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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Reform the Commission's Energy Efficiency Risk/Reward Incentive Mechanism.	Rulemaking 12-01-005 (Filed January 12, 2012)

ASSIGNED COMMISSIONER'S RULING SOLICITING COMMENTS REGARDING EFFICIENCY SAVINGS AND PERFORMANCE INCENTIVE DESIGN FOR ENERGY EFFICIENCY 2013-2014 PORTFOLIO

I. Introduction

This ruling provides notice and opportunity to comment regarding a proposal for a new Efficiency Savings and Performance Incentive (ESPI) mechanism to apply for the 2013-2014 energy efficiency program cycle, as outlined below. This new mechanism would supersede what has previously been called the "Risk Reward Incentive Mechanism" (RRIM).

In addition to addressing the overall merits of the proposed new incentive design, parties are directed to respond to the series of specific questions posed below in reference to each of the proposed incentive mechanism components. As detailed below, the respective incentive allocation among each of the utilities would be determined based upon each utility's relative share of the total energy efficiency budget as adopted for their 2013-2014 energy efficiency portfolios. Note that all budget amounts and estimated incentive payments included herein are based on the values included in the IOUs' original July 2012 applications for the 2013-14 portfolio cycle and do not reflect the budgets ultimately adopted in

D.12-11-015. Consequently, all estimated incentive payments in this Ruling are intended for illustrative purposes to provide a general sense of the magnitude of incentive payments being proposed.

To the extent parties' views relevant to this ruling have already been covered in prior comments, repetition is not necessary. Parties may simply make reference to those prior comments, where relevant. Depending on the comments received, the proposed ESPI may be further refined or revised, as deemed appropriate.

The proposal for an ESPI is designed to provide the following incentives for the investor-owned energy utilities to aggressively pursue energy efficiency goals during the 2013-2014 cycle. The ESPI would reward investors based on four primary categories of the utilities' administration of the energy efficiency portfolio:

a. **Non-Resource Programs**: For non-resource programs (activities that support savings based programs but in which there are no direct savings) I propose a management fee equal to 3% of non-resource program expenditures, not to exceed authorized expenditures for these programs. The management fee would exclude administrative costs.

b. **Codes and Standards Programs**: For codes and standards programs, I propose a management fee equal to 10% of codes and standard program expenditures, not to exceed authorized expenditures for these programs. The management fee would exclude administrative costs.

c. **Ex-Ante Review (EAR) Process Performance**: For successful implementation of the EAR process, I propose a reward of up to 2% of resource program expenditures. The reward would be based on conformance with the Commission's review of ex ante parameters, based on metrics and scoring as outlined in the Appendix. The reward would exclude codes and standards programs (since the utilities are being rewarded for these programs separately); funding dedicated to the Regional Energy Network (RENs) and Community Choice Aggregator (CCA) efficiency programs; utility administrative costs; and Evaluation, Measurement, and Verification (EM&V) expenditures.

d. **Ex Post Savings Achievement**: A reward of up to 8% of resource program expenditures for achieving energy efficiency savings up to 110% of the established portfolio savings net goals, as verified by EM&V activities. The resource program expenditures would exclude funding dedicated to the RENs, CCA, EM&V and code and standards programs.

The maximum incentive earnings cap for would be approximately $158 million for the 2013-2014 portfolio cycle. A more detailed discussion of each component and related questions for comments are presented below.

II. Management Fee for Non-Resource Programs

I propose to offer utilities an incentive for successful administration of critical activities where savings cannot be directly attributed. These programs are important in promoting long term market transformation and supporting other portfolio activities. Under the current framework, these 'non-resource' based programs are viewed as all costs and no benefits, and thus harder to reward properly. In prior versions of the incentive mechanism, utilities were not directly given an incentive for these activities. I propose a management fee based on the budget authorized for these activities. Under this proposal, utilities are rewarded for these non-resource programs by earning a fixed percentage of recorded non-resource program expenditures, as verified by Commission audit reports. Designing the incentive as a fixed percentage of program expenditures offers the advantage of administrative simplicity as compared with the alternative of awarding incentives based on achievement of specific program performance metrics. The premise of the management fee is that recorded program expenditures represent a reasonable proxy of accomplishments in pursuing non-resource goals.

To reward utilities for non-resource program activities in the 2013-2014 portfolio cycle, I propose a fixed percentage, 3%, of the total non-resource program budget, applied as a management fee. Based on a budget of $250 million adopted for non-resource programs for 2013-2014, the maximum possible annual award for non-resource programs would thus be approximately $7.5 million for the portfolio cycle. The resulting maximum non-resource management fee awards by utility are shown below in Table 1

Table 1: Illustrative Example of 2013-14 Non-Resource Program Management Fee by Utility[1]

Utility	2013-14 Non-resource budget (minus administrative funds)	3% Management Fee
PG&E	$110,795,379	$3,323,861
SCE	$105,251,873	$3,157,556
SDG&E	$21,116,468	$633,494
SoCalGas	$12,567,759	$377,033
Total	**$249,731,479**	**$7,491,944**

Specific Questions for Comment:

1. *Should non-resource based programs be a component of the ESPI for the 2013-2014 energy efficiency portfolio?*
2. *Does a management fee, paid as a fixed percentage of expenditures of non-resource programs, adequately incent utilities for successful implementation and investment in quality non-resource programs?*

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[1] As identified above, the budget amounts used in this Ruling are derived from the IOUs' original July 2012 applications for the 2013-14 cycle and do not reflect the budgets ultimately adopted in D.12-11-015. In D.12-11-015, the Commission adopted a budget of $180 million for non-resource programs, including administrative costs.

3. *In lieu of a management fee, should the Commission reward utilities for non-resource based programs using* specific *program performance metrics as a more appropriate measure of non-resource program performance?*
4. *If program performance metrics (e.g., number of whole home retrofit projects in hot climate zones; number of measures adopted into the portfolio from the Emerging Technology Program) are utilized rather than a management fee based on expenditures, which program performance metrics should be utilized? Are there specific programs that should be targeted over others? What level of incentive earnings potential should be offered for specific performance metrics and for non-resource programs in the aggregate?*

III. Management Fee for Codes and Standards Program Implementation

Energy savings calculations for codes and standards programs are different from other resource based activities because the expenditures from this cycle do not result in savings until after the portfolio is complete, and similarly, the codes and standards savings resulting in this portfolio cycle are the result of activities and expenditures from a previous portfolio cycle. Additionally, calculating savings associated with these activities involves complicating factors, including code compliance estimates, attribution factors that estimate how much the IOUs' efforts contributed to the code development, and estimates of measures captured by code that were "naturally occurring market developments." Because of these differences in calculation methods and funding sources, the Commission approved distinct codes and standards savings goals separate from the rest of the savings goals in the 2013-14 energy efficiency portfolio.

Because of the complications associated with codes and standards program savings, I propose that the incentive for this part of the portfolio reward utilities via a management fee. This component is intended to recognize the important role utilities play in achieving significant, cost-effective energy efficiency savings through their codes and standards programs. The management fee would be a fixed percentage expenditure of the budget approved for the codes and standards programs, less the administrative costs. I propose that the fixed percentage be equal to 10% of Codes and Standard Program expenditures.

Table 2: Illustrative Example of 2013-14 Codes and Standards Programs Management Fee by Utility

Utility	2013-14 Codes and Standards program budget (minus administrative funds)	10% Management Fee
PG&E	$12,248,324	$1,224,832
SCE	$10,096,460	$1,009,646
SDG&E	$1,897,848	$189,785
SoCalGas	$1,511,778	$151,178
Total	**$25,754,411**	**$5,150,882**

Specific Questions for Comment:

5. *Is rewarding codes and standards program activity via a management fee is appropriate?*
6. *Is the fixed percentage of 10% an appropriate level to set the management fee?*

IV. Award for Conformance with the Ex Ante Review (EAR) Process

I propose that the ESPI include an earnings potential based on utility conformance with the EAR process. This proposed component is similar to the "performance bonus" that was adopted in the incentive formula for the 2010-2012 cycle in D.12-12-032.

Under the proposal, utility performance in complying with the EAR process would be evaluated and scored using a 100-point scale. The proposed scoring scale applicable to each performance metric is shown in the Appendix to this ruling. Based on the performance evaluation, a score would be assigned which would translate into a percentage figure. For the 2010-2012 incentive mechanism adopted in D. 12-12-032, the EAR incentive was capped at 1% of budgeted expenditures. For purposes of this proposal, the EAR component of the mechanism would provide earnings up to 2% of resource program expenditures. The resource program expenditures would not include funding dedicated to administrative activities, codes and standards programs (since those would receive an incentive, as described above) and non-utility administration of programs (CCA/RENs programs). The ex ante performance award caps for the 2013-2014 total resource budgets total approximately $30 million for all four IOUs, as shown in Table 3 below.

Table 3: Illustrative Example of Ex Ante Performance Award Caps by Utility

Utility	2013-14 Adjusted Resource budget	2% Ex Ante Performance Bonus
PG&E	$650,916,565	$13,018,331
SCE	$521,611,551	$10,432,231
SDG&E	$171,396,828	$3,427,936
SoCalGas	$145,963,980	$2,919,279
Total	**$1,489,888,924**	**$29,797,779**

The EAR process previously utilized for the 2010-2012 cycle remains in place. The applicable process was articulated in D.10 12 054 and was subsequently modified by D.11 07 030 and D.12 05 015. The EAR requirements are a response to the challenges that arose with the ex post true-up associated with the 2006-08 incentive mechanism, and they ensure that the utilities are applying sufficient due diligence and engineering rigor in developing ex ante savings estimates.

As noted in D. 12-11-015, although the Commission adopted EE budgets for the 2013-2014 cycle, the Commission staff still must complete an independent review of the resource ex ante savings estimates associated with the utilities' cost-effectiveness showings for the 2013-2014 cycle. Commission staff and consultants completed the EAR of the Database of Energy Efficiency Resources (DEER) prior to IOU submittal of the 2013-2104 portfolio applications, and they completed their review of selected non-DEER workpapers on March 1, 2013[2]. The EAR process will continue throughout the remainder of the 2013-14 portfolio cycle to review and approve savings estimates on a prospective basis for non-DEER workpapers submitted throughout the portfolio, for custom projects, and potentially for select non-DEER workpapers submitted with the applications that that the EAR team did not have time to review by March 1, 2013.

The 2013-2014 EAR performance metrics presented in the appendix to this ruling have been revised based on party comments on the EAR performance metrics adopted for the 2010-12 incentive mechanism. These revisions address concerns regarding subjectivity and the level of detail in the metrics used to assess IOU performance. Significant revisions to the metrics include the addition of more quantitative measures of IOU efforts to streamline the EAR process and improve engineering estimates on an ongoing basis.

To develop a more transparent ex ante review performance evaluation process for the 2013-2014 portfolio cycle, I propose that a designated team of EAR staff and contractors implement the following process improvements:

a. Produce semi-annual ex ante scorecard updates that provide utilities with feedback and an opportunity to make mid-year and mid-cycle process improvements; and

[2] Ideally, the review of all non-DEER workpapers submitted with portfolio applications would have been completed before the programs were launched; however, due to the fast timeframe for 2013-2014 portfolio approvals, this was not possible.

b. Provide metric-specific performance scores and rationale as advice on the record of the proceeding, subject to due process at the end of each program year.

Further, the designated team of EAR staff and contractors may explain their scoring and rationale to decision-makers, but they will not otherwise advise Commission decision-makers regarding EAR-related incentive award calculations in this same proceeding.

Specific Questions for Comment:

7. *Are the ex ante metrics included in the Appendix adequately designed to provide objective assessment of utilities' ex ante review performance? Are there other benchmarks that should be utilized to objectively measure utilities' ex-ante review performance?*

8. *Parties have expressed concern over rewarding utilities for process conformance since it is not results (i.e., energy savings) oriented and other Commission processes are not, and historically have not been, assessed under any incentive mechanism. Which Commission energy efficiency policy goals would be compromised or unattainable in the event that an incentive is based on process conformance?*

V. Incentive Earnings for Energy Savings and Demand Reduction Achievements

I propose that the ESPI feature a component that rewards achievements in meeting energy efficiency resource savings goals as established in D.12-11-015. In recognition of the importance of the incentive mechanism in promoting energy efficiency savings as the first resource in the utility loading order, I propose that a savings-based component be the largest opportunity for earnings in the ESPI. In my mind, ESPI should incent utility activity that results in actual resource savings.

In previous iterations, there were multiple challenges in properly rewarding utilities for accomplishments in energy efficiency savings, either on an ex ante or on an ex post basis. I take the lessons learned from previous attempts and apply them to today's proposal in order to address these past challenges.

The RRIM was originally designed to reward or penalize IOUs based on detailed formulas and protocols that provided for interim awards based on ex ante savings and a final true up based on independently verified ex post load impacts. The RRIM calculated a "Performance Earnings Basis" (PEB) measuring the monetary net benefits of the energy and/or capacity savings achieved. The net benefits were allocated between utility investors and ratepayers using a designated shared savings percentage.

In response to the controversies relating to ex post updates, the Commission determined in D.10-12-049 that final awards for 2006-2008 and 2009 would be based on the ex ante savings estimates used in developing the 2006-2008 portfolios. The ex ante parameters were not subject to true up on an ex post basis, but incentive earnings were allowed only for actual measures installed. A similar approach was used for the 2009 bridge year, since it was an extension of 2006-2008.

Although an initial attempt was made to apply a similar ex ante approach for 2010-2012, such an approach was not feasible, as discussed in D.12-12-032. In the case of the 2006-2008 cycle, by the time that the Commission determined to base final incentive payments on the original ex ante parameters, those parameters had already been established in D. 05-09-043. Consequently, the ex ante parameters had been known since before the beginning of the 2006-2008 cycle.

Unlike the 2006-2008 cycle, ex ante parameters for the 2010-2012 portfolio remained unresolved by the start of the cycle. The ex ante lockdown for the 2010-12 cycle experienced substantial delays and was not completed until mid-

2011. As such, the ex ante review and lockdown process was a "work in progress" throughout the 2010-12 portfolio implementation period (and party comments and IOU recommendations in the 2013-14 energy efficiency portfolio proceeding suggest this continues to be the case). Ultimately, the Commission determined that it was not feasible to base incentives on ex ante savings for the 2010-2012 cycle, instead opting to adopt an alternative methodology for incentives for the 2010-2012 cycle.

Likewise for 2013-2014, the funding cycle began without locking down ex ante parameters associated with non-DEER Workpapers. In approving budgets for 2013-2014, the Commission reviewed the utility proposals from a budget perspective and a cost effectiveness perspective based on the benefits and costs filed. However, given the timeframe for rendering a decision, the Commission was unable to conduct a thorough review of savings estimates associated with the cost effectiveness showings. Consequently, the lock down of 2013-2014 ex ante estimates was completed on March 1, 2013.

In addition to these timing considerations, a number of unintended consequences could result if future ex ante parameters were relied upon to determine utility performance and resulting final incentive earnings for 2013-2014. Awarding shareholder incentives based on savings parameters locked down in advance creates an incentive for the utilities to develop ex ante estimates that are as large as possible, rather than as accurate as possible (the latter being the goal behind the ex ante review process performance metrics). In addition, relying on fixed ex ante estimates provides no opportunity (or incentive) for utilities to update parameter estimates mid-cycle even if errors or updated data are identified that determine that certain measures in the portfolio are far less cost-effective than they were originally forecast to be.

Also, use of locked down ex ante parameters does not provide a pathway to provide savings claims (and, in turn, shareholder incentive opportunities) for new and innovative measures for which there is insufficient information to set ex ante parameter estimates with any confidence. Finally, because ex post savings will still need to be determined for the purpose of program improvements and resource planning, institutionalizing the ex ante approach would require maintaining two sets of savings estimates for energy efficiency portfolio savings: a (typically) higher set of savings that would be used to award IOUs efficiency shareholder incentives, and a lower set that would be used to determine, among other things, IOU new capacity authorizations in the Long Term Procurement proceeding. This practice would likely introduce significant confusion into these proceedings.

For all of these reasons, I propose an ex post approach to reward energy efficiency savings accomplishments for IOU resource programs, in addition to the EAR performance award. A number of differences between this draft proposal and the original RRIM suggest that calculating an ex post savings reward may not result in the same level of contention experienced in determining 2006-2008 award:

- The proposed award is a linear function that begins at zero – that is, there is no penalty range or deadband below which the IOUs would receive no savings incentive or a potential penalty;
- The savings incentive is one of four separate components of the award, so all of the potential earnings "eggs" are not in this single basket;
- The other resource program component of the proposed mechanism is specifically designed to award the utilities based on their exercising the highest standard of care in developing ex ante savings estimates, which I would

expect to result in ex post results that are more in line with ex ante estimates than the disparities witnessed in the 2006-2008 portfolio; and

- Commission implementation of, and transparency associated with, the portfolio evaluation process has evolved significantly since the 2006-2008 period and will continue to do so in the 2013-2014 cycle.

The proposed mechanism for 2013-2014 would offer incentive earnings for energy and demand savings achieved (in GWh, MW, and MMTherms) based on an earnings rate per unit energy saved. Each utility's earnings rate is calculated by developing coefficients that correlate its energy and demand savings goals, adjusted to reflect net lifecycle savings, to its adopted 2013-14 EE portfolio budget. The final savings-based award would be calculated as the product of each utility's earnings rate and its ex post verified net lifecycle savings.[3]

Calculating the earnings rate coefficients is a two-step process. The first step is to determine the total savings-based award cap and allocate it to each utility's different types of savings (electricity, demand, and/or gas, as appropriate). The proposed cap is equal to 8% of the authorized resource program funds, excluding funding dedicated to administrative activities, EM&V, ME&O, codes and standards programs,[4] and the REN/CCA programs that are not administered by the utilities.

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[3] NRDC proposed an ex ante based version of this savings-based mechanism in filed comments in response to the Administrative Law Judge's Ruling Calling for Comments on Incentive Reform Issues, filed July 16, 2012.

[4] As discussed earlier, I propose to reward the IOUs' codes and standards program efforts via a management fee.

All of SoCalGas' savings are attributable to gas, SCE's savings include both electricity and demand, and SDG&E and PG&E's savings include electricity, demand, and gas. To allocate the savings-based earnings cap among electricity, demand, and gas savings for SDG&E and PG&E, this proposal modifies the approach NRDC used in their October 1, 2012 Post-Workshop comments on Incentive Reform Issues for 2013-14. To divide the potential earnings between electricity and demand, NRDC referred to the relative TRC benefits in the 2013-2014 EE portfolio applications, which identify that approximately 85% of benefits are attributable to electric savings and 15% are attributable to gas savings. The electric portion of savings must be further divided to reflect separate energy and demand savings benefits. The 85% of potential electric savings earnings is further divided into energy and demand based on the relative proportion of net benefits of each in the IOUs' 2013-2014 portfolio applications, which is approximately 67% energy and 33% demand. Using this approach, the allocation of the savings-based earnings cap between electricity, demand, and gas savings for SDG&E and PG&E is 57% (i.e., 85%*67%), 28% (i.e., 85%*33%), and 15%, respectively. The allocation of the savings-based earnings cap between electricity and demand savings for SCE is 67% and 33%, respectively, and as noted earlier, the allocation for SoCal Gas is 100% for gas savings.

The second step in developing the correlation coefficients requires that the gross, first-year savings goals adopted for the 2013-2014 portfolios be converted to net lifecycle savings by multiplying them by the portfolio average effective useful life (EUL) of the efficiency measures and portfolio average net-to-gross (NTG) ratios. To create further incentives for the utilities to achieve Commission goals, and as a "quid pro quo" for setting a high potential earnings on resource programs (2% EAR performance + 8% ex post verified savings = 10%) with no a priori risk of penalty, I propose that the savings correlation coefficients be calculated using "stretch" portfolio average EUL and NTG values that are not representative of recent values and may not be achievable in this portfolio. However, with well designed and implemented resource programs, the utilities should ultimately achieve these stretch values over time. The target portfolio average EULs are 12 years for electric measures and 15 for gas measures, and the target NTG ratio is 0.8 (equivalent to 20% free ridership). The following equation accomplishes this conversion:

*Savings-Based Incentive Goal = adopted goal * portfolio average EUL * portfolio average NTG*

Where:

- Adopted goal = the adopted gross, first year savings goal, minus the codes and standards goal for each type of energy savings, as applicable, for each utility;
- Portfolio average EUL = the target portfolio average effective useful life for electric (12 years) and gas (15 years) measures; and
- Portfolio average NTG = the target portfolio average net-to-gross ratio of 0.8.

The resulting savings incentive coefficients and maximum achievable ex post savings awards for the 2013-2014 EE portfolio cycle are provided in the tables below for each utility,[5] followed by a table that calculates the estimated ex

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[5] Note that financing programs that are in existence (on-bill financing) or under consideration for the 2013-2014 cycle (on-bill repayment and credit enhancement) possess unique characteristics (make use of revolving funds; "park" funds in escrow to help secure loans which are not used if loans are repaid in full; etc.) that likely require different incentive structures than traditional resource programs in order to promote optimal utility management of these programs. However, since these programs are in their nascent stages or still under development, funds associated with financing

Footnote continued on next page

post savings award that the IOUs might expect to achieve doing "business-as-usual," based on recent portfolio average EUL and NTG ratios. Note that portfolio average values are used to calculate the estimates in the "business as usual" tables, so variations in EUL and NTG between the utilities are not reflected in these estimates. Note, too, that the 5% spillover assumption is applied for the 2013-2014 portfolio in the business-as-usual tables, since spillover will be added to the ex post savings estimates.

Table 4a: PG&E Correlation Coefficients and Maximum Ex Post Savings Payment

Savings Coefficients	Adopted Goals (no C&S)	Target EUL	Target NTG	Lifecycle Goals[6]	Allocation[7]	Correlation Coefficients[8]
8% of Resource Budget (Cap)*	$52,073,325					
Electricity Savings (GWh)					56.7%	
IOU Program Targets	1192	12	0.8	11,443	$ 29,525,575	$ 2,580
Peak Savings (MW)					28.3%	
IOU Program Targets	214	12	0.8	2,260	$ 14,736,751	$ 6,521
Gas Savings (w/ IE) (MMtherms)					15%	
IOU Program Targets	41.3	15	0.8	545	$ 7,810,99 9	$ 14,328

* Resource budget does not include funds for administrative activities, EM&V, codes and standards programs, or regional energy network/community choice aggregator programs.

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programs are included in the resource program cap calculation for this program cycle. If an incentive mechanism is adopted for future portfolio cycles, we would anticipate that it would include a uniquely designed component for utility finance programs

[6] Lifecycle Goals = adopted goal * target EUL * target NTG. This equation is applicable to all following tables.

[7] Determined based on "Step 1" described on page 14-15.

[8] Correlation Coefficients = Dollars Allocated/Lifecycle Goals. This equation is applicable to all following tables.

Table 4b: PG&E "Business As Usual" Expected 2013-14 Savings Component Payment

	Adopted Goals (no C&S) + Spillover	Realized EUL	Realized NTG	Correlation Coefficients	Estimated Payment[9]
Electricity Savings (GWh)	1,251.6	9	0.65	$ 2,580	$ 17,992,147
Peak Savings (MW)	224.7	9	0.65	$ 6,521	$ 8,163,825
Gas Savings (w/ IE) (MMtherms)	43.4	14	0.65	$ 14,328	$ 5,384,855
Total					**$ 31,540,828**

Table 5a: SCE Correlation Coefficients and Maximum Ex Post Savings Payment

Savings Coefficients	Adopted Goals (no C&S)	Target EUL	Target NTG	Lifecycle Goals	Allocation	Correlation Coefficients
8% of Resource Budget (Cap)*	$41,728,924					
Electricity Savings (GWh)					67%	
IOU Program Targets	1338	12	0.8	12,845	$27,820,674	$2,166
Peak Savings (MW)					33%	
IOU Program Targets	293	12	0.8	2,813	$13,908,250	$4,945

* Resource budget does not include funds for administrative activities, EM&V, codes and standards programs, or regional energy network/community choice aggregator programs.

[9] Estimated Payment = (adopted goals + spillover) * realized EUL * realized NTG * correlation coefficient. This equation is applicable to all following tables.

Table 5b: SCE "Business As Usual" Expected 2013-14 Savings Component Payment

	Adopted Goals (no C&S) + Spillover	Realized EUL	Realized NTG	Correlation Coefficients	Estimated Payment
Electricity Savings (GWh)	1,405	9	0.65	$ 2,166	$ 16,953,223
Peak Savings (MW)	308	9	0.65	$ 4,945	$ 8,475,340
Total					**$ 25,428,563**

Table 6a: SDG&E Correlation Coefficients and Maximum Ex Post Savings Payment

Savings Coefficients	Adopted Goals (no C&S)	Target EUL	Target NTG	Lifecycle Goals	Allocation	Correlation Coefficients
8% of Resource Budget (Cap)*	$13,711,746					
Electricity Savings (GWh)					56.7%	
IOU Program Targets	318	12	0.8	3,358	$7,774,560	$2,547
Peak Savings (MW)					28.3%	
IOU Program Targets	69	12	0.8	729	$3,880,424	$5,858
Gas Savings (w/ IE) (MMtherms)					15%	
IOU Program Targets	4.3	15	0.8	57	$2,056,76 2	$39,860

* Resource budget does not include funds for administrative activities, EM&V, codes and standards programs, or regional energy network/community choice aggregator programs.

Table 6b: SDG&E "Business As Usual" Expected 2013-14 Savings Component Payment

	Adopted Goals (no C&S) + Spillover	Realized EUL	Realized NTG	Correlation Coefficients	Payment
Electricity Savings (GWh)	334	9	0.65	$2,547	$ 4,737,623
Peak Savings (MW)	72.5	9	0.65	$5,858	$ 2,364,634
Gas Savings (w/ IE) (MMtherms)	4.5	14	0.65	$39,860	$ 1,599,711
Total					**$ 8,661,967**

Table 7a: SoCalGas Correlation Coefficients and Maximum Ex Post Savings Payment

Savings Coefficients	Adopted Goals (no C&S)	Target EUL	Target NTG	Lifecycle Goals	Allocation	Lifecycle Coefficients
8% of Resource Budget (Cap)*	$11,677,118					
Gas Savings (w/ IE) (MMtherms)					100%	
IOU Program Targets	46.3	15	0.8	622	$11,677,118	$ 21,017

* Resource budget does not include funds for administrative activities, EM&V, codes and standards programs, or regional energy network/community choice aggregator programs.

Table 7b: SoCalGas Expected Total 2013-14 Savings Component Payment

Payments if First Year Goals are Met	Adopted Goals (no C&S) + Spillover	Realized EUL	Realized NTG	Coefficient	Payment
Gas Savings (w/ IE) (MMtherms)	48.6	14	0.65	$ 21,017	$ 9,297,905

Under the original mechanism, the utility was at risk for no incentive earnings (or for penalties) if performance fell below a tiered minimum performance standard (MPS), even though customers may still be receiving benefits. Originally, net benefits were allocated to utility shareholders based on a range of possible shared savings percentages (i.e., 12%, 9%, 0%, or penalty reductions) depending on multiple MPS tiers. The tiered MPS structure, together with risk of penalties, thus created the unintended consequence of a potential "cliff" effect whereby a single kilowatt-hour could result in a difference of tens of millions of dollars in rewards or penalties. The potential risk of significant swings in incentive earnings due to the cliff effect contributed to the intense controversy over the accuracy of ex post forecasts.

Unlike the original formula which incorporated potential penalties and a deadband where no earnings or penalties applied, the current proposal applies a uniform earnings rate across all ranges of performance, with no penalties or deadband. In order to help minimize the potential for controversy regarding ex post evaluations for the 2013-2014 cycle, the incentive proposal would provide for a team of ex-post evaluation staff and contractors to be designated to perform the following functions:

a. Work with utilities and stakeholders in designing the overall portfolio evaluation plan, draft research plans, and any interim findings produced during the evaluation process;
b. Provide annual ex post estimates of portfolio savings for each utility (including the 5% spillover assumption for the 2013-2014 portfolio) as advice on the record to the proceeding, subject to due process; and
c. Be available to explain their findings to decision-makers, but not otherwise advise Commission decision-makers regarding incentive award calculations in this same proceeding.

As long as savings parameters are relied upon as a metric to calculate incentive earnings, the potential exists for controversy, irrespective of whether the metric is calculated on an ex ante or ex post basis. Nonetheless, the various differences in circumstances and design features between the 2006-2008 cycle and the 2013-2014 cycle offers the potential for less contention and for a more collaborative and workable approach.

In particular, by reducing the potential for extreme earnings swings, incentive earnings potential will not be as volatile, and the potential for litigation and disagreement accordingly diminish. For example, without a deadband or any penalty potential, differences in incentive payments depending on total ex post savings achieved will have less extreme swings. Also, since incentive earnings from savings would constitute only one of four components of incentive awards, the intense focus on arguing over savings measurement precision may be mitigated. And as previously noted, the other resource program component of the mechanism is specifically designed to award the utilities for exercising the highest standard of care in developing their ex-ante savings estimates, which we expect will result in ex-post results that are far more in line with ex-ante estimates than we witnessed in the 2006-2008 portfolio.

Finally, to reward the utilities for achieving the energy savings in as cost-effective manner as possible, I propose applying a multiplier to their resource program savings award equal to the amount that the ex post verified TRC ratio of their combined resource programs exceeds the TRC ratio of these programs that results from the final adopted 2013-14 portfolios (via portfolio compliance filings), including the resource program pro-rated portion of overall portfolio administrative and EM&V costs. Using this approach, if an IOU's ex ante resource program TRC ratio were 1.2 (after adding in the pro-rated portion of portfolio administrative and EM&V costs), and its ex post resource program TRC were 1.45, resulting in a TRC improvement of 0.25 for resource program implementation, then the resource program award would be multiplied by 1.25 (1 + 0.25). On the other hand, if this same IOU's ex post resource program TRC were 1.1, then its resource program award would be multiplied by 0.9 (1 - 0.1).

Specific Questions for Comment:

9. *What are the pros and cons associated with calculating the savings award based on net benefits, using a modified version of the original PEB calculus, versus using NRDC's approach, as modified, which multiplies energy and demand savings by coefficients that would be derived from the adopted savings goals and the predetermined savings component cap?*

10. *Given the focus on deeper, longer-lived energy savings, is the use of proposed "target" EULs and NTG ratio of 12 years (electric EUL), 15 years (gas EUL), and 0.8 (NTG)*

appropriate as goals for utilities to achieve in the 2013-14 or future portfolio cycles?

11. *One potential unintended consequence of using the proposed approach is that customers are exposed to some risk that the utilities will make changes to the measure mixes in their adopted portfolios that maximize total savings rather than maximizing total cost-effective savings. What is the magnitude of the risk that implementation of a non-cost-effective (i.e., TRC < 1.0) portfolio would result from a net savings-based approach? Does the TRC calculated for the authorized portfolio based on ex ante savings estimates and utility proposed measure mix, in combination with* the existing fund-shifting rules, adequately protect against this risk? What other steps could be taken to protect *customers from this risk if the Commission adopted a net savings, rather than net benefits, based savings component of the incentive mechanism?*

12. *Will the differences identified between the 2006-08 mechanism and the mechanism proposed herein sufficiently reduce the risk of contention associated with an ex post savings basis to warrant using an ex post approach rather than an ex ante approach, which resulted in unintended consequences related to the ex ante lockdown?*

13. *Should the Commission include bonus "adders" for results not captured explicitly by the four proposed components (e.g., Energy Upgrade California projects in hot climate zones, increases in portfolio average Effective Useful Lives, etc.)? If so, which ones, and how should they be calculated?*

14. *Should we include a cost-effectiveness adder in the ESPI? If so, is the proposed approach appropriate, or would a different approach be superior? Is there a need for an explicit cap on the potential resource program award to protect ratepayers? If so, how would we best determine a cap on an adder that is rewarding increases in program cost effectiveness? Should the cost-effectiveness adder be symmetric (i.e., increase or reduce resource program savings benefits) or should it only be applied if ex post cost-effectiveness is greater than the ex ante estimate?*

15. *Is it possible that funds used to establish the On-Bill Financing programs in the 2010-2012 portfolio cycle will be re-loaned in the 2013-2014 cycle, and therefore should be included in the savings cap calculation and in ex post savings estimates? Alternatively, should these issues be deferred to future cycles, when the overall financing program designs are better understood? If the former, how should the portion of 2010-2012 On Bill Financing funds that will be available for loans in the 2013-2014 cycle be calculated for inclusion in the cap and savings calculations?*

VI. Maximum Total Payment Caps and Estimated "Business-As-Usual" Payments Associated with Proposed ESPI

The following tables provide the maximum total payments and rough estimates of what the actual payment would be using "business as usual" assumptions (i.e., each utility achieves identical EAR performance scores as they did in the 2010 shareholder incentive mechanism decision and all utilities achieved average portfolio EULs and NTGs consistent with recent portfolio-wide averages), also assuming that 100%, rather than the cap maximum of 110%, of first year savings goals were achieved.

PG&E

Table 8a: PG&E 2013-14 Maximum Incentive Payment Cap

	Budgets	Non-resource Management Fee (3% of non-resource budget)	EAR Cap (2% of resource budget)	Savings Cap (8% of resource budget)	C&S Mgmt Fee (10% of C&S budget)	Total
Resource	$650,916,565		$13,018,331	$52,073,325		$65,091,657
C&S	12,248,324				$ 1,224,832	$ 1,224,832
Non-resource	$110,795,379	$ 3,323,861				$ 3,323,861
						$69,640,350

Table 8b: PG&E 2013-14 Estimated "Business As Usual" Payments

	Cap	Achievement (out of 100%)	2013-14 Payment
Non-resource Management Fee	$3,323,861	100%	$3,323,861
EAR Performance	$13,018,331	68%	$8,852,465
Savings Attainment	$52,073,325	100% goals, lower EUL and NTG	$ 31,540,828
C&S Management Fee	$1,224,832	100%	$1,224,832
Total			**$ 44,941,987**

SCE

Table 9a2: SCE 2013-14 Maximum Incentive Payment Cap

	Budgets	Non-resource Management Fee (3% of non-resource budget)	EAR Cap (2% of resource budget)	Savings Cap (8% of resource budget)	C&S Mgmt Fee (10% of C&S budget)	Total
Resource	$521,611,551		$10,432,231	$41,728,924		$52,161,155
C&S	$10,096,460				$1,009,646	$1,009,646
Non-resource	$105,251,873	$3,157,556				$3,157,556
						$56,328,357

Table 9b: SCE 2013-14 Estimated "Business As Usual" Payments

	Cap	Achievement (out of 100%)	2013-14 Payment
Non-resource Management Fee	$3,157,556	100%	$3,157,556
EAR Performance	$10,432,231	56%	$5,842,049
Savings Attainment	$41,728,924	100% of goals, lower EUL and NTG	$25,428,563
C&S Management Fee	$ 1,009,646	100%	$1,009,646
Total			**$35,437,815**

SDG&E

Table 10a3: SDG&E 2013-14 Maximum Incentive Payment Cap

	Budgets	Non-resource Management Fee (3% of non-resource budget)	EAR Cap (2% of resource budget)	Savings Cap (8% of resource budget)	C&S Mgmt Fee (10% of C&S budget)	Total
Resource	$171,396,829		$3,427,937	$13,711,746		$17,139,683
C&S	$1,897,848				$189,785	$189,785
Non-resource	$21,116,468	$633,494				$633,494
						$17,962,962

Table 10b: SDG&E 2013-14 Estimated "Business As Usual" Payments

	Cap	Achievement (out of 100%)	2013-14 Payment
Non-resource Management Fee	$633,494	100%	$633,494
EAR Performance	$3,427,937	31%	$1,062,660
Savings Attainment	$13,711,746	100% of goals, lower EUL and NTG	$8,661,967
C&S Management Fee	$189,785	100%	$189,785
Total			**$10,547,906**

SoCalGas

Table 11a: SoCalGas 2013-14 Maximum Incentive Payment Cap

	Budgets	Non-resource Management Fee (3% of non-resource budget)	EAR Cap (2% of resource budget)	Savings Cap (8% of resource budget)	C&S Mgmt Fee (10% of C&S budget)	Total
Resource	$145,963,980		$2,919,280	$11,677,118		$14,596,398
C&S	$1,511,778				$151,178	$151,178
Non-resource	$12,567,759	$377,033				$377,033
						$15,124,609

Table 11b4: SoCalGas 2013-14 Estimated "Business As Usual" Payments

	Cap	Achievement (out of 100%)	2013-14 Payment
Non-resource Management Fee	$377,033	100%	$377,033
EAR Performance	$2,919,280	36%	$1,050,941
Savings Attainment	$11,677,118	100% of goals, lower EUL and NTG	$9,297,906
C&S Management Fee	$151,178	100%	$151,178
Total			**$10,887,057**

Table 12a: Maximum Payment Cap by Component and IOU

Total Incentive Caps	PG&E	SCE	SDG&E	SCG	Total
Non-resource program Management Fee	$ 3,323,861	$ 3,157,556	$ 633,494	$ 377,033	$ 7,491,944
Ex Ante Compliance Performance Award	$ 13,018,331	$ 10,432,231	$ 3,427,937	$ 2,919,280	$ 29,797,779
Codes and Standards program Management Fee	$ 1,224,832	$ 1,009,646	$ 189,785	$ 151,178	$ 2,575,441
Ex Post Savings Performance Award	$ 52,073,325	$ 41,728,924	$ 13,711,746	$ 11,677,118	$ 119,191,114
All IOU 2013-14 Payment Cap	**$ 69,640,350**	**$ 56,328,357**	**$ 17,962,962**	**$ 15,124,609**	**$ 159,056,278**

Table 12b: Estimated "Business as Usual" Payments by Component and IOU

	PG&E	SCE	SDG&E	SCG	Total
Non-resource program Management Fee	$ 3,323,861	$ 3,157,556	$ 633,494	$ 377,033	$ 7,491,944
Ex Ante Compliance Performance Award	$ 8,852,465	$ 5,842,049	$ 1,062,660	$ 1,050,941	$ 16,808,116
Codes and Standards program Management Fee	$ 1,224,832	$ 1,009,646	$ 189,785	$ 151,178	$ 2,575,441
Ex Post Savings Performance Award	$31,540,828	$25,428,563	$ 8,661,967	$ 9,297,906	$ 74,929,264
Total 2013-14 Estimated Payment	**$ 44,941,987**	**$ 35,437,815**	**$ 10,547,906**	**$ 10,887,057**	**$ 101,804,765**

VII. Form and Schedule for Submission of Claims, Review and adjudication, and Issuance of CPUC Decision Regarding Award of Incentive Payments

I believe that in order to be the most effective and obtain the greatest market value and ratepayer benefit, ESPI payments needs to be on a regular, predictable schedule. The proposed mechanism contemplates a schedule for submission, review, adjudication and issuance of a Commission Decision regarding incentive payments such that incentives would be paid according to the schedule in Table 13 below. The adopted schedule would provide for stability and continuity in the payment of incentive awards. Under the incentive mechanism for the 2010-12 cycle adopted in D.12-12-032, the utilities are due to receive incentive payments for 2011 program activity in calendar year 2013, and for 2012 program activity in calendar year 2014.

Accordingly, to provide for a seamless transition and continuity in a flow of regular annual incentive earnings into 2015 and 2016 (for the 2013 and 2014 program years), the following schedule would apply for payment of awards under the new mechanism. Awards for program year 2013 non-resource, codes and standards, and ex ante review activities would be made in calendar year 2015. The ex post savings incentive component for program year 2013 would not be awarded, however, until calendar year 2016. This additional time is needed to complete the necessary work involved in an ex post savings evaluation and to allow for adequate vetting of the results with the parties.

This staggered payment schedule would continue for 2014 program year activities (resulting in a similar sequence of payments in calendar years 2016 and 2017, respectively, and beyond, if this proposed incentive structure were continued in the next portfolio cycle). The Commission would also need to establish a schedule for timely submission and review of incentive claims early enough to allow for the payments schedules as contemplated.

The following table illustrates how the proposed payment schedule for incentive components under the proposed mechanism would continue the flow of annual incentive earnings starting in 2015 (pending program year 2011 and 2012 awards scheduled for payment in calendar years 2013 and 2014, respectively, are completed).

Table 13: Proposed Incentive Payment Schedule

Payment/ Calendar Year	Program Year	Payment Combinations
2013	2011	Payment for 2011 program activities (per D.12-12-032).
2014	2012	Payment for 2012 program activities (per D.12-12-032.
2015	2013	Payment for 2013 non-resource, codes and standards, and ex-ante review activities.
2016	2013 and 2014	Payment for 2013 ex post savings and 2014 non-resource, codes and standards, and ex-ante review activities.
2017	2014 and 2015	Payment for 2014 ex post savings [and non-resource, codes and standards, and ex-ante review activities if this incentive mechanism were continued in the next portfolio cycle].

Questions for Comment

16. *As described in Table 13, the payment for the ex post savings component is delayed by an additional year to allow time to complete impact evaluation studies. Does this delay create an unnecessarily complicated payment schedule? Or would it be preferable to delay the full payment by the additional year to provide all four components of each year's incentive in the same year, even if it meant a one-year pause (in 2015) as we transitioned to the reformed mechanism?*

17. *The proposed payment approach provides annual payments, obviating the need for an end-of-cycle true-up mechanism. Would the true-up approach be a preferable method to address the resulting staggered payment or one-year pause associated with the annual payment approach?*

In putting together the proposal for ESPI, Commission Staff created a useful spreadsheet tool to understand how the different variables impacted both the Maximum Payment Cap by Component and IOU (Table 12a) and the Estimated "Business as Usual" Payments by Component and IOU (Table 12b). I direct Commission Staff to serve the spreadsheet tool (in Microsoft Excel format) to the parties along with any necessary instructions. The spreadsheet tool is able to accept alternative variables to those proposed in this ruling. As part of the response to the questions in this ruling, parties should submit its own version of

Tables 12a and 12b. This will help inform me how the various different positions of the parties impact its view on ESPI.

IT IS RULED that:

Comments are solicited regarding the merits of the draft proposal for an incentive mechanism for the 2013-2014 cycle in accordance with the provisions outlined above, and as further elaborated in Appendix A. As part of their comments, parties should include a version of Table 12a and Table 12b that represents its views on changes to the Energy Savings and Performance Incentive

Opening comments may be filed no later than April 26, 2013 and reply comments may be filed no later than May 3, 2013.

Dated April 4, 2013, at San Francisco, California.

/s/ MARK J. FERRON
Mark J. Ferron
Assigned Commissioner