ATTACHMENT A

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Draft Demand Response Cost Effectiveness Protocols

SECTION 1: BASIC INFORMATION

Introduction

The staff's draft Demand Response (DR) cost-effectiveness protocols are intended to provide a set of interim methods for measuring the cost-effectiveness of demand response resources during the 2009-2011 program cycle. These draft protocols will also provide a basis for more permanent cost-effectiveness protocols. These protocols are intended for *ex ante* evaluations of demand response resources which provide long-term resource value.

The draft DR cost-effectiveness protocols that are described in this document are based largely on two proposals filed in Commission Rulemaking (R.) 07-01-041: the cost effectiveness framework submitted by the three large California investor-owned utilities (IOUs) – Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E) and Southern California Edison Company (SCE) (Joint IOU Framework)[1] and the Demand Response Cost Effectiveness Evaluation Framework submitted by the Consensus Parties (Consensus Parties Framework).[2] The draft protocols described in this document are designed for these three IOUs. Nevertheless, they should be applicable to Demand Response activities developed by any Load Serving Entity (LSE). However, LSEs other than those three IOUs may require additional guidance.

The two cost-effectiveness proposals referenced above provide a basic framework for the analysis of Demand Response cost-effectiveness. While the draft protocols proposed here modify and adapt those documents, the methods, procedures, and models proposed in those documents should be used to determine the cost-effectiveness of Demand Response resources *only to the extent that they do not conflict with the modifications presented in these draft protocols.*

The purpose of these draft cost-effectiveness protocols is to:

- Address the broad variety of DR resources, including current programs and anticipated future activities;

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[1] *Revised Straw Proposals For Demand Response Load Impact Estimation And Cost Effectiveness Evaluation Of Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E) and Southern California Edison Company (U 338-E)*, filed September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf)

[2] *Joint Comments Of California Large Energy Consumers Association, Comverge, Inc., Division Of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) and The Utility Reform Network Recommending a Demand Response Cost Effectiveness Evaluation Framework*, filed September 19, 2007 (http://docs.cpuc.ca.gov/efile/CM/75556.pdf).

- Identify all relevant quantitative and qualitative inputs that are important for determining the cost-effectiveness of DR;
- Recommend methods for determining the value of the inputs; and
- Determine a useable overall framework and methods for evaluating the cost effectiveness of each of the different types of DR activities.

The draft protocols proposed here are not intended to address the following issues, which are more appropriately addressed in other Commission proceedings:

- Identification of proceedings where DR cost effectiveness protocols will be used;
- The means by which the Commission will use these protocols to determine whether to pursue various DR programs, activities or policies;
- Anything other than a short-term, interim methodology for determining the appropriate methods of measuring avoided cost for demand response; and
- Consistency between load impact measurements for DR cost effectiveness and the rules for determining whether a resource counts for resource adequacy.

Section 1.A: Intended Use of Protocols

These protocols will be used for determining the cost effectiveness of both individual DR programs and a utility's overall DR portfolio in the 2009-2011 program cycle. It will be used for evaluations associated with approval of DR programs of all types – event-based and non-event based, price-responsive and emergency, day-ahead and day-of. Finally, these draft protocols will also be a key tool for evaluating third-party aggregation proposals. These protocols are not designed to measure educational or general marketing and outreach programs which promote DR.

We recognize that there are a wide variety of DR programs with differing attributes. Therefore, flexibility in the application of these draft protocols may be necessary to fully reflect the attributes of some DR programs. These draft protocols should be viewed as appropriate guidelines for developing the primary inputs for the cost effectiveness equations contained here, but not requiring excessive and unnecessary rigidity in the application of the methods. The valuation of DR programs may also be affected by future Commission decisions on short-term and long-term resource adequacy, avoided costs, or other issues, by actual program design and operations, and by the California Independent System Operator's (CAISO's) Market Redesign and Technology Upgrade (MRTU). It may become necessary for a utility to update or modify methods or values in future cost effectiveness evaluations, if doing so is necessary to provide accurate results. However, if any such updates or modifications are required, they must be clearly described and justified.

These protocols assume that, at least as an interim approach, DR programs be viewed as an alternative to other resources from a long-term resource planning perspective. Therefore, the cost effectiveness of DR programs should be evaluated by comparing the costs and benefits of DR programs to the costs and benefits of supply-side (or other alternative) resources. The time period for the cost effectiveness evaluation should cover all the years in which benefits will be provided and costs will be incurred.

The methods described in these draft protocols should be used for *ex ante* evaluation of DR cost effectiveness. *Ex post* evaluations of the cost effectiveness of DR activities would not be an appropriate way to determine cost-effectiveness, because in general, demand response resources provide "insurance" against relatively low probability and/or intermittent events that can have severe consequences when they occur. If those events did not occur during a given time period, it does not necessarily mean that those demand response resources were less valuable or less cost effective *ex post*. However, *ex post* analysis is useful for informing assumptions or forecasts needed for *ex ante* analysis. *Ex ante* cost-effectiveness evaluations should be adjusted for actual *ex post* experience from previous demand response program budgeting cycles or filings. Thus, each cost-effectiveness test should use, to the maximum degree possible, actual program experience from previous budgeting cycles to ensure the new forecasts are consistent with actual experience.

Section 1.B: Sources of Input Data

The utilities are expected to provide accurate and up-to-date forecasts of DR program benefits and costs in any program approval submissions. Cost-effectiveness calculations should be based on the most recent expected values for all inputs. This includes values for the future annual market value of generation capacity, future electricity prices, as well as each utility's marginal T&D cost(s) and line loss rates. In some cases, those values may be obtained from published sources, to the extent that such data are available from those sources at the required level of detail and/or aggregation, are practical, reasonably accurate and up-to-date. A utility's general rate case marginal cost studies may provide CT cost and avoided T&D cost data. Either general rate case marginal cost studies or modeling studies which underlie the utility's long-term procurement plans may provide avoided energy cost data.

Estimates of the load impacts of a Demand Response resource will be based on expected load impacts as measured using Commission-approved DR load impact protocols.[3]

Section 1.C: Confidentiality

The DR cost effectiveness methods presented in these draft protocols should promote transparency by using published data and public data sources where practicable. However, confidential or proprietary data and analyses underlying utility cost effectiveness are entitled to the confidentiality protections recognized in Commission decisions.[4]

Section 1.D: Relationship to the Standard Practice Manual

These draft cost-effectiveness protocols are a modified version of the California Standard Practice Manual (SPM),[5] which was developed to measure the cost-effectiveness of energy efficiency programs. The SPM contains four different tests which each measure cost-effectiveness from a different perspective. These tests are not intended to be used individually or in isolation. Rather, the tests are to be compared to each other, and tradeoffs between the tests considered. These protocols require that *all* the SPM tests, as defined below, be used to describe

[3] Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance, proposed decision mailed 3/25/2008.
[4] *See* Section 454.5(g) of the California Public Utilities Code and D.06-06-066.
[5] http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

the cost-effectiveness of both individual Demand Response programs and each utility's Demand Response portfolio. The relative weight given to any SPM test in determining program approval will be determined within the 2009-2011 DR budget proceeding, or other application or advice letter proceeding in which a utility is requesting approval of a Demand Response resource.

The results of each SPM test are based on the net present value of program impacts over the lifecycle of those impacts. Because the SPM is the starting point for the cost effectiveness methods in these protocols, modifications have been made to selected elements of the SPM tests to better adapt them for use with DR. Unlike energy efficiency programs, most of the benefits provided by DR programs are related to avoiding relatively low probability future events (e.g., unusually high demand and/or energy prices) in relatively few hours, whose occurrence could have significant economic consequences. Furthermore, event-based DR programs provide options whose value is related to the degree of uncertainty about exactly when those events will occur, and the actual magnitude of the resulting consequence. However, other DR programs are not event-based, but are designed to encourage continuous shifting of energy use from what are generally high-cost hours to lower-cost hours. Examples of these DR programs are real time pricing and thermal storage. The day-to-day benefits of these programs still need to be assessed. In light of these differences, there may be a particular need for flexibility or additional modification in the application of these draft protocols when applying them to dynamic pricing and load shifting programs.

Therefore, the benefits and costs of DR resources usually should be evaluated on an hourly basis over relevant time periods by using analytic methods that take into account the uncertainties about when and how often circumstances such as extremely high demand or energy prices will occur, the magnitude of the resulting economic consequences, and the impact of behavior on the load changes that occur under those DR programs.

Section 1.E: Relationship to the Planning Reserve Margin and Resource Adequacy

DR programs avoid the need for generation capacity since they are designed to reduce customer usage during periods of peak demand. The amount of total capacity that the Commission requires each LSE to maintain, from a resource planning perspective, is determined by the Resource Adequacy (RA) requirements established by the Commission.

As a result, the extent to which DR programs enable a LSE to avoid generation capacity costs depends upon the extent to which the Commission's RA "counting rules" allow that LSE to count the capacity of DR programs in complying with its RA requirement. At the present time, dispatchable (i.e., event based) Demand Response resources are counted towards an LSE's RA requirement, although discounted from enrolled values by the counting rules. Non-dispatchable (i.e., non-event based) DR resources reduce the LSE's demand forecast, and so ultimately also reduce the LSE's RA requirement. All DR programs covered by these protocols should be designed, to the greatest extent possible, to provide RA value.

However, there is a timing challenge associated with counting DR for RA. The RA program currently requires that each LSE to show, on a year-ahead basis, that they own or have under contract sufficient resources to meet 90 percent of their system RA obligations (i.e., their forecasted demand plus a 15 to 17% capacity planning reserve margin) and 100% of local

RA capacity requirements in certain transmission constrained load pockets. For this showing DR programs are evaluated for the counting rules in May-June for the Sep-Oct RA showings. For example DR programs undertaken or expanded in the summer are not currently counted for the following year. A protocol that would provide information on DR performance on a more timely basis would facilitate the use of DR resources in RA. In addition, depending on how proactive an LSE is in meeting this obligation, there is a chance that the LSE may be fully or close-to-fully resourced several years in advance. In staff's opinion, this circumstance does not translate to a lack of need for DR resources or a lack of cost-effectiveness.

Another factor to consider in this context is that cost effectiveness analyses of DR programs done for resource planning purposes are designed to examine the value of projected load impacts over the appropriate planning horizon. This is likely to encompass a relatively long time period. Load impacts and other DR assessments needed by the CAISO will likely need to be estimated within a much shorter time frame to allow for the CAISO to quickly determine the availability and magnitude of a DR resource. As a result, these draft cost-effectiveness protocols are not expected to be completely consistent with the CAISO's perspective at this time. In particular, there are significant differences between the CAISO identified needs, long term procurement needs, and the Resource Adequacy counting rules, especially in how emergency-triggered DR (i.e., DR which is opertionally triggered during a CAISO Stage Two or Three Emergency) is valued. It is hoped that as DR resources play more of a role in the emerging MRTU framework that CAISO identified needs, long term procurement needs and RA counting rules will become more aligned, which will allow us to not only value these program appropriately but also determine their optimum MW level.

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Section 1.F: Types of Analyses Expected

Many of the costs and benefits of Demand Response (and other) programs are uncertain, and have considerable variation among participants, LSEs and others, making them difficult or prohibitively expensive to quantify. Costs and benefits which cannot be easily quantified are often approximated, and if they cannot be approximated they are generally ignored. This approach, while pragmatic, does not allow for an assessment of the true costs and benefits of these programs. In that light, these draft protocols require LSEs to provide additional types of analyses than have been required in past proceedings. These analyses are not meant to be costly, extensive or overly burdensome. What is required is simply a good faith effort on the part of the LSEs to expand upon current practice and provide more insight into the true impact of any proposed Demand Response resource.

Hence, these draft protocols require that sensitivity analysis be performed on key variables, defined as those costs and benefits (or components thereof) which are (a) substantially uncertain and (b) likely to have a significant impact on SPM test calculations. For each key variable, the LSEs should provide a "best guess," based on the LSE's best available data and a reasonable set of assumptions. Justification for those assumptions should be provided, and the methods used to approximate the "best guess" should be reasonable and transparent. A sensitivity analysis should be done on at least **four** different values for each key variable: A minimum and maximum value

which describe a 90% confidence interval, and a minimum and maximum value which describe a 50% confidence interval.[6]

Where it is not possible to approximate an uncertain cost or benefit even within a 50% confidence interval, qualitative analysis of that cost or benefit should be provided. Qualitative analysis is a descriptive analysis of the possible magnitude and impact of that cost or benefit. It may also include a description of any variation based on location, customer class, or any other significant factor. In addition, relevant research may be referenced, or future research proposed, in the qualitative analysis.

Specific cases requiring sensitivity or qualitative analyses are discussed in the sections discussing each SPM test, and also in the sections discussing each SPM cost and benefit.

SECTION 2:
USING THE STANDARD PRACTICE MANUAL TESTS TO DETERMINE DR COST-EFFECTIVENESS

This section describes the modified SPM tests that should be used to determine DR cost-effectiveness. The output of each modified SPM test is based on the net present value of the costs and benefits, discounted over the lifetime of the relevant Demand Response resource. Hence, the costs and benefits listed below are not simply added together to produce the SPM outputs. Rather, the costs and benefits should be computed using Commission-accepted discount rates and the net present values calculated as described in the Standard Practice Manual. The paragraphs below are simply meant to be generalized and simplified descriptions of those calculations.

Section 2:A: Total Resource Cost (TRC) Test

The TRC test calculates the costs and benefits to "society" of a demand response resource. For the purposes of these draft protocols, "society" is considered to be each LSE and its customers.[7]

In the SPM, TRC benefits are limited to the LSE's avoided costs of supplying electricity and tax credits (if available). However, to make the TRC test better reflect the true cost and benefits of Demand Response to society, these additional benefits should be considered:

- environmental benefits
- market benefits

From the perspective of the TRC, the costs of a Demand Response resource are:

- Administrative costs
- Net Participant costs (capital costs less rebates to participant + value of service lost + transaction costs)
- Increased supply costs, if any

[6] A 90% confidence interval is defined as a range of numbers between which there is 90% confidence that the true value lies.

[7] This assumes that each LSE is capturing any possible "spillover" impacts that may occur outside its service territory.

Each of these costs and benefits is discussed further below. Some of these costs and benefits are difficult, if not impossible, to calculate. Hence, for each of the benefits and costs which are not easily calculated, the utilities are required to either (a) approximate its value using a reasonable and transparent method or (b) provide a qualitative discussion of the likelihood and extent of that value. If values are approximated for any of the above benefits or costs, sensitivity analysis should be provided if it is expected to have a significant impact on the results, as per the section on "Types of analyses expected" above. It is expected that these types of analyses may be necessary for environmental benefits, market benefits, value of service lost and participant transaction costs. Qualitative analysis of these variables may be used if approximating them is found to be prohibitively expensive or difficult. Note that qualitative analysis should be performed even on those inputs, such as environmental and market benefits, which are currently assumed to be zero, although sensitivity analysis is not necessary for those inputs even if actual values are estimated.

In addition, some sensitivity analysis of key variables which determine the avoided costs of supplying electricity should be performed.

Section 2:B: Program Administrators Cost (PAC) Test

The PAC test measures cost-effectiveness from the perspective of the LSE or other entity administering the Demand Response program. The benefits are the LSE's avoided costs of supplying electricity and market benefits.

From the perspective of the PAC, the costs of a Demand Response resource are:

- Administrative costs
- Incentives paid
- Increased supply costs, if any

Each of these costs and benefits is discussed further below. Most of these costs and benefits are relatively easy to quantify. However, if there is any uncertainty associated with variables which significantly affect the results, sensitivity analysis should be performed as per the section on "Types of analyses expected" above. In addition, some sensitivity analysis of key variables which determine the avoided costs of supplying electricity should be performed.

Section 2:C: Ratepayer Impact Measure (RIM) Test

The RIM test, also called the non-participants test, measures the costs and benefits of a Demand Response program from the perspective of its impact on rates. The benefits are:

- Avoided costs of supplying electricity
- Revenue gain from increased sales, if any
- Market benefits

From the perspective of the RIM test, the costs of a Demand Response resource are:

- Administrative costs
- Incentives paid
- Increased supply costs

- Revenue loss from reduced sales

Each of these costs and benefits is discussed further below. Most of these costs and benefits are relatively easy to quantify. However, if there is any uncertainty associated with variables which significantly affect the results, sensitivity analysis should be performed as per the section on "Types of analyses expected" above. In addition, some sensitivity analysis of key variables which determine the avoided costs of supplying electricity should be performed.

Section 2:D: Participant Test

The Participant Test measures the cost-effectiveness of a Demand Response program from the perspective of a participant. For the purposes of these protocols, a participant is considered to be a ratepayer who is an end-user of electricity and participating in a DR program. From this perspective, the benefits of the DR program are:

- Bill Reductions
- Incentives Paid
- Non-monetary benefits (non-energy benefits)
- Tax credits, if available

From the participant's perspective, the costs are:

- Bill Increases
- Capital, O&M, removal and any other costs associated with DR equipment installed
- Value of service lost (lost productivity and comfort costs)
- Transaction costs (opportunity costs associated with education, equipment installation, program application, energy audits, etc.)

Each of these costs and benefits is discussed further below. Some of these costs and benefits are difficult, if not impossible, to calculate. However, it is safe to assume that a customer would not voluntarily participate in a DR program if the benefits to that customer did not exceed the costs. Hence, for the purpose of DR programs which require customer enrollment (generally referred to as "voluntary" programs), it can be assumed that the costs are less than or equal to the benefits, since a rational electricity end-user would not otherwise participate in the program. Therefore, when presenting cost-effectiveness analysis of voluntary DR program, the utilities should simply state that the benefit/cost ratio for the Participant Test is greater than 1.

For default programs (i.e., programs in which all customers are considered participants, such as Peak Time Rebate or default CPP), a more detailed analysis must be provided. LSEs should provide an estimate for each cost and benefit which can be calculated. Sensitivity analysis should be provided if it is expected to have a significant impact on the results, as described in the section on "Types of analyses expected" above. For costs and benefits which are not easily quantified, such as non-monetary benefits, value of service lost and transaction costs, LSEs should make as much of an attempt as is practical to analyze them. In this analysis, a list of the specific costs and benefits in each of the larger categories of costs and benefits should be made. Examples of specific costs and benefits are listed below. For each specific cost and benefit, an approximate value should be determined when feasible, and sensitivity analysis should be

provided if it is expected to have a significant impact on the results, as described in the section on "Types of analyses expected" above. Qualitative analysis of specific costs and benefits should be used when approximating them is found to be prohibitively expensive or difficult.

Section 2:E: Costs and Benefits Used in the Modified SPM Tests for DR

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
Capital costs to participant	COST			COST
Environmental benefits	BENEFIT			
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-monetary benefits				BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

Shaded rows indicate those costs and benefits which are not listed in the SPM but have been added to these Demand Response draft protocols.

Section 2.E.a Administrative costs

Administrative costs of a DR program are considered to be an LSE's marketing and outreach costs associated with the program, equipment-related capital, operations and maintenance costs, program operational costs, IT costs, DR system operation and communication costs, and measurement, evaluation and verification costs. LSEs are expected to provide budgets which detail these costs for each proposed DR program.

DR program costs should include all costs which are caused by the program. Overall DR costs which are not caused by an individual program, such as non program-specific marketing (e.g., the Flex Your Power Now! program), should only be included in the evaluation of a utility's overall portfolio of DR programs.

Section 2.E.b Avoided costs of supplying electricity

The avoided costs of supplying electricity are the primary benefit of any demand side resource, and, in addition, an important consideration for comparing the various supply-side options. However, the calculation of avoided costs differs depending on the nature of the options that are being compared. More discussion of the various methods used to calculate avoided costs that are found in different Commission proceedings can be found in Appendix B.

Evaluations of cost effectiveness of DR programs are better served when avoided capacity costs, avoided energy costs, and deferred transmission and distribution (T&D) costs are distinguished separately rather being aggregated together as "all-in" avoided costs. The use of an "all-in"

avoided cost approach would preclude the use of the types of stochastic techniques that are necessary to value the benefits that can be provided by event-based DR.

Sensitivity analyses should be performed on key variables, including the price of gas, the availability of gas during peak periods, CT heat rates and operations on the hottest days, line losses on the hottest days, future wholesale electricity prices, and any other factors deemed to represent an important uncertainty in the electricity supply costs avoided by DR, as described in the section on "Types of analyses expected" above.

Capital and operating costs of the CT resource used to estimate avoided generation capacity costs should include capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants (NOx, PM 10, VOCs, SOx). These costs should be clearly identified in the avoided cost calculations.

In general, the avoided cost calculations will be made according to the Consensus Parties Framework or the Joint IOU Framework, except as specifically noted in this section. In addition, the Joint Utilities will be asked to provide a worked-out example of these calculations which will be attached to these protocols as an appendix.

Avoided generation capacity costs: The generation capacity costs avoided by a DR program will be based on the annual market price ($/kW-year) of the capacity of a new combustion turbine (CT), annualized using a real economic carrying charge rate that takes into account return, income taxes, and depreciation, with O&M, ad valorem and payroll taxes, insurance, and similar incremental costs added. The CT cost data will take into account service-area-specific CT construction and fixed environmental costs, and any other relevant inter-regional differences, where such values materially differ from state averages. The CT cost will be further adjusted to reflect the ability of a DR program to avoid procuring Commission-required reserve margin capacity and to reduce line losses.

While these draft protocols largely follow the Joint IOU Framework and the Consensus Parties Framework, an important difference between them concerns the treatment of expected gross margins. Staff recommends that the CT cost *not* be further adjusted to reflect expected "gross margins" earned by selling energy. A discussion of the rationale for this recommendation can be found in Appendix A, *Discussion of Gross Margins*.

The capacity value of DR programs without usage or availability constraints will be equivalent to the full annualized and adjusted CT cost. For DR programs with constraints on their availability, utilities will use an hourly stochastic method which matches the availability of the DR program against an hourly allocation of capacity value according to the relative probability of need. The value of generation capacity in those periods will be determined by allocating the annual market value of generation capacity among the hours of the year in proportion to the relative need for capacity in those hours (e.g., in proportion to hourly Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP) across all the hours in a year).

Because LOLE or LOLP is used to determine the hourly availability of resources, the LOLE or LOLP model could have a significant impact on the avoided capacity cost calculation. As a

result, it is important that the factors which drive the LOLE or LOLP values are better understood. The utilities should provide some additional information about the assumptions, inputs and outputs of this model which will clarify how these estimates are determined. This should include descriptive information as well as some sensitivity analysis of key inputs and assumptions. In addition, the utilities should demonstrate exactly how the model is applied to all resources, and demonstrate that the proportional allocation of LOLE or LOLP across all hours of the year is applied to both generation and DR (e.g., how adjustments are made for forced and unforced outage rates when comparing a CT with DR resources).

In general, the annualized and adjusted CT cost will not be adjusted to account for periods in which a region's capacity resources are projected to be greater than the Commission-adopted planning reserve margin standard. As previously discussed, this approach recognizes the position of DR in the state's loading order and the importance of maintaining participation levels in existing DR programs. For periods in which the planning reserve margin is expected to be substantially exceeded, however, it may be appropriate to reconsider this position for any new or expanded DR programs.

Avoided Energy Costs: For both event-based and non-event based DR programs, the value of avoided electricity generation may be based on wholesale energy prices averaged over the highest-price hours of an hourly price forecast. The utilities may also use a stochastic method that reflects the correlation between electricity prices and the times when DR program events are expected to occur, based on the times in which the program will be available, constraints on the use of the program, and the probability distribution of and correlations between the trigger conditions under which events can be called under that program. The calculation of avoided energy costs will take into account avoided line losses. The incremental cost of any additional generation resulting from a load-shifting program will be taken into consideration based on the expected electricity prices during the time that the additional electricity is used.

After the CAISO establishes a system of locational marginal prices (LMP) as part of MRTU, and after sufficient LMP price data have been accumulated, it will be possible to incorporate the value of DR programs in avoiding transmission congestion costs by calculating avoided energy costs on a locational basis. (This will also incorporate the local value of reducing transmission losses.) Utilities should plan to incorporate any such locational value beginning with the 2012-2014 DR program cycle, presuming adequate information exists by that time.

Avoided Transmission and Distribution Costs: Utilities may defer and/or reduce transmission and/or distribution (T&D) capacity investments (and thus avoid T&D costs) in local areas experiencing load growth as a result of DR programs, although the conditions under which DR programs actually do avoid such investment and the amount of investment avoided is viewed by some as uncertain and speculative.

As an interim method, utilities will establish a default avoided T&D cost (or area-specific default avoided T&D costs) which will be applied to DR programs which meet "right place" and "right certainty" criteria. As more experience with the ability of DR programs to avoid transmission and distribution investments is developed (particularly after roll-out of advanced metering technologies), it is anticipated that the utilities will be able to refine this approach.

The default avoided T&D costs will be calculated from marginal transmission and distribution costs by using the component of these marginal costs associated with non-ISO transmission and distribution substation equipment, which is principally related to transformer capacity.[8]

The criteria "right place" and "right certainty" are intended to limit the application of the avoided T&D costs to programs that (1) are located in areas where load growth would result in a need for additional delivery infrastructure but for demand-side potential; (2) are located in areas where the specific DR program is capable of addressing local delivery capacity needs;[9] (3) have sufficient certainty of providing long-term reduction that the risk of incurring after-the-fact retrofit/replacement costs is modest,[10] and (4) can be relied upon for local T&D equipment loading relief. Utilities will review specific DR programs based on these criteria, and either apply the default avoided T&D costs or apply the results of a specific investment study to the cost effectiveness evaluation of any qualifying DR program load reduction.

Section 2.E.c Bill Increases and Reductions

Bill increases and reductions are included only in the Participant Test. They are calculated from the perspective of end-users who participate in DR programs. However, they only have to be calculated for default DR programs. This calculation can be complex because these end-users often switch from one rate to another when they sign up for DR. Hence, a participant's bill reduction (or increase) is the difference between the actual bill received by the participant, *less any incentives paid*, and the bill the participant would have received had the participant not signed up for DR.

For example, in a program which changes the participant's rates but does not provide any incentives, such as CPP, the bill reduction (or increase) would be the difference between the actual bill and the bill the participant would have received had the participant not signed up for CPP. For a program which does not change the rates but simply provides an incentive structure on top of the existing rate structure, such as an Air Conditioner Cycling Program, the bill reduction (or increase) is simply the total load drop (or increase) during DR events multiplied by the participant's rate. For a program which both changes rates and provides incentives, the incentives must be subtracted from the actual bill before the difference between the actual bill and the bill that would have been received under the old rates is calculated.

Again, at the current time, this calculation is mostly unnecessary because of the way the Participant Test is determined for voluntary DR programs. In addition, even if it is necessary to make these calculations, the expense of accurately calculating these bill reductions and increases may be very large, and not worth the cost given the relatively small values likely for these costs

[8] The marginal T&D costs calculated in a general rate case include local transmission and distribution lines, towers and power poles, and underground conduit and structures which are added as service is extended into new geographic areas. These costs are generally not related to the peak demands in a specific area, and thus are not avoided by a DR program.

[9] For instance, an air conditioning cycling program is unlikely to avoid distribution investments in coastal areas with low air conditioning penetration where distribution circuits typically peak as a result of evening lighting loads.

[10] For programs which do not involve direct load control technology, utilities may discount the long-term load reduction potential until there has been sufficient experience to reliably assess load impacts.

and benefits. Hence, when assessing default DR programs, the utilities are directed to approximate these values using load impacts estimated using the established Load Impact Protocols, and a reasonable and transparent method.

Section 2.E.d Capital costs to participant
This cost includes the fixed (capital) costs actually incurred by a program participant when installing equipment designed to facilitate the participant's ability to provide demand reductions. It also includes operations and maintenance cost of that equipment, as well as removal costs (less salvage value), and any other equipment-related costs associated with DR-enabling equipment installed by the participant. Note that this does *not* include costs such as the participant's time spent in arranging the installation, or other indirect costs which are more properly accounted for as participant transaction costs. If a participant receives full or partial rebates for DR-enabling equipment purchases, the cost of those rebates must be subtracted from the capital costs.

Section 2.E.e Environmental benefits
The avoided costs calculation includes capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants (NOx, PM 10, VOCs, SOx). Hence, the utilities have stated that the criteria emission pollutant-related costs that can be avoided by DR programs are already reflected in estimates of the capacity costs avoided by that DR program. However, environmental regulations are enacted to limit pollutants, not the abatement of pollutants. There are residual benefits of avoiding criteria pollutants above and beyond the level of existing environmental regulation.

There are several other environmental impacts that might be avoided depending on the specific type(s) of capacity – generation, transmission, or distribution – that the DR program is expected to defer or avoid. These potential environmental impacts include, but are not limited to:

- environmental justice, particularly for supplying electricity in urban areas (Note that calculation of this benefit will require better documentation of exactly which peakers are on the margin during likely DR event days);
- biological impacts, including human health and safety;
- impacts on cultural resources;
- diminishing visual resources (e.g., due to power plant stacks or transmission towers);
- land use, including impacts of energy infrastructure on local ecosystems;
- water quality/consumption; and
- noise pollution.

As with criteria pollutants, the preferred approach is to incorporate these benefits in cost-effectiveness evaluation of DR programs by incorporating the compliance costs into the avoided cost calculation. However, as with criteria pollutants, there are residual benefits in addition to existing compliance costs, but they are difficult to quantify.

At present, the value of the avoided GHG emissions that are calculated for Energy Efficiency programs are described in Commission Decision (D.) 05-04-024[11]. In that Decision, the Commission suggested that a reasonable estimate of the avoided benefits associated with avoided GHG emissions would be $8 per ton in 2004, escalated in later years.

The Consensus Parties have suggested that, because implementation of AB32's requirement to reduce GHG emissions starting in 2012 is still in the formative stages, that a GHG adder should not be used for DR until that time. However, Staff sees no reason why, in the interim, the value of avoided GHG emission should not be used in the SPM calculations, consistent with D. 05-04-024. The estimates of the volume of GHG emissions avoided by a DR resource should be based on the operating and emission rate characteristics of the utility-specific new CT capacity used to calculate avoided cost.

This approach to estimating the value of the GHG emissions avoided by a DR program should be re-evaluated and revised based particularly on any additional information available on federal and state programs to limit GHG emissions, including AB32. Those revisions should be consistent with Commission direction in D.05-04-024 and D.07-09-024, or subsequent related decisions by the Commission.

While methods exist to calculate many of these environmental benefits, until such time as it can be determined exactly which methods to use and how to use them, any environmental benefits above the costs of complying with existing environmental regulation should not be counted in the calculation of the SPM tests, with two exceptions: (1) in specific situations where those additional environmental impacts clearly cause regulatory agencies to impose significantly higher control costs or fines, the value of the additional environmental impacts can be based on the additional control costs or penalties; and (2) the greenhouse gas (GHG) adder discussed above.

Although LSEs are not required to include most environmental benefits in their calculations for DR programs, some analysis of these benefits is required. This analysis should begin with a list of various types of possible environmental benefits of DR, which can be based on the bulleted list above. If estimates can be made for any of these benefits, those should be provided. In addition, qualitative analysis of the likelihood and extent of each of these benefits must be provided. This can be done in general, for a utility's entire DR portfolio, or on a case-by-case basis when there is reason to think that a particular DR program provides more (or less) of a particular environmental benefit than the larger DR portfolio does. In addition, qualitative analysis should be provided when a particular environmental benefit might cause impacts to a particular customer class or geographic area. An example of this type of analysis would be a discussion of the potential for use of Backup Generators (BUGs) by DR participants. While there is no current requirement for LSEs to track the use of BUGs, an LSE may be aware of a case in which a particular DR program is more (or less) likely than other programs to contain participants who use might use BUGs during DR events. In that case the environment impact of that program differs and should be noted.

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[11] Further detail can be found in the report *Methodology and Forecast of Long Term Avoided Cost for the Evaluation of California Energy Efficiency Programs* (http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf).

Section 2.E.f Incentives paid
This category consists of the total amount of all capacity and energy incentives paid by the utility to participants for "pay for performance" programs. In the case of contracts between a utility and a third-party aggregator, the incentives paid are considered to be the total amount of all capacity and energy incentives paid by the utility to the third-party aggregator.

The cost of incentives paid to participating customers should be determined consistent with the forecasted usage of the DR program, determined from the Load Impact protocols, that is used to calculate avoided generation capacity and energy benefits. This may differ from the budgeted cost of the DR program, which may be based on the maximum potential use of the DR program.

Section 2.E.g Increased supply costs
Increased supply costs are any costs incurred by the utility in providing additional electricity to ratepayers as the result of a DR program. These costs would normally be zero, as DR generally decreases electricity consumption. However, there may be programs in which electricity consumption might increase, especially during certain time periods, such as load shifting programs. In these cases, it may be appropriate to calculate this cost.

Section 2.E.h Market benefits
This category of benefits includes increased reliability (over and above the increased reliability offered by equivalent supply-side measures, particularly when DR can provide ancillary services), increased market efficiency improvement in overall system load factors, improved market performance (e.g., decreasing price volatility), increased flexibility, portfolio benefits, and others. Most of these benefits are difficult to quantify, and there is disagreement as to whether some of them exist at all. There are also concerns about the potential for double-counting these benefits. The utilities have argued that most of these benefits would be provided equally by either demand response or the equivalent supply-side generation resource. Others have argued that this cannot be the case, since an investment that uses scarce resources must be different than an investment which conserves resources. The exact nature of these benefits will likely become clearer as new research emerges and as the CAISO's MRTU proceeds.

The energy efficiency decision (D.05-1-04-024) has established the precedent of including adders for (1) reliability, and (2) the price elasticity of demand market price effect. In that proceeding, the generation capacity and energy benefits were based on forecast market prices[12]. The reliability adder is appropriate in that proceeding because reliability services are purchased through a separate ancillary services market that is not captured in the forecasts of market prices used for the energy and capacity avoided costs. Similarly, the elasticity adder is appropriate because the value of reducing load when the market is at a steep portion of the market supply curve would not be reflected in the market price forecasts. For the interim DR protocols, however, we are directing utilities to base capacity benefits on the cost of a simple cycle CT unit, and not the market price of capacity. The shift to a "resource-based" cost from a "market-based" cost for the interim DR protocols makes the energy efficiency adders non-transferable.

[12] Note that energy and capacity avoided costs in that proceeding are reported as combined or "all-in" hourly values, and are not reported separately.

Therefore, for the purpose of these interim protocols the utilities are not required to include these market benefit adders in the calculation of the SPM tests[13].

The staff recognize that the electricity markets are constantly changing, and potential developments such as a capacity market could alter the methods and benefits used to value DR. For example, if a capacity market were to become the basis for the generation capacity value, then this return to a market valuation would require a reconsideration of including reliability and price elasticity adders. For this reason, we will require utilities to list the potential market benefits of DR. This list should include, but is not limited to, all of the factors mentioned in the first sentence of this section. In addition, there are several other issues that the utilities should examine:

- **Equitable pricing.** An important benefit for the electricity markets is that an effective DR program places a value on an important attribute – flexibility – that may not now be fully valued. With most rate structures today, those customers who have the ability to shift loads are provided little incentive to do so. At the same time, it is more expensive to serve customers who cannot shift energy use.
- **Innovation in retail markets.** Providing a DR framework can result in new retail product and pricing innovations, ultimately benefiting the customer through increased choice and a better matching of the customers' needs with choices offered by electric markets.
- **Incentive for development of efficient controls and end-use technologies.** The customer's potential for cost savings through load shifting creates a new market for technology that now has an appropriate value proposition and business case.
- **Reduced market power on peak days.** Tight supplies and/or transmission constraints that can exist on days when DR is likely to be called can lead to an excess of market power. Since most generation is already committed, generators not yet committed may have greater market power for meeting the remaining peak demand (i.e., there is less competition once most generation has already been committed).
- **Overall productivity gains by better utilizing industry investment.** Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing the fixed investment that comprise one of the largest capital investments made in a region. Improved capacity factors should result in improved electric system efficiency.

For each of the potential market benefits, the utilities should either (a) approximate the value of a market benefit adders using a reasonable and transparent method or (b) provide a qualitative discussion of the likelihood and extent of that benefit. This qualitative analysis can be done in general, for a utility's entire DR portfolio, for a particular customer class or geographical area, or

[13] However, this does not preclude utilities from including market values in their SPM tests. For example, it is not clear that during times of supply constraint, a MW of additional supply would provide the same price suppressing effect as a MW of reduced demand (even after adjusting for losses). To be sure, one would expect the effects would be similar if one assumes no market power for generators --- but that is a significant assumption.

on a case-by-case basis when there is reason to think that a particular DR program provides more (or less) of a particular market benefits than the larger DR portfolio does.

At the current time, the utilities are not required to include any values for these market benefits in their calculations of the SPM tests, even for those benefits that they have been able to estimate. However, even if the utilities choose to provide a qualitative analysis which explains why some (or all) of these market benefits provide no additional value for DR, this analysis is required. In this way we can reduce the risk that the value of DR would be artificially low because we have neglected to consider and quantify market benefits that may emerge as the markets evolve.

Indeed, staff believes that the requirement for the utilities to continue to address the market benefit adders is consistent with the Consensus Parties' own concern about unclear market treatments and the need for further research for ancillary service value. The Consensus parties document states that:

> "At present, utilities will not make any adjustment (upward or downward) to account for any difference in the ability of a CT and a DR program to contribute ancillary service value. Once it becomes clearer how the CAISO will incorporate the value of DR programs in supplying ancillary services (e.g., in response to a recent FERC ANOPR), utilities will consider the relative ability of a new CT and a DR program to earn revenues in CAISO ancillary service markets as part of the cost effectiveness framework. Further research in this area would be helpful"[14]

Section 2.E.i Non-monetary benefits

Demand response program participants receive non-monetary benefits from participation in DR programs. These benefits are sometimes referred to as non-energy benefits.[15] This category of benefits includes the benefits participants receive in lessening their impact on the environment, being good citizens by helping to prevent outages, improved ability to manage their energy usage, better public image (for commercial enterprises), improved working conditions, etc. These benefits, by their nature, are difficult – if not impossible – to quantify. As in the case of bill reductions and increases, most of the time this calculation is unnecessary because of the way the Participant Test is calculated for voluntary DR programs.

When assessing a default DR program, the LSEs are directed to list the potential non-monetary benefits likely to accrue to program participants and then, if possible, approximate a value for each benefit using a reasonable and transparent method. For each of the benefits approximated, sensitivity analysis should be provided if it is expected to have a significant impact on the results, as per the section on "Types of analyses expected" above. If approximating a value of a particular benefit is found to be prohibitively expensive or difficult, the LSE will provide a qualitative discussion of the likelihood and extent of the benefit. The qualitative analysis of any one particular non-monetary benefit may be the same across the LSE's entire DR portfolio, or it

[14] Consensus Parties Framework, p. 5

[15] Non-energy benefits are somewhat different than non-monetary benefits, in that non-energy benefits may include monetary gains such as lower labor costs. Either concept may be used to provide a basis for analysis for this category of benefits, as our understanding of this type of benefit is still emerging.

may be specific to a customer class or geographic location, or it may pertain only to one DR program or even subset of a program's participants. The qualitative analysis should pay particular attention to cases in which there are significant differences between the likelihood or extent of the benefit among DR programs, so as to be able to better compare and assess the relative costs and benefits of the LSE's DR proposals.

Section 2.E.j Revenue gain from increased sales and revenue loss from reduced sales
These revenues are calculated only for the RIM test. Normally, a DR program will result only in revenue loss, rather than revenue gain, but there may be programs in which electricity consumption might increase, especially during certain time periods, such as load shifting programs. In these cases, it may be necessary to calculate revenue gain.

Revenue loss (or gain) from any one utility customer is the change in consumption due to the DR program multiplied by the customer's rate, and the total revenue loss (or gain) is of course the sum of this amount for all program participants. However, like the category "bill increases and reductions" above, this calculation is complicated by the fact DR participants often move from one rate to another when joining a DR program. It is further complicated because DR participants often receive incentives, making it impossible to calculate these revenues simply by examining customer bills.

Revenue loss (or gain) should be calculated in a similar manner as bill increases (or reductions), as discussed above, so that incentives are eliminated and any change in the participant's rate structure is accounted for. Also similar to the category above, utilities are not expected to go to great expense to accurately calculate revenue gains (or losses). Hence, when calculating these values for the RIM test, the utilities may simply approximate these values, using a reasonable and transparent method, if a more precise measurement is not available. If values are approximated for revenue loss (or gain), sensitivity analysis should be provided if it is expected to have a significant impact on the results, as per the section on "Types of analyses expected" below.

Section 2.E.k Tax Credits
Tax credits are not presently available for DR programs. In the event that they are available in the future, they are considered a benefit in the TRC and Participant tests. This includes any and all federal, state or local tax credits which may become available to participants for DR equipment installation or any other cost incurred in providing demand reductions.

Section 2.E.l Transaction costs and value of service lost
These are general categories of costs to the participant, other than bill increases and equipment costs, of participating in a DR program. Transaction costs are the opportunity costs associated with education, equipment installation, program application, energy audits, etc. Examples of transaction costs are the time spent filling out a DR program application, learning about DR, and making a decision about whether to install auto DR equipment.

Value of service lost includes any losses in productivity that occur because of demand reductions as well as "comfort costs," which are the losses in comfort participants may experience or perceive when particular end-uses become unavailable. Examples of lost productivity costs are

revenue losses incurred when a business is shut down during a DR event and food spoilage that may occur when freezers are turned off during a DR event. Examples of comfort costs are having to walk further to use a copy machine, feeling too hot or too cold because of changes in a thermostat setting, and having to change work hours.

These costs are significant to the participant, but some of them can only be approximated, even by an individual participant – most people cannot state with any certainty what monetary value they place on, for example, feeling warmer than preferred, and even when values can be determined they vary widely from one person to the next. This makes it extremely difficult to quantify these costs for any group of participants. Staff recognizes these difficulties, and acknowledges that estimates of these costs are likely to be highly uncertain.

However, for voluntary demand response programs, it is not necessary to calculate values for these categories of costs. As discussed above, from the perspective of participants, the total costs of a demand response program must be less than the total benefits. The total costs (for the Participant Test) are equal to the sum of the transaction costs, value of service lost, capital costs and any bill increases, and can be assumed to less than or equal to the total benefits (for the Participant Test) which are equal to the sum of participant's bill reductions, incentives paid, non-monetary benefits and any available tax credits. The TRC test uses slightly different costs, called "Net Participant Costs," which are equal to the sum of the transaction costs, value of service lost, and capital costs.

Stating the above in a more mathematical form, we get:

Total Participant Costs = Transaction Costs + Value of Service Lost + Capital Costs + Bill Increases

Total Participant Benefits = Incentives + Non-Monetary Benefits + Tax Credits + Bill Reductions

Total Participant Costs ≤ Total Participant Benefits

Transaction Costs + Value of Service Lost + Capital Costs + Bill Increases ≤ Incentives + Non-Monetary Benefits + Tax Credits + Bill Reductions

Tax credits and bill increases will generally be zero. For the purposes of this interim analysis, it can be assumed that non-monetary benefits are relatively small. Hence, the net result is:

Transaction Costs + Value of Service Lost ≤ Incentives + Bill Reductions – Capital Costs.

Hence, for the purpose of calculating values for the TRC test, *for voluntary DR programs only,* LSEs should assume that the maximum value of the transaction costs and value of service lost can be approximated as the value of all incentives paid to customers plus the customers' total estimated bill reductions minus any capital costs (not including rebates) customers have paid for DR equipment.

Nevertheless, as a first step in the process of starting to better understand these benefits, LSEs should list the various types of transaction costs, productivity losses, and comfort costs that, pending further research, should be included in future cost-effectiveness calculations. The examples above can serve as the basis for developing this detailed list of costs. For each of these costs, the LSE should provide a qualitative discussion of the likelihood and extent of that cost. This can be done in general, for a utility's entire DR portfolio, or for an entire class of participants, a particular, geographical area, or on a case-by-case basis when there is reason to think that a particular DR programs provides more (or less) of a particular market benefit than the larger DR portfolio does.

For default DR programs, LSEs will have to expand on the above analysis, and to the best of their abilities, provide estimates of the values of the various transaction costs, productivity costs and comfort costs.

APPENDIX A: DISCUSSION OF GROSS MARGINS

The IOUs have proposed that avoided generation capacity costs should be adjusted to account for the profits that a CT would make on energy sales (gross margins). Other parties have taken issue with this proposal, for several different reasons:

1. **There is some question of whether it is appropriate regulatory policy, within the SPM framework, to subtract gross margins from avoided generation capacity costs.**

   The only capacity cost that is directly avoided by Demand Response is the actual capital cost of the plant. The fact that a utility can earn margins on future sales from the plant could be viewed as a transfer payment from ratepayers to shareholders, in which case those margins should be accounted for differently in the different SPM tests.

   The fact that gross margins exist for a CT that is deemed the marginal plant from a capacity perspective (i.e., it would be the next plant built and therefore the plant avoided by investment in cost-effective DR investments) indicates that on a peak day the marginal plant from a dispatch perspective is not the same CT. The operating costs of the CT must be less than other plants for it to earn a gross margin (i.e., profit from operations) during the year. This is an appropriate investment analysis from an internal corporate perspective, but there is some concern with paying out margins on plants that have not been built due to cost-effective resource decisions. From a ratepayer's perspective, the utility should always be making the best decision that produces the lowest cost for meeting electric demand. For example, if a higher return could be earned on a plant based on clean coal technologies than on an investment in wind resources, should ratepayers essentially compensate the utility for foregone profits due to the differential between what would have been earned on the clean coal plant and the margins on the wind resource? This question delineates some of difficulties of making least cost resource planning decisions while also providing appropriate financial returns to the utility. There are many questions regarding whether the appropriate least-cost resource decision should include a reduction in the value of one resource due to lost margins from another resource that "could have" been built but was determined not to be the least cost investment. The answer does not seem clear cut given current arguments and position statements.

2. **There are questions about the appropriate treatment of uncertain costs and benefits.**

   The Joint IOU Framework expresses concern about incorporating uncertain benefits into the cost-effectiveness analysis. Specifically, recommendation 22 states that "Other potential benefits associated with DR programs (e.g., portfolio benefits, future potential reductions in DR technology costs, and spillover energy efficiency benefits) may exist, but are difficult to quantify and highly speculative for reasons discussed herein. Therefore, it would is (sic) inappropriate to include these asserted benefits in evaluating the cost effectiveness of DR resources."

   The calculation of gross margins also seems to depend on many uncertain factors. It is subject to considerable uncertainty both over the life of the plant and on a year to year basis –

the estimated magnitude of the gross margins will be influenced by the assumptions about the weather in any year, the growth in demand on peak days, fossil fuel costs (particularly natural gas), and the build rate of other resources that can influence the available capacity in a market. Each one of these factors is subject to considerable uncertainty.

As is the case with a number of DR benefits where further research is recommended, additional work on the sensitivity of the gross margin calculation is also be needed. Additional information on the reliability with which gross margins can be estimated along with sensitivity analyses on input data and key model assumptions are likely to influence the estimates of gross margin.

Avoided generation capacity costs is the most significant benefit measured in the TRC, PAC and RIM tests. Subtracting gross margins from the avoided generation capacity costs result in a significant reduction in the benefits accorded to DR investments. From this perspective, gross margins are counted as a cost for the purposes of those tests. However, the magnitude of this cost is uncertain. At the same time, there is significant disagreement about the nature, magnitude, and even existence of the market and environmental benefits of DR. However, available evidence indicates that the total value of all these benefits must be greater than zero, although the total magnitude is uncertain. Therefore, an assumption that the uncertain market and environmental benefits of DR and the uncertain gross margins cancel each other out until more research can be conducted is viewed as appropriate for this interim CE framework. This echoes SDG&E's testimony in their AMI application in which it was stated that "AMI enabled demand response provides unique benefits that a CT cannot provide, including reduced demand volatility, pricing flexibility, and improved reliability options. When CT market profits are weighed against these unique AMI and demand response benefits, on balance, they have a canceling effect."[16]

3. During the workshops held last summer as part of this proceeding, parties questioned the IOU's proposed methodologies for estimating the gross margins.

The IOUs use different methodologies for estimating gross margins – SCE uses a production cost model and PG&E an options pricing approach[17]. Both of these models lack transparency in terms of regulatory review and intervenor review. In other words, they are relatively complex and rely heavily on proprietary data. This makes the influence of the inputs and assumptions, as well as the computational approach, on the model outputs unclear. The factors in each model that determine the magnitude of each IOU's gross margins are not publicly available. Several parties have expressed dissatisfaction with this lack of transparency for the calculation of such a significant variable.

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[16] SDG&E Application.05-03-015: Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Testimony of John C. Martin, Chapter 7, p. JCM-20 http://sdge.com/ami/docs/chapter_7.pdf

[17] It is unclear from the Joint IOU Framework which method, if any, SDG&E is proposing to use.

Sensitivity analyses would clearly be necessary to assess the relative importance of different inputs and assumptions, and might also be necessary for the computational approach. Additional experience and applied work with these models is needed before the outputs are viewed as "certain" enough to be directly counted in the cost-effectiveness analysis. It is expected that actual gross margins would likely vary substantially from year-to-year due to weather variability, fuel prices, performance of system generating units (e.g., outage rates), and growth in peak and energy demands.

4. **Evidence has been presented that the IOUs have, in several proceedings, consistently overestimated the amount of the gross margins.**

   The proposed gross margin calculation is based on a number of variables which are known to be highly uncertain. In its comments on the Joint IOU Cost-effectiveness framework, the California Large Energy Consumers Association (CLECA) stated that "the expected gross margins depend on the heat rate of the new CT, variable O&M costs, natural gas prices, wholesale market energy prices, and the expected operating life of the new CT, none of which is easy to forecast over a period of 20 or more years."[18] CLECA claims that both proposed methodologies overestimate the amount of energy sales a CT makes into the market and thus understate the capacity value of the CT. CLECA has provided evidence to support its position in this proceeding as well as other Commission proceedings.[19]

It is possible that eventually California may have a liquid, robust, public market for generation capacity. At that time, it might be reasonable to consider requiring LSEs to utilize the market prices of long-term generation capacity from that source to evaluate the avoided capacity costs of DR. Until then, a new CT unit which is a peaker but not quite a marginal unit may be the best approximation available. However, the question of exactly how to value the costs of that peaker in comparison with Demand Response resources requires a level of research and examination which is outside the scope of this proceeding.

While the majority of parties have together proposed the Consensus Parties Framework, that agreement states that there *is no consensus* among the parties on the issue of gross margins.[20] This puts the Commission in the position of either deferring the issue to the 2009-11 Demand Response budget proceedings or making an interim decision. Staff believes that deferring the issue would not in any way clarify these issues. In fact, the budget proceeding is likely to have far less focus on the specific details of Demand Response cost-effectiveness than this proceeding. Hence, staff has determined that until such time as these issues can be properly examined, the gross margin adjustment to the avoided generation capacity costs should not be made. Staff recommends that this issue be taken up in an appropriate proceeding where the relevant facts can be argued in detail, and that in the interim the gross margin adjustment be assumed to be more or less equal to the omitted Demand Response benefits.

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[18] Comments of the California Large Energy Consumers Association on the Straw Proposals for Demand Response Load Impacts and Cost-Effectiveness, July 26, 2007, p. 8

[19] For example, see CLECA's testimony in PG&E's GRC Phase 2 (A. 06-03-005) and SDG&E GRC Phase 2 (A.05-03-015)

[20] Consensus Parties Framework, Section C.1, p. 3

APPENDIX B: DISCUSSION OF AVOIDED COST APPROACHES

In addition to the DR methodology, there are two extant methodologies adopted by the Commission for the determination of avoided generation costs: the Market Price Referent (MPR) and the long-run avoided cost methodology for energy efficiency (EE Method). All three methods use the levelized cost of new generation plant. The MPR and EE Method use the capital and operating cost of a combined cycle gas turbine (CCGT) to determine a total delivered cost (or market price) of energy that includes capacity. The DR method, on the other hand, uses the cost of a simple cycle CT unit as the avoided cost of capacity (not including energy). CCGT are highly efficient plants which are generally used as baseload plants (i.e., they run most of the time), and are viewed as an indicator of the long-run equilibrium cost of energy and capacity. CT plants have lower capital costs and higher operating costs than CCGT units and are typically used as a proxy for the cost of adding pure capacity because they operate as peakers (i.e., they run only when demand, and therefore the price of electricity, is relatively high).

Though the approach used is similar in all three cases, the input assumptions (i.e., overnight capital cost, financing cost, capacity factor and natural gas prices) differ. This is due not only to the different characteristics of CCGT and CT plants, but also to the fact that these methods have been developed independently, in separate proceedings, with final decisions and updates issued at different times. For example the EE natural gas prices in the near term are based on market NYMEX futures prices as of 3/10/06, and the long term prices use an average of EIA (Jan 2006), CEC 2005 IEPR, and SoCal Gas (April 2, 2004) forecasts. The MPR natural gas price forecast is updated for each RPS solicitation cycle. The 2007 MPR uses a 22 day average of closing NYMEX prices from May 2007 for the near term, and transitions to an average of three natural gas price forecasts, including the latest CEC forecast, for the long term.

The avoided cost calculations for DR are made on an hourly basis, since the purpose of DR is to reduce demand in a relatively small number (generally less than 100) of hours per year when the need for capacity is the highest. The hourly avoided DR costs are in proportion to the need for capacity, as determined using utility loss of load expectation probabilities (LOLPs). LOLPs represent the risk of having to shed customers, with the hours with the highest LOLP's receiving the highest avoided costs.

The EE method also uses hourly avoided costs. However, the variation in hourly costs is based on the historical PX hourly market prices rather than utility LOLP studies. In addition, the EE method's hourly costs represent the total "all-in" cost of energy plus capacity, whereas the DR costs described above are for capacity only. The EE method does not require more precise estimates of hourly variations or a separate estimate of capacity value because EE measures provide energy reductions of hundreds of hours and are predictable in their pattern of savings. Because of the sharper focus of DR on the peak hours, it is appropriate for those methods to use LOLPs that would more precisely estimate capacity needs as well as focus on the value of capacity that is separate from energy

The MPR calculations are done on an annual basis, since they are designed to compare, for long-term procurement purposes, renewable power plants with traditional power plants. The MPR also uses a detailed cash flow model simulating the financial operations of an

independent power producer over 20 years. This is in contrast the EE and DR methods, which rely on more simple levelized cost calculations.

The avoided cost calculations for DR and EE also include adjustments for avoided line losses, avoided transmission and distribution costs, and avoiding the need to meet the planning reserve margin (PRM). These adjustments represent additional benefits of demand-side reductions that do not occur when two supply-side options are being compared.

Another difference is in the calculation of gross (energy) margins. For DR, the IOUs propose that gross margins be subtracted from the avoided generation capacity cost to better reflect the actual cost of procuring new capacity for a utility. For the MPR and EE, there are no separate estimates of energy market and capacity market values. Rather, the EE and MPR CCGT long-run costs are used to set the total cost of electricity (energy and capacity). Because of this, there is no need for an energy margin adjustment to a capacity value for EE and the MPR.

Finally, it should be noted that the MPR is calculated assuming that the fixed costs are recovered over 20 years regardless of the contract term (10, 15 or 20 years). The MPR does not consider energy sales beyond the applicable contract term. DR and EE are evaluated over the expected useful life of the equipment or program, or the contract period.

(END OF ATTACHMENT A)