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Decision 05-04-024 April 7, 2005

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 ON E3 AVOIDED COST METHODOLOGY

TABLE OF CONTENTS

INTERIM OPINION ON E3 AVOIDED COST METHODOLOGY

1. Summary

This decision adopts a new avoided cost forecast methodology described in a report prepared by the consulting firm E3. This report, *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, (E3 report)[1] and associated spreadsheet models, describe and generate 20-year forecasts of (1) hourly wholesale electricity costs, and (2) monthly wholesale natural gas costs. These wholesale energy cost forecasts represent the total avoided cost of power that a utility would otherwise have to generate or procure in the absence of other resource options like energy efficiency programs.[2]

The cost-effectiveness of energy efficiency programs is evaluated on a prospective (budget) and retrospective (actual) basis[3] using the cost-effectiveness tests set forth in the Standard Practice Manual (SPM).[4] The avoided wholesale

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[1] *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004. (www.ethree.com/cpuc_avoidedcosts.html) We take official notice of the report, and incorporate it into the record of this proceeding.

[2] "Total avoided cost" refers to the total cost avoided to society through reduction in energy demand, which can be either electricity or gas.

[3] Prospective filings with proposed EE program budgets for the 2006-2008 program cycle are to be filed June 1, 2005. Annual retrospective filings with actual EE program expenditures are to be filed by April 1st following each year in the program cycle. Of the six SPM cost-effectiveness tests, the utilities are required to present budget and actual results for the Program Administrator test and the Total Resource Cost (TRC) test. In addition to these cost-effectiveness metrics, the utilities are required to estimate and report their energy savings targets on an energy basis in GWh and therms.

energy cost forecasts generated by the E3 models are only one of several data inputs to the SPM calculations.

Use of the E3 avoided cost methodology in this manner is recommended by E3, as well as several parties, for energy efficiency investments in the 2006-2008 program cycle, and is unopposed by parties in concept. As discussed in this decision, we intend to consider the permanent adoption of the E3 methodology for generating avoided cost energy forecasts for use in SPM cost-effectiveness tests used to evaluate energy efficiency programs. We will also consider any potential revisions to the E3 methodology in Phase 3 of this rulemaking. At that time, we will also consider the potential application of the E3 methodology to other resource options, such as distributed generation (DG) and demand response (DR) programs.

With this decision, we eliminate a potential gap in the review and approval process for potential energy efficiency programs for program year 2006 and beyond. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE) and Southern California Gas Company (SoCalGas), referred to collectively as "the utilities" are directed to use the adopted E3 methodology to generate avoided cost energy forecasts for use in SPM cost-effectiveness tests to evaluate energy efficiency programs, beginning with program year 2006, until further order by the Commission.

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[4] *California Standard Practice Manual: Economic Analysis Of Demand-Side Programs And Projects*, October 2001, as incorporated by reference in the Energy Efficiency Policy Manual, the latter of which was adopted as Attachment 1 to D.01-11-066. *Standard Practice Manual*, www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc

2. Background

On April 22, 2004, we issued Order Instituting Rulemaking (R.) 04-04-025 to develop avoided costs in a consistent and coordinated manner across Commission proceedings, including but not limited to R.02-06-001 (Demand Response), R.04-03-017 (Distributed Generation), and R.01-08-028 (Energy Efficiency). The need to update avoided cost calculations and to coordinate the development of input assumptions and methodologies across Commission proceedings has been articulated in several Commission Decisions over the past few years, including Decision (D.) 04-01-050, D.03-12-062, and D.03-04-055. In D.03-04-055, issued in R.01-08-028, the Commission initiated an avoided cost updating process to "assess externalities to reflect the societal costs of energy. "[5]

A draft report on this issue, entitled "A Forecast of Cost Effectiveness Avoided Costs and Externality Adders,"[6] was developed by Energy and Environmental Economics, Inc. (E3), under the direction of the Commission's Energy Division, in order to update the current avoided cost calculations used in evaluating energy efficiency programs to more accurately reflect current conditions. Among other things, the E3 report develops a forecast for the years 2004-2023 of avoided costs for use in quantifying the benefits of demand-reduction programs.

In this rulemaking, we directed the Energy Division to conduct a workshop on the draft E3 report to allow parties to comment on the application

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[5] See D.03-04-055, Section VI.D and Conclusion of Law 9.

[6] *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted to the CPUC Energy Division, October 25, 2004. (http://www.ethree.com)

of the E3 methodology and resulting forecasts for use in energy efficiency as well as other resource areas. Among other things, the workshop participants were directed to address whether the Commission should adopt the E3 methodology for updating avoided costs for the purposes of evaluating the resource value of energy efficiency programs, and if not, what aspects of the E3 methodology should be refined or modified.

Energy Division staff conducted a two-day workshop on avoided cost issues on June 30 and July 1, 2004. Pre-workshop comments were filed on June 4, 2004, by PG&E, SDG&E and SoCalGas jointly, SCE, the California Cogeneration Council (CCC), the California Large Energy Consumers Association (CLECA), the California Wind Energy Association (CalWEA), the Independent Energy Producers Association (IEP), the Natural Resources Defense Council (NRDC), Calpine Corporation (Calpine), and jointly by the Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC). Pre-workshop reply comments were filed on June 21, 2004, by PG&E, SDG&E, SCE, CAC/EPUC, CCC, IEP, and jointly by NRDC and the Union of Concerned Scientists (UCS).

Following the workshop, post-workshop comments were filed on August 16, 2004, by SCE and the Green Power Institute (GPI), and on August 20, 2004, by PG&E, SDG&E, IEP, CCC, CAC/EPUC, and the California Consumer Empowerment Alliance (CCEA). Replies to the post-workshop comments were filed by PG&E, SDG&E, SCE, CAC/EPUC, NRDC/USC, and CCEA on September 3, 2004. GPI and The Utility Reform Network (TURN) requested permission to late-file post-workshop reply comments and, having received permission from the Administrative Law Judge (ALJ), filed post-work reply

comments on September 7, 2004. A notice of availability of the final E3 Report, dated October 25, 2004, was sent to the parties on November 2, 2004.

On November 9, 2004, a prehearing conference (PHC) was held in this proceeding at which parties discussed the scope and schedule of the avoided cost rulemaking. In preparation for the PHC, parties filed and served PHC statements with their proposed approaches and schedules for addressing the issues raised in the rulemaking. PHC statements were filed by PG&E, SDG&E/SoCalGas, SCE, CAC/EPUC, NRDC, IEP, UCS, GPI, CCC/CalWEA and the California Biomass Energy Alliance , L.L.C. (CBEA) (jointly) and the Modesto Irrigation District (MID).

During the PHC, there was general agreement among the parties that the Commission should adopt the E3 methodology on an interim basis for use in generating avoided cost energy forecasts to be used in the evaluation of energy efficiency programs for the 2006 program year. The parties agreed that, in order for 2006 energy efficiency programs to be as effective as possible, program selection, using updated avoided costs, should occur by mid-year 2005. However, the parties disagreed slightly as to whether additional comments on the E3 methodology were necessary prior to Commission consideration. Parties urged the ALJ to adopt a schedule allowing for an interim decision updating avoided costs for energy efficiency in the first quarter of 2005.

On January 4, 2005, consistent with the suggestions at the PHC, the assigned ALJ issued a ruling directing that R.04-04-025 would be separated into three phases, the first of which would address the potential adoption of the E3

methodology for use in evaluating energy efficiency proposals for program year 2006.[7]

[7] A February 18, 2005 ACR issued jointly in R.04-04-003 and R.04-04-025 subsequently modified the procedural schedule for Phase II of R.04-04-025, but did not alter the determination that consideration of the permanent use of the E3 methodology would be considered in Phase III of R.04-04-025.

3. The E3 Methodology and Forecast of Avoided Costs

In D.03-04-055, the Commission directed E3, in the context of energy efficiency, to develop a methodology and long-term forecast of electric and gas avoided costs for the use (1) updating the current cost-effectiveness inputs used in evaluating energy efficiency programs to more accurately reflect current conditions, and (2) provide the Commission with a method and model for updating cost-effectiveness inputs on an ongoing basis:

> "The Commission will contract with a consultant to update the avoided costs and 'externality adders' presently used in assessing the benefits of energy efficiency programs to reflect the current societal costs of energy. This study will consider [the] impact of including additional externality adders in program [cost-] effectiveness calculations. The Commission allocates a maximum of $600,000 of PGC funds to this project."[8]

The E3 report establishes a forecast for the years 2004 – 2023 of avoided electric generation and gas procurement costs and certain externality adders for use in quantifying the benefits of demand-reduction programs. E3's presentation of avoided costs is designed to update the current avoided costs described in the *Policy Manual* for use within the existing cost-effectiveness evaluation framework as defined by the Standard Practice Manual (SPM).[9] The E3 report produces avoided costs that reflect certain changes in the methodology for determining avoided cost values. These methodological changes include (1) incorporating the market price effects, (2) including the value of reliability through ancillary

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[8] See D.03-04-055, p. 21.

[9] California Public Utilities Commission, *California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects*, October 2001

services, and (3) the disaggregation of the avoided costs to time (hour, month, or time-of-use (TOU) period) and to California climate zones.

The E3 report computes total avoided costs from a societal perspective in order to capture the overall benefits to all energy consumers associated with reductions in energy demand, including both direct savings and externality values of unpriced emission (e.g., CO_2). The resulting avoided costs are therefore appropriate for applying the "Total Resource Cost (TRC) test – Societal Version" [10] or a variation of the TRC that includes non-price adders, which is currently the approach to cost-effectiveness evaluation for California efficiency programs.[11] This test, as defined in the SPM, is intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective, taking into account benefits and costs from a wider perspective as opposed to one individual or stakeholder.

The E3 report documents a straightforward costing methodology that is implemented using a spreadsheet model and publicly available data, resulting in avoided cost estimates that are transparent and can be easily updated to reflect changes in major cost drivers, including the price of natural gas, the costs of new generation, and the expected load-resource balance year in California.

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[10] The CPUC's "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" designates five types of cost-effectiveness tests for programs, each of which captures the costs and benefits of a program from a different perspective. The Total Resource Cost Test: Societal Version (TRCSV), in attempting to measure the costs and benefits from the perspective of society as a whole, allows for the inclusion of externalities.

[11] California Public Utilities Commission, *Energy Efficiency Policy Manual: Version 2*, August 2003, Page 15, San Francisco, California.

The E3 report and methodology incorporates a number of forecasting methods and results used by the California Energy Commission (CEC). While alternative data sources are available, the CEC products provide unbiased estimates of future energy costs.

One of the key differences between the avoided cost forecasts resulting from E3's methodology and previous values in California is segmentation of the avoided costs by hour of a typical year and by planning areas and climate zones within the State. The E3 report produces forecasts of avoided costs of electric generation, transmission, and distribution that vary by hour, and avoided costs of natural gas procurement, transportation, and delivery that vary by month.

In 2003, the CEC adopted a "Time Dependent Valuation" (TDV) methodology into the 2005 Title 24,[12] Building Standards.[13] The TDV concept is that energy efficiency measure savings should be valued differently at different times and locations to better reflect the true avoidable costs to users, the utility system, and society. E3 utilized a large portion of the TDV methodology and data to develop the area- and time-specific (ATS) estimates of transmission and distribution (T&D) costs.[14] The E3 Report presents electric T&D costs that vary by utility service territory, planning division and by the 16 CEC Title-24 climate

[12] Title 24 refers to the Energy Efficiency Standards for Residential and Non-Residential Buildings in California, established in 1978. The TDV values are applied using the Alternative Calculation Methodology (ACM), PG&E was the lead contractor to the CEC on the TDV evaluation (Pat Eilert and Gary Fernstrom contract managers). Available on internet: http://www.energy.ca.gov/2005_standards/

[13] Heschong Mahone Group & E3 2002.

[14] E3 was the contractor responsible for estimating the avoided costs in the CEC's TDV project.

zones used in the CEC's TDV study, while the costs of electricity generation and of natural gas procurement, transportation, and delivery vary by utility service territory. E3 asserts that the resulting methodology captures differences in avoided costs due to weather, local capacity-demand conditions, and investment plans at times of peak demand.

The externality adders utilized in quantifying program benefits in the E3 report are the following: (1) an environmental externality adder; (2) a transmission and distribution (T&D) adder (also a part of recent cost-effectiveness calculations, which captures incremental demand-related capital expenditures, line losses and maintenance costs associated with increased energy use); (3) a system reliability adder, which includes the cost of maintaining a reserve margin; and (4) a price elasticity of demand adder, which recognizes that reduced demand results in a decrease in the market-clearing price for electricity and therefore an increase in consumer surplus.

The price elasticity of demand estimate varies by time-of-use (TOU) period and by month. The cost of maintaining reliability is calculated as annual percentages applied to the hourly electricity cost values. The estimated costs of environmental externalities, maintaining reliability and the benefit multipliers resulting from price elasticity of demand are uniform across the state.

The costs of environmental externalities are computed by multiplying the emissions rate of the assumed marginal plant in each hour by a forecasted cost of each pollutant (CO_2, NOx, and PM-10). The forecasted cost of emissions is based on the expected cost of controls. The expected emissions rates are based on new gas technologies. No adders are included when market prices for electricity are used, only when the cost of a combined cycle generation turbine (CCGT) power plant is used as the long term avoided resource. Since the CCGT cost does not

include the capitalized price of required emission offsets, it is appropriate to include an adder and there is no double counting.

The E3 avoided cost methodology and resulting costs presented in the report are most appropriate for evaluating resources that: (1) reduce load or produce energy for hundreds of hours per year in a predictable pattern, because reductions over hundreds of hours reduce the importance of knowing the exact shape of the electric generation market hourly shape during the peak hours; (2) are relatively small (such that they can be installed behind the customer meter), because the smaller the resource relative to the local T&D system, the less the utility needs to plan for the contingency case of the resource failing to provide reductions; and (3) are expected to be installed in large numbers, because the more resources that are installed, the more one can rely upon the expected level of reductions.

To account for the inherent uncertainty associated with forecasting avoidable electricity and gas costs over a long time horizon, the E3 methodology offers two options. First, even though the avoided cost estimates are used for programs with relatively long lives, E3's spreadsheet-based model allows input assumptions to be changed and updated by Commission staff as conditions warrant, perhaps as often as once per year, to reflect changes in important cost and policy drivers. Second, E3 developed a separate set of avoided costs for a *stress case* scenario characterized by high gas prices and poor hydro conditions. These avoided costs aim to capture the additional value that dispatchable resources can provide under stress case conditions.

The E3 methodology would replace the Commission's current avoided cost methodology (used for valuing certain energy efficiency programs) that has been in place for a number of years, and is set forth in the *Energy Efficiency Policy*

Manual (*Policy Manual*).[15] Under the current avoided cost methodology, "six sets of avoided cost streams were calculated on a statewide basis to apply to all program proposals":[16]

Electric ($/MWh, 20-year forecast, e.g., 2002-2021)

- Avoided Generation Costs ($/MWh). One annual value, e.g., $53.41/MWh.
- Avoided Transmission and Distribution Costs. One annual value, e.g., $5.74/MWh.
- Environmental externalities. One annual value, e.g., $7.04/MWh.

Gas ($/therm, 20-year forecast, e.g., 2002-2021)

- Commodity Procurement Costs. One annual value, e.g., $0.34/therm.
- Transmission and Distribution Costs. One annual value, e.g., $0.03/therm.
- Environmental Externalities. One annual value, e.g., $0.06/therm.

These statewide avoided cost figures are currently used by the utilities as the basis for cost-effectiveness evaluations of utility-specific energy efficiency programs.

[15] Energy Efficiency Policy Manual, Version 1, October 2001, D.01-11-066, Attachment 1, adopted in Ordering Paragraph 1. The Commission also employs separate avoided cost methodologies which are used to price power from Qualifying Facilities (QFs). QF avoided cost methodologies are not part of the Energy Efficiency Policy Manual.

[16] Energy Efficiency Policy Manual, p. 20.

Table 2 of the E3 report, shown below, compares the E3 avoided cost methodology with the Commission's current avoided cost methodology:

Table 1: Time and Area Dimensions of Avoided Costs and Externality Adders[17]

	E3 Avoided Cost Methodology		Current Commission Avoided Cost Methodology	
Avoided Cost	**Time Dimension**	**Area Dimension**	**Time Dimension**	**Area Dimension**
Avoided Electricity Generation	Hourly	Utility specific	Annual Average Values[18]	Statewide
Avoided Electric Transmission and Distribution	Hourly	Utility, planning area and climate zone specific		
Avoided Natural Gas Procurement	Monthly	Utility specific		
Avoided Natural Gas Transportation and Delivery	Monthly	Utility specific		
Environmental Externality Adders for Electric & Gas	Annual value, applied by hour according to implied heat rate	System-wide (uniform across state)		
Reliability Adder	Annual value	System-wide (uniform across state)	None	None
Price Elasticity of Demand Adder	TOU period (on-vs. off-peak) by month	System-wide (uniform across state)	None	None

[17] Table 2, E3 Report, p. 4.

[18] In some cases, some utilities have broken down these annual average avoided cost values into "costing periods," which are analogous to time of use (TOU) periods.

3.1. Electricity Avoided Cost Formulation

The E3 avoided cost methodology calculates and forecasts the total electric avoided cost using the same three basic components that are included in the current avoided costs described in the *Policy Manual*.[19] These are the (1) avoided generation costs, (2) avoided transmission and distribution costs, and (3) environmental externalities. The costing methodology and data used in the E3 report were intended to reflect the most recent publicly available estimates of market-based avoided costs by hour and location for both natural gas and electricity. The E3 report calculates updated avoided cost values to reflect current conditions and provides the Commission with a methodology and associated spreadsheet models[20] for updating the cost-effectiveness inputs on an ongoing basis. The total avoided cost is computed as the sum of three main components for each utility, climate zone, voltage level, hour, and year.

3.2. Generation Avoided Cost

E3 calculates the avoided generation cost as the product of the hourly market price for firm energy in each year, one plus ancillary services percentage, one plus energy losses percentage, and the market multiplier. The market price is calculated as the product of an hourly market price shape and an average market price. The market multiplier is calculated as the residual net short position (RNS) (unhedged position) and the market elasticity estimate of price response for changes in demand level. Finally, the average market price forecast

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[19] Ibid., p. 21.

[20] E3 prepared two spreadsheet models, one to calculate electric avoided costs and another to calculate gas avoided costs. These spreadsheet models are available for download on the E3 website, http://www.ethree.com/cpuc_avoidedcosts.html.

is developed over three distinct periods: (1) a period of forward market liquidity, (2) a transition period to resource balance, and (3) a post-resource balance year long run marginal cost (LRMC) forecast.

The E3 report uses two different approaches to forecasting future avoided generation costs. For 2004 and 2005, E3 uses on-peak electric futures prices (SP-15) published in Megawatt Daily as of October 15, 2003. E3 then escalates these prices to 2006 and 2007 using the observed 2004 -2007 escalation rates in NYMEX gas futures prices on that same date. The E3 report uses the cost of a new combined-cycle gas turbine (CCGT) power plant as a proxy for the future avoided cost of electricity production, post-2008, when the utilities are assumed to have achieved a state of resource balance. The E3 report uses the CEC generation cost report as the basis for its cost and performance data for the CCGT proxy.

3.3. Transmission and Distribution (T&D) Avoided Cost

E3's estimate of electric T&D avoided cost is broken apart by utility, climate zone, division, voltage level, hour, and year. E3 calculated the avoided cost as the product of an estimate of T&D capacity by utility division and year, hourly allocation factors for each climate zone, and one plus the peak losses on the system. The T&D capacity value is an estimate of the forward looking avoidable delivery costs. Each utility estimated these costs using either the present worth (PW) method, or the discounted total investment method (DTIM). The T&D allocation factors are percentages of the total T&D capacity cost for each hour of the year. These percentages, or weighted allocation factors are based on typical meteorological year (TMY) weather data for each climate zone. Peak losses are an estimate of the incremental losses during the peak hour of the year between the end-use customer and the distribution system and transmission

system. The T&D capacity costs are allocated by typical weather patterns for the State's climate zones, with the highest costs allocated to the hottest temperature hours, as done in the CEC TDV evaluation. Non-peak hours have zero avoided T&D capacity costs, reflecting that T&D capacity investments are made to serve peak hours. The losses vary by voltage level.

3.4. Environmental Externality Avoided Cost

E3 calculated the avoided environmental cost, or emissions costs as the sum of NOx, PM10, and carbon emissions (CO_2) costs increased by marginal energy losses for each TOU period. E3 estimated the emissions avoided cost streams by multiplying the costs per pollutant (on a yearly basis) by the emission rate (per hour of the year). The emissions costs vary by voltage level, hour, and year.

The NOx costs ($/MWh) are based on California offset prices generators must pay for NOx emissions, and the estimated emission rate of NOx at the implied heat rate of the market price. The NOx cost per MWh of energy saved at the customer is increased by the incremental energy losses in each TOU period between the end use and the bulk system. In Period 1, when the forward market prices of electricity are based on NYMEX forward market prices, we assume that these prices already include the cost of NOx emissions so this value is equal to zero in Period 1.

The PM10 costs ($/MWh) are computed similarly to the NOx costs, with the emission cost based on the California PM10 market prices and the estimated rates of emissions by implied heat rate. The PM10 costs are also assumed to be included in the NYMEX forward market prices.

The CO_2 costs ($/MWh) are an estimate of avoided costs for reduction in CO_2 per MWh saved at the customer site. There is not currently a requirement to

purchase CO_2 offsets in California so the avoided cost of the CO_2 emissions is based on prices in other markets.

3.5. Gas Avoided Cost Formulation

The total gas avoided costs are the sum of the forecasted commodity price for natural gas, the avoided transmission and distribution costs, and the emissions costs. The total avoided gas costs are calculated for each utility, service class, combustion type (emission control technology), month, and year.

The avoided commodity is calculated as the product of the forecasted market price and one plus the avoided compression gas and reduced loss and unaccounted for gas percentages. Similar to the avoided electricity calculation, the gas commodity is forecasted for three periods. Period 1 is the period when forward market prices for gas are available from NYMEX, Period 2 is a transition, and Period 3 is based on a long-run forecast of future prices. In addition to the gas avoided cost, the gas commodity costs are used in conjunction with the UDC's gas transportation tariff for generation to estimate the long-run avoided electricity generation costs.

The avoided gas T&D costs represent an estimate of marginal transportation cost for delivering gas to end-users, calculated as the product of the T&D marginal cost for each utility, service class, and year by the monthly T&D allocation.

The avoided emissions are computed as the sum of the reduced NOx and CO_2 costs based on the same offset market prices used in the calculation of the avoided electricity prices. Since PM10 emissions are negligible for natural gas end-use combustion, they do not represent a significant pollutant and are therefore not included in this estimate of avoided costs for gas.

4. Parties' Comments on the Interim Application of the E3 Avoided Cost Methodology for use in the Energy Efficiency 2006-2008 Program Cycle

The parties have had several opportunities to comment on the E3 draft report, including pre-workshop opening and reply comments and post-workshop opening and reply comments. These filings provide the Commission with an adequate record on which to consider the avoided cost forecast contained in the E3 Report for use on an interim basis in the generation of avoided cost energy forecasts to be used in the evaluation of energy efficiency programs for the 2006 program year.

Although this rulemaking contemplates using E3's proposed methodology in all calculations and forecasts of avoided costs across all Commission proceedings, we do not address the comments raised by parties with respect to the applicability of the E3 avoided cost methodology for purposes of calculating long-run avoided costs for use in valuing Distributed Generation (DG), Demand Response (DR), Qualifying Facility (QF) pricing or other resource options and programs at this time. Pursuant to the February 18, 2005 ACR Consolidating R.04-04-003 with this Rulemaking for purposes of addressing QF issues, QF policy and pricing issues will be addressed in Phase 2 and all other long-run avoided cost issues, including the development of a common methodology, including the potential development of a common methodology input assumptions and updating procedures will be addressed in Phase 3 of this rulemaking.

The majority of parties recommend that the Commission issue an interim order approving time differentiated avoided costs for energy efficiency based on the E3 report. The only exception is SCE. PG&E notes that "SCE alone… takes exception to using the E3 avoided costs for energy efficiency planning

purposes."[21] However, even SCE acknowledges that the avoided costs currently in use for demand side management and energy efficiency (DSM/EE) program evaluation, which were originally adopted in 1999, need to be replaced. SCE also agrees that the development of a revised forecast of avoided costs for DSM/EE program design and ex post analysis is a critical issue that needs to be resolved in early 2005. While SCE's comments focus primarily QF pricing and other resource areas, SCE suggests that the E3 report (and associated methodology) "if suitably revised," may be useful for DSM/EE applications.[22]

All other parties either support or are not opposed to the adoption of the E3 avoided cost methodology for use on an interim basis for the purposes of evaluating energy efficiency proposals for program year 2006. In particular, PG&E, SDG&E/SoCalGas, TURN, NRDC, and UCS each recommend that the Commission approve the E3 avoided cost methodology immediately for generating avoided cost forecasts to be used in the evaluation of energy efficiency programs for 2006, although SDG&E/SoCalGas each recommend that the Commission adopt certain technical changes to the model. PG&E and TURN also recommend certain changes to the model, but state that the Commission should adopt the E3 methodology and forecast for use in evaluating the 2006 energy efficiency programs immediately, and consider any potential changes at a later date.

Issues that were raised regarding the applicability of the E3 avoided cost methodology for evaluating energy efficiency programs related to both the

[21] PG&E, post-workshop reply comments, p. 5.

[22] SCE, PHC Statement, p. 2.

avoided cost methodology and the data inputs used in the avoided cost methodology. As stated above, this decision is limited to evaluating the applicability of the E3 Methodology and forecast for purposes of the program year 2006 energy efficiency proposals. We do not repeat or discuss the parties' comments regarding the applicability of the E3 methodology to other resource options.

4.1. All-in Hourly vs. Separate Capacity and Energy Costs

The issue of whether avoided costs need to be separated into capacity and energy components arose in the pre-workshop and post workshop comments of several parties. SCE strongly supports the separation of capacity and energy components of avoided costs. PG&E also supports this separation, but does not feel it is necessary immediately or in all applications.

For energy efficiency purposes beyond the 2005 and 2006 program years, PG&E recommends that the adopted methodology separate energy from capacity, in order to provide for a separate capacity value that could be used for dispatchable resources or as a replacement for the CCGT power plant that is used for the long-run avoided cost proxy. PG&E also suggests that the separation of capacity and energy avoided costs is needed to be able to give proper credit for avoided capacity to only those resources that reliably count for purposes of resource adequacy. PG&E further recommends that the estimation of avoided costs for capacity be stated for three categories of electric generation resources: peaking, intermediate, and baseload. PG&E states that this estimate can be accomplished within the E3 methodology by using the costs for the three categories to reshape the E3 load duration curves without changing the area under the curve.

SCE asserts that the Commission's implementation of a resource adequacy requirement has returned the utilities to a structure that requires the clear separation and identification of capacity and energy costs. SCE maintains that the full capital cost of a CCGT cannot be used as a proxy for capacity value alone because a portion of the capital costs are motivated by a desire to achieve fuel savings.[23] SCE recommends that the Commission use the deferral value of a CT for the avoided cost of capacity and system incremental cost (as determined using a production cost model) for estimating the avoided cost of energy instead of the CCGT approach proposed in the E3 report. SCE further recommends that the Commission use CT deferral costs and system incremental costs that are consistent with each utility's long-term procurement plan.

TURN strongly disagrees with SCE that capacity value is the cost of a CT. TURN asserts that the economic theory that established that the capacity value is based on the cost of a CT was established at a time when CTs were far less efficient than they are today. TURN argues that technology has changed, and that modern CTs are more efficient and offer more flexible operations than steam plants, therefore, the Commission can no longer simply add the full cost of a CT to market prices to calculate marginal generation costs, because the result would be a significant overvaluation of capacity. TURN states that this issue also relates to the dispatchability issues raised by PG&E, suggesting that because a CT has few limits on its dispatchability, it is clearly worth more than a program that can only be called upon to save energy for a limited number of hours per year.

[23] SCE, Comments, p. A2.

GPI agrees, stating that "for across-the-board programs such as energy efficiency, as well as renewables and QFs, an all-in, properly profiled avoided cost is a better approach to use than the traditional method of separate energy and capacity prices based on unrepresentative TOU periods."[24]

Discussion

Our primary goal in this phase of the proceeding is to identify whether the E3 avoided cost methodology and associated forecasts are appropriate for use in evaluating energy efficiency programs for 2006. One of the criticisms of the current avoided cost values is that they are outdated statewide average values that do not reflect on-peak vs. off-peak reductions, as well as utility-specific cost differences. E3 has presented us with a methodology that estimates current avoided costs by hour, time and location, a significant improvement over the current annual average method.

Forecasting avoided costs on hourly and location-specific bases better allows for the proper valuation of programs that target peak hours and particular locations.

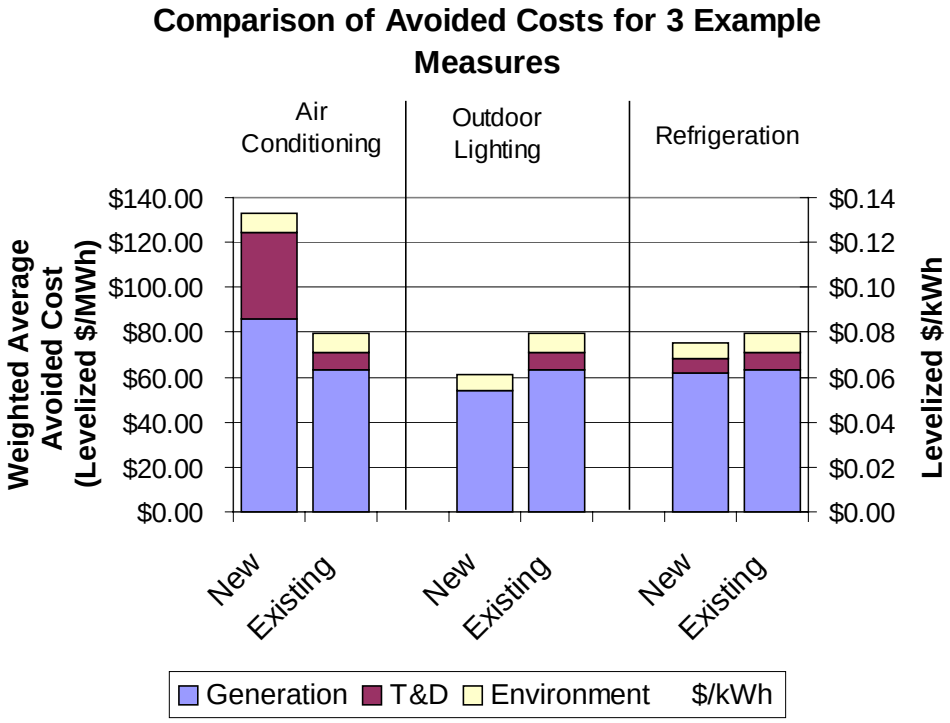
The E3 report sets forth a clear example on this point with a comparison between existing avoided cost values verses new avoided cost values based on the E3 methodology:

[24] GPI, post-workshop reply comments, p. 6.

"In Figure 1, we compare the results for three example electricity efficiency measures.[25] The three efficiency measures are air conditioning, outdoor lighting and refrigeration programs. The air conditioning measure (upgrade of a residential A/C [air conditioning] unit from 12 to 13 SEER) has a total avoided cost savings of $133/MWh with the new avoided costs compared to a savings of approximately $80/MWh under the existing avoided costs (this is equivalent to $0.133/kWh and $0.080/kWh as shown on the right-hand y-axis). The large differential in avoided costs under the two forecasts exists because the majority of the savings in an A/C upgrade occurs during the summer peak period when both the generation avoided cost and T&D avoided costs are highest. In contrast, the value for outdoor lighting efficiency drops under the new avoided costs from $80/MWh to approximately $61/MWh. For outdoor lighting, there is no T&D avoided cost benefit because the savings occur at times when the T&D system has excess capacity. Refrigeration, which is assumed to have a flat energy savings profile has a closer comparison under both sets of avoided costs ($75/MWh for the new avoided costs and $80/MWh in the existing avoided costs), and similar proportions of generation, T&D, and environmental avoided cost." (E3 Report, pp. 11-12.)

[25] The three EE measures are for secondary voltage customer in PG&E's Climate Zone 12 (the Central Valley area, including portions of the Diablo, Mission, North Bay, Sacramento, Stockton, Sierra and Yosemite Planning Divisions).

Figure 1



In response to the parties' comments, E3 states that capacity costs in $/kW-yr. form are not needed if analyses are performed using the hourly costs because hourly costs arrive at the same capacity value for a DSM/CEE measure as using $/kW-yr capacity costs with a weighted-average kW impact. (This weighted-average kW impact approach would be similar to the PCAF-weighted load factors that PG&E and SCE have been using for their cost of service analyses).

E3 further notes that, although it is not required for the evaluation of energy efficiency programs, the annual stream of total generation avoided costs can be separated into an annual value of generation capacity and residual energy. For example, prior to the resource balance year, the level of market-based returns that a CT owner would earn by selling energy into the spot market is a reasonable measure of the value of capacity. This can be estimated as the

difference between the estimated market prices (avoided costs) and the variable costs of operating a CT summed over an entire year. As California approaches resource balance, the CT owner's earnings should increase until it reached the full cost of owning a CT in the resource balance year.

Under this method, the resulting avoided costs would have the following characteristics. First, the capacity and energy costs would be equal to the full market price for firm delivered power forward contracts prior to resource balance. After resource balance, the capacity and energy costs would be sufficient to run and pay a reasonable return of and on a new CCGT. Second, the marginal energy costs would be capped at the running cost of a CCGT. Third, the capacity costs could be expressed in $/KW-year form. And finally, the value of capacity would be explicitly tied to the operating characteristics of the resource being evaluated. More efficient dispatchable resources with few operating restrictions would provide higher values of capacity. Conversely, resources that had limited ability to provide cost effective energy would have lower values of capacity.

We find that it is reasonable for the utilities to use the E3 avoided cost methodology and forecast, without modification to separate energy and capacity costs, for purposes of evaluating energy efficiency programs for program year 2006.

4.2. Environmental Adders

The E3 avoided cost methodology incorporated proposed environmental adders for NOx, PM-10, and CO_2. SCE and SDG&E/SoCalGas expressed concern that the draft avoided cost methodology 'double counts' the cost of NOx and PM10 emissions. The E3 report states that NOx and PM10 costs are internalized in the forward market prices used up until the resource balance year

in 2008 (referred to as 'Period 1' in the E3 Report). Therefore, NOx and PM10 abatement costs are only applied to the Long-Run Marginal Cost (LRMC) estimates after the resource balance year, and only on the residual emissions of new plants with the required abatement technology installed. E3 and SCE disagree as to whether abatement and permitting costs are included in the CEC plant cost numbers. The E3 report states that abatement and permitting costs are not included in the CEC plant costs, while SCE believes that abatement and permitting costs are included in the CEC plant cost numbers.

With regard to CO_2, SCE and SDG&E/SoCalGas argue that it is inappropriate to include a separate adder for non-regulated pollutants because future regulation is speculative. Other parties, such as TURN and NRDC disagree, as do we.[26]

Unlike criteria pollutants such as NOx and PM-10, which are regulated under the federal Clean Air Act and corresponding state legislation, CO_2 is not consistently regulated at either the federal or state levels. We recognize that CO_2 costs are not included in the marginal cost of producing electricity or thermal energy from natural gas today, and that CO_2 is strictly an unpriced externality. However, as discussed in the body of the E3 Report, there is a precedent going back to at least 1994 for including emissions costs in the avoided cost calculation for comparing efficiency measures in California (California Energy Commission Energy Report 1994 – ER94). The current avoided costs used for program evaluation adopted in D.01-11-066 in the Energy Efficiency Policy Manual

[26] PG&E agrees that CO_2 emission values be used for 2008 and beyond in screening and selecting resources, but that emission reduction values for non-regulated pollutants not be included in any pricing for generation resources. (PG&E, comments, p. 10.)

include externality benefits for reduced electric and gas consumption including CO_2. In addition, there is significant likelihood that the US and California will be a participant in the CO_2 market over the life of the efficiency measures (as long as 20 years). The States of Oregon and Washington already regulate CO_2 emissions from new power plants, and California has enacted legislation to limit CO_2 emissions from automobiles, making state-level limitations on stationary sources more likely.

The California Energy Commission's finding that "Global climate change is real… and matters to California,"[27] also suggests that state level limitations on stationary sources are likely. Given the 20-year time frame of the E3 avoided cost analysis, it is highly likely that CO2 will be regulated and become part of the cost of producing electricity.

If we were to ignore the future cost of CO_2 emissions, we would be assuming that the probability of CO_2 emission costs being significant during the entire 20-year period would be zero, i.e., that the probability of the cost being zero is 100% for 20 years. While there is some finite probability that this cost will remain at or near zero during that time, it seems far more reasonable to assume that the future CO_2 emission cost has a probability distribution over a range of values from zero to the high values forecasted by some analysts (see page 97 of the E3 Report for reference of forecasts up to $69/ton under some Kyoto compliance scenarios). This approach supports an intermediate price trajectory such as the $8/ton value used in the E3 Report.

[27] California Energy Commission, "Climate Change and its Impacts on California," July 2, 2004, www.energy.ca.gov/global_climate_change/index.html.

A key goal of the Commission's energy efficiency effort is to reduce per capita energy use and peak demand through energy efficiency and a reduced reliance on fossil fuels. Assuming zero emission cost, or zero probability of significant emission costs for 20 years, would encourage utility investments that ignore the potential financial risk of CO_2 emission costs. While CO_2 limitation and regulation is controversial and uncertain, there is a wide range of potential cost levels, and an assumption of zero future does not adequately reflect the potential risk. Rather, a value that reflects the full range of reasonably possible outcomes would be more responsible.

We agree with the NRDC that it would be illogical to conclude that carbon emissions costs will be zero over the timeframe of the E3 report, as suggested by the SCE. Multiple scenarios do not suggest that the value should be zero, but rather than the value should fall within a reasonable range. It is reasonable to adopt a policy that requires utilities to calculate avoided costs using a methodology that incorporates a CO_2 adder. The E3 report examines a range of carbon values from $5 to $69 per ton of CO_2 and uses $8 per ton as a levelized cost in its analysis, based on a trend of $5 per ton in the near term, $12.50 per ton by 2008, and higher values thereafter. Adopting the E3 forecast of CO_2 values as an adder in the avoided cost calculation and forecast reasonably reflects the cost to California of carbon emissions. The CO_2 values adopted here will be used as an analytic tool in the evaluation of energy efficiency programs.

4.3. Generation Avoided Costs

SCE argues that the use of the full capital cost of a CCGT as a proxy for the avoided cost of capacity will misstate avoided costs for high-usage periods when CTs would be operating as the marginal units and low-usage periods when

baseload units may be operating on the margin and CCGTs would not be in operation.

Both TURN and SDG&E/SoCalGas recommend modifications to the energy price forecast. TURN recommends that the energy price duration curve be modified at the bottom end because it expects few zero cost hours over the next 20 years, while SDG&E/SoCalGas recommends that the top end of the price duration curve be modified to contain the explicit cost of a CT if the commission intends to use the methodology outside of EE program evaluation.[28]

Discussion

E3 states that it used three years of electricity forward price data published by Platts to estimate the market-based generation avoided cost for the period 2004-2006. The expected electricity price level for 2007 is calculated by escalating the 2006 electricity forward price using the NYMEX natural gas futures price. The avoided cost for the load-resource balance year of 2008 and beyond is the LRMC based on the all-in cost of a CCGT. E3 recommends this approach on the basis that the forward price data represent the best publicly available source for the four-year (2004-2007) sub-period for EE/DSM evaluation over a 20-year planning period.

E3 states that using forward price data reflects market prices, including capacity, because 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. Therefore, the energy delivery under a forward contract is firm. As part of forward price determination, the market assigns a value to the capacity used to

[28] SDG&E/SoCalGas, post-workshop comments, p. 13.

ensure firm delivery of the contracted energy. This value does not necessarily track the historic fixed cost of capacity. The value is small (large) to reflect the expected surplus (shortage) in the capacity used for firm delivery. In the years prior to resource balance, the forward prices do not cover the full cost of a new entrant.

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).

The proposed generation costing methodology relies on California PX hourly NP 15 and SP 15 zonal prices from April 1998 to April 2000 to develop hourly market price values. The historical market prices incorporate bids from a variety of resources including CTs and CCGTs during both high and low-usage periods. The relative differences in the historical market prices over high and low usage periods is maintained throughout the forecast period by proportional scaling to reflect future market price quotes prior to resource balance, or the all-in cost of a CCGT for the resource balance year and beyond. E3 states that the historical hourly market prices over the 25-month period prior to the energy crisis provide reasonable price variations over time that are reflective of variations in both the level of energy usage by time period and the characteristics of different generating resources that might be the most cost effective resources by time period.

On balance, we conclude that the forecasting methodology in the E3 report should be approved, but with updated electric forward prices (through 2007).

The parties claim that the Commission should use either a CT on a CCGT to represent avoided generation costs run contrary to our objective of developing a methodology that attempts to reflect hourly and utility-specific differences in avoided cost values. Certain suggestions also run contrary to our goal of adopting a methodology that is based on public information and easily updated.

We agree with the parties that we should use the most current market data, to the extent possible, and for this reason, we will update the E3 methodology to reflect current energy prices. The adopted approach is workable for the 2006 energy efficiency programs, but will remain subject to modification for future uses.

4.4. Market Price Referent (MRP) Assumptions

CCC suggested that the Commission should draw upon the record in the California Renewables Portfolio Standard (RPS) R.04-04-026**,** as the basis for a more detailed and sophisticated source of all-in CCGT costs for use in E3's long-run avoided cost methodology.[29] In R.04-04-026**,** we have considered the inputs and methodology to estimate the costs of baseload (CCGT) and peaking generation (CT) in order to establish a benchmark price for Renewables Portfolio Standard purchases called the Market Price Referent (MPR).

SDG&E/SoCalGas note that the E3 method and the Commission's RPS methodology are generally consistent, using natural gas forward prices for the first years transitioning to forecasts of fundamentals, but the specific methods are different.[30] SDG&E/SoCalGas state that both methods seem equally acceptable

[29] CCC, pre-workshop comments, p. 10.

[30] SDG&E/SoCalGas, post-workshop comments, p. 9.

and suggest that the Commission allow the EE proceeding to use both forecasts for purposes of program evaluation.

Discussion

As SDG&E/SoCalGas notes, the E3 methodology gas forecast and the MPR approach are generally, but not entirely consistent. When E3's gas price forecast is input into the MPR model, the resulting annual average market prices are nearly identical to the results in the draft report.

We agree with the parties that the use of the same gas price forecast methodology would be ideal, given our intent to eventually develop consistent inputs and assumptions across all uses of avoided cost data. However, the MPR methodology currently does not offer monthly estimates of price or price differences by location. Since the energy savings associated with energy efficiency measures can vary greatly depending upon when and where they are used or installed, we view the availability of time and location specific forecasts as critical to the development of accurate avoided cost forecasts.

Consistent with the goals of this rulemaking, we will update the E3 methodology to reflect the CCGT cost inputs used in calculating the MPR, where applicable, but will not substitute the MPR methodology for the E3 gas forecast methodology at this time. Specifically, we will utilize the following CCGT MPR inputs in the E3 model, as set forth in Appendix C of the Revised MPR Staff Report issued on February 11, 2005, via ACR, as briefly described here: All "Capital Inputs" (although the E3 model only uses an average heat rate, not the new and clean value or a heat rate degradation factor); All "Finance Inputs" to the extent that these inputs are currently utilized in the E3 model; All "Power Delivery Inputs" to the extent that these inputs are currently utilized in the E3 model; and All the "Tax Rate Inputs" listed in Appendix C to the Revised MPR Staff Report.

With regard to updating the gas forecast, the E3 models will utilize a 60-day average of NYMEX gas futures data (similar to that done in the MPR gas forecast methodology.) The 60-day sample of NYMEX data should extend back from the effective date of this decision. The E3 models will also incorporate the same fundamentals forecast as was used in the MPR gas forecast model. Specifically, the MPR fundamentals forecast should replace the existing fundamentals forecast currently used as an input in the E3 methodology.

4.5. Transmission and Distribution Costs

SCE and SDG&E/SoCalGas raise issues concerning E3's proposed methodology for calculating T&D costs. In contrast to the existing values contained in the Policy Manual, E3's forecasts of T&D avoided costs are differentiated by utility service territory, customer class and season to recognize the time- and area-specific nature of the avoided costs. The report provides gas T&D avoided cost streams for core residential customers, core commercial/industrial customers and total core consumption. The avoided costs of each customer class are further allocated to the winter season (November through March), when the utilities normally experience peak demand. This approach is designed to allow the Commission to attribute greater value to DSM programs that (1) are implemented in areas with higher avoided costs; and (2) provide reductions when they are most needed -- at the time of the peak load for transmission and local peaks for distribution, as opposed to measures that affect off-peak consumption.

PG&E and SCE question the validity of a universal T&D avoided cost adder, arguing that consideration of T&D costs on a case-by-case basis is a more reasonable approach. In support of their positions, SCE and PG&E both reference prior to Commission Decisions in R.99-10-025, concerning Distributed

Generation, and claim that these decisions support a finding that the impact of DSM/EE programs on transmission and distribution can only be ascertained through case-by case analysis. E3 responds, and we agree, that while a case-by-case analysis should be applied to determine payments related to specific projects for long-term conservation measures it is appropriate to credit programs with T&D avoided costs for program evaluation purposes.

The E3 Report does not present costs for specific investments, but averages numerous investments within large geographic areas. These costs are meant to be used for evaluating long-lived DSM/CEE programs that are being credited with the avoided cost of representative (not specific) investments. In this application, for long-lived measures with fairly predictable kW reductions over many hundreds of hours, E3 believes that the issue of "reliably in place" is sufficiently addressed through the use of hourly costs that capture the timing of the demand reductions, combined with traditional adjustments such as persistence factors.

The E3 report discusses the deration of T&D avoided costs, and supports well-reasoned adjustments to the level of T&D avoided costs used for program evaluations, but maintains that a general assumption of zero value for T&D avoided costs is inappropriate.

4.6. Natural Gas Issues

Price Forecast

SDG&E/SoCalGas suggest that the natural gas price forecast presented in the E3 report is flawed. SDG&E/SoCalGas proposed a different process based on an average of the basis differential for two years of basis swaps and three years of historical data. A basis differential between Henry Hub and the California Border/PG&E Citygate based on a five-year average would be

comparable to the E3 approach to calculating the spark spread in the electric price forecast. SDG&E/SoCalGas suggest that an alternative would be to use the Henry Hub and San Juan Basin basis differential, or other appropriate basin, plus full transportation costs to the California Border/PG&E Citygate.
SDG&E/SoCalGas note that the E3 method, the RPS Method, and the SDG&E gas price forecast included in its long-term resource plan are all consistent; all have some reference to gas forward prices and all rely on long-term gas price forecasts based on fundamentals prepared by government agencies or private consulting firms.

Storage

SDG&E/SoCalGas and TURN recommend that future updates to the gas avoided costs could include gas storage costs and core firm pipeline capacity costs. We agree in principal, and will consider SDG&E/SoCalGas' and TURN's suggestions in our consideration of revisions to the E3 report methodology in Phase 3, with the caveat that gas storage costs should not be included if the purpose of the project is the management of seasonal gas price swings. We also note that if core firm gas pipeline costs are already captured in the gas T&D adder, care must be taken to avoid double counting of that cost item.

4.7. Discount Rate

NRDC urges the PUC "to adopt a discount rate in the range of 2%-3% real. This is consistent with the 3% real discount rate that has been used for many years by both the CEC in evaluating energy efficiency standards and the Northwest Power Planning Council." (NRDC, pre-workshop comments, p. 4.)

The E3 Report uses the discount rate of 8.15% adopted in D.01-11-066 in the Energy Efficiency Policy Manual. We decline to adopt a specific discount rate

for use here. The discount rate used should be determined in R.01-08-028, the energy efficiency rulemaking.

4.8. Conclusion

We are pleased with the degree of consensus that appears to have been reached regarding the E3 methodology. The utilities, while generally supportive of adoption of the E3 methodology for evaluating energy efficiency programs, each recommend slight modifications to the approach. On an overall basis, however, the E3 avoided cost methodology offers significant improvements compared to the existing methods. In contrast to the current approach and the production simulation method advocated by SCE, the E3 avoided cost methodology produces forecasts which are disaggregated by area and time for both electricity and natural gas over a 20-year period, from 2004 through 2023. For electricity, avoided costs are calculated by hour for each year for the 16 climate zones, 24 electric utility planning divisions, and three service voltage levels. This produces separate avoided cost estimates for customers served at each voltage level (transmission as well as primary and secondary distribution levels). For natural gas, E3 calculated the avoided costs by month for each year, utility, and customer type. The E3 avoided cost methodology more accurately estimates the electricity and natural gas a utility would avoid having to supply to its customers as a result of certain energy efficiency measures.

Compared to the current method, these hourly avoided costs will enable the Commission to recognize the full value of programs, such as air conditioner efficiency, which contribute disproportionately to reducing peak demand, especially on days of peak demand.

The avoided costs resulting from E3's methodology are also transparent and easily updated. In the existing hybrid market, an open and dynamic method

is if critical importance. For example, while the avoided costs methodology incorporates a substantial reserve margin beyond what is currently maintained by the California Independent System Operator, the costing methodology can be easily modified to reflect any changes. For example, if a new standard requires additional capacity purchases beyond what is already included in the estimate, an adder could be included based on these additional costs. Alternatively, if these standards are implemented in the bilateral energy market, they can be reflected as a multiple of the long-run cost proxy, which is the cost of a combined-cycle plant.

Finally, the recommended methodology is relatively simple, transparent and relies on no proprietary data or software. PG&E agrees that E3's methodology is straightforward, transparent, and easily updated, and that the resulting avoided costs are acceptable for immediate evaluation of EE programs and ranking them for spending within given budgets. SDG&E/SoCalGas also stated that the E3 avoided cost values, albeit with certain modifications, are appropriate for use in determining the benefits of potential EE programs.[31]

We concur with the parties that we should continue to refine the E3 methodology and forecast as part of our effort to develop consistency in the methodology and input assumptions for Commission applications of avoided costs. However, this effort requires more time and effort than is available prior to the PY 2006 -008 program cycle. Our primary objective in adopting the E3 methodology on an interim basis is to promote cost-effective energy efficiency programs to assist the utilities in meeting the energy savings goals identified by

[31] SDG&E/SoCalGas, post-workshop comments, p. 2.

the Commission in D.04-09-060. In order to achieve this goal we must update the avoided cost calculations used to evaluate competing EE programs prior to the time for program selection and design.

We believe that the parties' proposed modifications to the E3 methodology and forecast for other resource options should be carefully considered in the third phase of this rulemaking prior to adoption of the method on a permanent basis, and concur with the parties recommending immediate adoption of the approach for use in the generation avoided cost energy forecasts to be used in evaluation of energy efficiency programs for program year 2006. As PG&E and TURN point out, the existing energy efficiency avoided costs are so dated that the current E3 avoided costs, even without further refinement, represent an improvement needed now to avoid inefficient energy efficiency program planning for 2005 and 2006.

We have set ambitious goals for energy efficiency programs in the Energy Action Plan. Based on these goals, we directed the utilities to optimize electric energy efficiency investments in their resource plan portfolios. We increased energy efficiency funding to over $800 million for the 2004-2005 funding cycle, or an average of approximately $400 million per year and augmented natural gas energy efficiency funding for PG&E, SDG&E and SoCalGas on an expedited basis, in order to expand current programs for the 2004/2005 winter season.[32] In addition, in D.04-09-060, we recently established increased natural gas and electric savings goals for the utilities by service territory through the year 2013, subject to updates for 2009 and beyond, and directed that the next program cycle

[32] See D.04-12-019.

would cover program years 2006 through 2008.[33] The next program cycle begins on January 1, 2006, and the program selection process, for which the updated avoided costs adopted in this decision are necessary, will begin in the next few months.

5. Next Steps

Today's decision approves the E3 methodology to generate new avoided cost energy forecasts to be used in the evaluation of energy efficiency programs savings. PG&E, SDG&E, SCE, and SoCalGas are directed to use the E3 methodology adopted in this decision in their evaluation of energy efficiency program proposals for program year 2006 and beyond, until further order of the Commission. Each utility should use the adopted methodology, as updated herein, and the resulting avoided cost forecasts in the appropriate SPM tests to determine the combination of programs that will best provide cost-effective energy savings and meet our adopted savings goals.

In order to comply with today's decision and utilize the adopted E3 methodology for forecasting avoided costs, the utilities may need additional guidance on the input data assumptions developed in the E3 report. As discussed above, the E3 forecast will be updated to reflect current gas and electric price forecasts and the applicable CCGT input assumptions approved for use in developing the MPR in R.04-04-026.

The Commission's Energy Division shall conduct a workshop within 10 days of the effective date of this decision for the purpose of discussing any implementation steps necessary prior to utility application of the E3

[33] See D.04-09-060, *mimeo.*, pp. 37; Ordering Paragraph 1.

methodology we adopt today. We are informed by the Energy Division that E3 has constructed an evaluation tool (spreadsheet) that takes output from the E3 avoided cost models and then performs the various cost-effectiveness test calculations set forth in the Standard Practice Manual (SPM). We expect that the workshop will discuss this implementation advancement and address the instances in which it is appropriate to use hourly data or time-of-use data to evaluate certain EE measures. The workshop should also address the role of the Database for Energy Efficient Resources (DEER) data base[34] and the Energy Efficiency Programs Reporting Requirements Manual, however, the focus of the workshop should be primarily focused on work and issues necessary for the utilities to meet their upcoming compliance Advice Letter (AL) filing deadlines. Following the workshop, the utilities shall prepare and file compliance Advice Letters describing the steps taken to update the E3 methodology within 14 days of the effective date of this decision.

6. Need for Expedited Consideration

Rule 77.7(f)(9) of the Commission's Rules of Practice and Procedure provides in relevant part that:

> "…the Commission may reduce or waive the period for public review and comment under this rule regarding draft decision…for a decision where the Commission determines, on the motion of a party or on its own motion, that public necessity requires reduction or waiver of the 30-day period for public review and comment. For purposes of this subsection, 'public necessity' refers to circumstances in which the public interest in the Commission adopting a decision before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full30-day period for

[34] DEER database, http://www/energy.ca.gov/deer.

> review and comment. 'Public necessity' includes, without limitation, circumstances where failure to adopt a decision before expiration of the 30-day review and comment period… would cause significant harm to public health or welfare. When acting pursuant to this subsection, the Commission will provide such reduced period for public review and comment as is consistent with the public necessity requiring reduction or waiver."

The next energy efficiency program cycle covers the program years 2006 through 2008. The program design and selection process must be completed before the end of 2005. The updated avoided cost values considered in today's decision are necessary to update the current avoided cost forecasts used to evaluate potential energy efficiency programs. We balance the public interest in having available an updated avoided cost methodology and forecast values for the evaluation of energy efficiency program savings in time for the program year 2006-2008 planning process against the public interest in having a full 30-day comment cycle on the proposed methodology. We conclude that the former outweighs the latter. The updated avoided cost values adopted herein affect public health, safety and welfare by providing current, relevant avoided cost values for use in evaluating energy efficiency programs designed to assist in reducing per capita energy use and peak demand. Any delay in adopting these updated values would cause significant harm to public health and welfare by unreasonably and unnecessarily necessitating the use of outdated and inaccurate avoided cost values. We seek public review of, and comment on, our proposed changes, and find that a reduced period balances the need for that input with the need for timely action.

7. Comments on Draft Decision

PG&E, SDG&E, SCE, NRDC, CCC, and CAC/EPUC filed opening comments on the draft decision on March 30, 2005. Reply comments were filed

by PG&E, SDG&E, SCE, and NRDC on April 4, 2005. We have carefully considered the comments received and made changes to the decision where appropriate. In particular, we clarify that the E3 methodology is adopted for purposes of evaluating energy efficiency programs in R.01-08-028 and related energy efficiency proceedings on an interim basis, subject to further review in Phase 3 of this rulemaking. We also clarify that, consistent with the February 18, 2005 ACR consolidating R.04-04-003 with this proceeding for purposes of QF issues, all QF issues will be addressed in Phase 2 of R.04-04-025. Phase 3 will continue to focus on the development of a common methodology, consistent input assumptions, and updating procedures to quantify all elements of long-run avoided costs,[35] and will necessarily take into account any determination made by the Commission in Phase 2 regarding long-run avoided cost pricing for QFs.

Finally, in response to CCC's statement that its comments on the E3 report were limited to the possible future use in setting LRAC prices paid to QFs, we remove references to the CCC's positions on the use of electric futures prices and the extent to which capacity value is included in the current market prices.

8. Assignment of Proceeding

Susan P. Kennedy is the Assigned Commissioner and Julie Halligan is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission's existing forecasts of avoided energy costs and associated methodology are set forth in the *Energy Efficiency Policy Manual* (*Policy*

[35] To the extent parties recommend use or modification of the E3 Methodology and Forecast for purposes of QF pricing, additional review of the E3 methodology may also occur in Phase 2 of R.04-04-025.

Manual). These forecasts of avoided energy costs are outdated and require updating prior to their use in various Standard Practice Manual (SPM) cost-effectiveness tests used to value energy efficiency proposals for the 2006-2008 program cycle.[36]

2. It is reasonable to adopt the *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted to the CPUC Energy Division, October 25, 2004, modified as discussed herein, in order to update the current avoided cost forecasts used in the SPM tests to evaluate energy efficiency programs.

3. It is reasonable to require the utilities to update the electric and gas price forecasts utilized in the *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004 to reflect current forecasts.

4. It is reasonable for the utilities to use the E3 avoided cost methodology and forecast, without modification to separate energy and capacity costs, for purposes of evaluating energy efficiency programs for program year 2006.

5. Adopting the E3 forecast CO_2 value of $8/ton (annual levelized) as an adder in the avoided cost calculation and forecast is a reasonable estimate of the avoided cost to California of carbon dioxide emissions.

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[36] Energy Efficiency Policy Manual, Version 1, October 2001, D.01-11-066, Attachment 1, adopted in Ordering Paragraph 1. The Commission also employs separate avoided cost methodologies which are used to price power from QFs. QF avoided cost methodologies are not part of the Energy Efficiency Policy Manual.

6. For the evaluation of Program Year (PY) 2006-2008 energy efficiency proposals, it is reasonable to require the utilities to update the E3 methodology with the applicable Combined Cycle Generation Turbine (CCGT) capital cost input assumptions approved for use in calculating the MPR in R.04-04-026, consistent with our stated goal of developing consistency in methodology and input assumptions across Commission applications of avoided cost.

7. It is reasonable to require the utilities to prepare and file compliance Advice Letters describing the steps taken to update the E3 methodology within 14 days of the effective date of this decision.

8. Delay in the adoption of updated avoided cost values would compromise the Commission's efforts in reducing per capita energy use and peak demand through cost-effective energy efficiency programs, adversely affecting public health, safety and welfare.

Conclusions of Law

1. Because of the time and location dimensions in the E3 methodology, adopting the E3 methodology for purposes of evaluating potential energy efficiency proposals will best reflect the savings associated with candidate energy efficiency programs.

2. With the methodology adopted in this decision, the avoided costs associated with selected energy efficiency programs will more accurately reflect the utilities' actual avoided costs.

3. As discussed in this decision, the avoided cost energy forecasts for evaluation of PY 2006 Energy Efficiency programs should be updated as soon as practicable.

4. The *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted to the

CPUC Energy Division, October 25, 2004 should be adopted on an interim basis for use in evaluating energy efficiency programs, with the further guidance provided in this order.

5. The public interest in the timely adoption of updated avoided cost values for use in evaluating program year 2006 energy efficiency programs outweighs the public interest in having a full 30-day comment cycle on the proposed values.

6. In order to proceed expeditiously with the evaluation of potential energy efficiency programs for the program year 2006, this decision should be effective today.

7. The utilities should use the avoided cost values for CO_2 adopted herein as the "greenhouse gas adder" pursuant to D.04-12-048 in long-term resource procurement and planning.

INTERIM ORDER

IT IS ORDERED that:

1. We adopt the *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted on October 25, 2004, updated as discussed herein, for purposes of evaluating energy efficiency programs in Rulemaking 01-08-028 and related energy efficiency proceedings.

2. Until further order by the Commission, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), and San Diego Gas and Electric Company (SDG&E) shall each undertake its Energy Efficiency program evaluation for program year 2006 and beyond using avoided cost forecasts in conformance with the adopted methodology.

3. PG&E, SCE, SDG&E, and SoCalGas shall prepare and file compliance Advice Letters updating the *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, E3 Research Report submitted to the CPUC Energy Division, October 25, 2004, as directed in this decision, within 14 days of the effective date of this order.

4. This proceeding remains open to address ongoing issues in Rulemaking 04-04-025.

This order is effective today.

Dated April 7, 2005, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

Comr. Grueneich recused herself
from this agenda item and was not
part of the quorum in its consideration.

ATTACHMENT 1
List of Acronyms

ACM	Alternative Calculation Methodology
ALJ	Administrative Law Judge
AS	Ancillary Services
CAC	Cogeneration Association of California
CBEA	California Biomass Energy Alliance
CCC	California Cogeneration Council
CCEA	California Consumer Empowerment Alliance
CLECA	California Large Energy Consumers Alliance
CalWEA	California Wind Energy Associations
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
D.	Decision
DG	Distributed Generation
DR	Demand Response
E3	Energy and Environmental Economics, Inc.
EE	Energy Efficiency
IEP	Independent Energy Producers
ISO	Independent System Operator
IOUs	Investor-Owned Utilities
LRMC	Long Run Marginal Cost
MCP	Market Clearing Prices
MPR	Market Price Referent
MID	Modesto Irrigation District
MTDCC	Marginal Transmission and Distribution Avoided Capacity Costs
NRDC	Natural Resources Defense Council
ORA	Office of Ratepayer Advocates
PG&E	Pacific Gas and Electric Company
PHC	Prehearing Conference
PW	Present Worth
QFs	Qualifying Facilities

R.	Rulemaking
RFP	Request For Proposal
RNS	Residual Net Short
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SoCalGas	Southern California Gas Company
T&D	Transmission and Distribution
TDV	Time Dependent Valuation
TOU	Time of Use
TRCSV	The Total Resource Cost Test: Social Version
TURN	The Utility Reform Network
UCS	Union of Concerned Scientists
UDC	Utility Distribution Company

(END OF ATTACHMENT 1)