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)

SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) AND SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) COMMENTS ON ORDER INSTITUTING RULEMAKING R.12-01-005 AND ASSIGNED COMMISSIONER'S RULING SOLICITING FURTHER COMMENTS AND PRODUCTION OF DATA REGARDING ENERGY EFFICIENCY INCENTIVE REFORMS

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I. INTRODUCTION

Pursuant to direction provided in R.12-01-005 and the December 16, 2011 Assigned Commissioner's Ruling Soliciting Further Comments and Production of Data Regarding Energy Efficiency Incentive Reforms ("Ruling"), San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas") (also referred to as the "Joint Utilities") respectfully provide their comments and modified proposal regarding the "Risk/Reward Incentive Mechanism ("RRIM"). In addition, the Joint Utilities provide the relevant calculations and supporting assumption applicable to the calculation of a share savings rate for the 2010-2012 cycle using the steps described in the Ruling.

II. GENERAL OVERVIEW

An incentive mechanism for energy efficiency should be designed to align the goals of utility management and shareholders, toward whom management has fiduciary responsibility, with those of customers and regulators by providing an opportunity to earn a return on the net benefits that accrue from implementing successful energy efficiency programs. In order to facilitate the most cost effective and successful energy efficiency programs, incentives should be of sufficient size and structured in such a manner to encourage utility management to give attention to these programmatic opportunities.

The value of the return to shareholders on supply-side resource investments was a logical starting point to consider in determining the magnitude of incentives associated with energy efficiency activities. The US Department of Energy ("DOE") recognized that performance-based incentive mechanisms can provide a useful means to achieve energy efficiency targets in their report on *State and Regional Policies that Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities*. In this report, DOE recommends (at page 65) that, "Regulators should consider allowing utilities' returns at least as great from prudent investments in energy efficiency as from supply-side investments."[1] In addition, California's Energy Action Plan calls for several specific actions to optimize energy conservation and resource efficiency. One of those actions is directed specifically at utility incentives and called for action to provide utilities with demand response and energy efficiency investment rewards comparable to supply-side resources.[2]

SDG&E and SoCalGas have successfully participated in past incentive structures governing energy efficiency, natural gas acquisition, customer service, safety, and overall distribution cost management. SDG&E has also had successful incentive structures to encourage performance for generation and dispatch decisions and electric system reliability. Under these incentive mechanisms, regulators established the guiding policy and goals, and left the implementation details to the utility, providing incentives to ensure that the utility's interests are aligned with its customers' interests. The history of these mechanisms is, by-and-large, that when the utility was able to achieve or exceed the Commission's established benchmark, customers gained added benefits in terms of lower costs and/or higher quality service.

The adopted energy efficiency earnings mechanisms demonstrate the efficacy of incentives. The EE earnings mechanisms provided incentives to achieve various program objectives the Commission set forth for the utilities. The results in Chart 1 below show that EE savings and EE savings per dollar spent were higher in periods with incentives and a focus on energy savings. And EE savings have been higher in recent periods for utilities with incentives than comparable utilities that did not have incentives as shown in Chart 2.

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[1] State and Regional Policies that Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities, A Report to the United States Congress Pursuant to Section 139 of the Energy Policy Act of 2005, March 2007, U.S. Department of Energy, pages 57-58.

[2] EAP 1, p. 5.

CHART 1

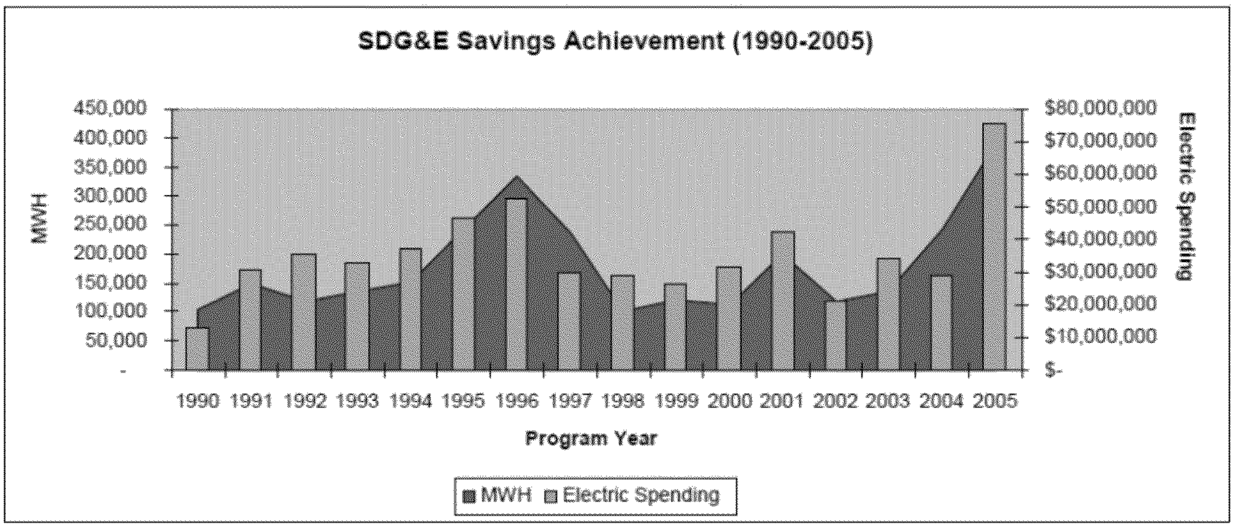
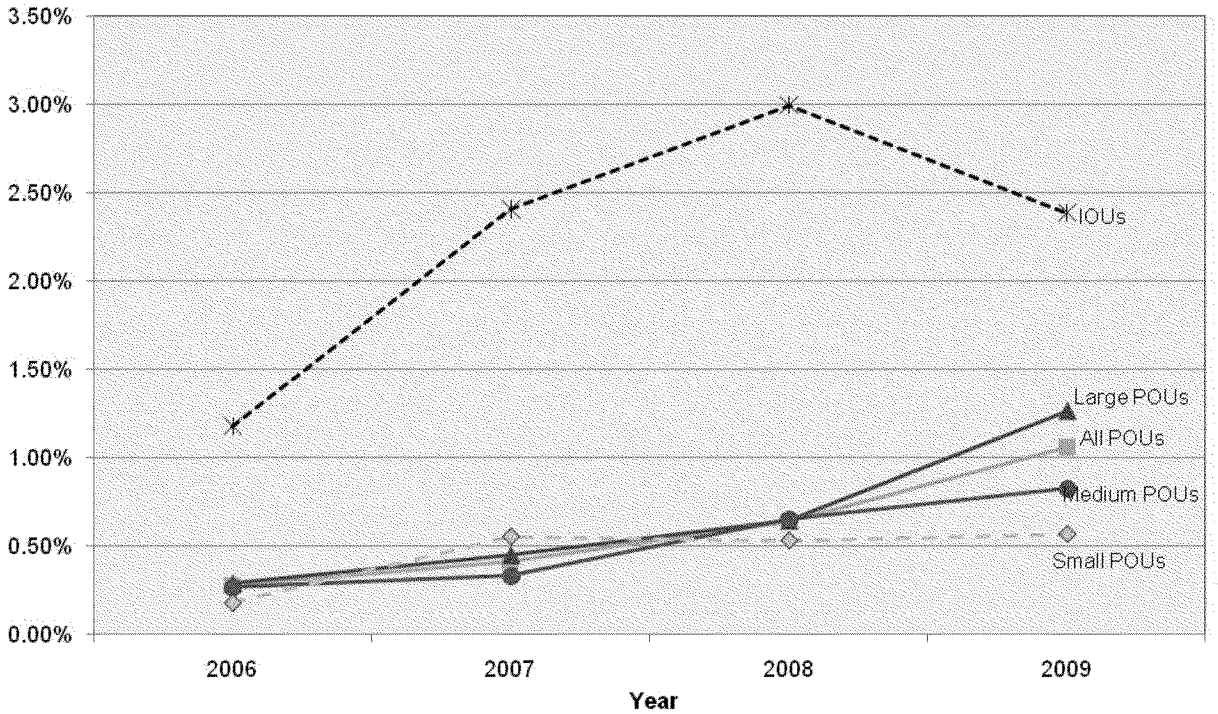


CHART 2
Energy Savings as a Percentage of Total Sales



The hallmarks of incentive mechanisms that worked well were 1) an agreed-upon goal, 2) an agreed-upon benchmark, 3) clear measurement of results, and 4) a level of incentives that the Commission determined was in proportion to the benefits accruing to ratepayers. The Gas Cost

Incentive Mechanism (GCIM) of SoCalGas is an example of such a mechanism. There was a clear goal – reducing the cost of procuring gas for customers; a clear market benchmark in monthly and daily gas price indexes; clear measurement of results in the average price of gas purchased; and a level of incentives proportional to the benefits accruing to customers. However, other goals entered into the picture during the energy crisis, namely protecting customers from market price spikes. SoCalGas undertook hedging to protect customers which led to very large shareholder incentive amounts during that unusual period of California energy history. As a result, the GCIM mechanism was modified to cap the shareholder incentive amounts and to exclude certain specified hedging costs incurred on behalf of customers and the resulting hedging benefits. The incentive structure was modified to cap the level of incentives to a level proportional to the benefits provided to customers.

A RRIM based on *ex ante* assumptions can serve its intended purpose in terms of motivating superior performance in the utility acquisition of energy efficiency savings. But in order to do so there has to be the clear goal - achieving energy savings. Then there has to be a clear benchmark of energy savings - *ex ante* savings assumptions established prior to the planning and the execution of the energy efficiency program. Next, measurement of results, there must be clear accounting standards for measurement of program energy savings based on the verified installations. And finally, the level of incentives must be at a level that the Commission determines is proportional to the ratepayer benefits. Clearly, the distractions of EM&V need to be avoided in the future by establishing *ex ante* values for all measures including custom measures.[3] And a more limited level of earnings or a more limited cap may be needed so regulators are not so preoccupied with the magnitude of potential rewards in the face of the uncertainty of measured benefits.

The RRIM, as currently configured, is based on achieving energy savings. It is inconsistent with some forms market transformation activities; however, SDG&E and SoCalGas would dispute the explicit assumption in the ACR that EE programs should move away from resource acquisition. As the State embarks on Greenhouse Gas ("GHG") reduction through the Air Resource Board ("ARB") cap-and-trade program, there should be <u>more</u> emphasis on attaining as much cost effective energy savings as possible in order to reduce GHG allowance

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[3] EM&V results should be used to update and inform the future program cycle.

costs of all utility customers. There should be no backing off from the targets embedded in utility resource plans and the ARB Scoping Plan.

Further, a long-term shared savings approach with *ex ante* assumptions is compatible with "learning-by-doing" market transformation. Initially the cost effectiveness of a measure or program may be marginal, but as the EE measure becomes more widely adopted due to utility EE program support, the cost effectiveness improves as the cost of the measure drops. Evidence of market transformation can be measured by increased gross savings per dollar expense for a measure combined with a changing net-to-gross ratio over time. Using *ex ante* assumptions for savings and the net-to-gross ratio allows the utility to be rewarded for market transformation. In the current cycle, the adoption of the measure increases as the price drops. In the next cycle, the cost effectiveness increases as the price of the measure drops, but this is partially or fully offset by the decreased net-to-gross ratio that lowers the earnings basis.

Other types of market transformation are not amenable to an incentive mechanism. Education programs aimed at influencing customer preferences, reducing market barriers such as facilitation of financing, etc. fail to provide a clear benchmark. True market transformation is a function of the "entire" market participating in creating changes. The utilities' programs seed the beginnings of market transformation but true and permanent changes in the market result from changes in manufacturing, distribution, retail and customer acceptance, all of which are not controlled by the utilities. At best a market transformation mechanism would be based on market indicator-type milestones that would relate to specific utility program activities. However, the problems with the milestone approach used for market transformation programs in the late 1990s should not be repeated. Therefore, for EE market transformation programs that the Commission wants utilities to pursue should take a management fee approach, or where a benchmark can be established, a performance incentive mechanism based on achieving clear and measurable objectives.

III.
PROPOSED RRIM STRUCTURE

A. 2010-2012 PROGRAM CYCLE PROPOSAL

For the current Program Cycle 2010-2012 and succeeding future program cycles, SDG&E and SoCalGas propose a RRIM structure that draws from the significant amount of thinking that has already taken place in this proceeding in prior decisions, proposed decisions, and parties' comments. The RRIM would have the following structure:

1. Resource Programs

- The incentive earnings would equal an earnings rate multiplied by the performance earning basis ("PEB").
- The earnings rate would equal 7 percent as in D.10-12-049. There would be an elimination of goals and minimum performance for purposes of the RRIM, rewards would simply be a percentage of the net benefits of energy savings delivered to customers. The 7 percent figure started out at 12 percent in a comparison to supply-side, but was reduced to recognize the lower risk of using *ex ante* values rather than *ex post*, but it also put the incentive amount in a range the Commission was more comfortable with for the uncertain level of measured ratepayer benefit.
- The PEB would equal 2/3 of the Total Resource Cost ("TRC") net benefits and 1/3 the Program Administrator Cost ("PAC") net benefits. Again this is has been the approach has been in place since the mid-1990s EE shared savings earnings mechanisms.
- Non-resource programs including market transformation programs would be excluded from this shared savings mechanism and the calculation of the PEB and RRIM.
- Only resource programs with net-to-gross ratios greater than 20% would be allowed. Once market transformation is fairly complete (a net-to-gross ratio of less than 20% would be used as an indicator), measures should no longer be subsidized.
- *Ex ante* data frozen before the earnings period would be used to determine savings achievements. This is consistent with the approach in the Proposed Decision, but would take it farther to specify values outside of DEER.
- *Ex post* verification of installations and expenditures would be used to determine the final PEB. This is also consistent with the approach in the Proposed Decision.
- EM&V *ex post* study results be used to determine *ex ante* values in the next cycle - consistent with the approach in the Proposed Decision.
- For purposes of the RRIM only, custom projects submitted after the publication of D.11-07-030 would use only 75 percent of engineering estimates of savings for determining PEB with no additional adjustments from the net-to-gross ratio. All custom measures submitted prior to D.11-07-030 would use the decision provided default rate of .9 or 90% of engineering estimates of savings for determining PEB with no additional adjustments from the net-to-gross ratio. Custom measures are problematic for determination of energy savings primarily due to the difficulty in determining the net-to-gross ratio since custom measures tend to be unique. It is often an arbitrary determination of the probability of whether the customer would have installed the measure without incentives. A 75 percent assumption, while appearing to be arbitrary, assumes the utility assessment is accurate, that the customer is not likely to install the

measure without incentives (net-to-gross greater than 50%) and some discount for the fact that engineering calculations may overestimate actual savings.

- Annual recovery holdback of 25% subject to completed verification of installations and costs. This verification should be completed prior to the next year's earnings assessment. Given the reduced *ex post* verification risk (verification is limited to installations and costs), a larger percent of the incentive should be paid immediately.

- Cap on earnings of RRIM would be utility-specific and would be equal to 1.5 times the overall EE program expected PEB. While the cap is somewhat arbitrary, it is consistent with caps on other incentive programs to limit payments to a level the Commission would find acceptable under different circumstances and is less than the level of incentives paid for the 2006-2008 program years.

2. Non-Resource/Strategic Plan Programs

The Joint Utilities acknowledge that given 2013 is the last year of the current program cycle, it may not be practical to consider a separate component for non-resource programs. However, below is a general description of a mechanism that could be considered.

- Non-resource programs (those excluded from the RRIM) would have a separate cap equal to 3 percent of the non-resource program budgets. It is reasonable to use this benchmark for the cap as the benefits of these programs are difficult to quantify.

- Non-resource programs would have performance metrics where there are clear measureable outcomes. For example, the number of green jobs for those receiving green job training or customer satisfaction for customer education programs.
- Non-resource programs without metrics would have no payment.

B. GENERAL CONSIDERATIONS FOR 2013 AND BEYOND (THIS IS FROM THE WHITE PAPER)

The Joint Utilities provide high level considerations for a prospective RRIM. The Joint Utilities propose that the following principles continue to guide the development of the next generation for RRIM:

- The RRIM must send clear unambiguous signals to the utilities on CPUC expectations.

- The RRIM must drive the utilities to deliver a more cost effective portfolio for ratepayers.

- The RRIM must drive towards the achievement of the GHG goals of the state through the delivery of aggressive energy efficiency savings for California.

In order to develop a consensus RRIM, the Joint Utilities offer the following guiding principles:

- RRIM should not be solely focused on achievement of savings goals to ensure adequate attention is provided to the Commission's various objectives, including those in the EE Strategic Plan;
- The Commission must establish targets, target bands and weighting for various components of the RRIM prior to the program cycle;
- Clear benchmarks for key performance indicators must be developed;
- Appropriate measurement protocols must be established for determining success prior to the program cycle;
- A collaborative approach to working with Energy Division and other stakeholders should be established for measuring program success.
- Indicators of success must be measurable in a reasonable timeframe to not only reward/penalize program success/failures but to allow for program adjustments to ensure meeting Commission objectives.

The following illustration below is an example of a different RRIM that the Commission could consider for 2013 and beyond:

***An illustrative example:* Item**	**Weighting**	**Min**	**Target**	**Max**
Energy Savings (Carbon)	40%	121 Units	151 Units	182 Units
Customer Satisfaction	30%	60%	80%	100%
Cost Reductions	10%	2%	5%	8%
Innovation	10%	1 new measure/new delivery approach	3 new measures/new delivery approaches	5 new measures/new delivery approaches
Other Key Measurable Items	10%	A	B	C

IV. CALCULATING THE SHARED SAVINGS RATE FOR THE 2010-2012 PROGRAM CYCLE

The Ruling directed the utilities to perform calculations following the step laid out by the Assigned Commissioner. The Joint Utilities provide the following calculations using the assumption that it has incorporated the savings assumptions, including the modified savings for the custom project process, required by D.11-07-030.

1. **Identify the energy savings in GWh associated with the 2010-2012 portfolio based upon the achievement of (a) 100% of adopted savings goals and (b) 125% of adopted savings goals.**

   a. **SDG&E**

2010-2012 GWh at 100% of Goal	540
2010-2012 GWH at 125% of Goal	675

   b. **SoCalGas**

2010-2012 MMthm at 100% of Goal	90
2010-2012 MMthm at 125% of Goal	112.5

2. **Provide the calculations of the Performance Earnings Basis (PEB).**[4]

   a. **SDG&E**

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Year	kWh Goal	kWh Saved from Monthly Reports (projected Through 2012)	Weighted Average Savings Adj Factor from Engineering	kWh Saved Adj	PEB/kWh Estimated from Impacts from D.11-07-030	PEB @ Goal	PEB 125% Goal
2010	195,000,000	271,936,652	89%	242,023,621	$ 0.136	$ 26,520,000	$ 33,150,000
2011	187,000,000	269,223,972	95%	255,617,392	$ 0.136	$ 25,432,000	$ 31,790,000
2012	158,000,000	177,528,090	89%	158,000,000	$ 0.136	$ 21,488,000	$ 26,860,000
2010-2012	540,000,000	718,688,714		655,641,013		$ 73,440,000	$ 91,800,000

Notes:

(1) Column (c) provides the EEGA reported monthly savings for 2010 through 2011 prior to the adjustments required by D.11-07-030. The results for 2012 were forecasted assuming the same performance trend of 2010-2011.
(2) Column (d) shows the estimated overall impact of D.11-07-030 on the reported savings. In SDG&E's case, it is approximately 89% resulting from the final adjustments for DEER and Deemed savings. The 2011 results reflect the custom project measure gross adjustment of 90% as SDG&E made this additional adjustment going back to 2010.
(3) Column (e) shows the resulting adjusted monthly KWH when the adjustment factor in column (d) is applied.
(4) Column (f) is the average PEB ($)/KWH achieved. To determine this average, the E3 calculator was run to establish the total portfolio achieved PEB at the end of 2010 based on the reported KWH, KW and Therm savings. The same was done for 2011. The results were

[4] The following PEB calculations do not assume a reduced PEB from the proposed reduction of savings from custom projects.

practically identical and therefore, SDG&E concluded that this average is relatively stable and can be used to estimate the PEB at 100%of goal—Column (g) and PEB at 125% of goal—Column (h), respectively. This approach simplifies the estimation process without having to create various scenarios between KWH, KW and Therm achievements.

b. SoCalGas

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Year	Therm Goal	Therms Saved from Monthly Reports (projected Through 2012)	Weighted Average Savings Adj Factor from Engineering	Therms Saved Adj	PEB/Therm Estimated from Impacts from D.11-07-030	PEB @ Goal	PEB 125% Goal
2010	28,000,000	27,413,193	90%	24,671,874	$ 0.75	$ 21,000,000	$ 26,250,000
2011	30,000,000	37,233,193	97%	36,283,747	$ 0.75	$ 22,500,000	$ 28,125,000
2012	32,000,000	35,555,556	90%	32,000,000	$ 0.75	$ 24,000,000	$ 30,000,000
2010-2012	90,000,000	100,201,941		92,955,620		$ 67,500,000	$ 84,375,000

Notes: The same notes listed above apply to SoCalGas.

3. Calculate 2010-2012 earnings associated with supply-side resources.

As requested in the Ruling, SDG&E and SoCalGas have recalibrated the supply-side earnings with updated data presented in Step 2 above. The same assumptions were used as in the 2006-2007 analyses except for the updates requested in the ACR at page 7 and the addition of a gas utility supply-side analysis. Specifically, there were five major changes to the supply-side analysis of the electric utilities:

(1) The measure life was reviewed and changed to 9 years for electric utilities for 2010-2012, while maintaining the 12 year life for gas utility energy efficiency measures.

(2) The percentage of supply-side resources met by utility-procured assets was modified. The utilities[5] could not agree on an assumption so SDG&E has made the calculations under two alternate assumptions: a 25/75 split, meaning 25 percent of supply-side resources would be utility-owned, and also maintaining the 50/50 split from the 2006-2007 analysis. For gas supply-side resources, it is assumed that 100 percent are utility-owned.

(3) The cost of capital assumptions were updated to current values and the electric utilities used a 25 percent risk factor for debt equivalence, down from 30 percent used in 2006-2007.

[5] SDG&E and SoCalGas conferred with PG&E and SCE as to the methodology each utility was using to complete Step 3.

(4) The supply-side resources were updated to reflect current values for the cost of avoided/deferred resources. Common assumptions were used for the cost of generation on the electric side, basing it on the new cost of a combined cycle combustion turbine from the California Energy Commissions 2009 Report, "Comparative Cost of California Central Station Electricity Generation Technologies," CEC-200-2009-07SD, $1,180/kW, and a line loss factor at peak of nine percent based on an average of the utility generation peak load line losses consistent with the current Energy Efficiency avoided costs.

(5) SDG&E used its own updated value of deferred distribution costs of $267/KW based on SDG&E's 2012 GRC filing. The assumptions for SoCalGas are not based on the electric side, but include new costs for deferred transmission and distribution pipeline costs based on three recent or proposed pipeline capacity expansion projects.

The utilities all use the costs of "new build" in their calculations. The Ruling requests the utilities consider "additional material changes in the relevant assumptions of 2010-2012 supply-side equivalent resources since the calculation made in D.07-09-043." There are three major changes that are relevant: (1) the economic recession that has extended the time before SDG&E will need to build more generation to meet new peak load; (2) the once-through cooling timeline that has accelerated the timeline to build new replacement generation; and (3) the fact that the 33% RPS means that EE allows utilities to avoid having to acquire 20-33% renewables. The utilities chose to maintain the assumptions consistent with 2006-2007 analyses rather than try to evaluate the impacts of these three factors given the relatively short timeframe for analysis. It is noted that the first factor would decrease the supply-side savings, while the latter two factors would increase supply-side savings.

The results and a comparison to D.07-09-043 are shown in the tables below at 100% of goal. The *ex ante* goal is presented as well as an adjusted *ex ante* goal incorporating the adjustments to *ex-ante* values approved in D.09-09-047 (as modified by D.10-12-054), and as updated, augmented or modified by D.11-07-030. The result is that the equivalent returns are higher for electricity in spite of the reduced average measure life and the change in percentage of investments between utility-owned and PPAs to 25 percent because of the increase in avoided costs and the SDG&E level of peak savings as a percent of the performance earnings basis. The equivalent returns for SoCalGas are roughly the same as in D. 07-09-043.

a. SDG&E

SDG&E Calculationof Shareholder Earnings as a Percent of PEB Based on Electricity

Percent Utility-Owned	25%		50%		
Goals	Unadjusted	Adjusted	Unadjusted	Adjusted	D.07-09-043
Savings (MW)	104.5	93.1	104.5	93.1	
Avoided capital cost ($/kW)	1564	1564	1564	1564	
Supply-side Savings (Millions $)	163.4	145.6	163.4	145.6	
Percent Utility-Owned	25%	25%	50%	50%	50%
Wtd.Average Shareholder Earnings Rate	14.0%	14.0%	17.7%	17.7%	20.8%
Total Shareholder Supply-side Earnings	22.9	20.4	28.9	25.7	62
PEB	73.4	73.4	73.4	73.4	297
Shareholder Earnings as % of PEB	31%	28%	39%	35%	21%
Annual Shareholder Return at Goal (mil $)	7.6	6.8	9.6	8.6	20.7

b. SoCalGas

SoCalGas Calculation of Shareholder Earnings as a Percent of PEB

Goals	Unadjusted	Adjusted	D.07-09-043
Savings (Million Therms)	90.0	81.0	
Earnings Foregone per Therm ($/therm)	0.20	0.20	
Shareholder Earnings (Millions $)	18.0	16.2	38.0
PEB (Million $)	67.5	67.5	134.5
Shareholder Earnings as % of PEB	27%	24%	28%
Annual Shareholder Return at Goal (mil $)	6.0	5.4	12.7

4. Calculate the RRIM shared-savings percentage rate required to yield the supply-side equivalent earnings calculated in Step 3 above, before any adjustments to reflect reduced risk associated with RRIM earnings relative to the corresponding supply-side earnings.

Based on the given formula in the Ruling:

(1) Equivalent Supply Side Earnings (as determined in Step 3 above)

Divided by

(2) Performance Earnings Basis (as determined in Step 2 above)

Utility	(1) Supply- Side Earning ($Million)	(2) RRIM PEB @ 100% ($Million)	Ratio – (1)/(2)
SDG&E (25/75)	20.4	73.4	28%
SDG&E (50/50)	25.7	73.4	35%
SoCalGas	16.2	67.5	24%

5. Adjust the shared savings percentage rate as appropriate to reflect the reduced risk associated with earnings received as incentives for energy efficiency compared with rate-of-return earnings received as incentives for energy efficiency compared with rate-of-return earnings from supply side equivalent resources.

The Ruling states (at page 8), "Parties should not simply assume the 7% shared savings rate applied in D.10-12-049 is the relevant starting point for calculating incremental changes in the shared savings rate for 2010-2012. I ask that the parties independently evaluate all relevant comparisons between the financial risks and rewards associated with earnings from supply-side resources versus earnings from the RRIM formula, as applied in D.10-12-049, based upon 2010-2012 ex-ante values."

The Joint Utilities discuss the three factors that affect the shared savings rate below:

1) Comparable Rate of Return on Supply-Side Investments as Indicated by the Relative Financial Risks and Rewards Associated with Earnings from Supply-Side Resources Versus Earnings from the RRIM Formula

The Joint Utilities do not believe it is productive to debate the financial risks and reward comparison delved into extensively in 2006-2007 and summarized clearly in 19 pages of Decision 07-09-043 (from page 94 through 113). There the Commission explained its reasoning in going from supply-side earnings of 20 to 30 percent to 12 percent. As D.07-09-043 states, the final shared savings rate is a judgment call of the Commission.

> "As most parties to this proceeding acknowledge, establishing the level of earnings opportunity for a shareholder risk/reward incentive mechanism is ultimately a judgment call that the Commission must make, and not a precise science.[176] Generally speaking, we believe that the earnings potential under such a mechanism should be designed both to balance the potential penalties under the mechanism and to offset existing financial and regulatory biases in favor of supply-side procurement. In this context, consideration should be given to what level of earnings potential will provide a clear signal to utility investors and shareholders that achieving and exceeding the Commission's savings goals (and maximizing ratepayer net benefits in the process) will create meaningful and

> sustainable shareholder value. At the same time, we should weigh and consider differences in the risk/reward profile of utility resource choices in applying the comparable earnings benchmark to our incentive mechanism."[6]

However, the Decision indicates that there was a balancing of the risks and rewards of the RRIM in deciding on the 12 percent shared savings rate.[7] If the RRIM mechanism is changed to eliminate significant risks such as "realized net benefits" and a savings goal separate from net benefits, then the chosen shared savings value would be less than the 12 percent adopted in D.07-09-043.

> "Although ratepayers put up 100% of the investment capital for energy efficiency programs, shareholders are at risk under the adopted incentive mechanism for losses to that capital and face sizable per-unit penalties for substandard performance of the portfolio. Unlike a rate-based plant, shareholder earnings will vary in direct proportion to performance **<u>(i.e., realized net benefits)</u>**, even when factors entirely beyond the utility's management control affect that performance." [8] [Emphasis added]

2) Expected Decrease in Earnings from Ex Post Savings Estimates

Earnings are the product of the shared savings rate and the performance earnings basis. If *ex post* estimates of savings had the same probability of increasing or decreasing, there would be only less risk from measurement error if *ex ante* values are used. However, there are two elements that assure that *ex post* measurements of savings will be less than *ex ante* savings estimates – use of historical estimates forming the *ex ante* values and the market reality that the net-to-gross (NTG) ratio should decline over time. To account for the expected decline in *ex post* savings estimates compared to *ex ante* values, the shared savings rate can be reduced in the same proportion of the expected decline in *ex post* savings compared to *ex ante* to keep ratepayers neutral as far as incentive payments. That is, using *ex ante* values in the earnings basis can be offset by lowering the shared savings rate.

As the Commission pointed out in D.10-12-049, "significant variances exist between the savings estimates from the Energy Division *ex post* evaluation and the assumptions underlying the original *ex ante* assumptions used to develop the Commission's efficiency goals. This is not

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[6] D.07-09-043, page 104.
[7] D.07-09-043, page 109. The 12 percent figure is for meeting 100 percent of goals.
[8] D.07-09-043, page 106.

because those initial assumptions were necessarily inaccurate when they were adopted, but because market dynamics are likely to have changed in the intervening years."

NTG calculations are the most obvious element that only moves in one direction, from a higher value to a lower value. While most EE programs are designed to acquire energy efficiency savings, they are also trying to change the market, to transform it so that utility subsidies are no longer necessary in the long-term. If an EE resource acquisition program is changing the market, then the NTG will be lower *ex post* and incentive payments based on *ex post* NTG will be less than based on *ex ante* values. A program that is a great success at market transformation will have low earnings from a resource acquisition point of view *ex post*. If the Commission intended to lower IOU earnings for successful market transformation, the shared savings rate can be adjusted downward to capture on average the expected change in NTG ratios between the *ex ante* value and the *ex post* realized NTG.

Net-to-Gross studies are completed long after the decision to implement a measure has been made, often conducted at least 2 to 3 years after programs are implemented and long after the decision makers have decided to go with an EE measure. In D.10-12-049, the Commission stated, "it was/is unreasonable to expect the utilities to anticipate the very substantial changes in a number of the key parameters over the three year cycle that drive their energy efficiency program results." But since NTG ratios can go only one direction – lower – due to market transformation, an expected reduction can be factored into the shared savings rate based on past trends instead of relying on *ex post* adjustments.

New and innovative EE programs start out with high NTG values but then naturally decline. Often the more successful the program, the more quickly the NTG values decline. It is not reasonable to require the IOU to guess what the NTG value will be 3 years after the EE program implementation. This type of guessing could be harmful, leading to reduced innovation and the use of cutting edge technology and could become a major cause of lost opportunity for energy efficiency in California. Further, it could lead to the abandonment of energy efficiency programs too early if guesses about future NTG ratios are wrong. If the Commission originally intended to lower utility incentives for successful market transformation, a better way is to lower the shared savings rate based on expected market transformation. This makes more sense from an IOU incentive approach. Instead of trying to guess which EE resource acquisition programs will be successful in market transformation and which will not, just recognize that on average some will be successful and lower earnings through a reduced shared savings rate rather than the *ex post* change in NTG. If the NTG on average has declined such that *ex post* earnings have been reduced by 20 percent in the past, the shared savings rate can instead be adjusted downward by some fraction of 20 percent. An earnings basis using the *ex ante* values and a lower shared savings rate would yield a similar level of utility earnings as a higher shared savings rate applied to a lower *ex post* performance earning basis.

A second type of reduction is that estimated energy savings appear to decline over time. While one might expect that *ex ante* energy saving values would have an equal chance of being higher or lower, past studies indicate there is a downward trend in energy savings from measures over time. To-date, no *ex post* saving estimate for SDG&E or SoCalGas has been determined to be higher than the *ex ante* estimate. It is unclear if this phenomenon will continue, but if it is expected that *ex post* values will be less than *ex ante* values, on average, there might be an expectation that future *ex post* values will be less than current *ex ante* values. Over time, it might be expected that *ex ante* values would be more accurately measured so that future differences would be smaller than past differences. The shared savings rate can be reduced by a small amount to account for an expectation that future *ex post* estimates of energy savings will be lower than *ex ante* estimates.

3) Reduced Risk from Using Ex Ante Savings Values Compared to Ex Post

Once the shared savings rate has been adjusted for the expectation that *ex post* measured savings will be less than *ex ante* estimates, there is another adjustment – for the reduced **risk** of the use of known *ex ante* values versus unknown *ex post* values. Here the benefit is in the reduction of the variance in earnings. While it is equally likely *ex post* energy savings and NTG ratios could be higher or lower than the *ex ante* values (assuming an adjustment for expected reductions as described above), there is an added variability in earnings outcomes using *ex post* values while there is no variance associated with *ex ante* values. Number of installations and costs will still have a variance since they are measured *ex post*, but energy savings and NTG ratios would be fixed using *ex ante* values. This reduces the risk due to measurement error.

Measurement error is significant. In many studies, the sample sizes are so small that it is difficult to make inferences related to the entire population (i.e., wide confidence intervals). Site specific measurements can also be subject to significant measurement error depending upon when and how the measurements were taken since most measurements are undertaken over very short periods of time and then extrapolated to the entire earnings period. On the other hand, a significant number of independent measures should reduce the overall portfolio risk since some measures would have *ex post* measurements higher than the *ex ante* values and some would have measurements lower than the *ex ante* estimates (where *ex ante* values are corrected for expected reductions as described above). Given the large number of different measures, this variance is probably small in comparison to variance due to costs and installations. Statistically, if each measure was independent and had the same sample variance, the overall variance would be reduced by the square root of the number of independent measures. This would suggest only a small reduction in the shared savings rate in addition to the reduction for the downward trend in *ex post* values.

In conclusion, the analysis of supply-side earnings indicates a potential for increased earnings due to higher avoided costs than the analysis of five years ago and that a shared savings rate similar to the 12 percent adopted in D.07-09-043 is appropriate. However, if the RRIM mechanism is simplified to eliminate the minimum performance savings goal, there is less variability to the sharing mechanism which would suggest a value less than 12 percent. Also, if *ex ante* values are used there is a small reduction in the variance in earnings, which would suggest a shared savings percent below 12 percent. And finally, if the *ex post* savings are expected to be less due to the one-way nature of the change in NTG ratio and the trend in *ex post* energy savings realization rates; equivalent earnings to what would occur *ex post* can be achieved by adjusting the shared saving rate lower. These factors suggest something lower than 12 percent shared savings rate adopted in D.07-09-043. A rate of 7 percent, the value adopted by the Commission for the 2009, is reasonable given the level of supply side earnings as compared to the analysis completed in 2006 for the current 2010-2012 program cycle and the adjustments to simplify the RRIM mechanism and use *ex ante* values.

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Respectfully submitted

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