As discussed during the workshops, there are three different types of load factors that can be used as the basis for this conversion factor, e.g., a coincident load factor, a non-coincident load factor, or a load factor based on the historical relationship observed between kW and kWh savings from ratepayer-funded program activities.

[23] "Coincident peak" generally refers to demand reductions from energy efficiency that occur at the time of the system peak, however that peak period is defined.

In addition, workshop participants discussed a kW metric consistent with Resource Adequacy counting rules for demand response (DR) resources. The various peak metrics are described further in Table 1, together with a summary of the associated data requirements and the pros and cons of each approach.

Metric	Data Requirement	Pros and Cons
DEER kW	Available for measures in the DEER database. For temperature sensitive measures, peak demand is defined as the average grid level impact for the measure from 2 p.m. to 5 p.m. on peak days	Pro: Is currently used by utilities for measures where DEER kW is available, though there are some differences among utilities. Both SCE and SDG&E report DEER kW for all programs. PG&E states that only 60% of its program impacts are based on measures in the DEER database. (The rest calculated from larger, complex projects.) Cons: Not available for all measures. DEER kW is derived using building simulation tools based on prototypical buildings and as such has some limitation in terms of accuracy.

Metric	Data Requirement	Pros and Cons
Summer on peak kW	Based on old utility studies, or can be calculated from hourly end use or impact shapes	Pro: Readily available from old utility studies, which often used load research data and conforms with utility time of use period definitions. Con: On peak periods vary for each utility, so the reported on peak demand reduction for the same measure could differ across utility service territory (even if all other things were equal). On peak demand estimates from the TOU studies can differ from the DEER kW estimates. This fact prompted SDG&E to report DEER kW (also referred to as Deemed kW) for all of their programs.
Load Factor based kW (CEC kW)	Annual energy reductions multiplied by a fixed conversion factor.	Pro: Easy to estimate. Requires little additional measurement and verification (M&V) effort. Con: Does not recognize the fact that peak load factors vary by measure, and could therefore allow an overemphasis on poor peak-load-factor measures such as residential compact florescent lamps.
Resource Adequacy (RA) consistent peak kW	Early discussions centered around requirements for Demand Response which currently counts peak load as the average reduction over 48 hours of operation, 4 summer months, 4 operations per month, 3 hours per operation. According to the newly adopted RA counting rules, the RA value of energy efficiency is 115% of its monthly coincident peak impact.	Pro: Might reflect the actual avoided costs of capacity if resource adequacy (RA) counting rules were to apply to energy efficiency measures. Con: RA rules are interim. Requires hourly data. Unclear which hours should be designated as the peak period dispatch hours, or the single hour monthly coincident peak. PG&E also cautions that peak impacts calculated from an RA perspective could be significantly lower than peak impacts estimated from past and current methods.
Coincident peak kW	Requires hourly load shapes and specification of peak hours. For PG&E's end use shapes, the peak hours were identified as the five top system load hours in each month. Monthly coincident	Pro: Provides the most precise metric of peak or critical peak load reduction. Con: Requires hourly load data which is not currently available. May be a challenge for M&V ex-post estimations.

Metric	Data Requirement	Pros and Cons
	peak kW = average load during the five peak hours. Coincident peak is the average July through September monthly peak kW.	

4.1. Workshop Consensus and Non-Consensus

After lengthy discussion in the March workshops, the participants reached general consensus that the DEER definition of peak kW should be used for the verification of goal achievements and performance basis calculations/thresholds during the 2006-2008 program cycle. DEER defines peak kW as the average grid level impact for a measure between 2 p.m. and 5 p.m. during the three consecutive weekday period containing the weekday with the hottest temperature of the year. DEER identifies these three contiguous peak kW days for each of the 16 California climate zones, based on the weather data sets developed for the California Title 24 Building Energy Efficiency Standards.[24]

There was also discussion during the workshop on the related issue of how the utilities should report program and portfolio accomplishments during the 2006-2008 program cycle as they are rebalancing their portfolios and reporting program and portfolio achievements prior to *ex post* verification of load impacts. For those measures that are included in the DEER database, the general

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[24] See Final Report, Attachment 3: *Definition of Demand (kW) Impacts Used in the 2005 DEER Update*. As indicated in that Attachment, DEER also defines a "secondary" peak demand period for educational facilities and other buildings that tend to operate at greatly reduced use during the peak demand period defined above. For this purpose, DEER uses the next highest peak during a period in which the facility is operated in full use mode.

consensus was that the 2005 DEER Update estimates of annual kWh and peak kW reductions should be used until additional EM&V study results are available that would update those DEER values.

However, participants recognized that the DEER values do not cover all program measures, and that the utilities use peak kW and kWh savings values that are not explicitly linked to DEER measures for custom applications where the specific mix of measures is not known at the outset. For this purpose, participants agreed that the utilities should continue to use their best estimates of kW (and kWh) impacts, which would also be subject to *ex post* verification using the DEER definition of peak kW discussed above.

Nonetheless, workshop participants articulated the need for Joint Staff and the program advisory/peer review groups to have additional information on these non-DEER values, in order to determine if further investigation is needed for the reported kW reductions as implementation proceeds. Accordingly, at the suggestion of the ALJ, workshop participants agreed on an action item to obtain such information.

Workshop participants did not reach consensus on a peak definition for use beyond the current program cycle (2006-2008). They did, however, identify two potential peak definitions for further consideration. The first was to continue the use of the current DEER peak kW definition (or potentially a variant that would shift the block of hours based on further research and updated system peak data). The second was to use a metric for coincident peak, possibly utilizing 12 monthly single hours that represent the highest loads on the system.

Workshop participants did agree that resolution of the definitional issue over the long-term is likely to depend upon the availability of load shape information. They discussed a framework for considering what energy efficiency load shape data will be needed in the future, in order to produce peak kW metrics for energy efficiency that address a variety of purposes in Commission proceedings. These included: energy efficiency goal attainment, resource adequacy, critical peak pricing, long-term resource planning, among others. Workshop participants noted that the development of hourly energy efficiency load data, or a subset of those hours during the summer peak, would provide the granularity of information needed to develop any of the peak kW metrics that might be needed.

Rather than defining the peak for all possible Commission purposes at this time, workshop participants reached consensus that effort should be focused on assuring that load shape research and EM&V efforts produce additional hourly load data in time for the 2009-2011 program cycle. They developed an action plan for this purpose, which is discussed further in Section 8 below.

Finally, workshop participants reached consensus that a critical peak metric should not be developed at this time for energy efficiency. They concluded that such a metric is not necessary for non-dispatchable energy efficiency, and that developing such a metric is likely to exceed the accuracy of available load data.

4.2. Other Comments

Post-workshop comments on the issues discussed above echo general support for the workshop consensus recommendations. TURN additionally recommends that the Commission require the utilities to provide the data source and basis for the non-DEER energy and demand estimates, as well as establish a due date for the provision of all supplemental non-DEER information.

In its post-workshop comments, PG&E raises some concerns with respect to using the DEER definition of peak kW, at least for its own system. PG&E

recommends that the peak kW definition be extended to 6 p.m. for the *ex post* studies of its 2006-2008 portfolio savings impacts, in order to reflect the fact that its system can peak after 6 p.m. More specifically, PG&E concludes based on further research that a summer peak period of 4 p.m. to 6 p.m. would better reflect current system level consumption patterns.

PG&E also notes that within DEER, the peak definition appears to differ both among weather-sensitive measures (i.e., for non-residential, school and residential), as well as between weather-sensitive and non-weather sensitive measures. PG&E recommends that the Commission clearly indicate which definition it is adopting, should it adopt a DEER definition.

More generally, PG&E urges the Commission to initiate the Phase 3 proceeding as soon as practicable to resolve the longer term issue of a common yardstick for defining and valuing the contribution of resource options to reducing system peak loads.

4.3. Final Report Recommendations

The 2006 Update consultants support the consensus recommendations reached during the workshop on the peak definition issues.

4.4. Discussion

We find the workshop consensus for the definition of energy efficiency peak kW reductions to be reasonable for use during the current 2006-2008 program cycle. It is a pragmatic approach to addressing load impact data limitations at this time, while taking advantage of a database that we have determined "should be the source of all assumptions that are used to estimate load impacts, to the extent possible."[25] Accordingly, until further notice of the Commission, we will use the 2005 DEER Update definition of peak kW for the purpose of verifying energy efficiency program and portfolio performance. In addition, until further notice, the utility program administrators are required to apply this definition to energy efficiency uses during the 2006-2008 program cycle, including any necessary portfolio rebalancing.[26]

With respect to PG&E's concerns over the consistency of peak (kW) definitions used in the DEER database, we note PG&E quotes a sentence from the on-line DEER report that refers to the definition of peak as "the average demand savings between noon and 6:00 p.m. during the months from May through October." The ALJ has confirmed with the 2006 Update consultants that this is an isolated error in the DEER documentation, due to an oversight in updating the documentation from earlier versions (and definitions of peak), and will be corrected. The 2005 DEER Update peak demand definition for all weather sensitive DEER measures (residential and non-residential) is exactly as presented during the 2006 Update workshops in the Final Report (Attachment 3). There is no underlying inconsistency in the use of that definition within the most current version of DEER, for estimating the peak kW demand impacts for weather-sensitive measures.

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[25] D.05-04-051, *mimeo.*, p. 25; Attachment 3, Rule IV.11.

[26] In comments on the draft decision, the utilities request further clarification on how to select the three day consecutive weekday period when applying the DEER peak kW definition to ex post measurement. This issue is more appropriately addressed during EM&V implementation, in coordination with DEER updating.

PG&E also suggests that the sources of data used to develop the load impact values for non-weather sensitive measures (e.g., refrigerators, compact florescent bulbs) may not be consistent in terms of the DEER definition of peak kW used for weather-sensitive measures, and recommends that these inconsistencies be acknowledged by the Commission.[27] However, PG&E provides no documentation that, upon investigation of the actual data sources (provided in the DEER report sections), there are significant differences in the definition of the afternoon periods used to derive these values.

Moreover, DEER values for non-weather sensitive measures are all state-wide averages, to which the weather-sensitive definition cannot be directly applied. PG&E does not suggest that the use of state-wide average values is inappropriate for measures with load impacts that do not vary by weather/temperature or climate zone. Rather, PG&E points to two examples where the statewide values are developed from different data sources, again implying that this is an inconsistency to be reconciled—or at least noted by the Commission.[28] However, nowhere in its comments does PG&E evaluate whether the resulting DEER values (based on the source data it references) are inconsistent with the impacts of these measures on summer weekday loads (between 2 to 5 p.m.), based on a comparison with hourly impact data, or its own TOU load shape information (H-factors).

In sum, PG&E alleges inconsistencies with respect to DEER that do not appear to be based upon relevant analysis or documentation. Similarly, PG&E

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[27] PG&E Comments, March 27, 2006, footnote 1, p. 3.

[28] *Id.*

proposes an expanded peak period without documentation of the additional research to which it refers, and without the opportunity for interested parties to review the underlying data or to address the potential ramifications of this proposal. If PG&E believes that these issues warrant further evaluation, it may present them in the context of future DEER updates.

As discussed in the workshops, an appropriate long-term definition for energy efficiency peak kW impacts will need to be considered in the context of available load shape data for individual energy efficiency measures. We discuss an action plan for moving forward with the requisite load shape data collection and evaluation in Section 8 below.

The workshop discussion and comments also raise the issue of what estimates of peak kW the utilities should use for rebalancing their portfolios and reporting program accomplishments during the program cycle. The consensus recommendations on this issue are that the utilities should: (1) use DEER values for peak kW and kWh savings for those measures that are included in the DEER database and (2) continue to use their best estimates of those values for measures that are not currently included in DEER, or for programs with measure categories rather than specific measures, such as customized rebate programs. These recommendations are fully consistent with our policy rules for energy efficiency, and we will adopt them.[29]

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[29] See D.05-04-041, Attachment 3, Rule IV.11, which states (in part): "To the extent possible, the assumptions that are used to estimate load impacts (e.g., kWh, kW and therm savings per unit, program net-to-gross ratios, incremental measure costs and useful lives) in the calculation of the TRC and PAC tests shall be taken from the Database for energy Efficiency Resources (DEER)."

However, we further clarify that the utilities are required to update their *ex ante* estimates of kW and kWh savings for customized rebate programs as they proceed with implementation, based on site specific installations for these programs, just as they are required to do for the incremental measure costs.[30] In doing so, they must utilize DEER savings values for the installed measures, if that data is available in DEER. Until further notice, the utilities should present these updates of *ex ante* estimates to Joint Staff and the utilities' program advisory/peer review groups every six months, i.e., by June 15 and by December 15 of each year.

We also agree with workshop participants that there needs to be an ongoing exchange of information concerning the peak kW load reduction factors (ratio of kW to kWh savings) that the utilities use for portfolio rebalancing and reporting. We direct the utilities to provide the information necessary for Joint Staff and other program advisory/peer review group members to review the methodology and/or baseline load shape (measure or end use) estimates they are using to estimate peak kW reduction load factors. This information should indicate clearly where DEER and non-DEER values of kWh and peak kW impacts are used, and for the latter, present other sources of load factor data, such as the CEC load factors, as a basis for comparison.

In addition, as recommended by TURN in its comments, the utilities should include the data source and basis for the non-DEER energy and demand estimates. We direct the utilities to provide this information within 15 days from

[30] See *Administrative Law Judge's Ruling on EM&V Protocols,* R.01-08-028, September 2, 2005, p. 20.

the effective date of this decision, and on an ongoing basis thereafter, as requested by Joint Staff or the utilities' program advisory or peer review groups during this program cycle. The utilities should post this information on a website and notify the following of its availability: (1) the 2006 Update service list in this proceeding and (2) the services lists in A.05-06-004 et al. and R.06-04-010. In addition, the utilities should jointly schedule a statewide meeting (or series of meetings) with their program advisory and peer review groups to present and discuss this information as soon as practicable.

The consensus recommendations recognize that, irrespective of the source (e.g., DEER), all *ex ante* estimates of energy efficiency load impacts are subject to *ex post* verification and true-up per our direction in D.05-04-051 and the adopted EM&V protocols in R.06-04-010 and its predecessor rulemaking, R.01-08-028. While D.05-04-051 allows for some exceptions to this requirement for specific measures, today's decision does not modify the Commission's general policy that load impact estimates are subject to *ex post* true-up in evaluating energy efficiency portfolio achievements.[31] Rather, today's decision provides an important clarification to this true-up process by defining the peak kW metric that will be verified in *ex post* studies for the 2006-2008 program cycle, namely, the DEER definition of peak demand.

5. Undervaluation from TOU Averaging

In calculating resource benefits, the E3 calculator maps 8760 hours of avoided cost values to available load impact data for energy efficiency measures. TOU-based load shapes only present information at the aggregate TOU period

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[31] See D.05-04-051, *mimeo.*, pp. 44-45.

level.[32] PG&E and SCE use five TOU periods to represent the year, and SDG&E uses six. In contrast, hourly load shapes have 8,760 values. For measures with hourly load data, the mapping of avoided costs is one-to-one and the resource benefit calculations are performed on an hourly basis. For measures that depend on TOU-based load shapes, the hourly avoided costs are averaged over each TOU period.

Parties agree that this averaging process could undervalue measures that produce relatively more load reduction during the highest cost hours. To estimate this potential undervaluation, E3 presents in the Draft Report a comparison between the avoided costs obtained when hourly load shape versus TOU-averaged load shape data is used for office cooling, office lighting, residential air-conditioning (a/c) and residential refrigeration energy efficiency measures. The comparison was developed from hourly load shape data available for these measures within PG&E's service territory, in two different climate zones. E3 presented the comparison for four different TOU period definitions (i.e., May-Oct. noon to 6 p.m., June to Sept. noon to 6 p.m., May-Oct. 2-5 p.m., and July-Sept. 2-5 p.m.).

This analysis shows that residential a/c is the most undervalued end-use when using TOU period averaging, ranging from 5.7% to 12.5% undervaluation in climate zone 13 (Fresno, Bakersfield), depending on the TOU definition. The

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[32] More specifically, for energy, the TOU-based load shape indicates the share of the load shape's total annual energy consumption that occurs in each of the five or six TOU periods (e.g: Summer On-Peak = 20%, Summer Partial Peak = 25%, summer Off Peak = 5%, Winter Partial Peak = 35%, Winter Off-Peak = 15%, and the sum of the shares for all periods sums to 100%). For demand, the TOU values indicate the relative magnitude of the peak demand that occurs in each TOU period. (e.g., Summer Partial Peak = 90%).

narrower summer on peak period definition (July-Sept. 2-5 p.m.) produces the lower end of the range. For climate zone 3 (San Francisco Bay Area), the analysis showed a similar but smaller effect, i.e., an undervaluation of residential air conditioning that ranged from 5.0% to 8.8%, depending on the TOU period definition.

In order to further develop their recommendations, workshop participants requested to see the magnitude of the undervaluation problem for all of PG&E's end uses that have hourly load shapes, as well as the undervaluation inherent in the use of TOU averages for residential and small commercial air conditioning hardware measures based on utility-specific DEER hourly load shapes. E3 presented this information in its Final Report, which is reproduced in summary form in Attachment 2. The magnitude of the undervaluation is expressed as a ratio of the average avoided costs calculated using hourly loads and avoided costs, divided by the average avoided costs using TOU averaging. The ratio represents a multiplier factor that would be applied to the TOU average value to correct for the undervaluation.[33] We refer to this multiplier factor as a "correction factor" in our discussion below.

For residential a/c upgrades, the 2006 Update consultants developed correction factors for representative units with SEER 14, SEER 15 and SEER 16 ratings, and presented factors for each SEER rating, by utility and climate zone.[34]

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[33] For example, if the ratio is 1.15 and the TOU avoided cost is $100, one would multiply $100 by 1.15 (or increase $100 by 15%) to correct the TOU-averaged avoided cost to the hourly equivalent ($115).

[34] "SEER" stands for Seasonal Energy Efficiency Ratio, which is calculated by dividing the amount of cooling supplied by an air conditioner or heat pump (btus per hour) by

Footnote continued on next page

These results were then weighted by the estimated percentage of installations for each SEER rating to produce an average residential a/c correction factor by utility and climate zone. To present a single correction factor for each utility, the climate zone-specific correction factors were then weighted by the expected distribution of units across each zone.

A similar process was used to derive the commercial sector correction factors utilizing DEER data. More specifically, the 2006 Update consultants produced correction factors for the most representative unit upgrade for the commercial sector, and presented the results for two building types (small office and retail) that were selected to bound the results across all sub-sectors.[35]

In calculating the utility average correction factors, the 2006 Update consultants assumed an equal distribution of installed units across climate zones, i.e., weighted each climate zone-specific factor by 1.00. In doing so, the consultants stated that the weighting should be based on the expected number of unit installations in each climate zone relative to the total expected number of installations, but that they did not have the requisite information to perform these calculations for the Final Report. By ruling dated April 3, 2006, the assigned ALJ requested that the 2006 Update consultants prepare a supplement to the Final Report that would present correction factors weighted in the manner recommended, and to consult with the utilities in obtaining the requisite

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the power (watts) used by the cooling equipment under a specific set of seasonal conditions. The higher the SEER rating, the more efficient the unit.

[35] The level sub-sector disaggregation varies for each utility, however, in addition to retail and small office, the commercial sub-sectors include categories such as lodging, health care, colleges/universities, warehouses, K-12 schools, restaurants, grocery, assembly, and other commercial.

information. The ALJ directed that the supplement include a description and source(s) of data used to develop the weights. Parties were given an opportunity to comment on the reasonableness of the new weights used to recalculate the correction factors.

The analysis showed that the correction factor differs for each utility, reflecting differences in impact shapes and differences in TOU period definitions, as well as other factors. It is noteworthy that SDG&E's correction factor is significantly higher than the correction factor for SCE. This is largely due to SDG&E having a summer peak period that contains many more hours than SCE's. The more hours in the summer peak TOU period, the more averaging that occurs and the larger the averaging undervaluation.

5.1. Workshop Consensus and Non-consensus

There was consensus at the workshop that residential a/c measures that use TOU shapes should receive an adder to correct for the TOU undervaluation. There was no consensus as to the level of that correction, and whether the correction should vary by climate zone and/or utility. In addition, there was no consensus as to whether other customer sectors and measures that use TOU shapes should also receive a correction adder.

5.2. Other Comments

As summarized below, post-workshop comments clarified parties' positions on a correction factor to address TOU averaging.

Based on its review of the DEER correction factors, SDG&E recommends a 24% upward adjustment for residential a/c and a range of 10% to 20% for commercial a/c measures to account for TOU averaging. SDG&E would apply the lower end of this range to businesses that operate primarily on weekdays (e.g., office buildings), and the higher end of the range to businesses operating 7 days a week (e.g., retail).

For residential a/c measures, PG&E recommends using utility and climate-zone specific factors to adjust the TOU-averaged avoided costs. PG&E argues that the correction factors for its service territory should be based on PG&E's hourly load shape data, rather than the DEER load shape data. In PG&E's view, this is reasonable because its own hourly load shape data is based on metered data, rather than building simulation data. PG&E does not support adopting a correction factor for small commercial a/c at this time. PG&E contends that there is currently insufficient data to determine the appropriate TOU correction factor for this sector, and that applying one to this sector could be difficult because of definitional differences among the utilities. The correction factors that PG&E would use to adjust the avoided costs for its residential a/c measures range from 1.12 (zone 4) to 1.20 (zones 2 and 16).[36]

Initially, TURN and DRA recommended using climate-zone specific correction factors developed from the DEER hourly load shapes to calculate the avoided costs associated with residential and small commercial a/c units. However, noting that the correction factors in the Final Report were based on an equal distribution of measures across climate zones, TURN and DRA recommended that the distribution instead be based on the expected number of energy efficiency measures to be installed in each climate zone. In its written comments, SCE supports this approach for residential a/c correction factors, but

[36] See Attachment 2, Table 1 from the 3/21/06 Final Report.

is silent on the issue of whether correction factors should be adopted for commercial a/c measures, and if so, how.

Based on the additional information provided in the Supplement, TURN and DRA modified their recommendations. Instead of using climate-zone specific correction factors, they recommend that utility territory-wide factors be used for residential a/c energy efficiency valuation, using the weights presented in the Supplement. These are: 1.171 for PG&E, 1.202 for SCE and 1.276 for SDG&E.[37]

For commercial a/c installations, TURN and DRA recommend that the utilities apply the averaged correction factors weighted by climate-zone to retail building types. However, TURN and DRA would not use the weights presented in the Supplement by SDG&E for its program. In their view, the assumption implicit in that factor is unreasonable; namely, that all small commercial a/c unit efficiency improvements in SDG&E's service territory will be in retail buildings. They suggest that SDG&E revise this assumption to be more realistic. While not adverse to correction factors for office buildings, TURN and DRA believes that the need for correction factors for this sub-sector is less obvious.

No measures other than residential or commercial a/c equipment upgrades were proposed for the TOU-averaging correction adjustment or evaluated for such an adjustment in the Final Report and Supplement.

[37] See Attachment 2, Table 2 from the 4/11/06 Supplement.

5.3. Final Report Recommendation

For residential a/c measures using TOU-based load shapes, the 2006 Update consultants recommend applying the territory-wide weighted average correction factor.

With respect to commercial a/c measures, the Final Report points out that the E3 calculator does not currently differentiate avoided costs by commercial sub-sector (i.e., office building or retail), and similarly, the data entered into the calculator does not make this distinction. As a result, additional data input as well as modification to the E3 calculator would be required to apply different correction factors at the sub-sector level.

In view of the above, and to be conservative on the level of adjustment, the 2006 Update consultants suggest that the territory-wide average correction factors for the office building sub-sector be applied to all small commercial a/c installations that utilize TOU-based load shapes. The term "small commercial a/c units" refers to direct-expansion packaged or split-system air-conditioning system installations in the commercial sector.

5.4. Discussion

We recognize, as do the parties, that the averaging that occurs through the use of TOU-based load shapes will both undervalue avoided costs during some of the highest load (peak) hours and at the same time overvalue avoided costs during some of the lowest load (off-peak) hours. Therefore, there are inaccuracies produced by this averaging process that could be addressed through the use of correction factors for each measure and end-use, in varying degrees. Nonetheless, the record in this proceeding supports the workshop consensus that TOU-averaging significantly undervalues measures that produce relatively more load reduction during the highest cost hours, such as residential and small commercial a/c equipment upgrades. In addition, the Final Report and Supplement provides a reasonable basis for adopting correction factors to adjust the avoided cost valuation of these particular measures. As discussed in Section 8, improvements to load shape data over the next 18 months should diminish the need to make such adjustments during the next program cycle.

We agree with TURN and others that the correction factors should be based on the DEER data. As TURN notes in its comments, PG&E's load shape data has not be subjected to the same level of public vetting and data quality control as have the DEER hourly impact shapes. Moreover, the workshop discussion clearly revealed that PG&E itself has elected *not* to use its own hourly load shapes at any point heretofore in the 2006-2008 energy efficiency planning and design process in any significant manner. Instead, as the 2006 Update consultants documented during that workshop, PG&E used TOU blocks or shapes in its application for approval of its 2006-2008 energy efficiency programs and budgets that are in closer agreement with DEER hourly shapes converted to TOU shapes than the TOU shapes created from PG&E's own hourly load shapes.[38]

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[38] At the March workshop, the 2006 Update consultants presented materials contained within a workbook and a PowerPoint document that presented this comparison. The workbook used in making that presentation is contained in a ZIP archive located at http://www.doe2.com/download/AvoidedCost/Compare2006AvoidedCostCalcs_2006-03-10.zip with the document that explains its contents, use and the data and methods used to create the workbook found in the PDF document located at: http://www.doe2.com/download/AvoidedCost/Compare2006AvoidedCostCalcs-Description_2006-03-10.pdf and the PowerPoint presentation can be found at http://www.doe2.com/download/AvoidedCost/AComparisonOfMeasureAvoidedCostCalculationsv4.ppt.

As that discussion also revealed, the PG&E hourly load shapes are building end use shapes rather than measure impact shapes, and many of them are from relatively old (late 1980's and early 1990's) data collection exercises using relatively small sample sizes. While it is true that DEER load shapes are based on simulations, the documentation of DEER indicates that those simulations utilize field data that is more recent, more extensive, and more representative of climate and vintage variations than the PG&E hourly load shapes.[39] G&E has actively participated in every DEER update, including the most recent 2005 updating process. If PG&E truly believed that its building end use shapes were more characteristic of the hourly load impacts of energy efficiency measures than the DEER measure impact shapes, it would have (1) argued this issue during the 2005 DEER Update process and/or (2) proposed to use its building end use shapes during the 2006-2008 planning process in a significant manner for further consideration by the Commission. PG&E did neither.

In fact, an examination of PG&E's average hourly load shapes for office and retail indoor lighting reveal that these shapes show approximately 18-20% and 21-24% respectively, of all electric lighting power being consumed during the summer off-peak period, which does not seem to be representative of current office and retail building operation. PG&E's hourly load profiles for office and retail cooling indicate a large use of retail a/c during the night in mild climates compared to hot climates, with almost equal cooling electric use during the summer on-peak and off-peak periods for these building types. Again, these

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[39] See DEER documentation at www.energy.ca.gov/deer.

patterns do not appear representative of the load impacts associated with a/c energy efficiency measures, which may be why PG&E did not use these load shapes in developing its 2006-2008 program plans.[40]

In view of the above, we find PG&E's position in this proceeding on the issue of what hourly load shape data to use as the basis of the correction factors to be unpersuasive. We do not adopt it. Instead, we will adopt correction factors based on the DEER data presented in this proceeding, as described below.

5.4.1. Correction Factors for Residential A/C Units

We adopt the correction factors recommended by TURN and DRA for the installation of efficient residential a/c units. As noted in their joint comments, the data reflect that the climate-zone specific weighting results in higher correction factors than those where an equal distribution of measures across zones is assumed. This is logical and reasonable because the residential a/c unit energy efficiency savings are likely to be higher in the hotter climate zones, where efficiency improvements result in higher energy savings because of a/c usage patterns. Moreover, we agree with their observation that the additional precision gained from individual climate-zone correction factors does not justify the complexity and possible confusion resulting from having eight or nine different climate-zone correction factors. Accordingly, the following utility territory-wide correction factors will be applied to the avoided cost valuation

[40] To review these load shape data, open the PG&EComViewer.xls to the "Viewer" tab and select the desired climate zone, building type and "COOL" end use. The archive containing the IOU load shape data, as used in the E3 calculators, can be found at http://www.doe2.com/download/AvoidedCost/PGE-SCE-SDGE_LoadshapeViewers.zip.

using TOU shapes for residential a/c unit energy savings: PG&E: 1.171; SCE: 1.202 and SDG&E: 1.276.[41]

These correction factors should be applied to all residential a/c unit installations. The correction factors should be applied to the total avoided cost valuation for the installations, excluding transmission and distribution avoided costs. If the utilities do not currently identify residential a/c unit installations in the E3 calculator and the associated peak savings (or in other formats where projected savings are presented), they will need to develop a consistent and joint approach for doing so. This may entail estimating the fraction/percentage of installations for cooling end-use measures that represent the a/c unit hardware upgrades, and applying the correction factor to that fraction, or some other approach that is reasonable, consistent across utilities and practicable. We discuss in Section 11 the process for reviewing these and other updates to the E3 calculator and inputs in response to today's direction.

5.4.2. Correction Factors for Commercial A/C Units

The analysis presented in the Final Report and Supplement is based on data associated with two building types (small office and retail) within the commercial sector, which were selected to present a reasonable range of the potential undervaluation associated with TOU-averaging for small commercial a/c units across all building types. That data from Attachment 2 is summarized below:

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[41] See Attachment 2, Table 2 from 4/11/06 Supplement.

Weighting	PG&E Office	PG&E Retail	SCE Office	SCE Retail	SDG&E Office	SDG&E Retail
(1) Equal Distrib.	1.05	1.12	1.07	1.14	1.1	1.19
(2) Climate-Zone Specific Distrib.	1.055	1.115	1.063	1.136	0	1.194

The weighting options result in very little differences to the conversion factors calculated for PG&E and SCE. As TURN and DRA point out, SDG&E has projected that all of its installations of small a/c commercial units will occur in the retail sector. Therefore, the climate-zone specific weighting for SDG&E will produce conversion factors of zero for commercial sub-sectors other than retail.

Irrespective of which weighting approach is used, the DEER data indicates that the potential undervaluation associated with TOU-averaging in the commercial sector ranges from approximately 5% to 12% for PG&E, from 6% to 14% for SCE and from 10% to 19% for SDG&E, based on the building types used to bracket this analysis. Except for PG&E's general contention of insufficient data and TURN/DRA's concern over SDG&E's estimation of where the a/c units will be installed, no party raises objections to the methodology or data employed by the 2006 Update consultants to develop these ranges for the purpose of calculating a correction factor for commercial a/c units. In particular, no party asserts that bounding the range of correction factors utilizing data from the retail and office sub-sectors is unreasonable.[42] Given the inherent uncertainty in predicting the potential impact of TOU-averaging, we believe that the 2006 Update consultants have utilized the best available data and reasonable methodology for developing the potential correction factors for this sector.

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[42] In fact, selecting these two building types to bound the results is consistent with PG&E's sub-sector data as well. See Tables 6 and 7 of the Final Report, on p. 11.

However, as pointed out by the 2006 Update consultants, there are implementation challenges associated with adopting sub-sector (i.e., building type) specific correction factors based on this data. In particular, it appears that over 98% of PG&E's commercial a/c measures are currently entered into the E3 calculators with a generic "commercial" label. Applying sector specific correction factors to SDG&E and SCE's E3 calculator inputs would be more straightforward, given the manner in which that data is currently disaggregated. Still, adopting sector-specific correction factors would require additional data transfer for all the utilities.

We therefore question the value of approaching the commercial a/c correction factor on a sector-specific basis, in view of these additional implementation complexities. Moreover, the record indicates that such an approach is not likely to produce significantly improved accuracy. In particular, the expected distribution of small commercial a/c units across sub-sectors appears to be less certain for commercial applications, than for residential applications, especially in light of TURN and DRA's comments concerning SDG&E's projections for its service territory.

In view of the above, we believe it is reasonable to adopt correction factors for commercial sector installations of a/c units based on a simple average of the low (office) and high (retail) end of the range presented in the Final Report. Accordingly, we adopt the following utility territory-wide correction factors: PG&E—1.085; SCE—1.105 and SDG&E—1.145.

These correction factors should be applied to all small commercial a/c (i.e., packaged and split-system direct-expansion cooling) unit installations in the commercial sector. The correction factors should be applied to the total avoided cost valuation for the installations, excluding transmission and distribution avoided costs. As discussed above, if the utilities do not currently identify these types of installations in the E3 calculator and the associated peak savings (or in other formats where projected savings are presented), they will need to develop a consistent and joint approach for doing so. This may entail estimating the fraction/percentage of installations for cooling end-use measures that represent the small commercial a/c unit hardware upgrades, and applying the correction factor to that fraction, or some other approach that is reasonable, consistent across utilities and practicable.

6. Modification of Interim Avoided Cost Methodology

By far the most controversial issue in the 2006 Update phase of this proceeding revolved around modifying the interim avoided cost methodology adopted in D.05-04-024. To better understand the proposals presented by the parties, a brief summary of that methodology is presented below.

6.1. Interim Avoided Cost Methodology

The underlying theory of the interim avoided cost methodology is that long-run marginal costs (LRMC) establish proper price signals in the market to elicit the most efficient investment of new capital. The methodology uses the all-in costs of a combined cycle gas turbine (CCGT) as a proxy for this long-run price signal based on evidence from the CEC, the Western Electricity Coordinating Council and the Energy Information Association that the majority of new resources being added in the Western Interconnect are gas-fired combined cycle generators.[43]

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[43] *Methodology and Forecast of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs,* Prepared for the California Public Utilities Commission

Footnote continued on next page

In other words, the costs of a CCGT are assumed to approximate an electricity supply curve at long-run equilibrium, based on certain assumptions of free market entry and exit. Free entry means that market prices above the fully allocated cost of a CCGT cannot persist, because such high market prices would lead to the construction of new CCGTs that would tend to drive the price down. Free exit means that market prices below the fully-allocated cost of a CCGT cannot persist, because such low prices mean that existing units will be unable to earn enough margin to cover fixed costs and will exit the market (or alternatively, the construction of new resources will be delayed until growth in demand has consumed any temporary capacity surplus), driving the price back up. In the long run, therefore, these free market entry and exit assumptions dictate that the market price can neither be higher nor lower than, and must therefore be equal to, the fully-allocated cost of a CCGT.

Based on these assumptions, the interim avoided cost methodology proceeds to calculate avoided costs as follows:

(1) An annual average market price for years after the resource balance year (when new generation resources will be needed) is calculated based on the LRMC of a new CCGT power plant, including return on the equity investment in the generator. The methodology assumes that the resource balance year is 2008.

(2) An hourly price shape is developed based on California Power Exchange (PX) settlements that occurred between April 1998 and May 2000 (the 25 month period prior to the energy crisis) to reflect price variations in both the level of energy usage by time period and the

Energy Division, by Energy and Environmental Economics, Inc., October 25, 2004, pp. 47-48, 54-55.

characteristics of different generating resources that might be the most cost effective resources by time period.

(3) The annual value developed under (1) above is then allocated to the 8760 hours of the year by scaling the PX price shape so that the average value of the price shape is equal to the LRMC value.

(4) Prior to the resource balance year (i.e., when there is sufficient or even surplus generation capacity), the methodology uses published electricity forward market prices.[44]

(5) Other avoided cost components such as environmental costs and transmission and distribution avoided costs are also added to the hourly energy values to create the total avoided costs used for energy efficiency cost-effectiveness evaluations.

6.2. Workshop Consensus and Non-consensus

The workshop discussion explored the concept of including a capacity adder in the peak hours based on the cost of a combustion turbine (CT) plant. In particular, this discussion centered around the questions of (1) whether the resource balance condition by necessity should allow entry of both a CT and CCGT and/or (2) whether the LRMC price shape should be modified to contain sufficient margin to provide recovery of the capital investment in a new CT facility. There was also discussion of how the utility proposals for rate design

[44] A forward contract obligates the seller to sell and the buyer to buy at a specific price for a specific quantity delivered to a specific location, i.e., the energy deliveries are firm. As explained in D.05-04-024, forward price data is considered to reflect market prices, including capacity. As part of forward price determination, the market assigns a value to the capacity used to ensure firm delivery of the contracted energy. The value is small (large) to reflect the expected surplus (shortage) in the capacity used for firm delivery. This value does not necessarily track the historic fixed cost of capacity and, in the years prior to resource balance, forward prices do not cover the full cost of a new entrant. See D.05-04-024, pp. 31-32.

and evaluation of demand response incorporate CT costs in the valuation of demand reductions.

No consensus was reached at the workshop on the issue of whether to modify the current avoided cost methodology. Some parties indicated support for modifications that would add value to current avoided costs to reflect the cost of a CT (or some portion thereof), at least for certain peak hours, but agreement on the specifics of that methodological change was not reached. At the end of the workshop discussion on this topic, TURN presented a settlement proposal. TURN recommended increasing the present value of the generation avoided costs for residential and commercial a/c programs by 10% and 5%, respectively.

6.3. Positions of the Parties

In its comments, PG&E outlines its view of how short-run and long-run avoided costs should be developed, particularly in the future "when the Commission determines that there is an effective forward market for future capacity."[45] In PG&E's view, when that time arrives, the forward market prices will be a more accurate measure of future avoided capacity costs than the costs associated with any particular generation resource (e.g., a CCGT or CT). More generally, PG&E argues that the best measure for determining how much capacity an energy efficiency program avoids, and the avoided cost of that capacity, would be the amount of additional capacity the resource adequacy rules require each utility to have for each time period, and the market prices that utilities pay for that capacity.

[45] PG&E Comments, March 27, 2006, p. 9.

In the meantime, PG&E argues that the interim avoided cost methodology is flawed in several ways, and should be modified in this 2006 Update. For avoided cost prices once load-resource balance is reached (2008 and beyond), PG&E submits that (1) the new capacity needed to meet increases in load in those hours in which demand is highest is much more likely to be a new CT, rather than a CCGT, and (2) the new capacity needed to meet additional demand in other hours is likely to be a new CCGT. Accordingly, PG&E recommends that the interim methodology be modified so that a new CT could recover all of its annual fixed costs from selling energy in those hours in which the market prices exceeded its variable costs. In PG&E's view, this requires:

- Increasing prices in the higher price hours of the scaled up PX price shape, and
- Lowering prices in the lower price hours of that price shape by just enough to enable both the CT and the CCGT to recover amounts equal to but no greater than all of their respective fixed costs, including recovery of and return on investment.
- Making such modifications in such a way that the total area under the price shape remains unchanged, i.e., the net capacity cost of the new CT that is allocated to certain hours must be subtracted from the remaining hours.

PG&E presents three options for determining the hours in which the adjustments (increases) to avoided costs should be made, and how to allocate the appropriate amount to each hour and then subtract corresponding amounts from all the remaining hours. In addition, PG&E presents recommendations on how to modify the interim avoided cost methodology prior to resource balance, i.e., for 2006 and 2007. PG&E also outlines further methodological changes to avoided costs it recommends for Phase 3 of this proceeding.

In its opening comments, TURN also recommends modifications to the interim avoided cost methododolgy that involve adding costs related to a CT to high demand hours. TURN argues that these modifications are necessary to put low-load factor air conditioning measures on consistent footing with the valuation approaches being applied to both rate design and demand-response resources. In particular, TURN recommends that all utilities be required to add to the top 100 hours the CT capital costs, calculated using a real economic carrying charge rate, minus the energy savings created by the CT. TURN estimates that this approach would result in a residual capacity value in the vicinity of $20-$35 per kW-yr.

In DRA's view, the operational characteristics of dispatchable demand response programs are fundamentally different from those of energy efficiency and distributed generation programs, in the same way that peaking plants have different operational characteristics and economics from shoulder/baseload plants. Because of these differences, DRA argues that it is unreasonable to value demand response and energy efficiency programs using the same avoided costs even when both programs contribute to load reduction during the same hour. DRA supports valuing dispatchable programs targeted to reduce load during the critical peak period hours, such as demand response, based on the costs of a CT. However, DRA argues that non-dispatachable resources such as energy efficiency and distributed generation are more accurately valued using the current avoided cost methodology, which allows but does not ensure recovery of the fixed costs of a CT under all circumstances.

SDG&E and SoCalGas are opposed to changing the interim avoided cost methodology in this phase of the proceeding, but support a capacity adder of 10 percent for residential a/c and a 5 percent adder for commercial cooling, as suggested by TURN in the workshop. In their view, this is a reasonable settlement position in light of the lack of consensus on a method for calculating a precise CT-based adder, or on how to spread those capacity costs to hours in the year. In its reply comments, TURN supports this position.

SCE does not take a position on whether it is necessary at this time to include a CT-based adder to avoided costs, prior to full discussion of this matter in Phase 3 of this proceeding.

6.4. Final Report Recommendations

The 2006 Update consultants state that the threshold question is whether the resource balance condition requires entry of both CT and CCGT units. They believe that it is premature to conclude at this time that it does. In their view, this is a complex theoretical question that will be the subject of research efforts and future proceedings. They conclude that major revisions to the interim methodology should await the results of those proceedings.

The Final Report also presents a comparison between current avoided generation costs and the avoided costs derived from a CT-based adder. This adder was originally developed by E3 for the CEC Title-24 building standards investigation into the valuation of demand response measures. It was developed from the perspective looking at a CT as a "back stop" technology, that is, the technology that utilities would add for additional capacity if the market was not building enough to meet critical peak demand.

Using updated New York Mercantile Exchange (NYMEX) and natural gas fundamentals price forecasts, the Final Report presents calculations of a CT-based adder in the range of $28 to $34 per kW-yr range. Using spot gas prices, rather than an annual average value, increases the adder by approximately $10-yr.

6.5. Discussion

The debate in this phase of the proceeding over avoided cost methodology is not a new one. In Phase 1 of this proceeding, some parties argued that the use of a CCGT proxy for long-run avoided costs would misstate those costs for high-usage periods when CTs would be operating as the marginal units, and presented similar recommendations to modify the top end of the price shape to contain the explicit cost of a CT.[46] We rejected these arguments, stating that:

> "E3 is not providing a cost shape that assumes that CCGTs are the marginal plant for all 8,760 hours in the year. Rather, the CCGT is used to set the average annual market price. When this average price is applied to the hourly market shape, the result is that some hours will have costs higher than the CCGT annual average cost (when CTs would be on the margin) and some hours would have lower prices (when other baseload units would be on the margin)."[47]

It is clear that some parties are still dissatisfied with the methodological basis for our interim avoided costs with respect to the evaluation of energy efficiency programs, demand-response programs, or both. However, we agree with the conclusions of the Final Report that the CT-adder approach for modifying avoided costs during peak hours raises theoretical issues concerning LRMC that are more appropriately addressed in Phase 3.

In particular, PG&E's proposed methodology for modifying the current avoided costs is based on the assumption that "there are two marginal capacity resources: a new CT in hours when prices are relatively high, and a new CCGT

[46] See D.05-04-024, *mimeo.*, pp. 30-31.

[47] *Ibid.*, p. 32.

to meet baseload demand."[48] However, as indicated above, the current methodology is not based on assumptions of what type of plant operates at the margin. Nor is it based on the theory that avoided costs must be constructed to always provide sufficient margin for CT owners to operate their plants in peak demand periods, or to reflect a backstop technology that the utilities might have to build during periods of short-term peak capacity shortages.

Rather, as discussed in Section 7.1 above, the current methodology is based on the approximation of an electricity supply curve at long-run market equilibrium. We believe that the adopted approach represents a fundamentally different approach to avoided costs than the CT-adder based methodologies underlying PG&E's and TURN's recommended modifications. It is beyond the scope of this 2006 Update to explore these theoretical differences sufficiently in order to carefully consider the proposals before us for modifying avoided costs, whether for energy efficiency, demand-response, or both. This type of exploration is more appropriate for Phase 3 of this proceeding.

Moreover, even if we agreed with the theories underlying a CT-adder, there would be numerous approaches and assumptions to consider and resolve before one could be adopted. There is no consensus on these matters, and we lack a sufficient record in this phase of the proceeding for resolving them.

For example, in concept the adder is the capital cost of the new CT minus the "margin" or profit that operating the CT would make its owners in the market. There is more than one approach for calculating this margin. We note that PG&E recommends one approach and TURN uses another. The record in

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[48] PG&E Comments, March 31, 2006, p. 7.

this phase of the proceeding also indicates that the level of the adder would be affected by a number of assumptions, including heat rates, CT capital costs, the capital carrying charge rate (real or nominal), and the assumed years of the CT life.

There are also various approaches to consider for determining the hours in which the resulting increases to avoided costs should be made, and how to allocate the appropriate amount to each hour. In addition, one must decide whether to subtract the increased value in the peak hours from other hours so that the average avoided cost is no greater than a CCGT and if so, how to allocate those reductions to specific hours.

Finally, the comments of DRA and TURN raise the issue of whether it would be reasonable to apply the resulting adder to both energy efficiency programs and demand-response programs when they reduce demand in the same hour. These parties present arguments on both sides that need to be explored based on a more extensive record.

In sum, modifying current avoided costs using a CT-adder approach requires the resolution of complex theoretical issues, assumptions and methodological issues that are beyond the scope of this 2006 Update. As stated at the outset, this phase of the proceeding is not the forum for proposals that fundamentally reject or represent a major change to the interim method. Phase 3 of this rulemaking has been clearly designated as the forum for such proposals.

As discussed above, some parties have recommended a simple capacity adder of 10 percent for residential a/c and 5 percent for commercial cooling as an alternative to explicitly adopting a party's specific proposal to alter the hourly price profile with a CT-adder. However, this approach still assumes that the current hourly price profile fails to value avoided costs properly for low load-factor energy efficiency measures during peak hours. Until we examine further the underlying theoretical and methodological issues discussed above, we are not prepared at this juncture to accept this assumption. Moreover, as pointed out in the Final Report, the current price profiles may already reasonably capture the higher value of programs that save energy during peak demand periods, since they were developed based on market prices that were highly volatile during the 1998-2000 period.[49]

Finally, we disagree with TURN's contentions that such modifications are necessary to put low-load factor air conditioning measures on consistent footing with the valuation approaches being applied to rate design or the evaluation of other resource options. During the workshop, the assigned ALJ requested that TURN and the utilities identify the Commission proceedings in which a valuation approach utilizing a CT-adder approach was currently being applied, and to summarize the general method. Our review of these submittals indicates that a Commission decision has been rendered in only a few these proceedings. These proceedings address rate design, revenue allocation or demand response funding proposals in which the Commission has adopted settlements that resolve the issues without addressing the reasonableness of any party's proposed valuation methodology. In these instances the settling parties agreed that no specific assessment of a marginal cost or avoided cost methodology was required

[49] See Final Report, p. 18.

to resolve the issues in these proceedings, and the Commission found that the settlements were reasonable without resolving them.[50]

However, the Commission has recently considered methodological issues very similar to those raised by parties to this proceeding in the context of establishing the "market-price referent" (MPR) for the Renewals Portfolio Standard (RPS) program. One purpose of the MPR is to establish the market price at or below which the costs of long-term contracts entered into by the utilities with eligible renewable energy resources will be deemed reasonable and authorized in rates. To establish this market price, the Commission has developed a proxy plant to model the long-term costs associated with fixed-price electricity from new generating facilities. Under the adopted MPR methodology, time-of-delivery (TOD) factors are applied to the annual cost of the proxy plant in order to create a price shape that takes into account the value of different products.[51]

As SDG&E points out in its March 9, 2006 comments, the Commission's recent decision on a methodology for calculating the 2005 MPR would argue against making adjustments to the PX profile to allow the price shape to return

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[50] See D.05-11-005 in A.04-06-024 (PG&E's Rate Design Window), pp. 5, 20; D.05-12-003 in A.05-02-019 (SDG&E Rate Design Window) pp. 15-16; D.06-03-024 in A.05-06-008, A.05-06-006 and A.05-06-017 (Demand-Response Program Plans and Funding for PG&E, SDG&E and SCE), p. 12 and Appendix A.

[51] As discussed in the Final Report, SCE initially suggested that the TOD factors used for RPS replace the current PX hourly shapes in the interim avoided cost methodology. No parties currently suggest this modification to the interim methodology for the reasons discussed in the Final Report (pp. 23-24). However, the issue of consistency in the price shapes we use to evaluate various resource options may be an appropriate topic for Phase 3.

the capital cost of a CT. We note that in the RPS proceeding PG&E and several other parties specifically recommended against the use of a CT proxy for calculating the MPR. Rather, they argued that the MPR for peak period energy should be established by applying TOD factors exclusively to a CCGT. The Commission adopted this approach, agreeing with PG&E that "the application of TOD factors to the baseload MPR took into account the value of different products, including baseload, peaking and as-available output."[52]

For all the reasons discussed above, we do not modify the interim avoided costs methodology in this 2006 Update. The methodological issues raised in this phase of the proceeding may, however, be appropriate topics to explore further during Phase 3.

7. Modifying Natural Gas and Electric Generation Avoided Costs to Reflect Updated Market Prices and Natural Gas Forecasts

The Final Report presents updates to the electricity market prices and natural gas prices currently used in the E3 calculator to produce revised natural gas and electric generation avoided costs.

Natural gas prices are updated using gas futures price data from NYMEX for the years 2006-2011. The long-run gas forecast for the years 2015-2030 is based on an average of Energy Information Agency, CEC and SoCalGas forecasts, which were also updated by E3 using the most recent forecasts available.[53] The years 2012-2013 represent "transition" years based on a blend of

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[52] D.05-12-042 (as corrected by D.06-01-029), *mimeo.*, p. 33.

[53] *Ibid.*, pp. 36-39.

NYMEX futures and the long-run gas forecast. These values were developed by extrapolating the 2011 NYMEX futures price to the 2015 long-run forecast. Attachment 3 presents these updated inputs. Using the same assumptions for translating natural gas price inputs into avoided costs during the evaluation of 2006-2008 energy efficiency portfolio plans, we have produced monthly natural gas avoided costs that reflect these updated inputs, by utility service territory. These include avoided environmental costs. (See Attachment 3.)

The Final Report also presents updated electric generation avoided costs that reflect the updated gas price forecast described above. In addition, electric generation avoided costs are updated to reflect electricity market price data for the years 2006-2007, prior to the "resource balance" year of 2008. The Final Report describes these updates to electric generation avoided costs as follows:

> "The years 2006 through 2007 use electricity market prices. Electricity prices for January 2006, February 2006, and March 2006 are the historical closing prices from the final day of trading (dates were: 12/27/05, 1/30/06, and 2/27/06, respectively). The electricity forward prices are from Platts as of the close of the March workshops on 3/15/06. Years 2008 through 2011 are the long run cost of a CCGT (at resource balance) using natural gas prices from the NYMEX futures. Years 2012 through 2014 are the transition period, where the CCGT cost uses the natural gas prices that are transitioning from NYMEX to the long-run gas forecast. After 2014 the long run natural gas forecast is used exclusively for the CCGT cost. "[54]

Attachment 3 presents the updated natural gas price forecast adjusted to reflect gas delivery charges and surcharges for electric generators, and the

[54] Final Report, p. 40.

resulting electric generation avoided costs, by utility service territory. These avoided costs include all adders (e.g., environmental) and multipliers except for transmission and distribution, by utility.

The tables in Attachment 3 compare the updated natural gas price forecasts and electric generation avoided costs with the values used in the utilities' June 2005 filings in A.05-06-004 et al. for their energy efficiency portfolio plans. As indicated in those tables, electric generation avoided costs increase significantly through 2014, due somewhat to the updated electricity market data (2006 and 2007), but due mostly to the effect of the updated NYMEX natural gas forecasts (2008 to 2014). Similarly, the natural gas forecasts and resulting natural gas avoided costs increase significantly during that timeframe to reflect the updated NYMEX price data.

All parties agree that these updates should be made to the *ex ante* forecasts of avoided costs. TURN, however, expresses concern that if these updates are used to calculate shareholder earnings under a future risk/return mechanism, the utilities would receive a windfall for activities that they would have undertaken even with the lower avoided costs. However, using one set of avoided costs for program valuation and another set of costs for reward determination would not only be unduly complicated, but could create a disincentive for utilities to rebalance their portfolios to reflect the updated avoided costs. We note that TURN does not similarly argue that the higher avoided cost valuation for residential and commercial a/c units that it advocates (and that we adopt in terms of adjusting for TOU-averaging) would create such a windfall.

The *ex ante* avoided costs used for 2006-2008 portfolio rebalancing, as well as to evaluate 2006-2008 performance, should reflect the significantly changed realities in natural gas supplies and market prices that have emerged since the interim avoided costs were adopted in early 2005. These are reflected in the updated natural gas forecasts and avoided costs presented in Attachment 3**.** We will adopt them.

8. Improving Load Shape Data

All parties agree that improvements are needed to energy efficiency load/impact shape data in time for the next program cycle. As part of the workshop process, participants developed an action plan for this purpose that was modeled to a large extent after this 2006 Update process. We have reviewed the workshop proposal and post-workshop suggestions for refinements. Drawing from this input, we adopt an action plan today that, in our view, will enable us to address this high priority issue in a practical and timely manner.

Specifically, we direct the utilities to contract with appropriate expertise to develop a Load Shape Update Initiative in our energy efficiency rulemaking, R.06-04-010. The utilities should notify Energy Division of their intended contractor(s). The selected contractor(s) are expected to exchange information with the assigned ALJ and Energy Division in developing the work products for this initiative. The Load Shape Update Initiative should include public workshops with technical experts to help scope the effort as well as review the draft report described below. Energy Division may schedule and lead these workshops, or delegate this function to the contractor(s).

The primary purpose of the Load Shape Update Initiative is to assist with the following:

(1) Identifying near- and long-term improvement objectives for the updating process, including how best to incorporate recently completed studies and studies underway into the E3 calculator;

(2) Developing criteria for prioritizing end-uses/measures for load shape improvements, and

(3) Establishing priorities for load shape improvements by end uses/measures and a schedule for completing those improvements.

To this end, the Load Shape Update Initiative should provide Energy Division and interested parties with a better understanding of the following:

(4) What load shapes/blocks exist in the E3 calculators, CEC and utility load forecasts and the data source quality;

(5) The magnitude of the problem(s) with existing load shape data, utility vs. statewide; and

(6) The costs and benefits associated with potential improvements to existing load shape data.

The contractor(s) will be tasked with developing a draft report addressing the issues identified above, as well as others that emerge from the scoping workshop(s), as appropriate. The contractor(s) shall submit a draft report no later than October 1, 2006 that includes preliminary recommendations on issues (1)-(3) above. Energy Division (or the contractor(s)) will hold public workshops on the draft report as soon as practicable thereafter, so that the contractor(s) can respond to feedback and questions. Based on the workshop feedback, the contractor(s) will develop a final report by November 15, 2006 that, among other things, summarizes the areas of consensus and non-consensus among workshop participants by issue area and presents final recommendations. Energy Division, the assigned ALJ or Assigned Commissioner in R.06-04-010 may also solicit post-workshop written comments on the final report from interested parties, as they deem appropriate.

All reports, notices of availability, notices of workshops or other filings related to the Load Shape Update Initiative should be distributed to the service list in the energy efficiency rulemaking, R.06-04-010, consistent with the electronic service rules established for that proceeding.[55]

We will not take formal action on this matter by issuing a decision or ruling on specific improvements needed to load shape data, the scope of work for studies to improve the data, the associated budget level or schedule for these efforts. These determinations should be made by Energy Division, per our discussion in D.05-01-055 of EM&V responsibilities in 2006 and beyond:

> "Energy Division will be responsible for: (1) allocating Commission authorized funding for program and portfolio impacts-related EM&V among the individual studies, (2) developing the work scope for each study consistent with our adopted EM&V protocols, (3) writing RFPs and selecting the contractors, and (4) managing and contracting for the work."[56]

Accordingly, the information and recommendations obtained through the Load Shape Updating Initiative is designed to assist Energy Division as it proceeds to develop the study scopes, specific work tasks, schedules and budgets for load shape improvements as part of its ongoing EM&V responsibilities. We reiterate our expectation that, consistent with the working relationships we have already established with the CEC in our energy efficiency proceedings, "we

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[55] The electronic service rules are contained in Appendix A of *Ordering Instituting Rulemaking to Excamine the Commission's post-2005 Energy Efficiency Policies, Programs, Evaluation, Measurement and Verification, and Related Issues,* R.06-04-010, issued on April 13, 2006.

[56] D.05-01-055, *mimeo.*, p. 108.

anticipate that the CEC staff can be called upon to provide Energy Division with technical input and, if needed, staffing support for these functions."[57]

The results of these efforts to improve load shapes should be considered in the DEER updating process as well, as TURN suggests in its comments. However, we do not specify how the load shape studies should be managed (e.g., as part of the DEER updating process or through separate EM&V contracts, etc.) or at what level they should be funded out of authorized EM&V budgets, as some parties suggest. These determinations should be made by Energy Division as part of the division's ongoing EM&V responsibilities, as described above.

Nor do we specify today how final determinations will be made on what types of data generated by the load shape studies (or other EM&V studies) represent an improvement to existing values in DEER, and therefore should replace those values. Joint Staff is currently developing EM&V process protocols that will address this as well as other process issues related to updating DEER values (e.g., the process for obtaining input from interested parties and technical experts, and schedule for making revisions). Those protocols are subject to review and adoption under the procedures we established for EM&V protocols in D.05-04-051.[58]

We do specify today, however, that funding for the Load Shape Update Initiative and resulting load shape update studies to be conducted during 2006-2008 will come out of authorized EM&V funding for the 2006-2008 program cycle. Energy Division should determine the specific budget category (or

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[57] *Id.*

[58] See D.05-04-051, pp. 67-73.

categories) for funding these efforts, in consultation with the program administrators.

It is clear from the record in this proceeding that improvements in energy efficiency load shape data are needed in time to plan for the 2009-2011 energy efficiency program cycle. This planning process will be well underway six months before the utilities file their June 1, 2008 applications for their 2009-2011 portfolio plans. Therefore, it appears that the highest priority load shape improvements identified through the Load Shape Updating Initiative will need to be completed and incorporated into the E3 calculator by the end of December, 2007. As soon as practicable after the final report is submitted, Energy Division should update the EM&V roadmap in consultation with the assigned ALJ in R.06-04-010 to reflect this schedule.

9. Standard Practice Manual-Related Anomalies

The Standard Practice Manual (SPM) contains the Commission's methodology for evaluating energy efficiency investments using various tests of cost-effectiveness.[59] The policy rules adopted by D.05-04-051 (Rules) require that the energy efficiency portfolios as a whole pass both the total resource cost (TRC) test and the program administrator cost (PAC) tests of cost-effectiveness contained in the SPM. Individual program selections are also made by program administrators based on the results of these two cost-effectiveness tests, as well

[59] The latest version of the SPM (*California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, October 2001)* is posted on the Commission's website at: http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/eeevaluation.htm.

as other evaluation criteria. In addition, per D.05-04-051, the performance basis for the risk/reward incentive mechanism being developed in R.06-04-010 will be based on these two tests, for the majority of energy efficiency activities.

The Rules describe the TRC test as the measurement of net resource benefits from the perspective of all ratepayers produced "by combining the net benefits of the programs to participants and non-participants." The benefits are the costs of the supply-side resources avoided or deferred. The TRC costs encompass the costs of the measures/equipment installed and the costs incurred by the program administrator.[60] Under the PAC test, the program benefits are the same as the TRC test, but costs are defined differently to include the costs incurred by the program administrator (including financial incentives or rebates paid to participants). The PAC test does not include the costs incurred by the participating customer.[61]

Three anomalies were identified in the E3 calculators used for the utility June 1, 2005 filings with respect to the SPM tests, as discussed further below.

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[60] D.05-04-051, Attachment 3, Rule IV.2. As noted in footnote 7 of the Rules, the TRC test looks at the "incremental" measure cost (not the full cost) when an energy-efficient appliance or measure promoted through the program represents a replacement "on burn out" of the participant's existing appliance/measure. In other words, for these "replace on burn out" installations, the measure cost is the additional (incremental) cost of the equipment/measure relative to the standard (less efficient) appliance/measure that would have been installed, without the financial incentive or outreach program. Full measure/equipment costs are only used in instances where the program causes the participant(s) to do what they would not have done anyway (or at least not in the near future, e.g., 5 years), such as replace a working air conditioner with a more efficient one.

[61] *Ibid.,* Rule IV.3.

9.1. Treatment of Load Increases

The SPM states that load increases should be treated as a cost in the calculation of the TRC and PAC net benefits (or benefit-cost ratios). The E3 calculator treats a load reduction as a positive benefit, and a load increase as a negative benefit.

As pointed out in the Final Report, this treatment does not affect the calculation of net benefits under the SPM tests, and would not affect the benefit-cost ratios to any significant degree (i.e., it would not make a program with a benefit-cost ratio greater than one have a ration less than one, or vice versa). We concur with the consensus position of the workshop participants that that this is a minor inconsistency and does not merit changes to the E3 calculator

9.2. Overhead Double Counting

The reporting requirements developed by Energy Division require that utilities report program overhead costs as part of the administrative cost category, even in cases where contractors are performing the installation work.[62] The workshop discussion and parties' comments indicate that this could lead to a double counting of overhead costs in the SPM tests, because some of those costs may already be included in the labor component of the incremental measure cost. PG&E and other parties recommend that Energy Division modify the requirement to include all disaggregated overhead costs in reported administrative costs in order to avoid this double-counting problem. The Final Report explains why this approach would be preferable to modifying the E3

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[62] See *Administrative Law Judge's Ruling on Reporting Requirements*, issued February 21, 2006 in R.01-08-028, Appendix: Allowable Costs.

calculator to allow the removal of overhead costs from tens of thousands of measure line items in the calculators.[63]

The workshop participants propose an action item on this issue that we find to be reasonable: The utilities should work on a joint request to the assigned ALJ (in R.06-04-010) and Energy Division to fix this problem by modifying the reporting requirements.

9.3. Direct Install Costs in the TRC Test

During the review of the utilities' June 1, 2005 portfolio plans, Energy Division's consultant (TecMarket Works) pointed out an anomaly for selected programs where the TRC was greater than the PAC. Given the definition of these tests (see above), the opposite should generally be true because the PAC test does not include the costs incurred by participating customers, while the TRC test does includes these costs. The exception to this general rule can happen given the SPM definition of the TRC test when very large "transfer payments" between non-participating and participating ratepayers occur. But as discussed below, this should not be a frequent occurrence if the proper definition of transfer payments is used and installation costs are accounted for appropriately.

TecMarket Works determined upon review that "the condition is E3-based and is associated with program conditions that occur when an incentive equals the full cost of the measure."[64] TecMarket Works concluded that "this calculation approach appears to be different than the calculation approach described in the Standard Practice Manual" and that "there is a need to confirm

[63] See Final Report, p. 34.

[64] TecMarket Works Report, p. 34.

with the [utilities] the calculation approach that should be used to assess the portfolios and make that approach consistent in the E3 calculator and in the Standard Practice Manual."[65]

This issue was discussed during the workshop process and addressed in DRA's written comments. Parties now appear to agree that this was not an error in the E3 calculator, but rather an issue with how costs are defined in direct installation-type programs and in particular, how those costs are defined when the sum of direct install costs plus rebates/incentives exceed the incremental measure cost.

In its written comments, DRA characterizes this anomaly as one arising from the SPM definition of the costs that comprise the TRC test. According to DRA, the TRC test "excludes as a cost ratepayer dollars paid to a program participant."[66] Based on this understanding of the TRC test, DRA goes on to describe the following scenario for programs where participating customers incur no out-of-pocket expenditures:

> "If a program implementer makes a lump sum incentive payment to contractors that covers all costs associated with a retrofit at no cost to the customer, that lump sum incentive payment will not be included as a cost into the TRC. Under such a scenario, the TRC would be greater than the PAC, because the TRC would exclude as a cost ratepayer dollars paid to a program participant and there are zero net participant costs,

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[65] TecMarket Works Report, p. 14.

[66] *Comments of DRA in Response to the ALJ's Ruling Soliciting Preworkshop Comments on the Draft Report on the 2006 Update to Avoided Costs and E3 Calculator*, March 9, 2006 (DRA Pre-Workshop Comments), p. 7. See also: *Comments of DRA in Response to the ALJ's Ruling Soliciting Postworkshop Comments on the E3 Report on 2006 Update to Avoided Cost and E3 Calculator*, March 27, 2006 (DRA Post-Workshop Comments), p. 9.

> whereas the PAC would include ratepayer dollars paid to a program participant as a cost to the administrator. The resulting TRC net resource benefits would also exclude incentive payments as part of the program costs and therefore would be superficially high for such 'no cost' retrofit programs."[67]

DRA urges the Commission to consider instituting a cap on participant incentive amounts. In DRA's view, such a cap would serve to discourage program implementers or utility program administrators from shifting program funding into "no cost" retrofit programs to increase TRC net resource benefits. DRA also recommends that the input fields for the E3 calculator be revised to separately capture the incremental equipment cost of the energy efficiency measure as well as the installation costs.

Based on the record in this proceeding, we find that the treatment of costs in the TRC test has caused some anomalies in E3 model calculations that can, and should, be corrected for future applications of the TRC test and the E3 calculator. However, we do not agree with DRA's framing of the problem as a definitional issue that arises from the SPM.

The SPM is very clear on what the TRC represents, as are our Rules. The TRC test of cost-effectiveness includes *all* costs associated with the energy efficiency activity, whether paid for out-of-pocket by program participants or by non-participants through the authorized revenue requirements that fund the programs. [68]

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[67] *Id.* See also: *Comments of DRA in Response to the ALJ's Ruling Soliciting Postworkshop Comments on the E3 Report on 2006 Update to Avoided Cost and E3 Calculator*, March 27, 2006 (DRA Post-Workshop Comments), p. 9.

[68] SPM, p. 18.

The only costs that are excluded in the TRC test are those "incentives" that are to be are considered and treated as transfer payments. The SPM specifically directs that such incentives are restricted to include "only dollar benefits such as rebates or rate incentive (monthly bill credits)."[69] The conceptual basis for ignoring transfer payments in the development of the TRC is similar to the basis for ignoring tax credits in the Societal version of the test. That is, when some taxpayers receive cash transfers (in the form of a tax credit) as a result of higher taxes paid by others, economic theory suggests that those transfers be excluded when calculating the costs and benefits of the investment from the societial perspective. Historically, the SPM has incorporated a similar concept with respect to cash rebates to participating customers in the TRC test. That is, they have been excluded on both the benefit and cost side of the TRC equation, and considered to be a transfer payment between participating and non-participating customers.

In order to more fully explore the anomalies observed in the E3 calculator results for TRC cost-effectiveness and discuss ways to correct them, as well as respond to some of the comments on the draft decision on this issue, we need to further illustrate with numerical examples what the TRC and PAC tests intend to capture in their respective formulas. So, in a very simplified example, if the resource benefits are $3,000, the participant's measure installation cost is $2,000, the program administration cost is $100 (not including the cash rebate) , and the participating customer receives a $1,000 cash rebate for installing the measure,

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[69] SPM p. 11 (footnote 3 on page 11); 21.

the TRC equation *before cancelling out the cash rebate as a transfer* would look like this:

Benefit side: $1,000 + $3,000

(Benefit to participant of cash rebate + Resource benefits to all ratepayers)

Cost side: $2,000 + $100 +$1,000

(Participant's cost + Program admin cost (not including rebate) + Cost to non-participating customers of cash rebate)

By treating cash rebates as a dollar transfer payment, the SPM formula simply drops the $1,000 payment from both the benefit and cost side of the equation, producing TRC net resource benefits in this example of $900 ($3,000-$2,100) and a TRC benefit-cost ratio of 1.428 ($3,000/$2,100).

The PAC test, on the other hand, includes the cash rebate to the participating customer in calculating costs, but ignores the participant's costs. This is because the perspective of this test is the impact of the energy efficiency investment on utility revenue requirements. While the cash rebate to participating customers increases those requirements, the measure installation costs paid by the participant do not. The participant benefit of receiving a cash transfer payment from non-participating customers is not part of this test's perspective, so it never shows up on the benefit side of the equation at all.

Accordingly, for the simple numerical example presented above where the customer installs the measure and gets a cash rebate of $1,000, the PAC equation would look like this:

PAC Benefit side: $3,000

(Resource benefits to all ratepayers)

PAC Cost side: $100 +$1,000

(Program admin cost (not including rebate) + Cash rebate to participating customer)

Therefore, PAC net benefits would be $1,900 ($3,000 - $1,100) and the PAC benefit cost ratio would be 2.73 ($3,000/$1,100).

Prior to electric industry restructuring in the mid-1990s, most of the energy efficiency resource programs were similar in design to this numerical example—that is, participating customers would receive cash rebates to install energy efficient measures and equipment. Therefore, the term "incentive" and "rebate" were generally used interchangeably in the discussion of program costs and in the application of the SPM tests of cost-effectiveness. This is no longer the case, as pointed out in the workshop comments and discussion. Today, there are other forms of providing incentives to participating customers as well as other market actors purchasing and installing the equipment for the programs, resulting in misunderstandings and inconsistencies in how costs are being accounted for in the SPM tests and E3 calculator inputs. However, the manner in which the program is delivered or the rebate is provided to the customer should not result in different cost-effectiveness results, except in the very limited instances discussed below.

Let us look at the same simple numerical example under an early replacement "direct install" program design, where a third-party contractor replaces a customer's inefficient air conditioner with more efficient model. We assume that the resource benefits are $3,000, as in the prior example. We also assume that the utility incurs $100 in program administration costs. The utility authorizes the contractor to pay rebates of $1,000 on each installation. The contractor installs the unit at a cost of $2,000. The customer is presented with a bill for the $2,000 installation costs minus a $1,000 rebate. The contractor bills the utility for the $1,000 rebate given to the customer.

The SPM specifically states that "If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate) must be included in the PC_1 [participant cost]."[70] Consistent with the SPM formulas and definitions, the TRC and PAC tests would be calculated exactly the same as the example presented above for a program where the customer installs the equipment/measure instead of the third-party contractor, and receives a cash rebate:

TRC benefits: $3,000 **PAC benefits: $3,000**

TRC costs: $2,000 + $100 (Participant Costs + Program admin.)

PAC costs: $100 + $1,000 (Program admin. Costs + Cash rebate to participating customer paid through contractor)

TRC net benefits: $900; TRC benefit/cost ratio: 1.428

PAC net benefits: $1,900; PAC benefit/cost ratio: 2.73

Now let us look at an example where the direct install program does not bill or collect from the customer for any portion of the costs. Under both the TRC and PAC tests, the full $2,000 measure installation cost should appear as program administrator cost (rather than a participant cost), in addition to the $100 program administration costs. There would be no transfer payments or participant costs at all based on the SPM definition of these terms. The TRC test results would be the same as in the above examples. However, because the program results in higher utility revenue requirements (because now

[70] SPM, page 11, footnote 3.

participants are incurring zero out-of-pocket costs), the PAC test results are not as favorable as in the previous two examples. In fact, the TRC and PAC test results would be identical to each other, as indicated below:

TRC benefits: $3,000 **PAC benefits: $3,000**

TRC costs: $2,000 + $100 (Direct install costs paid by utility + Program admin. costs)

PAC costs: $2,000 + $100 (Same as above)

TRC net benefits: $900; TRC benefit/cost ratio: 1.428

PAC net benefits: $900; PAC benefit/cost ratio: 1.428

These numerical examples serve to illustrate what should be obvious: A direct install program where the utility or its contractor performs the installation of a measure should not be more cost-effective from a TRC perspective than a rebate program that provides a cash rebate to the customer up to the full cost of installation. We recognize that there may be limited instances for program design purposes where the cash rebate to the customer exceeds the measure installation cost. Under these circumstances, the TRC results will be the same for both direct install and the rebate program (all other things being equal), given the transfer payment treatment of cash rebates in the SPM. However, the PAC test will favor the direct install program. It was precisely to address these types of circumstances that we adopted the "Dual Test" of cost-effectiveness in our policy rules. Those rules recognize that both the TRC and PAC tests of cost-effectiveness need to be considered when evaluating program proposals, in order to ensure that program administrators and implementers do not spend more on rebates/cash incentives than absolutely necessary to achieve TRC net benefits.[71]

The discussion above also points out that when the SPM definition of transfer payments is properly implemented in the TRC test, participant costs are expected to be "non-negative." We recognize that there may be isolated instances where the energy efficiency measure actually costs less than the standard efficiency equipment, as PG&E points out in its comments on the draft decision.[72] However, one would not expect to see negative participant costs for the vast majority of measures or in the evaluation of program cost-effectiveness calculations where there is a mix of measures, if costs are inputted correctly into the E3 calculator and transfer payments are properly restricted per the SPM definition.

DRA's scenarios presume that if the participant pays no out-of-pocket costs under a direct-install program, then all of the costs associated with the equipment/measure installations simply disappear from the TRC cost-side of the equation. As discussed above in our third numerical example, that certainly

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[71] See D.05-04-051, Attachment 3, Section IV. In its comments on the draft decision, SCE correctly points out that a program may pass the TRC test but fail the PAC test under these circumstances, and therefore the draft decision proposed treatment of cash rebate costs in the TRC test was not fully consistent with the SPM. However, SCE's comments fail to acknowledge the more fundamental problem the draft decision identified; namely, the inconsistent treatment of incentives and participant costs in E3 calculator inputs and the calculation of TRC test results, particularly for direct install programs.

[72] PG&E gives the example in DEER of double pane clear windows and direct evaporative coolers, tankless gas water heaters, among others. However, a closer examination of the DEER dataset reveals that the incremental measure cost is not negative (set at 0) even when the difference in equipment cost is negative. As noted in the SPM, the equipment cost is only one element or the measure or participant cost.

should not be the case. Further, we note that this is not the case when the TRC test is performed for Low-Income Energy Efficiency programs, where participants generally incur no out-of-pocket expenditures for the installation of energy efficiency measures.

DRA also claims that when the customer rebate exceeds the equipment/measure installation costs, this creates "a distorted relationship between the TRC and the PAC benefit-cost ratios."[73] This should also not be the case if the SPM cost components are inputted into the E3 calculator in a manner consistent with the definition of both tests. Again, the TRC test reflects *all* participant and non-participant costs, meaning that the full resource costs of the energy efficiency investment must show up somewhere in the TRC cost-side of the equation with the limited exception of transfers of dollar benefits (rebates/monthly bill credits) to participants.

In our view, these clarifications speak to the need to ensure that the program cost components and transfer payments are properly entered into the E3 calculator (or in other platforms for calculating and reporting cost-effectiveness results) consistent with the SPM formulas and definitions, rather than the need to cap incentive payments, as DRA proposes. As discussed in Section 10.2, we request that Joint Staff, the utilities and their program advisory/peer review group members explore ways in which this can be best accomplished through technical workshops. There may also be refinements to the E3 calculator that can serve to flag potential input errors and inconsistencies

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[73] *Comments of DRA in Response to the ALJ's Ruling Soliciting Postworkshop Comments on the E3 Report on 2006 Update to Avoided Cost and E3 Calculator*, March 27, 2006, p. 9.

(e.g., negative participant costs, incongruous differences between TRC and PAC test results), that can assist in the quality control of input data. These refinements should be considered and presented during the E3 calculator updating process, discussed in Section 11 below.

We emphasize that today's discussion of the TRC and PAC tests of cost-effectiveness does not speak to the design of programs (or is intended to cap incentives in any manner). Instead, it speaks to need to ensure that all costs are inputted into the E3 calculator, or any other calculation platform for the SPM tests, in a manner that is consistent with the SPM formulas and definitions, as discussed above.

10. Other Issues

Two additional issues were discussed during the workshops and in comments, which we address below.

10.1. Appropriate Calculation Platform

The Final Report addresses the issue of what calculation platform to use for the *ex ante* evaluations and submissions of portfolio and program plans, for example, in preparation for the 2009-2011 program cycle. The consensus among workshop participants is that the benefits of the E3 calculator outweigh the shortcomings of a platform based on Excel spreadsheets, at least for the near term.[74]

We concur with this approach. As noted in the Final Report, some of the shortcomings can be addressed through a redesign of the calculator. In particular, the E3 calculator inputs and outputs can be separated from the

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[74] These benefits and shortcomings are described in the Final Report, pp. 31-32.

calculation engine as a near term enhancement. In addition to the advantages noted in the Final Report, this approach would also facilitate the development of standardized "default" input values to improve quality control, as discussed further below. Therefore, we direct that this enhancement be made to the E3 calculator platform as part of the E3 calculator updating process described in Section 11.

Over the longer term, we may consider alternative platforms to use for the *ex ante* evaluations and submissions of portfolio and program plans. However, migration to another platform should not be decided until more information is known about the availability of new hourly load shapes, as well as the cost and effort needed for such an undertaking. In this phase of the proceeding we also intended to explore whether further refinements to the E3 calculator are needed to create a common planning/forecasting tool for use by utility portfolio managers, third-party implementers, regulatory staff and possibly program advisory and peer group members. This is clearly a longer term effort. Rather than initiate work on this effort today, we will focus on improving the E3 calculation platform currently in use, as discussed further below.

There was some debate during the workshops over whether the utilities should also be required to use the E3 calculator to generate the monthly, quarterly and annual reports required under the reporting requirements established for post-2005 energy efficiency activities. We will leave this issue to be resolved as suggested by workshop participants. The utilities should meet among themselves, E3 and Joint Staff on a common approach and tool for reporting that applies the SPM cost-effectiveness tests as described in this decision and can generate the required reporting information. The utilities and Joint Staff should jointly report back on the common approach and tool that will be used for this purpose by October 15, 2006. The report should be submitted to the assigned ALJ in R.06-04-010. The ALJ should consider this report in consultation with Joint Staff, and may take any additional steps necessary to ensure that a common approach and tool for reporting is implemented by the utilities in a timely manner.

10.2. Quality Control of E3 Calculator Inputs

The *ex ante* inputs to the E3 calculator for measure/equipment costs, measure savings, program administrator program costs, etc., are currently made by utility program managers (for utility-implemented programs) or by third-party implementers, subject to regulatory review when the portfolio and program plans are submitted. This involves the entering of hundreds of lines of data by numerous individuals. While there are guidelines for this data entry (e.g., the requirement in our Rules to use DEER values where available), the current process is less than ideal from a quality control perspective, as recognized by most of the workshop participants. The TecMarket Works and peer review group assessment of the June 1, 2005 filings served the Commission well in identifying some of the potential inconsistencies and errors in the E3 calculator inputs, but as workshop participants point out, there may be additional ways to assure greater quality control on an ongoing basis in the future.

One such approach may be to have the E3 calculator use a common or standardized data base to draw from as default value for most or all measures, and include the capability to “flag” the entries that differ from those values. This would still allow program managers and third-party implementers the flexibility to enter alternative values if they believe (and document) that the default values do not apply for the specific application or that better data is available.

However, by flagging the data that does not utilize standardized default values, reviewers (Joint Staff, Energy Division consultants, peer review groups, etc.) can more easily identify areas for further examination. Currently, they must examine every single line of program input data and compare it to DEER data, for example, to evaluate whether or not the DEER values are used. The E3 calculator enhancement discussed in Section 10.1 (separating the input and output files from the calculation engine) would facilitate the development of such an approach.

Establishing a review process for the calculator inputs before they are entered into the calculator may also be a way to enhance the consistency of the data inputs, catch errors and address questions that arise about the input values. Based on DRA's comments, it appears that one area where such an "advance review" would be particularly useful is measure cost inputs. These and other approaches to quality control improvements should be explored collaboratively by Joint Staff, interested parties, the utilities and their program advisory/peer review groups in the coming months.

We direct the utilities to jointly plan and notice public workshops for this purpose during the third and forth quarters of 2006, and report back to the Assigned Commissioner and ALJ in R.06-04-010 on the consensus and non-consensus recommendations presented at those workshops no later than December 15, 2006. The workshop notice(s) should be sent to the service list in R.06-04-010 and to the utility program advisory group and peer review group members. The utilities are directed to jointly contract with appropriate technical expertise to assist in this effort so that options and specific implementation steps for quality control improvements can be fully explored during the workshops and in the report described below. In consultation with the utilities, Energy

Division shall determine the specific EM&V budget category for funding this technical expertise. The Assigned Commissioner and ALJ in R.06-04-010 will consider the report in consultation with Joint Staff, and implement quality control improvements as they determine are appropriate and practicable**.**

11. Updating the E3 Calculator in Compliance with Today's Decision

The E3 calculator for each utility will need to be updated to reflect today's determinations. In order to ensure that the required modifications are consistent across utilities, we direct the utilities to jointly contract with the appropriate expertise. The utilities should notify Energy Division of their intended contractor(s). The costs of the contract will be paid for out of the utilities' portion of EM&V budgets for the 2006-2008 program cycle.

Prior to submitting the required revisions to the Commission, the utilities and their contractor(s) should present the revised E3 calculators (including inputs) to their program advisory and peer review groups for review in joint statewide public meeting(s), with notice to the service list in R.06-04-010. At least two weeks prior to the meeting(s), the utilities and/or contractor(s) should post to a website all of the revisions responding to today's directives with a written summary of the changes made. At the same time, the utilities should notify the utility advisory group/peer review group members and the service list in R.06-04-010 of the availability of this information.

In addition to the revised E3 Calculator and input files, the website posting should include a summary of the changes made in response to today's decision. The website posting should also include a table summarizing the comments made at the review meeting(s) discussed above, the name/organization providing the comment, and the utilities/contractor(s) responses to each comment (e.g., whether the comment resulted in further modifications to the E3 calculator to satisfy the requirements of today's decision, or not—and why not).

After considering the input received at the meeting(s), the utilities should submit final E3 calculator and input revisions no later than September 8, 2006 in the form of a Notice of Availability (Notice). The Notice should provide a website address where the revised E3 calculator and associated inputs can be accessed, and include the due date for comments on the E3 calculator revisions and filing/ service requirements, as set forth below.

The Notice and all comments should be filed in the Commission's Docket Office and served electronically on the service list in R.06-04-010, consistent with the electronic service rules established for that proceeding. All interested individuals or organizations who are not already parties (appearances) to R.06-04-010, and who wish to have the opportunity to comment on the compliance submittal described above should file a motion to intervene for this purpose in R.06-04-010 without delay. Parties to R.06-04-010 may file opening comments on the compliance submittal by September 22, 2006 and reply comments by September 29, 2006. After considering written comments, and in consultation with Joint Staff, the assigned ALJ in R.06-04-010 will address the compliance submittal by ruling, or take other steps as necessary to ensure compliance with today's decision.

12. Coordination of Avoided Cost-Related Issues

During the March 2006 workshops, the ALJ requested additional information on pending proceedings where avoided cost-related issues are being raised. The responses points to the continued need to coordinate across proceedings on these issues. It is unavoidable that the utilities and interested parties will be proposing methodologies for avoided cost or marginal price valuation in the context of specific revenue allocation, rate design, or resource-related proceedings between now and when we initiate and complete Phase 3 of this rulemaking. As indicated in the comments in this proceeding, the utilities have proposed a CT-based valuation approach in pending applications for advanced metering infrastructure (AMI), rate design phases of general rate cases, among others.[75] However, the fact that the utility submittals propose a particular avoided cost methodology in a pending proceeding, does not mean that we will accept the merits of those proposals or, if we do require an estimate of avoided or marginal costs to resolve the pending issue(s), that this will establish a precedent for avoided cost valuation.

We have clearly stated that debate over avoided cost methodology should be conducted in this rulemaking, and not in multiple proceedings where the methods and inputs for specific applications of avoided costs are applied. We reiterate today that:

> "…this rulemaking serves as the Commission's forum for developing a common methodology, consistent input assumptions and updating procedures for avoided costs across our various proceedings, and for adopting avoided cost calculations and forecasts that conform to those determinations. It is the forum for considering similarities as well as appropriate differences in methods and inputs for specific applications of avoided costs, including QF avoided cost pricing. Our goal is to establish 'apples to apples' comparisons across resource options,

[75] A.05-06-028 (PG&E's AMI), A.05-03-015 (SDG&E's AMI), A.05-05-023 (SCE's GRC Phase 2), A.06-03-006 (PG&E's GRC Phase 2), A.05-12-030 (KRCC Contract Evaluation), and A.04-02-026 (SONGS Anaheim Transfer Evaluation). SCE's AMI docket (A.05-03-026) was closed, and there is no current docket opened for those issues.

> to the greatest extent possible. We will strive for consistent methodologies and assumptions across applications of avoided costs, while recognizing that statutory directions for specific programs may require some other considerations."[76]

The reasons we articulated for consolidated avoided cost issues into a single rulemaking are as valid today as they were two years ago. As we noted then, it is less confusing for all interested parties to follow and participate in avoided cost issues if they are addressed in a single rulemaking proceeding. Even with careful notice procedures and coordination among the assigned ALJs and Commissioners, it is difficult to ensure that the public knows clearly where and when avoided costing methods, assumptions, forecasts, and updating procedures will be considered by the Commission.

In addition, we continue to believe that consolidating these issues into a single rulemaking will ensure a consistent record as the Commission considers how best to calculate and update avoided costs for the various resource-related applications:

> "As we recognized in R.04-03-017, cohesive and rational policy making for resource procurement requires that we develop a common methodology for assessing avoided costs across the full range of supply- and demand-side technologies. QF pricing is part of this mix, and should not be addressed in isolation. Although there may be legitimate reasons for differences in avoided cost calculations, depending upon the application, we believe that addressing methodological issues, input assumptions, and updating

[76] *Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities*, (Avoided Cost OIR), issued April 22, 2004, *mimeo.*, p. 2.

procedures in a single forum is the best way to consider those differences as we develop avoided costs for use in our proceedings."

Accordingly, we reiterate and emphasize today that this rulemaking continues to serve as the forum for developing "the common methods, input assumptions, and updating procedures" for avoided cost calculations used in all Commission proceedings where avoided cost calculations or forecasts are to be applied.[77]

13. Comments on Draft Decision

The Draft Decision of ALJ Gottstein in this matter was mailed to the parties in accordance with Public Utilities Code Section 311(g)(1) and Rule 77.7 of the Commission's Rules of Practice and Procedure. Cogeneration Association of California and the Energy Producers and Users Coalition jointly filed opening comments. The following parties filed both opening and reply comments: PG&E, DRA, SCE and SDG&E/SoCalGas (jointly).

In their comments on the draft decision, PG&E, SCE and SDG&E object to the discussion in today's decision of how costs should be treated in the TRC test. PG&E, in particular, argues that the 2006 Update is not the appropriate procedural forum for addressing this issue. We disagree. In D.05-09-043, the Commission clearly articulated the need to investigate the cause of E3 calculator anomalies with respect to the SPM tests in the 2006 Update, the issue was discussed during the workshop process and all parties had an opportunity to address it in written comments.

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[77] *Ibid.*, p. 13.

The joint comments of the Cogeneration Association of California and the Energy Producers and Users Coalition speak to QF pricing and fundamental changes to the interim avoided cost methodology. As discussed in this decision, these issues are beyond the scope of the 2006 Update phase. We do not make any modifications to the draft decision in response to them.

We do, however, make substantive modifications to the draft decision's discussion of the appropriate treatment of costs and transfer payments in the TRC test, and make minor clarifications and corrections in response to comments.

14. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Meg Gottstein is the assigned ALJ to this phase of the proceeding.

Findings of Fact

1. The workshop consensus for the definition of energy efficiency peak kW reductions is a pragmatic approach to addressing load impact data limitations at this time. In addition, it takes advantage of a database that the Commission has determined should be the source of all assumptions for estimating load impacts, to the extent possible.

2. As discussed in this decision, PG&E alleges inconsistencies with respect to DEER that do not appear to be based upon relevant analysis or documentation.

3. PG&E proposes an expanded peak period without documentation of the additional research to which it refers, and without the opportunity for interested parties to review the underlying data or to address the potential ramifications of its proposal.

4. If PG&E believes that the issues it raised in written comments concerning the definition of peak kW warrant further evaluation, it may present them in the context of future DEER updates.

5. An appropriate long-term definition for energy efficiency peak kW impacts needs to be considered in the context of available load shape data for individual energy efficiency measures, to be further explored as discussed in this decision.

6. The consensus recommendations concerning the estimates of peak kW the utilities should use for rebalancing their portfolios and reporting program accomplishments during the program cycle are consistent with Rule IV.11 of the Commission's adopted energy efficiency policy rules. However, further clarification is warranted with respect to customized rebate programs, as discussed in this decision.

7. Ongoing exchange of information is needed concerning the peak kW load reduction factors (ratio of kW to kWh savings) that utilities use for portfolio rebalancing and reporting.

8. The record in this proceeding supports the workshop consensus that TOU averaging significantly undervalues measures that produce relatively more load reduction during the highest cost hours, such as residential and to a lesser extent, small commercial a/c equipment upgrades.

9. The Final Report and Supplement provides a reasonable basis for adopting correction factors to adjust the avoided cost valuation of these particular measures, when TOU averaging is utilized to calculate their avoided costs.

10. Adopting correction factors based on DEER hourly load shape data is consistent with Rule IV.11 and preferable to using PG&E's hourly load shape data for several reasons discussed in this decision, including:

a. PG&E itself has elected not to use its own hourly load shapes at any point heretofore in the 2006-2008 energy efficiency planning and design process in any significant manner.

b. Instead, PG&E has utilized TOU blocks or shapes in its application for approval of its 2006-2008 energy efficiency programs and budgets that are in closer agreement with DEER hourly shapes converted to TOU shapes than the TOU shapes created from PG&E's own hourly load shapes.

c. PG&E's hourly load shapes are building end use shapes rather than measure impact shapes, and many of them are from relatively old data collection exercises using relatively small sample sizes.

d. The documentation of DEER indicates that the DEER simulations utilize field data that are more recent, more extensive and more representative of climate and vintage variations than the PG&E hourly load shapes.

e. An examination of PG&E's average hourly load shapes for certain applications (e.g., office and retail indoor lighting, office and retail cooling) indicate patterns that do not appear representative of the load impacts associated with energy efficiency measures.

11. Residential a/c unit energy efficiency savings are likely to be higher in the hotter climate zones, where efficiency improvements result in higher energy savings because of a/c usage patterns. Therefore, TOU-averaging correction factors for these measures should be based on a climate-zone specific weighting of projected measure installations, as opposed to a weighting that assumes an equal distribution of measures across climate zones.

12. The additional precision gained from individual climate-zone correction factors does not justify the complexity and possible confusion resulting from having eight or nine different climate-zone correction factors for the measure.

13. The DEER data for small office and retail building types within the commercial sector presents a reasonable range of the potential undervaluation associated with TOU-averaging for small commercial a/c (packaged and split-system direct-expansion cooling) units across all building types.

14. The weighting options (equal weighting or based on an estimate of installations across climate zones) result in very little difference to the conversion factors for commercial a/c measures. The only exception is in the case of SDG&E's weighting for office installations, which assumes that all installations of small a/c commercial units will occur in the retail sector (and none in commercial offices).

15. In view of the implementation complexities and uncertainties over the distribution of measure installations for the commercial sector, there is questionable value to approaching the commercial a/c correction factor on a sector-specific (i.e., by building type) basis. Instead, a simple average of the low (office) and high (retail) end of the range presented in the Final Report presents a reasonable approach to calculating a TOU-correction factor for territory-wide commercial a/c unit installations.

16. The CT-adder recommendations made by some parties to this proceeding represent a fundamentally different approach and theory to avoided costs than the interim methodology adopted in D.05-04-024. As discussed in this decision, modifying current avoided costs using this CT-adder approach requires the resolution of complex theoretical issues, assumptions and methodological issues that are beyond the scope of this 2006 Update.

17. Adopting a simple capacity adder, as some parties recommend as an alternative to the CT-adder approach, relies on the assumption that the current hourly price profile fails to value avoided costs properly for low load-factor

energy efficiency measures during peak hours. Until the Commission further examines the theoretical and methodological issues raised with respect to the interim methodology, there is insufficient basis in the record for making this assumption.

18. Contrary to TURN's assertions, the Commission has not adopted specific methodologies that put low-load factor air conditioning measures on a different footing with the valuation approaches being applied to rate design or the evaluation of other resource options. In fact, the Commission's recent decision on a methodology for calculating the 2005 MPR would argue against making adjustments to the PX profile to allow the price shape to return the capital cost of a CT.

19. The *ex ante* avoided costs used for 2006-2008 portfolio rebalancing, as well as to evaluate 2006-2008 performance, should reflect the significantly changed realities in natural gas supplies and market prices that have emerged since the interim avoided costs were adopted in early 2005.

20. Using one set of avoided costs for program valuation and another set for reward determination under a risk/reward incentive mechanism would not only be unduly complicated, but could create a disincentive for utilities to rebalance their portfolios to reflect the updated avoided costs.

21. Improvements are needed to energy efficiency load/impact shape data in time for the 2009-2011 program cycle.

22. Load/impact shape improvements should be considered in the DEER updating process. However, as discussed in this decision, the 2006 Update is not the appropriate forum for specifying the DEER updating process, such as how final determinations are made on what types of data generated by load shape studies (or other EM&V studies) represent an improvement to existing values in

DEER, and therefore should replace those values. Instead, these and other aspects of the DEER updating process will be considered in R.06-04-010 according to the EM&V protocol review procedures established in D.05-04-051.

23. As discussed in this decision, Energy Division is responsible for determining how the load shape studies will be managed (e.g., as part of the DEER updating process or through separate EM&V contracts) and at what level they should be funded out of EM&V authorized budgets.

24. The E3 calculator treatment of load increases as a negative benefit (versus a cost) does not affect the calculation of net benefits under the SPM tests, and would not affect the benefit-cost ratios to any significant degree.

25. As discussed in this decision, the reporting requirements developed by Energy Division could lead to a double counting of overhead costs in the SPM tests because some of those costs may already be included in the labor component of the incremental measure cost.

26. The TRC test of cost-effectiveness includes all costs associated with the energy efficiency activity, whether paid for out-of-pocket by program participants or by non-participants through the authorized revenue requirements to fund the programs.

27. The only costs that should be excluded in the TRC test on both the benefit and cost side of the equation are those incentives that represent transfer payments, as defined in the SPM. The SPM restricts such transfer payments to dollar benefits to the participant, such as rebates or rate incentive (monthly bill credits).

28. Given the definition of the TRC and PAC tests, it should generally be the case that TRC net benefits or benefit-cost ratios should be lower than the PAC cost-effectiveness results because the PAC test does not include the costs

incurred by participating customers, while the TRC test does include these costs. The exception to this general rule can happen under the SPM definition of the TRC test when very large "transfer payments" between non-participating and participating ratepayers occur. However, as discussed in this decision, this should not be a frequent occurance if the proper definition of transfer payments is used and installation costs are accounted for properly.

29. The manner in which the energy efficiency program/measure is delivered or the rebate is provided to the participating customer should not alter cost-effectiveness results, all other things being equal, except under the very limited circumstances discussed in this decision.

30. The numerical examples in this decision serve to illustrate what should be obvious: A direct install program where the the utility or its contractor performs the installation of a measure should not be more cost-effective from a TRC perspective than a rebate program that provides a cash rebate to the customer up to the full cost of installation.

31. If the SPM cost components are inputted into the E3 calculator in a manner consistent with the SPM formula and definitions for the TRC test, then the scenario that DRA poses for a direct install program, where all costs associated with equipment/measure installations "disappear" from the TRC cost-side of the equation, should not occur.

32. When the SPM definition of transfer payments is properly implemented in the TRC test, participant costs are expected to be "non-negative." As discussed in this decision, there may be isolated instances where an energy efficiency measure actually costs less than the standard efficiency equipment it is replacing. However, one would not expect to see negative participant costs for the vast majority of measures, in or in the evaluation of program cost-effectiveness

calculations where there is a mix of measures, if costs are inputted correctly into the E3 calculator and transfer payments are properly restricted consistent with the SPM definition.

33. The record supports the workshop consensus that, at least for the near term, the benefits of the E3 calculator outweigh the shortcomings of a platform based on Excel spreadsheets.

34. Some of the shortcomings of the current E3 calculator platform can be addressed through a redesign of the calculator, such as separating the E3 calculator inputs and outputs from the calculator engine. This separation would also facilitate the development of standardized default input values, as discussed in this decision.

35. Over the longer term, it may be appropriate to consider alternative platforms to use for the *ex ante* evaluations and submissions of portfolio and program plans. However, migration to another platform should not be decided until more information is known about the availability of new hourly load shapes, as well as the cost and effort needed for such an undertaking.

36. Further refinements that might be needed to the E3 calculator to create a common planning/forecasting tool for use by utility portfolio managers, third-party implementers, regulatory staff and possibly program advisory/peer review group members is also a longer term effort.

37. The issue of whether the utilities should be required to use the E3 calculator to generate the monthly, quarterly and annual reports requires further consideration among the utilities, E3 and Joint Staff.

38. As discussed in this decision, there may be additional ways to assure greater quality control over data entry into the E3 calculators on an ongoing basis.

39. The comments in this proceeding points to the continued need to coordinate across proceedings where avoided costs are being raised.

Conclusions of Law

1. Until further notice of the Commission, it is reasonable to:

   a) Use the 2005 DEER Update definition of peak kW for the purpose of verifying energy efficiency program and portfolio performance, and

   b) Require the utilities to apply this definition to energy efficiency uses during the 2006-2008 program cycle, including any necessary portfolio rebalancing.

2. The consensus recommendations concerning the estimates of peak kW that the utilities should use for rebalancing their portfolios and reporting program accomplishments during the program cycle are reasonable and should be adopted.

3. The utilities should be required to update their *ex ante* estimates of kW and kWh savings for customized rebate programs and provide information on the peak kW load reduction factors used for portfolio rebalancing and reporting, as described in this decision.

4. Nothing in today's decision modifies the *ex post* verification and true-up requirements for energy efficiency load impacts directed in D.05-04-051 and in the adopted EM&V protocols in R.06-04-010 and its predecessor rulemaking, R.01-08-028. Today's decision provides a clarification to the true-up process by defining the peak kW metric that will be verified in *ex post* studies for the 2006-2008 program cycle, namely the DEER definition of peak demand.

5. It is reasonable to adopt TOU averaging correction factors for residential and small commercial a/c unit installations based on the DEER data presented in this proceeding.

6. Modifications to the interim avoided costs methodology for peak valuation adopted in D.05-04-024 should not be adopted for the reasons discussed in this decision. However, the methodological issues raised in this phase of the proceeding may be appropriate topics to explore during Phase 3.

7. The updated natural gas forecasts and avoided costs presented in Attachment 3 reflect the significantly changed realities in natural gas supplies and market prices that have emerged since the interim avoided costs were adopted in early 2005, and should be adopted.

8. As discussed in this decision, it is reasonable to adopt an action plan for improving load shape data in a practical and timely manner.

9. The minor inconsistency between the E3 calculator and the SPM with respect to the treatment of load increases does not merit changes to the E3 calculator.

10. The utilities should work on a joint request to the assigned ALJ in R.06-04-010 and Energy Division to modify the reporting requirements in order to fix the problem identified during workshops with respect to the potential double counting of costs in the SPM tests.

11. As discussed in this decision, the treatment of costs and transfer payments in the TRC test has caused some anomalies and inaccuracies in the E3 model calculations. This treatment should be corrected in future applications of the TRC test and the E3 calculator.

12. Nothing in today's decision speaks to the design of programs, or is intended to cap incentives in any manner. Rather, today's determinations speak to the need to ensure that the program cost components and transfer payments are properly inputted into the E3 calculator (or other platforms for calculating

and reporting cost-effectiveness results) consistent with the SPM formulas and definitions, as discussed in this decision.

13. As discussed in this decision, our near term focus should be to improve the E3 calculation platform currently in use. In particular, the E3 calculator should be redesigned to separate the inputs and outputs from the calculator engine.

14. As discussed in this decision, approaches to quality control improvements with respect to E3 calculator data entering should be explored by Joint Staff, interested parties, the utilities and their program advisory/peer review groups in the coming months.

15. The utilities, Joint Staff and E3 should confer on the use of a common approach/tool to produce the required reports for post-2005 energy efficiency activities and report back to the ALJ, as directed in this decision.

INTERIM ORDER

IT IS ORDERED that:

1. Until further notice of this Commission, the definition of peak kilowatt (kW) contained in the 2005 Database for Energy Efficient Resources (DEER) shall be used for the purpose of verifying energy efficiency program and portfolio performance. As discussed in this decision, DEER defines peak demand as the average grid level impact for a measure between 2 p.m. and 5 p.m. during the three consecutive weekday period containing the weekday temperature with the hottest temperature of the year.

2. Until further notice, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), collectively referred to as

"the utilities," shall apply the definition of peak kW adopted herein to energy efficiency uses during the 2006-2008 program cycle, including any necessary portfolio rebalancing.

3. When rebalancing their portfolios and reporting program accomplishments during the program cycle, the utilities shall:

   a) Use DEER values for peak kW and kilowatt hour (kWh) savings for those measures that are included in the DEER database;

   b) Continue to use their best estimates of those values for measures that are not currently included in DEER, or for programs with measure categories rather than specific measures, such as customized rebate programs.

4. As discussed in this decision, the utilities are required to update their *ex ante* estimates of kW and kWh savings for customized rebate programs as they proceed with implementation, based on site specific installations for these programs, just as they are required to do for the incremental measure costs. In doing so, they shall utilize DEER savings values for the installed measures, if that data is available in DEER. Until further notice, the utilities shall present these updates of *ex ante* estimates to Joint Staff and the utilities' program advisory and peer review groups every six months, i.e., by June 15 and by December 15 of each year.

5. The utilities shall provide the information necessary for Joint Staff and other program advisory and peer review group members to review the methodology and/or baseline load shape (measure or end use) estimates they are using to estimate peak kW load reduction factors. In addition, the utilities shall jointly schedule a statewide meeting (or series of meetings) with their program advisory and peer review groups to discuss this information as soon as practicable. This information shall:

a) Indicate clearly where DEER and non-DEER values of kWh and peak kW impacts are used, and for the latter, present other sources of load factor data as a basis for comparison.

b) Include data sources and basis for the non-DEER energy and demand estimates.

c) Be provided within 15 days from the effective data of this decision, and on an ongoing basis thereafter, as requested by Joint Staff or the utilities' program advisory/peer review groups during the program cycle, and

d) Be posted on a website with notification of availability to the service list in Rulemaking (R.) 06-04-040.

6. The utilities shall meet among themselves, Energy and Environmental Economics, Inc. (E3) and Joint Staff on a common approach and tool for reporting that applies the Standard Practice Manual cost-effectiveness tests as described in this decision and can generate the required reporting information. The utilities and Joint Staff shall jointly report back on the common approach and tool that will be used for this purpose by October 15, 2006. The report shall be submitted to the assigned Administrative Law Judge (ALJ) in R.06-04-010. The ALJ shall consider this report in consultation with Joint Staff and may take any additional steps necessary to ensure that a common approach and tool for reporting is implemented by the utilities in a timely manner.

7. Until further notice, the following utility territory-wide correction factors shall be applied to the avoided cost valuation using time-of-use (TOU) shapes for residential air conditioning (a/c) unit energy savings:

PG&E—1.171; SCE—1.202; SDG&E—1.276.

These correction factors shall be applied to the total avoided cost valuation for all residential a/c unit installations, excluding transmission and distribution avoided costs.

8. Until further notice, the following utility territory-wide correction factors shall be applied to the avoided cost valuation using TOU shapes for small commercial a/c (packaged and split-system direct-expansion cooling) unit energy savings:

PG&E—1.085; SCE—1.105; SDG&E—1.145.

These correction factors shall be applied to the total avoided cost valuation for small commercial a/c unit installations in the commercial sector, excluding transmission and distribution avoided costs.

9. If the utilities do not currently identify the a/c unit installations and the associated peak savings referred to in Ordering Paragraphs 7 and 8 above in the E3 calculator (or in other formats where projected savings are presented), they shall develop a consistent and joint approach for doing so. This may entail estimating the fraction/percentage of installations for cooling end-use measures that represent the a/c unit hardware upgrades, and applying the correction factor to that fraction, or some other approach that is reasonable, consistent across utilities and practicable. The proposed approach shall be submitted with the E3 calculator updates directed in Ordering Paragraph 17.

10. The *ex ante* natural gas and electric generation avoided costs presented in Attachment 3 shall be used for 2006-2008 portfolio rebalancing as well as to evaluate 2006-2008 performance for energy efficiency activities.

11. As discussed in this decision, the utilities shall jointly contract with appropriate expertise to develop a Load Shape Update Initiative in R.06-04-010. The Load Shape Update Initiative shall include public workshops with technical experts to help scope the effort as well as review the draft report. Energy Division may schedule and lead these workshops, or delegate this function to the

contractor(s). The contractor(s) shall be tasked with developing draft and final reports addressing the following issues, as well as others that emerge from the scoping workshops, as appropriate:

(a) What load shapes/blocks exist in the E3 calculators, California Energy Commission and utility load forecasts, and the data source quality;

(b) The magnitude of the problem(s) with existing load shape data, utility vs. statewide;

(c) The costs and benefits associated with potential improvements to existing load shape data;

(d) Based on (a) through (c), what should be:

- The near- and long-term improvement objectives for load shape updating, including how best to incorporate recently completed studies and studies underway into the E3 calculator;
- The criteria used for prioritizing end-uses/measures for load shape improvements; and
- The priorities for load shape improvements by end uses/measures including a schedule for completing those improvements in time for the 2009-2011 program cycle.

12. The utilities shall ensure that the contractor(s) retained for the Load Shape Update Initiative develops a draft report by October 1, 2006 that includes preliminary recommendations on the issues listed under (d) above. Energy Division (or the contractor(s)) shall hold public workshops on the draft report as soon as practicable thereafter, so that the contractor(s) can respond to feedback and questions. The contractor(s) shall be tasked with developing a final report by November 15, 2006 that, among other things, summarizes the areas of consensus and non-consensus among workshop participants by issue area and presents final recommendations.

13. Energy Division, the assigned ALJ or Assigned Commissioner in R.06-04-010 may solicit post-workshop written comments on the final Load Shape Update Initiative report from interested parties, as they deem appropriate. As discussed in this decision, after considering the final report recommendations, Energy Division shall proceed to develop the study scopes, specific work tasks, schedules and budgets for load shape improvements as part of its ongoing evaluation, measurement and verification (EM&V) responsibilities. As soon as practicable after the final report is submitted, Energy Division shall update the EM&V roadmap in consultation with the assigned ALJ in R.06-04-010 to reflect a schedule that targets the completion and incorporation of the highest priority load shape improvements into the E3 calculator by the end of December, 2007.

14. Nothing in this decision is intended to preclude the Assigned Commissioner or ALJ in R.06-04-010 from directing the utilities to broaden the scope of the contractor(s) work, or take any other steps that may be necessary to address the Load Shape Update Initiative. The Load Shape Initiative and load shape studies to be conducted during 2006-2008 shall be funded out of authorized 20062-2008 EM&V funding levels. Energy Division shall determine the specific EM&V budget category (or categories) for funding these efforts in consultation with the utilities.

15. As discussed in Ordering Paragraph 18 below, Joint Staff, interested parties, the utilities and their program advisory/peer review groups shall collaboratively explore ways in which to ensure that the Total Resource Cost (TRC) cost components are entered into the E3 calculator (or in other platforms for calculating and reporting cost-effectiveness results) in the future in a manner that is consistent with the Standard Practice Manual (SPM) definitions and

formula for the TRC test. As discussed in this decision, all participant and non-participant costs shall be fully reflected in the TRC test with the limited exception of dollar benefits such as rebates or rate incentives (monthly bill credits) to the participating customer. Those dollar benefits shall be treated as a transfer payment and excluded on both the benefit and cost side of the TRC equation, as currently directed under the SPM. However, they will be included in the Program Administrator Costs (PAC) test. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate) must be included in the TRC test as a participant cost. In situations where a direct install program does not bill or collect from the customer for any portion of the costs, then all costs should appear as program administrator costs in both the PAC and TRC tests.

16. The utilities shall jointly contract with the appropriate expertise to update each of their E3 calculators in compliance with today's determinations. These updates shall reflect:

(a) Today's adopted definition of peak kW;

(b) The updated natural gas and electric generation avoided costs presented in Attachment 3;

(c) The TOU-averaging correction factors adopted by today's decision;

(d) A method for identifying the a/c unit installations and the associated peak savings to which the adopted correction factors will apply, if such measures/peak savings are not currently identified in E3 calculator inputs;

(e) Redesign of the calculator to separate inputs and outputs from the calculator engine;

(f) Refinements to the calculator that can be made relatively quickly to flag or correct potential input inconsistencies with respect to the SPM tests of cost-effectiveness.

The cost of the contract shall be paid for out of the utilities' portion of EM&V budgets for the 2006-2008 program cycle.

17. Prior to submitting the required updates to the E3 calculator described in Ordering Paragraph 16, the utilities and their contractor(s) shall present the revised E3 calculators (including all inputs) to their program advisory and peer review groups for review in joint statewide public meeting(s), with notice to the service list in R.06-04-010. At least two weeks prior to the meeting(s), the utilities and/or contractor(s) shall post to a website all of the revisions responding to today's directives with a written summary of the changes made. At the same time, the utilities shall notify the utility advisory group/peer review group members and the service list in R.06-04-010 of the availability of this information.

In addition to the revised E3 calculator and input files, the website posting shall include a summary of the changes made in response to today's decision. The website posting shall also include a table summarizing the comments made at the review meeting(s) discussed above, the name/organization providing the comment, and the utilities/contractor(s) responses to each comment (e.g., whether the comment resulted in further modifications to the E3 calculator to satisfy the requirements of today's decision, or not—and why not).

After considering the input received at the meeting(s), the utilities shall submit final E3 calculator and input revisions no later than September 8, 2006 in the form of a Notice of Availability (Notice). The Notice shall provide a website address where the revised E3 calculator and associated inputs can be accessed, and include the due date for comments on the E3 calculator revisions and filing/ service requirements, as set forth below:

(a) The Notice and all comments shall be filed in the Commission's Docket Office and served on the service list in R.06-04-010, consistent with the electronic service protocols in that proceeding.

(b) Parties to R.06-04-010 may file opening comments on the compliance submittal no later than September 22, 2006 and reply comments by September 29, 2006.

After considering written comments, and in consultation with Joint Staff, the assigned ALJ in R.06-04-010 shall address the compliance submittal by ruling, or take other steps as necessary to ensure compliance with today's decision.

18. During the third and fourth quarters of 2006 the utilities shall jointly plan and notice workshops for the purpose of exploring with Joint Staff, interested parties and program advisory and peer review group members ways to assure greater quality control over E3 calculator inputs on an ongoing basis. As discussed in this decision, the utilities shall jointly contract with appropriate expertise to assist in this effort. The utilities shall jointly report back to the Assigned Commissioner and ALJ in R.06-04-010 on the consensus and non-consensus recommendations presented at those meetings no later than December 15, 2006. The workshop notice and report shall be served on the service list in R.06-04-010 and on the utility program advisory group and peer review group members. The Assigned Commissioner and ALJ in R.06-04-010 shall consider the report in consultation with Joint Staff, and implement quality control improvements as they determine are appropriate and practicable. Approaches to consider during the workshops shall include:

(a) Programming the E3 calculator to use a common or standardized data base as default values for most or all measures, and include the capability to flag data entries that differ from those values, and

(b) Establishing a review process for selected calculator inputs before they are entered into the calculator, such as measure cost inputs.

(c) Additional refinements to the E3 calculator that can serve to flag or correct input inconsistencies to assist in the quality control of input data.

19. Today's refinements to the interim avoided costs adopted in Decision (D.) 05-04-024 are specific to the evaluation of energy efficiency resources, and do not address pricing for Qualifying Facilities or other applications of avoided or marginal costs. However, as discussed in D.05-04-024, and reiterated in this decision, in Phase 3 of this proceeding the Commission shall consider permanent adoption of the interim avoided cost methodology adopted in D.05-04-024 for energy efficiency as refined today, as well as consider the potential application of this methodology to other resource options, such as distributed generation and demand response programs.

20. In the meantime, as discussed in this decision, the Commission shall continue to coordinate its consideration of avoided-cost related issues across Commission proceedings to ensure that the avoided cost methodology is debated and resolved in this rulemaking, rather than in multiple proceedings where the methods and inputs for specific applications of avoided or marginal costs are applied.

21. Unless otherwise directed, all reports, notices of availability, notices of workshops or other submittals required by this decision shall be distributed to the service list in the energy efficiency rulemaking, R.06-04-010, consistent with the electronic service rules established for that proceeding. Those rules are contained in Appendix A of the Ordering Instituting Rulemaking in R.06-04-010,

issued on April 13, 2006. As indicated in those rules, hard copies of all submittals should also be served on the assigned ALJ and Commissioner in R.06-04-010.

22. The Assigned Commissioner or Administrative Law Judge in R.06-04-010 may, for good cause, modify the due dates established by this decision.

23. All interested individuals or organizations who are not already parties (appearances) to R.06-04-010, and who wish to receive the notices and submittals described in today's decision and have the opportunity to file comments, where solicited, shall file a motion to intervene for this purpose in R.06-04-010 without delay. For instructions on how to file such a motion, contact the Public Advisors Office at (415) 703-2074.

24. All individuals or organizations who do not wish to become parties (appearances) to this proceeding but wish to be served documents electronically may be added under the "state service" or "information only" categories of the service list in R.06-04-010 by submitting a written request to the Commission's Process Office. Such requests should include the full name, address, phone number and email address of the individual/organization and should reference R.06-04-010, and should be mailed to the Process Office at the California Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, California 94102.

25. This decision shall be served on the "2006 Update" service list in this proceeding, and the services list in Application 05-06-004 et al. and R.06-04-010.

This order is effective today.

Dated _____________________________, at San Francisco, California.

ATTACHMENT 1
Page 1

LIST OF ACRONYMS AND ABBREVIATIONS

A.	Application
a/c	air conditioning
ALJ	Administrative Law Judge
AMI	advanced metering infrastructure
CCGT	combined cycle gas turbine
CEC	California Energy Commission
CT	combustion turbine
D.	Decision
DEER	Database for Energy Efficient Resources
DR	demand response
DRA	Division of Ratepayer Advocates
E3	Energy and Environmental Economics, Inc.
EM&V	Evaluation, measurement and verification
Final Report	final report summarizing consensus and non-consensus positions on the 2006 Update issues, including final recommendations for Commission consideration
kW	Kilowatt
kWh	kilowatt hour
kWh-yr	kilowatt-year
LRMC	long-run marginal costs
mimeo.	Mimeograph
MPR	market-price referent
Notice	Notice of Availability
NYMEX	New York Mercantile Exchange
p.	Page
PAC	program administrator cost
PG&E	Pacific Gas and Electric Company
PX	California Power Exchange
QFs	Qualifying Facilities
R.	Rulemaking

ATTACHMENT 1
Page 2

RPS	Renewals Portfolio Standard
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SEER	Seasonal Energy Efficiency Ratio
SoCalGas	Southern California Gas Company
SPM	Standard Practice Manual
"the utilities"	Pacific Gas and Electric Company, Southern Califonria Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company, collectively
TOD	time-of-delivery
TOU	time-of-use
TRC	total resource cost
TURN	The Utility Reform Network
"2006 Update Consultants"	Energy and Environmental Economics, Inc. and James J. Hirsch and Associates
UC	utility cost
"workshop participants" or "participants"	Referred to those participating at the workshop collectively

(END OF ATTACHMENT 1)