ATTACHMENT 1

LIST OF ABBREVIATIONS AND ACRONYMS

ATTACHMENT 1
Page 1
LIST OF ABBREVIATIONS AND ACRONYMS

A.	Application
ACEEE	American Council for an Energy-Efficient Economy
ACR	Assigned Commissioner's Ruling
AEAPs	Annual Earnings Assessment Proceedings
ALJ	Administrative Law Judge
C&S	Code and Standards
CCGT	Combined-cycle natural gas turbines
CE Council	Community Environmental Council
CFL	Compact Fluorescent Lamp
Ch.	Chapter
CLECA	California Large Energy Consumers Association
CPIM	Core Procurement Incentive Mechanism
CTs	Combustion turbines
D.	Decision
DOE	Department of Energy
DRA	Division of Ratepayer Advocates
DSM	Demand-side management
EM&V	Evaluation, Measurement and Verification
ERAM	Electric Revenue Adjustment Mechanism
E3	Energy and Environmental Economics
Exh.	Exhibit
fn.	footnote
GHG	Greenhouse Gases
GWh	gigawatt-hour
INC	Incentive

ATTACHMENT 1
Page 2
LIST OF ABBREVIATIONS AND ACRONYMS

kW	kilowatt
kWh	kilowatt-hour
LIEE	Low-income Energy Efficiency
mimeo.	mimeograph
MPS	Minimum Performance Standard
MTherm	million therm
MW	megawatt
MWh	megawatt-hour
non-LIEE	non-low income energy efficiency
NRDC	Natural Resources Defense Council
NTG	Net-to-Gross
p., pp.	Page, pages
PAC	Program Administrator Cost
PBR	performance-based ratemaking
PC	Participant Cost
PCN	Participant Cost-Net
PEB	Performance Earnings Basis
PG&E	Pacific Gas and Electric Company
PRC	Program Administrative Cost
R.	Rulemaking
RT	Reporter's Transcript
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SoCalGas	Southern California Gas Company
SPM	Standard Practice Manual
Stats.	Statute

ATTACHMENT 1
Page 3
LIST OF ABBREVIATIONS AND ACRONYMS

The Utilities	PG&E, SCE, SDG&E and SoCalGas, collectively
TRC	Total Resource Cost
TURN	The Utility Reform Network
UC	Utility Administrative Costs
UIC	Utility Increase Supply Cost
WEM	Women's Energy Matters

(END OF ATTACHMENT 1)

ATTACHMENT 2

Potential Shareholder Earnings/Penalties Under Proposed Risk/Reward Incentive Mechanisms
PEB Including All Portfolio Costs (2006-2008)
($ million, pre-tax, uncapped, on a statewide basis)

Recorded Savings Goals	IOUs (PG&E) 1]		IOUs (SDG&E) 2]		IOUs (SCE) 3]	
	PEB	Earnings	PEB	Earnings	PEB	Earnings
155%	$5,395	$1,350	$5,395	$1,080	$5,395	$1,079
150%	$5,149	$1,276	$5,149	$1,019	$5,149	$1,030
125%	$3,919	$907	$3,919	$711	$3,919	$784
110%	$3,181	$686	$3,181	$526	$3,181	$636
100%	$2,689	$538	$2,689	$403	$2,689	$538
90%	$2,197	$439	$2,197	$330	$2,197	$330
80%	$1,705	$341	$1,705	$256	$1,705	$171
70%	$1,213	$0	$1,213	$0	$1,213	$0
65%	$967	$0	$967	$0	$967	$0
60%	$721	$0	$721	($8)	$721	($8)
55%	$475	$0	$475	($26)	$475	($26)
50%	$228	$0	$228	($44)	$228	($44)
45%	($18)	$0	($18)	($131)	($18)	($131)
40%	($264)	$0	($264)	($278)	($264)	($278)
35%	($510)	($369)	($510)	($510)	($510)	($510)
30%	($756)	($627)	($756)	($756)	($756)	($756)
25%	($1,002)	($890)	($1,002)	($1,002)	($1,002)	($1,002)
20%	($1,248)	($1,157)	($1,248)	($1,248)	($1,248)	($1,248)
15%	($1,494)	($1,425)	($1,494)	($1,494)	($1,494)	($1,494)
10%	($1,740)	($1,693)	($1,740)	($1,740)	($1,740)	($1,740)
5%	($1,986)	($1,962)	($1,986)	($1,986)	($1,986)	($1,986)
0%	($2,232)	($2,232)	($2,232)	($2,232)	($2,232)	($2,232)

Recorded Savings Goals	NRDC 4]		DRA 5]		TURN 6]		CE Council 7]	
	PEB	Earnings	PEB	Earnings	PEB	Earnings	PEB	Earnings
155%	$5,395	$647	$5,395	$189	$5,395	$162	$5,395	$189
150%	$5,149	$618	$5,149	$180	$5,149	$154	$5,149	$129
125%	$3,919	$470	$3,919	$118	$3,919	$118	$3,919	$98
110%	$3,181	$382	$3,181	$95	$3,181	$64	$3,181	$66
100%	$2,689	$323	$2,689	$81	$2,689	$54	$2,689	$54
90%	$2,197	$132	$2,197	$33	$2,197	$0	$2,197	$0
80%	$1,705	$0	$1,705	$0	$1,705	($17)	$1,705	$0
70%	$1,213	($52)	$1,213	($26)	$1,213	($52)	$1,213	$0
65%	$967	($61)	$967	($30)	$967	($61)	$967	$0
60%	$721	($77)	$721	($43)	$721	N/P	$721	$0
55%	$475	($182)	$475	($65)	$475	N/P	$475	$0
50%	$228	($217)	$228	($87)	$228	N/P	$228	$0
45%	($18)	($321)	($18)	($225)	($18)	N/P	($18)	($135)
40%	($264)	($486)	($264)	($382)	($264)	N/P	($264)	($135)
35%	($510)	($735)	($510)	($622)	($510)	N/P	($510)	($135)
30%	($756)	($997)	($756)	($877)	($756)	N/P	($756)	($135)
25%	($1,002)	($1,262)	($1,002)	($1,132)	($1,002)	N/P	($1,002)	($135)
20%	($1,248)	($1,525)	($1,248)	($1,386)	($1,248)	N/P	($1,248)	($135)
15%	($1,494)	($1,788)	($1,494)	($1,641)	($1,494)	N/P	($1,494)	($135)
10%	($1,740)	($2,050)	($1,740)	($1,895)	($1,740)	N/P	($1,740)	($135)
5%	($1,986)	($2,315)	($1,986)	($2,150)	($1,986)	N/P	($1,986)	($135)
0%	($2,232)	($2,579)	($2,232)	($2,405)	($2,232)	N/P	($2,232)	($135)

Shaded areas signify where earnings/penalty cap(s) would start under the various proposals.
NOTE: The PEB numbers (or "net benefits") at the various levels of % goal achievement are derived by holding the costs fixed, and verifying the benefits in proportion to the assumed savings percentage. For example, at 90% of savings, the benefits are calculated as 90% of the level at 100% of savings, and the costs are the same as at 100% of savings. Similarly, at 110% of savings, the benefits are calculated as 110% of the level at 100% of savings, and the costs are the same as at 100% of savings.

Footnotes:

1] PG&E proposes that for savings above 100% of savings goals, earnings are the sum of 20% of PEB at 100% of savings plus 30% of the additional PEB above 100% of savings. PG&E caps earnings at 110% of savings goals for all four utilities. PG&E's penalty numbers are based on negative net benefits calculated using the PAC test for all four utilities combined, with no cap on penalties.

2] SDG&E/SCG propose that for savings above 100% of savings goals, earnings are the sum of 15% of PEB at 100% plus 25% of the additional PEB above 100%. SDG&E/SCG proposal's implied earnings cap based on a fixed budget is near 140% of savings goals. SDG&E/SCG cap on penalties is 25% of resource programs budget, or around $520 million. At the implied cap under SDG&E/SCG's proposal, PG&E's earnings would be $362 million, and its capped penalties would be $244 million; SCE's earnings would be $377 million, and its capped penalties would be $154 million; SDG&E's earnings would be $100 million, and its penalties would be $70 million; and SCG's earnings would be $56 million, and its penalties would be $46 million.
3] SCE's cap on penalties is equal to cap on earnings, or $714 million. Under SCE's mechanism, PG&E's earnings would reach their cap at 120% of savings goals ($290 million) and its penalties would reach their cap at 30% of savings goals ($290 million); SCE's earnings would reach their cap at 110% of savings ($267 million) and its penalties would reach their cap at 25% of savings ($267 million); SDG&E's earnings would reach their cap at 140% of savings ($102 million) and its penalties would reach their cap at 25% of savings ($102 million); and SCG's earnings would reach their cap at 140% of savings ($55 million) and its penalties would reach their cap at 45% of savings ($55 million).
4] NRDC's penalty cap is 15% of budget if programs are providing net benefits ($277 million); if negative net benefits, penalty cap is at total cost of programs ($1.84 billion). Mechanism contains cost-effectiveness guarantee which is added to the per unit penalty. NRDC's cap on earnings is 30% of budget ($553 million). Under NRDC's proposal, PG&E's earnings are capped at $257 million, their per-unit penalty cap is $129 million and the total penalty cap (with cost-effectiveness guarantee) is $858 million; SCE's earnings are capped at $173 million, their per-unit penalty cap is $86 million and the total penalty cap (with cost-effectiveness guarantee) is $575 million; SDG&E's earnings are capped at $74 million, their per-unit penalty cap is $37 million and the total penalty cap (with cost-effectiveness guarantee) is $246 million; and SCG's earnings are capped at $49 million, their per-unit penalty cap is $25 million and the total penalty cap (with cost-effectiveness guarantee) is $164 million. All dollar figure caps are as provided under NRDC's proposal of "what counts" as costs for the purpose of the incentive mechanism (i.e., all costs except for CPUC EM&V).
5] DRA's cap on earnings is 8% of budget or actual program expenditures, whichever is smaller for each utility ($166 million total). Mechanism contains cost-effectiveness guarantee which is added to the per unit penalty. DRA's penalty cap is same as cap on earnings (8% of budget or actual program expenditures, up to $166 million total). Under DRA's proposal, PG&E's earnings would reach their cap above 150% of savings ($75 million) and reach their penalty cap at 40% of savings ($75 million); SCE's earnings would reach their cap at 130% of savings ($54 million) and reach their penalty cap at 35% of savings ($54 million); SDG&E's earnings would reach their cap above 150% of savings ($22 million) and reach their penalty cap at 40% of savings ($22 million); and SCG's earnings would reach their cap above 150% of savings ($15 million) and reach their penalty cap at 55% of savings ($15 million).
6] TURN's total penalty cap is equal to expected incentive payment at 100% of target goals, or $54 million. TURN's cap on total earnings is $104 million (5% of authorized portfolio budget). Under TURN's proposal, PG&E's earnings would reach their cap at 125% of savings ($47 million); SCE's earnings would reach their cap at 120% of savings ($34 million); SDG&E's earnings would reach their cap at 130% of savings ($14 million); and SCG's earnings would reach their cap at 150% of savings ($9 million). Uncapped penalty figures below 65% of savings were not provided ("N/P").
7] CE Council's cap on earnings is $134 million, or 5% of net benefits at 100% of savings goals, imposed on a statewide level. Under this mechanism, Tier 2 earnings levels cannot be reached as the cap is reached prior to Tier 2 earnings go into effect. CE Council's penalty cap is equal to cap on earnings, imposed in full at 45% of savings.

(END OF ATTACHMENT 2)

SUMMARY OF RISK-REWARD PROPOSALS - 15 September 2006

Shared-Savings Mechanism *Reward/Penalty Thresholds*	**Sempra**	**PG&E**	**SCE**	
Earnings Start (MPS)	80% of CPUC target Savings. Average of kW, Kwh, Therms with no individual metric below 70%; For single gas utility MPS for therms must be 70%.	Earnings start when 1) all three of annual MW, GWH, and MMThm accomplishments reach 70% of target, and 2) the average of the three % computed in step 1 (average % savings) is at or above 80%	>80% of Cumulative Commission Goals in each year (75% for 2006). Simple average of achievement percentages between actuals vs. Commission goals for each metric (kW, kWh).	
Deadband (no rewards and no earnings)	PEB positive and below 80% CPUC target	Average % savings of MW, GWh, and MMThm is at or above 40% and below 80%.	0-80% of Commission Goals. (75% for 2006)	
Penalties Start	Negative PEB	If average % savings is below 40%	PEB < 0 (portfolio c-e guarantee)	

SUMMARY OF RISK-REWARD PROPOSALS - 6/21/06

Shared-Savings Mechanism *Reward/Penalty Thresholds*	**Council**	**NRDC**	**TURN**	**DRA**
Earnings Start (MPS)	100% under our preferred mechanism, 95% under straw proposal mechanism, with "flexibility mechanism" allowing 90% for each savings goal, as long as average reaches the required MPS level	Verified levels for each savings metric (GWh, MW, Mtherms) ≥85% of adopted goals. *Cumulative* goals used for MPS. MPS must be met for each metric to be eligible for any earnings (and to qualify for Tier 2 reward, see below).	Verified levels for each savings metric (GWh, MW, Mtherms) ≥100% of adopted goals. *Cumulative* goals used for MPS. MPS must be met for each metric to be eligible for any earnings (and to qualify for Tier 2 reward, see below).	Verified levels for each savings metric (GWh, MW, Mtherms) ≥90% of adopted goals. *Cumulative* goals used for MPS. MPS must be met for each metric to be eligible for any earnings (and to qualify for Tier 2 reward, see below).
Deadband (no rewards and no earnings)	50% (inclusive) to 100% (non-inclusive)	≥70% and <85% of savings goals	≥85% and <100% of savings goals	≥75% and <90% of savings goals
Penalties Start	below 50% of the savings goals	PEB < 0 or <70% of savings goals (applied separately to each savings metric)	PEB < 0 or <85% of savings goals (applied separately to each savings metric)	PEB < 0 or <75% of savings goals (applied separately to each savings metric)

SUMMARY OF RISK-REWARD INCENTIVE PROPOSALS

Shared-Savings Mechanism

Magnitude of Potential Earnings	**Sempra**	**PG&E**	**SCE**
Earnings Rate/Curve (Once MPS met, rate is applied to PEB)	Tiered Approach: Tier 1 (80% to 100%): 15%; SCG Teir 1 (70% to 100%): 15%; Tier 2 (over 100%): 25% on incremental Portion	If average % savings is at least over 80% and at or below 100%, earnings are 20% of PEB. If average % savings are over 100%, earnings are the sum of 20% of the PEB at 100% savings plus 30% of the additional PEB above 100% savings.	Variable rate, based on savings: 80-90%: 10% (75%-90% for 2006: 10%) 90-100%: 15% 100+%: 20%
Cap on Earnings?	Earnings Limited by approved budget. Estimated Max about 140% of target	Earnings not to exceed earnings at 110% of savings	Yes--at 110% of forecasted net benefits and resulting earnings.
Earnings at 100% of Savings Goals ($millions, 2006-2008 cycle)	$51.1 Million (SDG&E) $26.2 Million (SCG)	Total 2006-2008 earnings estimated at 100% of savings targets: $222.5 million (before-tax)	$236.00 (SCE)
Earnings at 100% of PEB ($millions, 2006-2008 cycle)	$65.8 Million (SDG&E) $24.8 Million (SCG)--Based on IOU forecast	Total 2006-2008 earnings estimated at 100% of savings targets: $222.5 million (before-tax)	$243.00 (SCE)
Maximum Earnings ($millions, 2006-2008 cycle)	At 140% of target $107 Million (SDG&E) $62 Million (SCG)	Maximum 2006-2008 earnings estimated to be: $283.4 million (before-tax)	$267.00 (SCE)

SUMMARY OF RISK-REWARD INCENTIVE PROPOSALS

Shared-Savings Mechanism

Magnitude of Potential Earnings	**Council**	**NRDC**	**TURN**	**DRA**
Earnings Rate/Curve (Once MPS met, rate is applied to PEB)	Variable rate, based on savings: Tier 1 (100-150%): 2% of net benefits; Tier 2 (151-200%): 3% of net benefits; kWh kicker: 2.5% of net benefits above 125% and 3.5% above 150%	Variable rate, based on savings, **to provide pre-tax earnings**: Tier I (85%-100% savings goal): **6% rate** Tier 2 (>100% savings goal): **12% rate**	Variable rate, based on savings, **to provide pre-tax earnings**: Tier I (100-120% savings goal): 2**% rate** Tier 2 (>=120% savings goal): 2.5**% rate** Tier 2 kicker (kW savings > 125% savings goals): **3.0% rate**	Variable rate, based on savings, **to provide pre-tax earnings**: Tier I (90-100% savings goal): 1.5**% rate** Tier 2 (>=100% savings goal): 3**% rate** Tier 2 kicker (kWh/therm savings >= 100%; kW savings > 125% savings goals): **3.5% rate**
Cap on Earnings?	Yes, at $134 million (~5% of net benefits)	Yes--at **30%** of authorized budget (about **148%** of expected PEB avrg. across IOUs)	Yes--at 5**%** of authorized budget or actual expenditures, whichever is smaller ($1046M aggregate)	Yes--at 8**%** of authorized budget or actual expenditures, whichever is smaller ($166M aggregate)
Earnings at 100% of Savings Goals ($millions, 2006-2008 cycle)	PG&E: $21.2; SCE: $24.0; SDG&E: $6.2; SCG: $2.3; Total: $54.2	**100% Savings Goals** **$127** (PG&E) **$144** (SCE) **$36** (SDG&E) **$16** (SCG) **$323** (aggregate)	100% Savings Goals **$21.2** (PG&E) **$24.0** (SCE) **$5.9** (SDG&E) **$2.7** (SCG) **$54** (aggregate)	100% Savings Goals **$31.7** (PG&E) **$36.0** (SCE) **$8.9** (SDG&E) **$4.0** (SCG) **$80.6** (aggregate)
Earnings at 100% of PEB ($millions, 2006-2008 cycle)	PG&E: $21.2; SCE: $24.0; SDG&E: $6.2; SCG: $2.3; Total: $54.2	**100% PEB Goals** **$147** (PG&E) **$138** (SCE) **$49** (SDG&E) **$25** (SCG) **$360** (aggregate)	100% SPEB **$31.7** (PG&E) **$36.0** (SCE) **$8.9** (SDG&E) **$4.0** (SCG) **$80.76** (aggregate)	100% PEB **$36.9** (PG&E) **$40.2** (SCE) **$14.3** (SDG&E) **$6.3** (SCG) **$97.8** (aggregate)
Maximum Earnings ($millions, 2006-2008 cycle)	$134 million (~5% of net benefits)	$257 (PG&E) $173 (SCE) $74 (SDG&E) $49 (SCG) **$553 (aggregate)**	$47.0 (PG&E) $33.9 (SCE) $13.9 (SDG&E) $8.9 (SCG) **$104.0 (aggregate)**	$75.4 (PG&E) $54.2 (SCE) $22.2 (SDG&E) $14.6 (SCG) **$166.4 (aggregate)**

SUMMARY OF RISK-REWARD PROPOSALS

Shared-Savings Mechanism *Magnitude of Potential Penalties*	**Sempra**	**PG&E**	**SCE**
Penalty Rate/Curve	Cost Effectiveness Guarantee up to 25% of resource program budget	If average % savings is below 40%, PG&E would reimburse ratepayers for any difference between revenues from ratepayers and Program Administrator Costs PG&E incurred.	100% of neg net benefits
Cap on Penalties?	25% of Resource Programs Budget	No cap on penalty	Yes--equal to forecasted cap on earnings for PY
Est. Penalty Just Below MPS (or Tier Level, for all metrics at same % below goal)	$0	Just below the lower point on PG&E's proposed dead band (i.e. 40% of average % savings), PAC net benefits are estimated to be $24.2 million (before tax). This is the amount that would be due to ratepayers under PG&E's performance guarantee.	$0
Est. Maximum Penalty ($ millions, 2006-2008 cycle)	$59 Million (SDG&E) $36 million (SCG)	Should PG&E not produce any savings during 2006-2008, under its proposal the penalty would be $920 million (before taxes).	$267.00 (SCE)

Shared-Savings Mechanism *Magnitude of Potential Penalties*	**Council**	**NRDC**	**TURN**
Penalty Rate/Curve	If IOU falls below 50% of the savings goals, full penalty is assessed immediately	100% of neg net benefits and Tier 1: 55-70%: **2c**/kWh, **20c**/therm, **$10**/kW Tier 2: 0-55%: **4c**/kWh, **40c**/therm, **$20**/kW for each annual unit below the target (applied separately to each metric)	**lower** / **upper** / **per kwh** / **per therm** / **per kw** 70% / 85% / $0.01 / $0.10 / $ 5 0% / 70% / $0.02 / $0.20 / $ 10
Cap on Penalties?	Yes, capped at $134 million - equivalent to the cap on rewards	Yes--capped at **15%** of budget (**$277M** for all IOUs) if programs still providing net benefits. Capped at total cost of programs if neg. net benefits.	yes, capped at incentive payment at 100% of target or $54 M
Est. Penalty Just Below MPS (or Tier Level, for all metrics at same % below goal)	At 49% of the savings goals, $134 million penalty is assessed	at 69%: **$52** million (aggregate, all IOUs) at 54%: **$156** million (aggregate, all IOUs)	at 84% of savings, penalty totals $27.7M
Est. Maximum Penalty ($ millions, 2006-2008 cycle)	$134 million, equivalent to the cap on rewards	**$277M** if portfolio still producing net benefits. If not, max is **$1.84B** cost of portfolio.	$54 M, at 59% of % target

SUMMARY OF RISK-REWARD PROPOSALS

Shared-Savings Mechanism *Magnitude of Potential Penalties*	**Sempra**	**PG&E**	**SCE**
Penalty Rate/Curve	Cost Effectiveness Guarantee up to 25% of resource program budget	If average % savings is below 40%, PG&E would reimburse ratepayers for any difference between revenues from ratepayers and Program Administrator Costs PG&E incurred.	100% of neg net benefits
Cap on Penalties?	25% of Resource Programs Budget	No cap on penalty	Yes--equal to forecasted cap on earnings for PY
Est. Penalty Just Below MPS (or Tier Level, for all metrics at same % below goal)	$0	Just below the lower point on PG&E's proposed dead band (i.e. 40% of average % savings), PAC net benefits are estimated to be $24.2 million (before tax). This is the amount that would be due to ratepayers under PG&E's performance guarantee.	$0
Est. Maximum Penalty ($ millions, 2006-2008 cycle)	$59 Million (SDG&E) $36 million (SCG)	Should PG&E not produce any savings during 2006-2008, under its proposal the penalty would be $920 million (before taxes).	$267.00 (SCE)

Shared-Savings Mechanism *Magnitude of Potential Penalties*	**Council**	**NRDC**	**TURN**	**DRA**
Penalty Rate/Curve	If IOU falls below 50% of the savings goals, full penalty is assessed immediately	100% of neg net benefits and Tier 1: 55-70%: **2c**/kWh, **20c**/therm, **$10**/kW Tier 2: 0-55%: **4c**/kWh, **40c**/therm, **$20**/kW for each annual unit below the target (applied separately to each metric)	**lower / upper / per kwh / per therm / per kw** 70% / 85% / $0.01 / $0.10 / $ 5 0% / 70% / $0.02 / $0.20 / $ 10	100% of neg net benefits and Tier 1: 50-75%: 1**c**/kWh, 1**0c**/therm, **$5**/kW Tier 2: 0-50%: 2**c**/kWh, 2**0c**/therm, **$10**/kW for each annual unit below the target (applied separately to each metric)
Cap on Penalties?	Yes, capped at $134 million - equivalent to the cap on rewards	Yes--capped at **15%** of budget (**$277M** for all IOUs) if programs still providing net benefits. Capped at total cost of programs if neg. net benefits.	yes, capped at incentive payment at 100% of target or $54 M	Yes--capped at 8**%** of budget or actual program expenditures, whichever is smaller (**$166M** for all IOUs).
Est. Penalty Just Below MPS (or Tier Level, for all metrics at same % below goal)	At 49% of the savings goals, $134 million penalty is assessed	at 69%: **$52** million (aggregate, all IOUs) at 54%: **$156** million (aggregate, all IOUs)	at 84% of savings, penalty totals $27.7M	at 74%: **$22.5** million (aggregate, all IOUs) at 49%: **$88.2** million (aggregate, all IOUs)
Est. Maximum Penalty ($ millions, 2006-2008 cycle)	$134 million, equivalent to the cap on rewards	**$277M** if portfolio still producing net benefits. If not, max is **$1.84B** cost of portfolio.	$54 M, at 59% of % target	$75.4 (PG&E) $54.2 (SCE) $22.2 (SDG&E) $14.6 (SCG) **$166.4 (aggregate)**

SUMMARY OF RISK-REWARD PROPOSALS				
Shared-Savings Mechanism *What Counts?*	**Sempra**	**PG&E**	**SCE**	
Program costs/savings incl. In PEB	Resource Programs (as listed in Filing)	All program costs are included in net benefit (PEB) calculations except the CPUC EM&V costs.	Resource programs only. (in future, measurable savings can be attrib. To non-resource programs, these would be counted)	
Treatment of EM&V costs in PEB	Includes M&E controlled by Utility	EM&V costs are divided between those allocated to the utility and the CPUC (Energy Division). Costs allocated to the CPUC/ED not included in PEB	included	
Treatment of C&S savings/costs	Savings Excluded Costs included	Cost and savings of C&S programs included in the year in which they occur.	Per Commission's direction, includes pre-2006 C&S savings towards MPS. Future effects of Post 2005 C&S would count toward MPS.	
--Treatment of LIEE	Excluded in costs and benefits	LIEE savings to be included in the calculation of savings (MW, GWh, MMThm) accomplishments. Neither costs nor benefits included in PEB for determining earnings/penalties	savings count towards MPS	

Shared-Savings Mechanism *What Counts?*	**Council**	**NRDC**	**TURN**	**DRA**
Program costs/savings incl. In PEB	Include total portfolio costs (with EM&V) for all resource programs.	Include total portfolio costs and benefits of all programs (resource and non-resource), minus CPUC EM&V costs.	PEB costs include total portfolio costs including EM&V costs. PEB benefits include verified savings from resource programs.	PEB costs include total portfolio costs including EM&V costs. PEB benefits include verified savings from resource programs.
Treatment of EM&V costs in PEB	Included	Included except CPUC EM&V	Included	Included
Treatment of C&S savings/costs	50% of pre-2006 C&S savings that count towards goals will count towards MPS, but not towards PEB/earnings.	50% of pre-2006 C&S savings that count towards goals will count towards MPS, but not towards PEB/earnings.	50% of pre-2006 C&S savings that count towards goals will count towards MPS, but not towards PEB/earnings.	50% of pre-2006 C&S savings that count towards goals will count towards MPS, but not towards PEB/earnings.
--Treatment of LIEE	Savings count towards MPS, but not towards PEB/earnings.	Savings count towards MPS, but not towards PEB/earnings.	Savings count towards MPS, but not towards PEB/earnings.	Savings count towards MPS, but not towards PEB/earnings.

SUMMARY OF RISK-REWARD PROPOSALS

Other Issues	Sempra	PG&E	SCE	NRDC	TURN	DRA
Treatment of Non-Resource Programs For Current/Future Planning Cycles	No Mechanism	PG&E proposes that Non-Resource program costs (C&S, ET, Ed&Traning, SW M&O) be included in PEB calculations in the year incurred.	No proposal.	Performance adder mechanisms (award of 5% of expenditures for exceeding performance threshold) to reward superior performance for ET, E&T, M&O; balanced with including costs of non-resource programs in PEB.	Do not support including savings from non-resource programs within the PEB. Do not suport a separate incentive mechanism (e.g. performance adder) for non-resource programs.	Does not support including savings from non-resource programs within the PEB. Does not suport a separate incentive mechanism (e.g. performance adder) for non-resource programs.
				C&S should not be treated as non-resource program (once savings achieved through C&S beginning in 06-08 are realized in future cycles, they should be included in the PEB).		
Free Rider (NTG) Adjustments	In the TRC, a NTG should be applied to benefits and applicable participant costs.	In the TRC, a NTG should be applied to benefits and applicable participant costs to account for benefits and costs not due to the program.	Apply to benefits and correspond. Incremental measure cost (refers to SPM addendum)	Incentives paid to freeriders should be included as costs, but the free-riders own out-of-pocket costs should not be included in costs. That is, NTG adjustments should be applied to participants costs, but not to the utility cost of incentive payments.	Incentives paid to freeriders should be included as costs, but the free-riders own out-of-pocket costs should not be included in costs. That is, NTG adjustments should be applied to participant costs, but not to the utility administration costs or incentive payments.	Incentives paid to freeriders should be included as costs, but the free-riders own out-of-pocket costs should not be included in costs. That is, NTG adjustments should be applied to participant costs, but not to the utility administration costs or incentive payments.
	Apply to benefits and corresponding incrmental measure costs					
Treatment of shareholder incentives in cost-effectiveness tests	Shareholder incentive costs should be included as a cost in TRC and PAC tests.	Shareholder incentive costs should be included as a cost in final TRC and PAC test calculations	SPM tests exclude shareholder incentives. Only include them on projected basis for evaluation of future program plans.	Should be included.	Should be included.	Should be included.

Source: Joint Summary Documents on Energy Efficiency Shareholder Risk/Reward Incentive Mechanism Proposals, September 15, 2006.

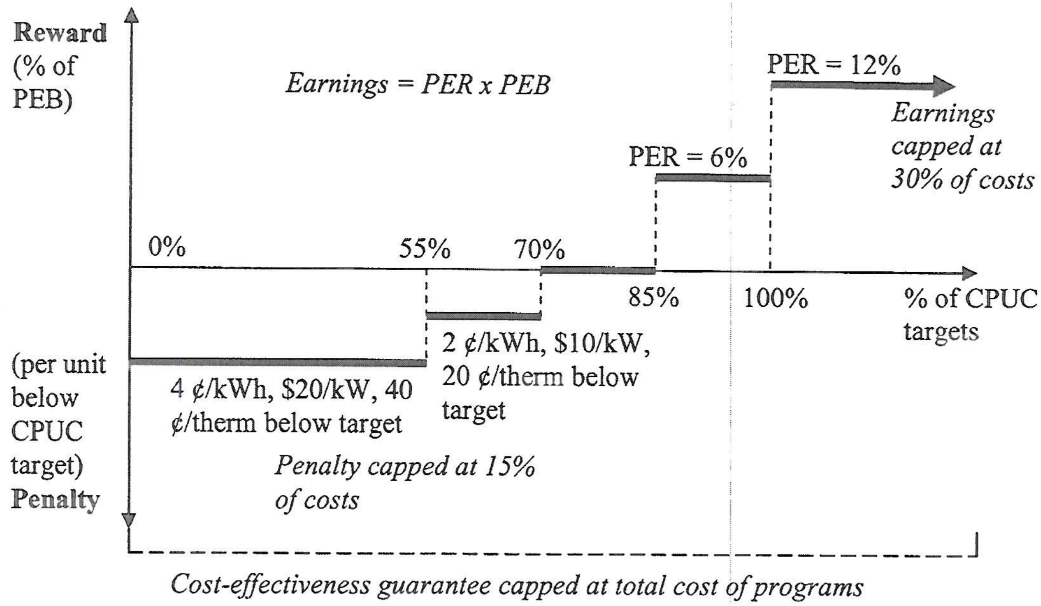
(END OF ATTACHMENT 3)

ATTACHMENT 4

GRAPHICAL ILLUSTRATIONS OF PROPOSED EARNINGS/PENALTY CURVES

Figure 1

NRDC Proposed Incentive Mechanism Earnings/Penalty Curve



PEB = Performance Earnings Basis (net benefits[1])

PER = Performance Earnings Rate

[1] Net benefits are defined as the weighted average of the total resource cost (TRC) test (2/3 weight) and the program administrator cost (PAC) test (1/3 weight).

Figure 2

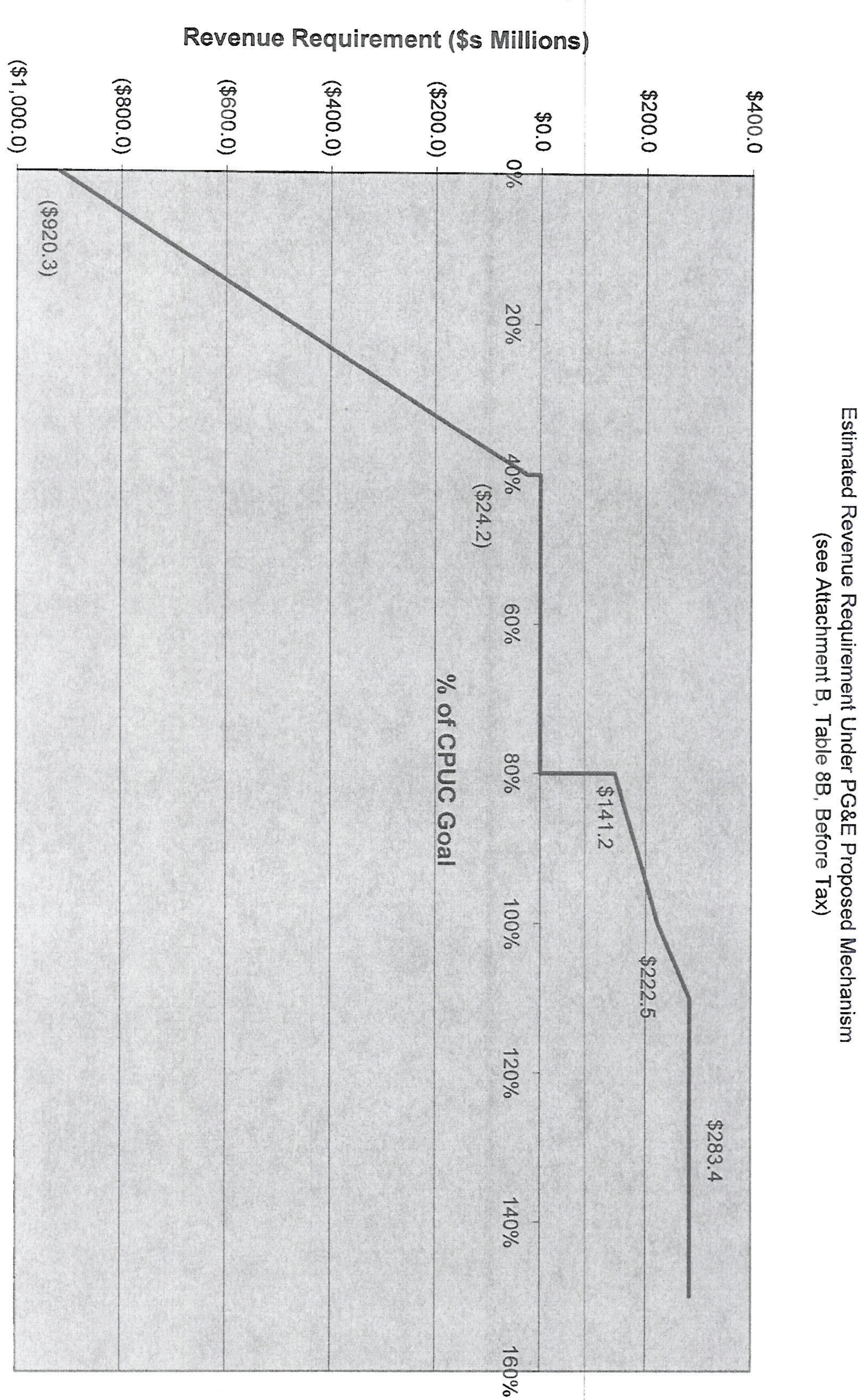

Estimated Revenue Requirement Under PG&E Proposed Mechanism
(see Attachment B, Table 8B, Before Tax)
Revenue Requirement ($s Millions)
$400.0
$200.0
$0.0
($200.0)
($400.0)
($600.0)
($800.0)
($1,000.0)
0%
20%
40%
60%
80%
100%
120%
140%
160%
% of CPUC Goal
($920.3)
($24.2)
$141.2
$222.5
$283.4

Figure 3

SCE's proposed tiered earnings rate

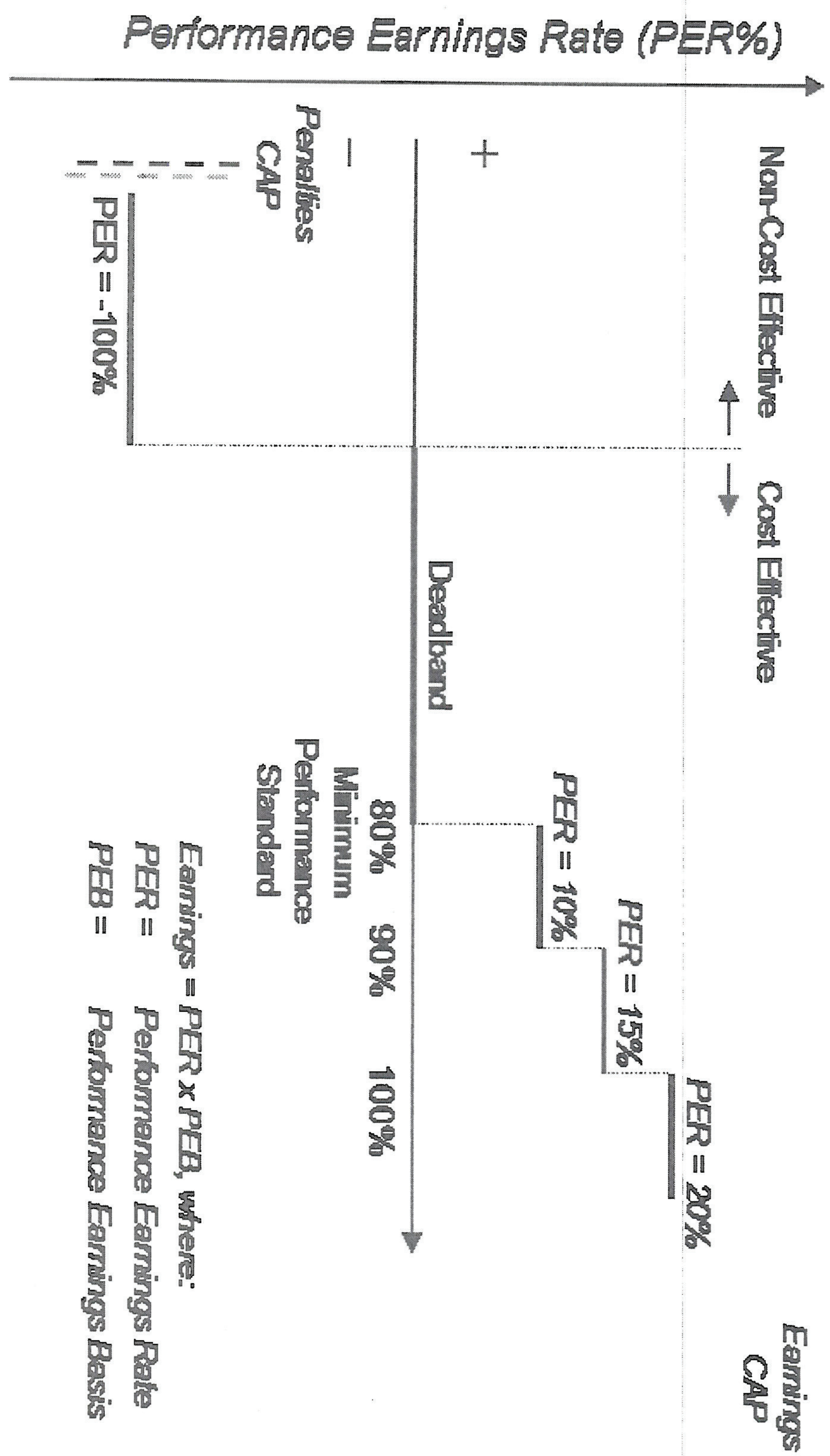
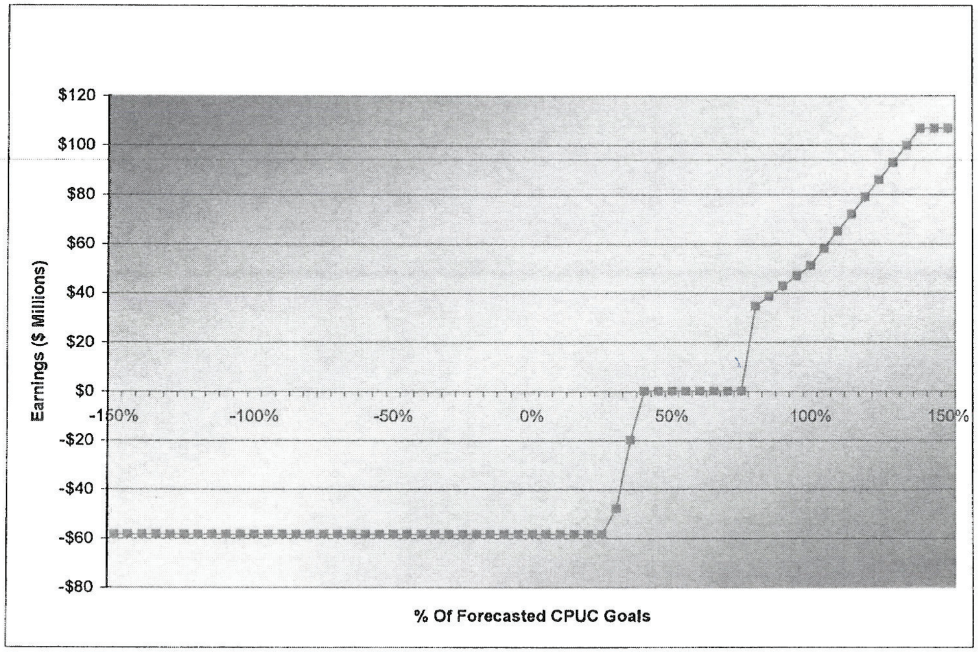


Figure 4

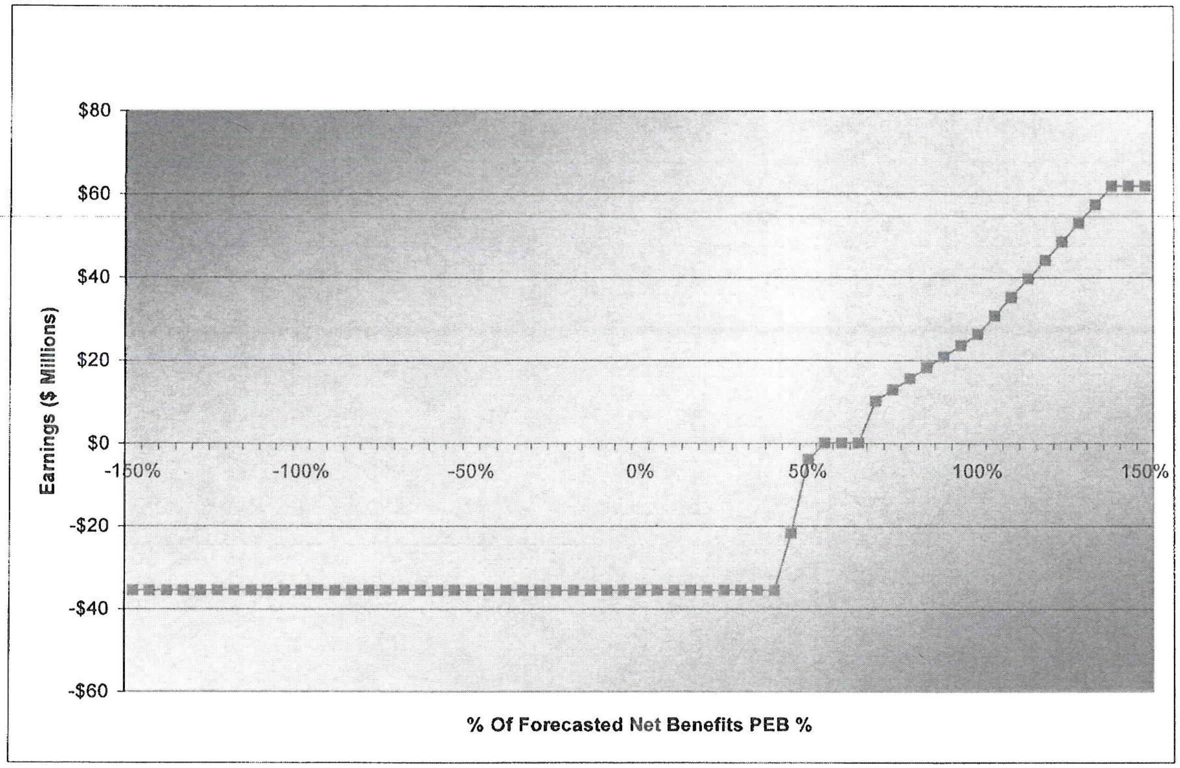
TABLE 8b GRAPHIC: RECOMMENDED SHAREHOLDER INCENTIVE MECHANISM APPLIED TO PROPOSED SDG&E RESOURCE PORTFOLIO - CPUC PEB GOALS



Assumptions	
PER% above MPS	15%
PER above 100% CPUC Goal	25%
Penalty Rate	25%
PEB @ 100%	$341.0
Earnings @ Target	$51
MPS	80%

Figure 5

TABLE 8B GRAPHIC: RECOMMENDED SHAREHOLDER INCENTIVE MECHANISM APPLIED TO PROPOSED SCG RESOURCE PORTFOLIO - CPUC PEB GOALS



Assumptions	
PER% above MPS	15%
PER above 100% of CPUC Goal	25%
Penalty Rate	25%
PEB @ 100%	$174.6
Earnings @ Target	$26.2
MPS	70%

Figure 6

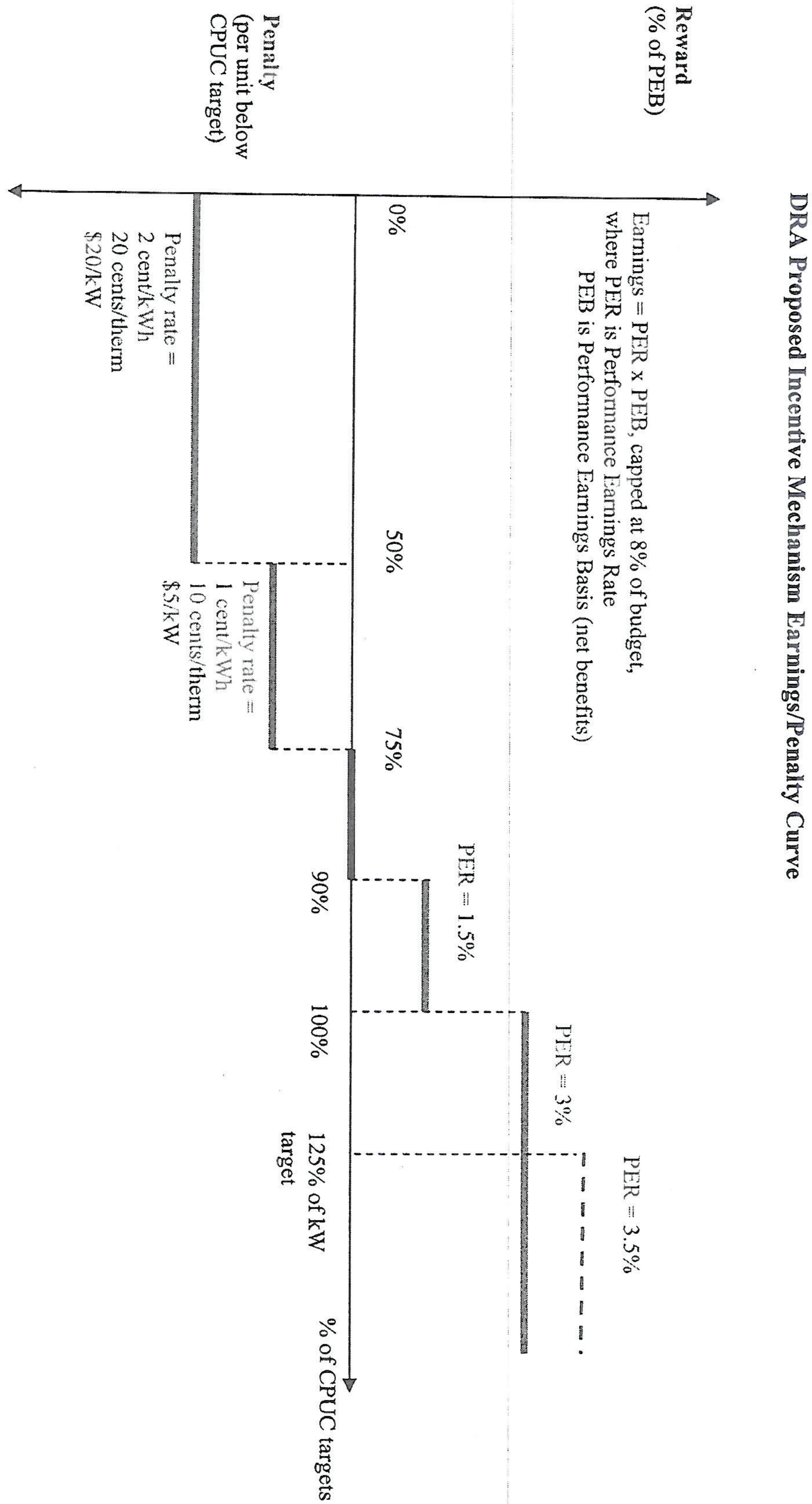

DRA Proposed Incentive Mechanism Earnings/Penalty Curve
Reward
(% of PEB)
Earnings = PER x PEB, capped at 8% of budget,
where PER is Performance Earnings Rate
PEB is Performance Earnings Basis (net benefits)
Penalty
(per unit below
CPUC target)
0%
50%
75%
90%
100%
125% of kW
target
% of CPUC targets
PER = 1.5%
PER = 3%
PER = 3.5%
Penalty rate =
2 cent/kWh
20 cents/therm
$20/kW
Penalty rate =
1 cent/kWh
10 cents/therm
$5/kW

Figure 7

Illustration of TURN 9-8-06 FINAL
Proposed Energy Efficiency
Performance Incentive Mechanism

Percent of Commission assigned savings

Tier II A incentive peak demand kicker
- Achieving > 125% of peak demand savings target
- Performance earnings rate = 3.0%
- Administrator's reward capped at 5% of authorized budget ($104M)

125%

Tier II incentive
- Simultaneously achieving > 120% of assigned savings target(s)
- Performance earnings rate = 2.5%
- Administrator's reward capped at 5% of authorized budget ($104M)
- At 100% of projected earnings basis, total incentives = $86 M

120%

Tier I incentive
- Simultaneously achieving >= 100% of assigned savings target(s)
- Performance earnings rate = 2.0%
- At 100% of projected earnings basis, total incentives = $ 54 M

100%

Deadband
- Between 85 to 100% of assigned savings targets, no reward or penalty

85%

Tier I penalty
- When realized savings fall below 85% of targets, administrator is penalized at 1¢/kWh, 10¢/therm, and $5/kW for each annual kWh, annual therm and kW below the assigned target
- At 84% of kWh, therm and kW targets, total penalty = $13 M

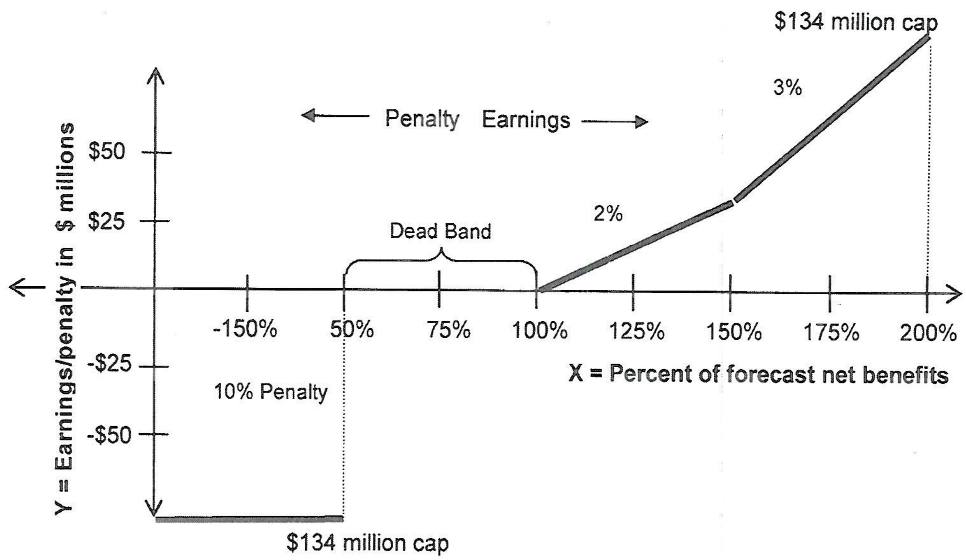
70%

Tier II penalty
- When realized savings fall below 70% of targets, administrator is penalized at 2¢/kWh, 20¢/therm, and $10/kW for each annual kWh, annual therm and kW below the assigned target
- At 69% of kWh, therm and kW targets, total penalty = $52 M
- Penalty capped at 2.5% of authorized budget ($54M)

0%

Figure 8

Community Environmental Council Potential earnings and penalty for utility portfolios (based on Fig. 1-B from D.94-10-059).



(END OF ATTACHMENT 4)

ATTACHMENT 5

SIMPLIFIED NUMERICAL EXAMPLES OF PROPOSED PAYOUT APPROACHES

We present numerical examples to illustrate the three different payout approaches to earnings in this attachment. We make a number of simplifying assumptions to keep the calculations simple.

In particular, we assume that there is a single savings metric (and associated savings goal) for each utility, and we express that goal as a dollar value, rather than as MW, GWh or MTherm units. More specifically, the dollar value for the savings goal is the product of the forecasted or "*ex ante*" number of units installed times the *ex ante* per-unit savings. This enables us to simply compare the dollar value of the verified savings calculated for each claim against the dollar value of the savings goal to determine if the MPS is met.

To calculate earnings once the MPS is met, we also need to calculate the performance earnings basis (PEB) under each claim. As discussed in this decision, the PEB is a metric that expresses the "net benefits" of the portfolio, and therefore reflects not only the achieved savings but also the costs to achieve those savings. Based on the results of Energy Division's Verification Reports, the PEB will be updated in each interim claim to reflect both verified installations and verified program costs. However, to keep our calculations (and assumptions) simple, we assume that the PEB does not consider costs, and is only updated to reflect the verified installations. Therefore, the verified savings calculated in each earnings claim is equivalent to the PEB in our numerical examples. To further simplify our calculations, we assume a 10% shared-savings rate. That is, if the MPS is met for the earnings claim, the utility is awarded 10% of the

PEB calculated for that claim. Similarly, if the PEB falls below the deadband, the penalties are calculated as 10% of the PEB.

A. Example 1: Verified (*Ex Post)* PEB is Above the MPS

In the following sections we compare the three proposed approaches to earnings payout under a scenario where the verified *ex post* results in the final true-up claim produce a PEB is *above* the required minimum performance threshold (MPS).

1. Single-Year Basis

Under the Single-Year Basis approach (proposed by PG&E), verified achievements for a single program year are compared to the savings goal for that year to determine whether performance is within, below or higher than the deadband. The associated earnings or penalties for each interim claim are also calculated based on the results for that single year. Accordingly, once the interim claim has been made, achievements of that particular program year are not considered in the calculation of the remaining interim claims, although they would count in the fourth true-up claim for the entire program cycle.

This approach is illustrated in Example 1 presented in this attachment. For Claim 1, the eight units installed during 2006 (valued at *ex ante* per-unit savings of $10) produce verified savings of $80. The savings goal for 2006 is $100.[1] Since the utility has achieved only 80% of the savings goal, it has not met the 85% MPS. Therefore, the utility is not eligible for any earnings in Claim 1. However, since portfolio performance has not fallen below the deadband, the utility is also not subject to penalties. Claim 1 is therefore zero.

---

[1] 10 units forecasted for 2006 x $10 ex ante per-unit savings = $100 value of the 2006 savings goal.

For Claim 2, the 15 units installed during 2007 (valued at *ex ante* per-unit savings of $10) produce verified savings of $150, which is 100% of the 2007 savings goal. Since this level of achievement meets the MPS, the utility can claim a share of the net benefits produced during program year 2007. Under this simplified numerical example, the Claim 2 payout is $15 (10% shared-savings rate x $150 PEB).

Claim 3 is similarly calculated by comparing 2008 verified savings with the savings goal for 2008. Again, the utility meets the MPS and qualifies for an interim payout. In our numerical example the PEB calculated for 2008 is $200, so the payout for Claim 3 is $20 (10% shared-savings rate x PEB).

Finally, for Claim 4, the results of the Final Verification and Performance Basis Report are considered, which true-up the *ex ante* estimates of per unit savings used in the interim claims. We assume for Example 1 that the final *ex post* value for per-unit savings is $11, versus the $10 *ex ante* value used for the interim claims. As a result, the final PEB for the three-year program cycle is $473 (the cumulative verified units installed over the program cycle of 43 times the $11 *ex post* value for per-unit savings). Using the 10% shared-savings rate assumed under this example, the utility is entitled to $47.3 in earnings for the 2006-2008 achievements. Since $35 was paid out during the interim claims, the Claim 4 "adjustment" (true-up) is $12.3.

In sum, based on the assumptions in our numerical example, the payout of earnings under the Single-Year Basis would be:

Claim 1: **0**; Claim 2: **$15**; Claim 3: **$20**; Claim 4: **$12.3**; Total: **$47.3**

2. Cumulative-to-Date Basis

SCE, DRA and NRDC propose that interim claims be evaluated and paid out based on cumulative-to-date achievements and savings goals. Unlike the Single-Year Basis approach, this Cumulative-to-Date Basis counts the verified achievements from the previous program year(s) in determining whether the MPS is met in each subsequent interim claim (and in the resulting calculation of earnings or penalties). This can best be illustrated by comparing the numerical calculations for the Single-Year Basis and Cumulative-To-Date Basis presented in Example 1.

As shown in those calculations, Claim 1 is exactly the same under the Single-Year Basis and Cumulative-to-Date Basis because, by definition, there is no difference between "annual" and "cumulative-to-date" achievements and goals for the first year in the program cycle. Using either approach, under this example the utility fails to meet the 85% MPS, but doesn't fall below the deadband, so the payout for Claim 1 is zero.

For Claim 2, under either the Single-Year Basis or Cumulative-to-Date Basis the utility meets the MPS, but the calculation for the latter is based on cumulative-to-date verified achievements and goals. As a result, the payout in Claim 2 under the Cumulative-to-Date Basis approach is higher. This is because the utility can count its 2006 verified achievements towards the PEB calculated for Claim 2, even though it did not meet the MPS in Claim 1. Under this example, the resulting Claim 2 PEB is $230 versus the Claim 2 PEB of $150 calculated under the Single-Year Basis approach. Therefore, by the second claim the utility should earn a total of

$23 under the Cumulative-to-Date Basis, versus a total of $15 under the Single-Year Basis.[2]

For Claim 3, given the numerical assumptions in Example 1, the two approaches result in identical payouts. However, this might not be the case under alternate assumptions. For example, if the achievements in the second program year were extremely strong, pulling the cumulative-to-date achievements up much higher than expected (above the goals), and the achievements in the third program year fell lower than expected for that single year, you might see a higher Claim 3 payout under the Cumulative-to-Date Basis than under the Single-Year Basis.

As one would expect, the Claim 4 payout (adjustment) is lower for the Cumulative-to-Date payout approach than for the Single-Year payout approach. This is because of the differences described above for the interim payouts under each approach.

In sum, based on the simplified assumptions in our numerical example, the payout of earnings under the Cumulative-to-Date Basis would be:

Claim 1: **0**; Claim 2: **$23**; Claim 3: **$20**; Claim 4: **$4.3**; Total: **$47.3**

3. Cumulative-Program-Cycle Basis

SDG&E and SoCalGas recommends that interim claims be based on expected achievements over the full 2006-2008 period with verified information progressively replacing forecast information at each claim. As

[2] Another difference between the "single-year" and any approach that looks at cumulative achievements and goals is that the single-year approach does not require that prior year payouts be subtracted from the calculation of payouts in subsequent interim claims. As shown in the numerical calculations, both the cumulative-to-date and cumulative-program-cycle approaches require that subtraction.

shown in Attachment 1, using a Cumulative-Program-Cycle Basis will level out the interim payouts relative to the two other approaches.

More specifically, Claim 1 achievements are comprised of the units installed in 2006 (as verified by the Energy Division report) *plus* the units projected for 2007 and 2008, all valued at the ex ante forecast of per-unit savings. Based on our numerical example, this results in a Claim 1 PEB of $430 (i.e., $10 per unit x (8 + 15 + 20 units)). This level of achievement is compared to the cumulative 2006-2008 goal for the program cycle, which represents a PEB of $450 in our example. Because $430 divided by $450 is greater than 85%, under the Cumulative-Program Cycle Basis the utility passes the MPS and is eligible for earnings in the first claim.

SDG&E/SoCalGas recommend that 25% of the cumulative PEB be paid out in each interim claim, so that 25% of $430, or $10.75, would be paid out for Claim 1. Applying the Cumulative-Program-Cycle approach to the subsequent claims yields the following payout of earnings under Example 1:

Claim 1: **$10.75**; Claim 2: **$10.75**; Claim 3: **$10.75**; Claim 4: **$15.05**; Total: **$47.3**

B. Example 2: Verified (*Ex Post)* PEB Falls Within the Deadband

Example 2 illustrates the payment payout (for the Cumulative-to-Date approach only) if the final true-up claim reveals that actual performance falls within the deadband, where no earnings or penalties accrue. Using the numerical assumptions presented above, this would happen if *ex post* per-unit savings were found to be $8, versus the $10 *ex ante* value assumed for the interim claims: At per-unit savings of $8, the final PEB would be $344 (43 cumulative verified units x $8). The cumulative savings goal for 2006-2008 is $450. Therefore, the verified portfolio savings at the final true-up is 76% of the goal ($344/$450 = .76), which is within the deadband. As a result, the utilities should receive no earnings on the portfolio for that program cycle. Since $43 was paid out in the interim claims, the true-up adjustment is -$43, and the utilities must return all of the previous payments.

Example 2 also illustrates how this final negative adjustment (pay back) of earnings would be reduced if the Commission "held back" 25% to 50% of the pay out in the interim claims.

C. Example 3: Verified (*Ex Post)* PEB Falls Below the Deadband.

This calculation illustrates what happens under our numerical example if verified savings calculated at the final true-up falls below the deadband. Under that scenario, the negative adjustment at the true-up claim would reflect both the penalty level as well as the return of all previous earnings paid out in interim claims.

ATTACHMENT

Simplified Numerical Examples of Pay-Out Proposals

Assumptions (Illustrative Only):

	PY2006	PY2007	PY2008
Savings Goal (PEB)	100	150	200
Cumulative Goal (PEB)	100	250	450
Forecasted units	10	15	20
Units verified (annual)	8	15	20
Units verified (cum)	8	23	43

Assume ex-ante savings per unit = 10; ex-post savings per unit vary in each example below
Also, these numerical examples assume "no costs" in the calculation of PEB

MPS=85% of Goals, Deadband between 75% to 85% of Goals
Earnings rate (% of PEB) =
10%
Penalty rate is 10% of PEB when it falls below the deadband

Example 1: Ex Post PEB Above MPS (ex post savings per unit = 11)

A. Single-Year Basis (PG&E Proposal)

	Claim 1	Claim 2	Claim 3	Claim 4	Total
100% Payout	PEB	PEB	PEB	PEB	PEB
	80	150	200	473	473
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**15**	**20**	**12.3**	**47.3**
				(47.3-35)	

B. Cumulative-To-Date Basis For Installment Payments

	Claim 1	Claim 2	Claim 3	Claim 4	Total
100% Payout	PEB	PEB	PEB	PEB	PEB
Each Installm.	80	230	430	473	473
(DRA)	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**23**	**20**	**4.3**	**47.3**
		(23-0)	(43-23)	(47.3-43)	

	Claim 1	Claim 2	Claim 3	Claim 4	Total
75% Payout	PEB	PEB	PEB	PEB	PEB
(SCE)	80	230	430	473	473
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**17.25**	**15**	**15.05**	**47.3**
		(.75x23)	(32.25-17.25)	(47.3-32.25)	

50% Payout	Installm	Installm	Installm	Adjustment	Earnings/Penalties
(NRDC)	**0**	**11.5**	**10**	**25.8**	**47.3**

ATTACHMENT

C. Cumulative Program Cycle Basis (SD&GE/SoCalGas)

100% Payout	Claim 1	Claim 2	Claim 3	Claim 4	Total
	PEB	PEB	PEB	PEB	PEB
	430	430	430	473	473
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	10.75	**10.75**	**10.75**	**15.05**	**47.3**
	(.25 x 43)	(.50x43)- 10.75	(.75 x 43) - 21.5		

Example 2: Ex-Post PEB lower than MPS within deadband (ex post savings per unit = 8)

Cumulative-To-Date Basis For Installment Payments

	Claim 1	Claim 2	Claim 3	Claim 4	Total
100% Payout Each Installm.	PEB	PEB	PEB	PEB	PEB
	80	230	430	344	344
(DRA)	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**23**	**20**	**-43**	**0**
			(43-23)	(0-20-23)	
	Claim 1	Claim 2	Claim 3	Claim 4	Total
75% Payout	PEB	PEB	PEB	PEB	PEB
(SCE)	80	230	430	387	387
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**17.25**	**15**	**-32.25**	**0**
		(.75x23)	(32.25- 17.25)	(0-17.25-15)	
50% Payout	Installm	Installm	Installm	Adjustment	Earnings/Penalties
(NRDC)	**0**	**11.5**	**10**	**-21.5**	**0**

Example 3: Ex-Post PEB below deadband (ex post savings per unit = 7)

Cumulative-To-Date Basis For Installment Payments

	Claim 1	Claim 2	Claim 3	Claim 4	Total
100% Payout	PEB	PEB	PEB	PEB	PEB
	80	230	430	301	301
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**23**	**20**	**-73.1**	**-30.1**
				(-30.1-23-20)	

ATTACHMENT

	Claim 1	Claim 2	Claim 3	Claim 4	Total
75% Payout	PEB	PEB	PEB	PEB	PEB
	80	230	430	301	301
	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**17.25**	**15**	**-62.35**	**-30.1**
		(.75x23)	(32.25-17.25)	(-30.1-17.25-15)	
50% Payout	Installm	Installm	Installm	Adjustment	Earnings/Penalties
	0	**11.5**	**10**	**-51.6**	**-30.1**

(END OF ATTACHMENT 5)

ATTACHMENT 6: EM&V STUDIES: SCHEDULE AND LINKAGE TO EARNINGS CLAIMS

A. EM&V Events For 2006-2008 Program Cycle: Modified Schedule (January 2, 2007 Ruling and February extension)

2007	2008	2009	2010
March 20: Utility Measure & Cost Report to ED (for 2006)	**February 29**: Utility Measure & Cost Report to ED (through 2007)	**February 29**: Utility Measure & Cost Report to ED [1] (for 2008)	not applicable (NA)
NA	**March: ED Interim** Performance Basis Report [1, 2] (for Jan 2006-July 2007)	NA	**March:** ED Final Verification and Performance Basis Report [1, 2] (for PY 2006-2008) [1, 2]
No Verification Report in 2007	**August**: ED Verification Report of Costs and Installations and Services Completed (For 2006 & 2007)	**August**: ED Verification Report of Costs and Installations and Services Completed (through 2008)	NA
No Interim Claim in 2007	**INTERIM CLAIM #1** **Mid-September:** Utilities submit compliance Advice Letters (A.L). **November/December:** ED disposition of A.L and earnings/penalties booked.	**INTERIM CLAIM #2** **Mid-September:** Utilities submit compliance Advice Letters (A.L) **November/December:** ED disposition of A.L and earnings/penalties booked.	**FINAL CLAIM/TRUE-UP** **Mid-May:** Utilities submit compliance Advice Letters (A.L) **July/August:** ED disposition of A.L and final adjustments to earnings/penalties booked.

B. EM&V Events For 2009-2011 Program Cycle: Back to Original Schedule (January 11, 2006 Ruling)

2010	2011	2012	2013
February 28: Utility Measure & Cost Report to ED (for 2009)	**February 29**: Utility Measure & Cost Report to ED (through 2010)	**February 29**: Utility Measure & Cost Report to ED [1] (through 2011)	NA
NA	**March:** ED Interim Performance Basis Report [1, 2] (for Jan. 2009-July 2010)	NA	**March:** ED Final Verification and Performance Basis Report [1, 2] (for PY 2009-2011)
August: ED Verification Report of Costs and Installations and Services Completed (for 2009)	**August**: ED Verification Report of Costs and Installations and Services Completed (through 2010)	**August**: ED Verification Report of Costs and Installations and Services Completed (through 2011)	NA
No Interim Claim in 2010	**INTERIM CLAIM #1** **Mid-September:** Utilities submit compliance Advice Letters (A.L). **November/December:** ED disposition of A.L and earnings/penalties booked.	**INTERIM CLAIM #2** **Mid-September:** Utilities submit compliance Advice Letters (A.L) **November/December:** ED disposition of A.L and earnings/penalties booked.	**FINAL CLAIM/TRUE-UP** **Mid-May:** Utilities submit compliance Advice Letters (A.L) **July/August:** ED disposition of A.L and final adjustments to earnings/penalties booked.

[1] Note: Per D.05-09-043 (pp. 100-101; OP 12) the expected useful lives to be reported by the utilities and verified by ED under (6) below will reflect updated *ex ante* values posted to the Commission's DEER website in August of 2005, rather than those submitted with the utility portfolio plans.

[2] ED Performance Basis Reports will address (where data is available for the interim report) the following parameters: (1) measure or unit energy savings and peak demand reductions; (2) program/portfolio energy savings and peak demand reductions; (3) load factors/daily load shapes; (4) incremental measure costs, (5) verify correct values used for avoided costs in PEB; (6) verify that correct ex ante is used for expected useful lives/technical degradation factors; (7) net-to-gross ratios.

See ALJ ruling dated January 11, 2006 on Protocols for Process and Review of Post-2005 EM&V Activities, as modified by ruling dated January 2, 2007.

Note: Interim Claims Are Based Only on the Verification Reports, and not the Interim Performance Basis Report. That report is available to provide the results of load impact studies to date to assist the program administrators in managing their portfolios.

(END OF ATTACHMENT 6)

ATTACHMENT 7

Procedures for Review and Approval of Earnings/Penalties under the Energy Efficiency Risk/Reward Incentive Mechanism[1]

Interim Claims

Payments under the interim claim(s) represent a "progress payment" towards total expected earnings:

1. Evaluation contractors use data requested from investor-owned utility (IOU) program tracking databases and reports to develop Contract Group[2] level reports that verify unit installations.

2. California Public Utility Commission (CPUC) audit team develops financial audit reports that verify portfolio costs for each utility.

3. Energy Division aggregates evaluation contractor reports for each utility to quantify the portfolio resource benefits and uses that quantity in connection with the audit team reports to develop the draft Verification Report, which is posted on a publicly accessible website. Energy Division notifies the CPUC Energy Efficiency service lists and lists of other interested stakeholders[3] maintained by Energy Division of the availability of the draft Verification Report and the website posting location. Energy Division also notifies all of those

[1] These procedures augment and substitute for Attachment 4 to *Administrative Law Judge's Ruling Adopting Protocols for Process and Review of Post-2005 Evaluation, Measurement and Verification Activities,* dated January 11, 2006.

[2] These procedures augment and substitute for Attachment 4 to *Administrative Law Judge's Ruling Adopting Protocols for Process and Review of Post-2005 Evaluation, Measurement and Verification Activities,* dated January 11, 2006.

[3] "Stakeholders" refers to those listed on one of the CPUC's Energy Efficiency service list or who have notified Energy Division of their interest.

ATTACHMENT 7
(continued)

stakeholders of the conference described in the next Step.

4. Energy Division holds a conference by telephone or in-person. At this meeting, all stakeholders have an opportunity to discuss the draft Verification Report with those who prepared it (and supporting consultants). Stakeholders may raise questions about the draft report, receive responses from those who prepared it, and point out any errors they believe are contained in the report. The goal is to have a give and take between the stakeholders, report authors, and the supporting technical experts.

5. Stakeholders have an opportunity to provide written comments to Energy Division identifying any errors in the draft Verification Report. Stakeholders will be required to include in the written comments at least a brief description of every point in the draft report which they believe needs correction, even if discussed at the conference.

6. Energy Division makes any necessary changes to the Verification Report stimulated by the oral conference and written comments. All written comments, and Energy Division's treatment of them, will be reflected in an appendix to the Final Verification Report, which is posted on a publicly accessible website.

7. Final Verification Report is made publicly available.

8. Within 45 days of issuance of the Final Verification Report, the utility will file an advice letter for Energy Division disposition pursuant to section 7.6.1 of General Order 96-B, citing the Verification Report. The advice letter will address whether based on that report there are any earnings or penalties, and if so at what level, for the interim claim.

ATTACHMENT 7
(continued)

9. Energy Division will approve the advice letter as soon as practicable thereafter so long as it correctly incorporates the results of the Verification Report; if it does not, Energy Division will take other appropriate action under General Order 96-B.

Final Claim

The final claim and true-up of savings and performance basis estimates will be based on the Final Performance Basis Report:

1. Evaluation contractors complete draft final evaluation reports[4] and post them on a publicly accessible website. The evaluation contractors will notify the CPUC Energy Efficiency service lists and lists of other interested stakeholders maintained by Energy Division of the availability of the draft final evaluation reports and their website posting location(s). Energy Division will notify all of those stakeholders of the conference described in the next Step.

2. Evaluation contractors hold a conference, under Energy Division sponsorship, with stakeholders, by telephone or in-person, to discuss draft final evaluation reports.

3. Stakeholders have an opportunity to provide written comments identifying any errors in the draft final evaluation reports. Stakeholders will be required to include in the written comments at least a brief description of every point in the draft report which they believe needs correction, even if discussed at the conference.

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4 Evaluation reports refer to either interim or final reports submitted to Energy Division by program evaluation contractors describing results of evaluations (e.g, impact evaluation studies) of the Contract Groups.

ATTACHMENT 7
(continued)

4. Energy Division directs evaluation contractors to make any necessary changes to final evaluation reports stimulated by the comments. All written comments, and Energy Division's treatment of them, will be reflected in appendices to the final evaluation reports. The final evaluation reports are posted on a publicly accessible website.

5. Within 60 days of public release, program administrators will respond in writing to the final report findings and recommendations indicating what action, if any, will be taken as a result of study findings as they relate to potential changes to the programs. Energy Division can choose to extend the 60 day limit if the administrator presents a compelling case that more time is needed and the delay will not cause any problems in the implementation schedule, and may shorten the time on a case-by-case basis if necessary to avoid delays in the schedule.

6. Energy Division aggregates evaluation contractor reports for each utility to quantify the portfolio resource benefits and uses that quantity in connection with the audit team reports to develop the draft Final Performance Basis Report. Energy Division will notify the CPUC Energy Efficiency service lists and lists of other interested stakeholders maintained by Energy Division of the availability of the draft Final Performance Basis Report and the website posting location. Energy Division also notifies all of those stakeholders of the conference described in the next Step.

7. Energy Division, with the assistance of relevant contractors holds a conference with stakeholders, by telephone or in-person. At this meeting, all stakeholders have an opportunity to discuss the draft Final Performance Basis Report with those who

ATTACHMENT 7
(continued)

prepared it (and supporting consultants). Stakeholders may raise questions about the draft report, receive responses from those who prepared it, and point out any errors they believe are contained in the report. The goal is to have a give and take between the stakeholders, report authors, and the supporting technical experts.

8. Stakeholders have an opportunity to provide written comments identifying any errors in the draft Final Performance Basis Report. Stakeholders will be required to include in the written comments at least a brief description of every point in the draft report or which they believe needs correction, even if discussed at the conference.

9. Energy Division makes any necessary changes to the Final Performance Basis Report stimulated by the oral conference and written comments. All written comments, and Energy Division's treatment of them, will be reflected in an appendix to the Final Performance Basis Report.

10. Final Performance Basis Report is made publicly available by posting on a publicly accessible website and sending it to the Energy Efficiency proceeding service list(s).

11. Within 60 days of issuance of the Final Performance Basis Report, the utility will file an advice letter for Energy Division disposition pursuant to section 7.6.1 of General Order 96b, citing the Final Performance Basis Report. The advice letter will address whether based on that report there are any earnings or penalties, and if so at what level, for the final claim.

ATTACHMENT 7
(continued)

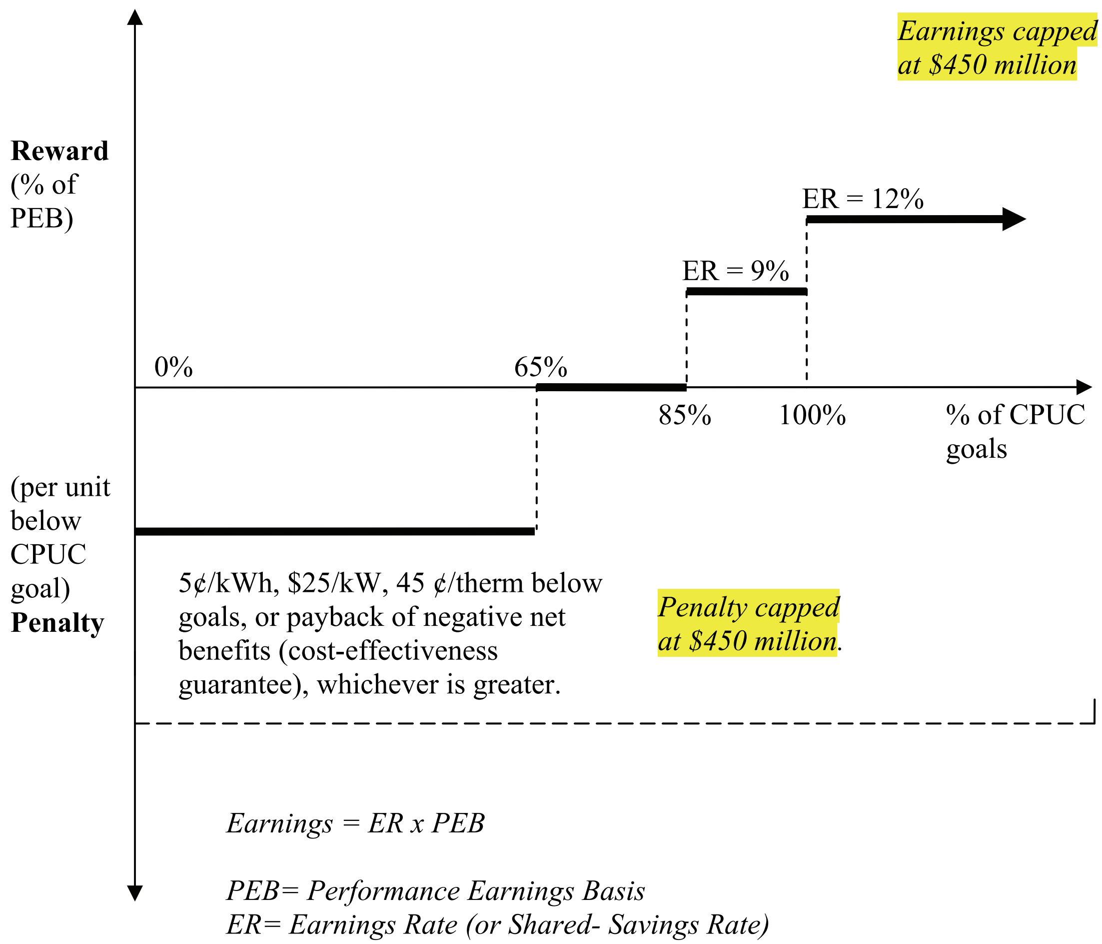
12. Energy Division will approve the advice letter as practicable as possible thereafter so long as it correctly incorporates the results of the Final Performance Basis Report; if it does not, Energy Division will take other appropriate action under General Order 96-B.

(END OF ATTACHMENT 7)

ATTACHMENT 8

Adopted Earnings/Penalty Curve and Projected Shareholder Earnings and Penalties Based on Savings Performance (For 2006-2008 Portfolio Costs and Savings Goals)

Figure 1: Adopted Incentive Mechanism Earnings/Penalty Curve



ATTACHMENT 8

TABLE 1

Projected Shareholder Earnings/Penalties Under Adopted Risk/Return Incentive Mechanism
PEB Including All Portfolio Costs (2006-2008)
($ Million, Pre-Tax, Uncapped)

RECORDED SAVINGS GOALS	PG&E		SCE		SDG&E		SoCalGas		STATEWIDE TOTAL		
(% OF FORECAST)	PEB	Earnings	PEB	Earnings	PEB	Earnings	PEB	Earnings	PEB	Earnings	
150%	$2,074.2	$248.9	$2,187	$262.4	$574.8	$69.0	$313.0	$37.6	$5,149.0	$617.9	
145%	$1,972.6	$236.7	$2,088	$250.6	$547.0	$65.6	$295.2	$35.4	$4,903.0	$588.4	
140%	$1,870.9	$224.5	$1,990	$238.7	$519.2	$62.3	$277.3	$33.3	$4,657.0	$558.8	
135%	$1,769.3	$212.3	$1,891	$226.9	$491.4	$59.0	$259.5	$31.1	$4,410.9	$529.3	
130%	$1,667.7	$200.1	$1,792	$215.0	$463.6	$55.6	$241.6	$29.0	$4,164.9	$499.8	
125%	$1,566.1	$187.9	$1,693	$203.2	$435.9	$52.3	$223.8	$26.9	$3,918.9	$470.3	Capped at
120%	$1,464.4	$175.7	$1,594	$191.3	$408.1	$49.0	$205.9	$24.7	$3,672.8	$440.7	$450
115%	$1,362.8	$163.5	$1,496	$179.5	$380.3	$45.6	$188.0	$22.6	$3,426.8	$411.2	
110%	$1,261.2	$151.3	$1,397	$167.6	$352.5	$42.3	$170.2	$20.4	$3,180.8	$381.7	
105%	$1,159.5	$139.1	$1,298	$155.8	$324.7	$39.0	$152.3	$18.3	$2,934.8	$352.2	
100%	$1,057.9	$126.9	$1,199	$143.9	$297.0	$35.6	$134.5	$16.1	$2,688.7	$322.6	
95%	$956.3	$86.1	$1,101	$99.1	$269.2	$24.2	$116.6	$10.5	$2,442.7	$219.8	
90%	$854.6	$76.9	$1,002	$90.2	$241.4	$21.7	$98.8	$8.9	$2,196.7	$197.7	
85%	$753.0	$67.8	$903	$81.3	$213.6	$19.2	$80.9	$7.3	$1,950.6	$175.6	
80%	$651.4	$0.0	$804	$0.0	$185.8	$0.0	$63.1	$0.0	$1,704.6	$0.0	
75%	$549.7	$0.0	$706	$0.0	$158.1	$0.0	$45.2	$0.0	$1,458.6	$0.0	
70%	$448.1	$0.0	$607	$0.0	$130.3	$0.0	$27.4	$0.0	$1,212.6	$0.0	
65%	$346.5	($60.0)	$508	($57.6)	$102.5	($16.8)	$9.5	($9.6)	$966.5	($144.0)	
60%	$244.9	($69.6)	$409	($67.2)	$74.7	($19.2)	($8.4)	($12.0)	$720.5	($168.0)	
55%	$143.2	($76.8)	$311	($74.4)	$47.0	($21.6)	($26.2)	($26.2)	$474.5	($199.0)	
50%	$41.6	($86.4)	$212	($82.8)	$19.2	($25.2)	($44.1)	($44.1)	$228.4	($238.5)	
45%	($60.0)	($94.8)	$113	($91.2)	($8.6)	($27.6)	($61.9)	($61.9)	($17.6)	($275.5)	
40%	($161.7)	($161.7)	$14	($99.6)	($36.4)	($36.4)	($79.8)	($79.8)	($263.6)	($377.5)	Capped at
35%	($263.3)	($263.3)	($85)	($108.0)	($64.2)	($64.2)	($97.6)	($97.6)	($509.6)	($533.1)	($450)
30%	($364.9)	($364.9)	($183)	($183.0)	($91.9)	($91.9)	($115.5)	($115.5)	($755.7)	($755.3)	
25%	($466.6)	($466.6)	($282)	($282.0)	($119.7)	($119.7)	($133.3)	($133.3)	($1,001.6)	($1,001.6)	
20%	($568.2)	($568.2)	($381)	($381.0)	($147.5)	($147.5)	($151.2)	($151.2)	($1,247.9)	($1,247.9)	
15%	($669.8)	($669.8)	($480)	($480.0)	($175.3)	($175.3)	($169.0)	($169.0)	($1,494.1)	($1,494.1)	
10%	($771.4)	($771.4)	($578)	($578.0)	($203.1)	($203.1)	($186.9)	($186.9)	($1,739.4)	($1,739.4)	
5%	($873.1)	($873.1)	($677)	($677.0)	($230.8)	($230.8)	($204.8)	($204.8)	($1,985.7)	($1,985.7)	
0%	($974.7)	($974.7)	($776)	($776.0)	($258.6)	($258.6)	($222.6)	($222.6)	($2,231.9)	($2,231.9)	

Notes:

[1] MPS starts at 85%
[2] Earnings rate >= 85% and < 100% of goals: 9%
Earnings rate >= 100% and above of goals: 12%
[3] Penalties start at 65%, using the following penalty rates: 5c/kWh, 45c/therm, $25/kw for each unit below the savings goal.
[4] Penalty based on per unit penalty or negative net benefit (cost-effectiveness guarantee), whichever is higher
[5] Cap on earnings at $500 million and cap on penalties at -$450 (all utilities combined). Individual
utility caps are as follows: PG&E-$180 million; SCE-$200 million; SDG&E-$50 million and SoCalGas-$20 million

Proposed Decision Penalty Worksheet

RECORDED SAVINGS GOALS	PG&E			SCE			SDG&E			SoCalGas			Total (Statewide)		
(% OF FORECAST)	Per Unit	C-E Guarantee	Combined	Per Unit	C-E Guarantee	Combined	Per Unit	C-E Guarantee	Combined	Per Unit	C-E Guarantee	Combined	Per Unit	C-E Guarantee	Combined*
65%	($60.0)	$0.0	($60.0)	($57.6)	$0	($57.6)	($16.8)	$0.0	($16.8)	($9.6)	$0.0	($9.6)	($144.0)	$0.0	($144.0)
60%	($69.6)	$0.0	($69.6)	($67.2)	$0	($67.2)	($19.2)	$0.0	($19.2)	($12.0)	($8.4)	($12.0)	($168.0)	($8.4)	($168.0)
55%	($76.8)	$0.0	($76.8)	($74.4)	$0	($74.4)	($21.6)	$0.0	($21.6)	($12.0)	($26.2)	($26.2)	($184.8)	($26.2)	($199.0)
50%	($86.4)	$0.0	($86.4)	($82.8)	$0	($82.8)	($25.2)	$0.0	($25.2)	($13.2)	($44.1)	($44.1)	($207.6)	($44.1)	($238.5)
45%	($94.8)	($60.0)	($94.8)	($91.2)	$0	($91.2)	($27.6)	($8.6)	($27.6)	($15.6)	($61.9)	($61.9)	($229.2)	($130.5)	($275.5)
40%	($103.2)	($161.7)	($161.7)	($99.6)	$0	($99.6)	($30.0)	($36.4)	($36.4)	($16.8)	($79.8)	($79.8)	($249.6)	($277.9)	($377.5)
35%	($111.6)	($263.3)	($263.3)	($108.0)	($85)	($108.0)	($32.4)	($64.2)	($64.2)	($18.0)	($97.6)	($97.6)	($270.0)	($510.1)	($533.1)
30%	($120.0)	($364.9)	($364.9)	($116.4)	($183)	($183.0)	($34.8)	($91.9)	($91.9)	($19.2)	($115.5)	($115.5)	($290.4)	($755.3)	($755.3)
25%	($128.4)	($466.6)	($466.6)	($124.8)	($282)	($282.0)	($37.2)	($119.7)	($119.7)	($20.4)	($133.3)	($133.3)	($310.8)	($1,001.6)	($1,001.6)
20%	($138.0)	($568.2)	($568.2)	($133.2)	($381)	($381.0)	($39.6)	($147.5)	($147.5)	($21.6)	($151.2)	($151.2)	($332.4)	($1,247.9)	($1,247.9)
15%	($146.4)	($669.8)	($669.8)	($141.6)	($480)	($480.0)	($42.0)	($175.3)	($175.3)	($22.8)	($169.0)	($169.0)	($352.8)	($1,494.1)	($1,494.1)
10%	($154.8)	($771.4)	($771.4)	($150.0)	($578)	($578.0)	($44.4)	($203.1)	($203.1)	($25.2)	($186.9)	($186.9)	($374.4)	($1,739.4)	($1,739.4)
5%	($163.2)	($873.1)	($873.1)	($158.4)	($677)	($677.0)	($46.8)	($230.8)	($230.8)	($26.4)	($204.8)	($204.8)	($394.8)	($1,985.7)	($1,985.7)
0%	($171.6)	($974.7)	($974.7)	($166.8)	($776)	($776.0)	($49.2)	($258.6)	($258.6)	($27.6)	($222.6)	($222.6)	($415.2)	($2,231.9)	($2,231.9)

Notes:

1] Penalties begin at 65% of savings goals and below
2] Penalties are $.05/kWh, $.45/therm, $25/kw per unit below savings goal
3] Estimated penalties are based on NRDC's Tier 2 rates, increased by 20%
4] Combined column shows higher of per unit penalty or cost-effectiveness guarantee (negative PEB)

* Due to differences in levels of cost-effectiveness amongst utilities, no direct comparison may be made between "Per Unit" and "C-E Guarantee" columns. For example, at 55%, SCG's C-E Guarantee penalty ($26.2) is higher than their per unit penalty ($12), the resulting difference between $26.2 and $12 ($14.2) makes up the difference in the Total at 55% of savings.

(END OF ATTACHMENT 8)

Numerical Examples of Adopted Net-to-Gross Adjustment to Total Resource Costs

As discussed in today's decision, the total costs that free riders actually incur should be removed from the cost side of the Total Resource Cost (TRC) test. The total cost free riders actually incur is equal to the measure cost used for all participant ratepayers less any cost for measure installations reimbursed or paid by the program. Below, we present the formulas and sample calculations that accomplish this adjustment.

We also show sample calculations that use the formulation presented in 1998 Standard Practice Manual (SPM) Correction Memo, which is included in this attachment. This formulation suggests that the adjustment for free riders would be applied to participant costs *before* rebates are accounted for. We do not adopt this formulation for the reasons discussed in this decision.

In D.06-06-063, the numerical examples were single participant only since free rider adjustments were not addressed. Therefore, those examples did not need to break down the participant cost term (PC_t) that appears in the SPM into two components, namely, the "rebate" incentive versus the actual participant expense. [1] We do so in the following definitions and formulas in order to illustrate how the free rider adjustment should be applied.

A. Definitions and Formulas

The relevant definitions are:

Variable	Definition
Meas$	Full or incremental cost of measure per SPM definition (per measure installation)[2]
Admin$	Program administrative cost including all the administrative costs related to each measure (rebate processing, implementor/third party non-measure costs, etc.) as well as overall program administration costs (marketing, overhead, etc.) Administrative costs do not include any measure cost (Meas$).
Rebate$	Program rebate payment to ratepayer participant per SPM INC definition (per measure installation)

[1] *California Standard Practice Manuel: Economic Analysis of Demand-Side Programs and Projects*, October 2001.
[2] See D.05-04-051, Attachment 3, Rule IV.2 and D.06-06-063, p. 63, footnote 60 for a discussion of when "full" versus "incremental" cost of measure is used.

ATTACHMENT 9
Page 2 of 7

DirectI$	Cost paid by program for direct installation of measures at customer's premises (per measure installation). By definition, this value must be less than or equal to Meas$.
FreeRF	The fraction of participants which are free riders
NTG	The fraction of participants which are not free riders (1-FreeRF)
NP	Number of participants

Total net program cost = Total program cost – Total free riders' costs

Total net program cost = Program Administrator Costs + Program Participant Costs
- Total Free- Riders' costs
= Program Administrator Costs + Net Program Participant Costs

Where:

Total Free-Riders' costs = Free-Rider Costs net of any costs reimbursed by others.
Program Participant Costs=Participant Costs net of any costs reimbursed by others. [3]
Net Program Participant Costs = Program Participant Costs - Total Free-Riders' costs.

A direct installation ("direct install") program is any program delivery model by which the program directly (through staff action) or indirectly (through a contractual arrangement with a third party) arranges for measures to be either delivered to a participating customer for their installation or installed at a participating customer premises. This contrasts with rebate, mid-stream and up-stream program where the program may undertake a marketing activity to induce the customer to install measures and participate in the program, but the participant makes all arrangements for the purchase and installation of the measures through third parties with no contractual relationship with the program. For a direct install program the difference between Direct$ and Measure$ for a particular measure is the participant co-payment cost for the measure.

The definitions and formulas we present below are for rebate and direct install programs. However, the direct install formula may also be applicable to certain programs that the utilities call "mid-stream" activities if they deliver measures/services to the customer premises. The Air-conditioning system refrigerant charge programs are one such example. Under this "mid-stream" program, the utility contracts with verified service providers who then contract with heating, ventilation and air-conditioning (HVAC) contractors to go to customer premises and tune up their HVAC systems. Therefore, this "mid-stream" program would actually have a

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[3] This definition of program participant costs relates to the SPM "PC_t" term by subtracting from that term the program rebate payment ("INC") , any federal, state or local tax credit received ("TC_t") or any other costs reimbursed by others. See 2001 SPM at p.8 for the listed benefits to participants that would reduce the actual expense of participating in the program.

direct install cost (Direct$), equal to the amount paid to the verified service providers. Meas$ may exceed direct install cost if the participating customer is also charged a co-payment for the services.

In contrast, the formulas for direct install or rebate programs presented below are not directly applicable to mid- or upstream programs that provide incentives to manufacturers to "buy down" the shelf price, or that provide incentives to wholesalers to stock high-efficiency equipment. This is because there is neither a rebate (Rebate$ or "INC" term as defined by the SPM) nor a direct install cost (Direct$) for measures installed at the participants' premises. Instead, as discussed in D.06-06-063, all program costs for these types of mid- or up-stream programs would be allocated fully to utility administrative costs (where the NTG adjustment does not apply). However, the participant cost under these programs is what the participant actually pays for the measure (the shelf price), to which the NTG ratio would apply.

For rebate program:[4]

Program Administrator Costs = Admin$ + NP * Rebate$
Program Participant Costs = NP * (Meas$ - Rebate$)
Total Free-Riders Costs = NP * FreeRF * (Meas$ - Rebate$)
= NP * (1-NTG) * (Meas$ - Rebate$)
Net Program Participant Costs = NP * (Meas$ - Rebate$) –
NP * (1-NTG) * (Meas$ - Rebate$)
= NP * NTG * (Meas$ - Rebate$)

Combining the above gives us:

Total net program cost

= Admin$ + NP*Rebate$ + NP*NTG*(Meas$ - Rebate$)
= Admin$ + NP*(Rebate$ + NTG* (Meas$ - Rebate$))

The Rebate$ terms in the above formula do not fully cancel, but rather a term remains that represents the rebates paid to free riders:

= Admin$ + NP*(NTG*Meas$ + (1-NTG)*Rebate$)

[4] If Rebate$ exceeds Meas$ (the program pays rebates that exceed the cost of the measure) the total program TRC cost will be less than the program budget and associated revenue requirements. Because of the "transfer payment" formulation of the SPM, these "excess" rebate dollar amounts are treated as a revenue shift from all ratepayers to participating ratepayers and are not counted as a program cost. However, as we discuss in D.06-06-063, this is expected to be a rare circumstance.

ATTACHMENT 9
Page 4 of 7

As illustrated below, this application of the NTG adjustment results in a consistent treatment of rebate and direct install programs, without eliminating the revenue requirement costs that ratepayers incur when free riders receive financial incentives under the program.

For direct install:[5]

Program Administrator Costs = Admin$ + NP * DirectI$
Program Participant Costs = NP * (Meas$ - DirectI$)
Freerider Costs = NP * FreeRF * (Meas$ - DirectI$)
= NP * (1-NTG) * (Meas$ - DirectI$)
Net Program Participant Costs = NP * (Meas$ - DirectI$) - NP * (1-NTG) * (Meas$ - DirectI$)
= NP * NTG * (Meas$ - DirectI$)

Combining the above gives us:

Total net program cost

= Admin$ + NP* DirectI$ + NP*NTG* (Meas$ - DirectI$)
= Admin$ + NP*(DirectI$ + NTG* (Meas$ - DirectI$))

The DirectI$ terms do not fully cancel, and we get the following:

= Admin$ + NP*(NTG*Meas$ + (1-NTG)* DirectI$)

In the case when the direct install program covers all measure costs (DirectI$ = Meas$)

= Admin$ + NP*DirectI$

B. Numerical Examples

Below, we provide numerical examples for rebate and direct install programs to illustrate how the NTG should be applied to TRC costs, based on the clarification adopted in today's decision. This clarification is contrasted with the formulation presented in the 1998 SPM Correction Memo (copy attached), which suggests that the NTG adjustment could be applied to participant costs before rebates are accounted for. Note that the TRC test results are only identical for rebate and direct install programs (all other things being equal) with the clarification we make today.

[5] Note here that the total TRC cost cannot be less than the program budget and associated revenue requirements as in the rebate program formulation, because the Direct$ cannot be more than Meas$ and the full Direct$ amount appears in the program administrator cost term. See D.06-06-063 at pp. 71-72.

ATTACHMENT 9

Participant Net Costs for the rebate program calculation are net of free riders, but reflect participant out-of-pocket costs prior to receiving the program rebate. Participant Net Costs for the direct install calculation are net of free riders and reflect the participant co-payment under the program. Program Net Costs are program costs (net of free rider adjustments) that do not appear in the Participant Net Cost terms. As discussed above, these numerical examples show the break out of individual components that are included in the SPM's "PC_t" term in order to illustrate how all revenue requirements are still captured when the NTG adjustment is properly applied.

1. Rebate Program

4	participants	$2,000	measure cost
1	free rider	$3,000	measure benefit per measure
0.75	NTG	$1,000	rebate per measure
		$100.0	admin cost per measure
	TRC benefits=	4 participants x 3,000 x 0.75 NTG	

1988 SPM Correction Memo:

Program Net Costs = 4 participants x 100 admin costs per measure
Participant Net Costs =4 participants x 2,000 measure cost x 0.75 NTG

Adopted Clarification:

Program Net Costs = 4 participants x 100 admin costs/measure + 4 participants x (1-0.75)x $1,000 rebate per measure
Participant Net Costs=4 participants x 2,000 measure cost x 0.75 NTG

Methodology	**TRC Benefit**	**Program Net Costs**	**Participant Net Costs**	**TRC Cost**	**TRC**
1988 SPM Correction Memo:	$9,000	$400	$6,000	$ 6,400	**1.41**
Adopted Clarification	$9,000	$1,400	$6,000	$7,400	**1.22**

ATTACHMENT 9
Page 6 of 7

2. Direct Install

4	participants	$2,000	measure cost
1	freerider	$3,000	measure benefit per measure
0.75	NTG	$1,000	Direct program paid cost per measure
		$100.0	admin cost per measure

TRC benefits=4 participants x 3,000 x 0.75 NTG
Program Net Costs= 4 participants x 100 admin costs/measure + 4 participants x 1,000 direct program paid cost/measure
Participant Net Costs = 4 participants x 0.75 NTG x (2,000 measure cost - 1,000 direct program paid cost per measure)

Methodology	**TRC Benefit**	**Program Net Costs**	**Participant Net Costs**	**TRC Cost**	**TRC**
Per D.06-06-063	$9,000	$4,400	$3,000	$7,400	**1.22**

FILED
12-21-06
02:07 PM

To : Standard Practice Manual Distribution List October 7, 1988

From : Don Schultz

Re : Correction to Total Resource Cost test in Standard Practice Manual

<u>Standard Practice Manual: Economic Analysis of Demand-Side Management Programs</u>. published December 1987, CEC Publication Number P400-87-008

Pat Herman (BHC) and Eric Hirst (Oak Ridge National Laboratory) both noticed that the formula for calculating participant costs in the Total Resource Cost (TRC) test is wrong. The needed correction is explained below.

Specifically, the formula for calculating TRC costs includes three terms: utility administrative costs, participant device costs, and (for fuel substitution programs) utility increase supply costs (see page 29).

$$C(TRC) = \sum_{t+1}^{N} \frac{UC + PC + UIC}{(1+d)\hat{}t-1}$$

should be "t=1"

The Manual indicates that utility administrative and participant costs are not modified to reflect program attribution adjustments (i.e., the gross-to-net issue) while utility increased supply costs and program benefits are adjusted for attribution.

In order to retain symmetry with the benefit side of the equation, the participant cost (PC) component of the TRC costs should be corrected to reflect program attribution. To make this clear, we suggest renaming the participant cost as PCN to designate "Participant cost - net". The change would also carry through to the Levelized Cost (LCRC) test. Please note that this application of gross-to-net ratios applies only to the participant costs and not to the utility administrative costs.

The next time we publish the Standard Practice Manual we will correct this error. In the meantime, please mark up your manual on page 29 (definitions and formula), page 31 (example), page C-2 (summary of equations), and page C-6 (glossary).

13 and

This correction has been approved by all major California participants to the Standard Practice revision process. Future DSM cost-effectiveness filings by all parties in California should reflect this correction.

If you have any questions regarding this correction, please contact either Don Schwartz at the CEC (916-324-3488) or Don Schultz at the CPUC (916-324-5935).

(END OF ATTACHMENT 2)

(END OF ATTACHMENT 9)

ATTACHMENT 10

AVERAGE SHORT-TERM RATE AND BILL IMPACTS TO RECOVER EARNINGS FOR 2006-2008 ENERGY EFFICIENCY (at 100% goals)

Estimated Rate and Bill Impacts for SCE

Average Annual Effect Over 3 Years

	Total Recovery	Annual Amount	Average Bundled % Change	Average Residential % Change	Average Residential Increase per Month
5%	$ 59,969,495	$ 19,989,832	0.17%	0.22%	$ 0.19
10%	$ 119,938,990	$ 39,979,663	0.34%	0.43%	$ 0.38
15%	$ 179,908,485	$ 59,969,495	0.51%	0.65%	$ 0.58
20%	$ 239,877,981	$ 79,959,327	0.68%	0.86%	$ 0.77

Average Annual Effect Over 4 Years

	Total Recovery	Annual Amount	Average Bundled % Change	Average Residential % Change	Average Residential Increase per Month
5%	$ 59,969,495	$ 14,992,374	0.13%	0.16%	$ 0.14
10%	$ 119,938,990	$ 29,984,748	0.25%	0.32%	$ 0.29
15%	$ 179,908,485	$ 44,977,121	0.38%	0.48%	$ 0.43
20%	$ 239,877,981	$ 59,969,495	0.51%	0.65%	$ 0.58

Notes: Percent changes are reflected over current rates & forecast, Effective 4/1/07

ALJ 3 Year Request
Southern California Edison Company
Average Rate and Bill Impact Estimates - by Rate Group
Energy Efficiency Incentive Proposal
Rates Effective April 1, 2007
Bundled Service

	2007 - Base Year			Scenario 5% of Annual $ 19.99 million/year			Scenario 10% of Annual $ 39.98 million/year			Scenario 15% of Annual $ 59.97 million/year			Scenario 20% of Annual $ 79.96 million/year		
	Average Monthly Usage (kWh)	Average Rate ($/kWh)	Average Monthly Bill ($)	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change
Residential	590	0.15157	89	0.00033	0.19	0.22%	0.00065	0.38	0.43%	0.00098	0.58	0.65%	0.00130	0.77	0.86%
Lighting-SM Med Power															
GS-1	868	0.17487	152	0.00025	0.22	0.14%	0.00050	0.43	0.29%	0.00075	0.65	0.43%	0.00100	0.87	0.57%
GS-2	11,196	0.14464	1,619	0.00023	2.61	0.16%	0.00047	5.23	0.32%	0.00070	7.84	0.48%	0.00093	10.45	0.65%
TC-1	422	0.13310	56	0.00027	0.11	0.20%	0.00054	0.23	0.40%	0.00080	0.34	0.60%	0.00107	0.45	0.81%
TOU-GS-2	85,123	0.13749	11,703	0.00019	16.15	0.14%	0.00038	32.30	0.28%	0.00057	48.44	0.41%	0.00076	64.59	0.55%
Group Total	3,814	0.14813	565	0.00022	0.86	0.15%	0.00045	1.71	0.30%	0.00067	2.57	0.45%	0.00090	3.42	0.61%
Large Power															
TOU-8-SEC	285,528	0.12772	36,469	0.00017	48.22	0.13%	0.00034	96.45	0.26%	0.00051	144.67	0.40%	0.00068	192.90	0.53%
TOU-8-PRI	634,054	0.11791	74,764	0.00014	91.81	0.12%	0.00029	183.61	0.25%	0.00043	275.42	0.37%	0.00058	367.23	0.49%
TOU-8-SUB	2,837,386	0.07956	225,745	0.00003	88.16	0.04%	0.00006	176.32	0.08%	0.00009	264.48	0.12%	0.00012	352.63	0.16%
Group Total	499,917	0.11085	55,416	0.00012	58.42	0.11%	0.00023	116.84	0.21%	0.00035	175.26	0.32%	0.00047	233.67	0.42%
Agricultural & Pumping															
PA-1	1,582	0.19370	307	0.00046	0.73	0.24%	0.00093	1.47	0.48%	0.00139	2.20	0.72%	0.00186	2.94	0.96%
PA-2	9,112	0.13486	1,229	0.00029	2.60	0.21%	0.00057	5.21	0.42%	0.00086	7.81	0.64%	0.00114	10.41	0.85%
TOU-AG	24,088	0.10255	2,470	0.00016	3.92	0.16%	0.00033	7.84	0.32%	0.00049	11.76	0.48%	0.00065	15.67	0.63%
TOU-PA-5	51,703	0.09361	4,840	0.00016	8.37	0.17%	0.00032	16.75	0.35%	0.00049	25.12	0.52%	0.00065	33.50	0.69%
Group Total	8,244	0.11574	954	0.00022	1.79	0.19%	0.00043	3.58	0.38%	0.00065	5.37	0.56%	0.00087	7.16	0.75%
Street & Area Lighting	1,660	0.17016	283	0.00003	0.05	0.02%	0.00006	0.10	0.04%	0.00009	0.15	0.05%	0.00012	0.21	0.07%
System Total	1,363	0.13967	190	0.00024	0.33	0.17%	0.00048	0.65	0.34%	0.00072	0.98	0.51%	0.00095	1.30	0.68%

Notes:

Base 2007 averages based on 2007 ERRA sales forecast and rates effective April 1, 2007. The average annual bill assumes an increase in authorized revenue of 1/3 of 5%, 10%, 15%, and 20%. Authorized revenues are allocated to all rate groups based on adopted 2006 GRC distribution methodology. This charge is identical to bundled service and DA service. The average annual bill impacts would be the same for each of the 3 years in each scenario.

ALJ 4 Year Request
Southern California Edison Company
Average Rate and Bill Impact Estimates - by Rate Group
Energy Efficiency Incentive Proposal
Rates Effective April 1, 2007
Bundled Service

	2007 - Base Year			Scenario 5% of Annual $ 14.99 million/year			Scenario 10% of Annual $ 29.98 million/year			Scenario 15% of Annual $ 44.98 million/year			Scenario 20% of Annual $ 59.97 million/year		
	Average Monthly Usage (kWh)	Average Rate ($/kWh)	Average Monthly Bill ($)	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change	Average Rate Change	Average Bill Change	Average % Change
Residential	590	0.15157	89	0.00024	0.14	0.16%	0.00049	0.29	0.32%	0.00073	0.43	0.48%	0.00098	0.58	0.65%
Lighting-SM Med Power															
GS-1	868	0.17487	152	0.00019	0.16	0.11%	0.00038	0.33	0.21%	0.00056	0.49	0.32%	0.00075	0.65	0.43%
GS-2	11,196	0.14464	1,619	0.00018	1.96	0.12%	0.00035	3.92	0.24%	0.00053	5.88	0.36%	0.00070	7.84	0.48%
TC-1	422	0.13310	56	0.00020	0.08	0.15%	0.00040	0.17	0.30%	0.00060	0.25	0.45%	0.00080	0.34	0.60%
TOU-GS-2	85,123	0.13749	11,703	0.00014	12.11	0.10%	0.00028	24.22	0.21%	0.00043	36.33	0.31%	0.00057	48.44	0.41%
Group Total	3,814	0.14813	565	0.00017	0.64	0.11%	0.00034	1.28	0.23%	0.00050	1.93	0.34%	0.00067	2.57	0.45%
Large Power															
TOU-8-SEC	285,528	0.12772	36,469	0.00013	36.17	0.10%	0.00025	72.34	0.20%	0.00038	108.50	0.30%	0.00051	144.67	0.40%
TOU-8-PRI	634,054	0.11791	74,764	0.00011	68.86	0.09%	0.00022	137.71	0.18%	0.00033	206.57	0.28%	0.00043	275.42	0.37%
TOU-8-SUB	2,837,386	0.07956	225,745	0.00002	66.12	0.03%	0.00005	132.24	0.06%	0.00007	198.36	0.09%	0.00009	264.48	0.12%
Group Total	499,917	0.11085	55,416	0.00009	43.81	0.08%	0.00018	87.63	0.16%	0.00026	131.44	0.24%	0.00035	175.26	0.32%
Agricultural & Pumping															
PA-1	1,582	0.19370	307	0.00035	0.55	0.18%	0.00070	1.10	0.36%	0.00104	1.65	0.54%	0.00139	2.20	0.72%
PA-2	9,112	0.13486	1,229	0.00021	1.95	0.16%	0.00043	3.90	0.32%	0.00064	5.86	0.48%	0.00086	7.81	0.64%
TOU-AG	24,088	0.10255	2,470	0.00012	2.94	0.12%	0.00024	5.88	0.24%	0.00037	8.82	0.36%	0.00049	11.76	0.48%
TOU-PA-5	51,703	0.09361	4,840	0.00012	6.28	0.13%	0.00024	12.56	0.26%	0.00036	18.84	0.39%	0.00049	25.12	0.52%
Group Total	8,244	0.11574	954	0.00016	1.34	0.14%	0.00033	2.68	0.28%	0.00049	4.03	0.42%	0.00065	5.37	0.56%
Street & Area Lighting	1,660	0.17016	283	0.00002	0.04	0.01%	0.00005	0.08	0.03%	0.00007	0.12	0.04%	0.00009	0.15	0.05%
System Total	1,363	0.13967	190	0.00018	0.24	0.13%	0.00036	0.49	0.26%	0.00054	0.73	0.38%	0.00072	0.98	0.51%

Notes:

Base 2007 averages based on 2007 ERRA sales forecast and rates effective April 1, 2007. The average annual bill assumes an increase in authorized revenue of 1/4 of 5%, 10%, 15%, and 20%. Authorized revenues are allocated to all rate groups based on adopted 2006 GRC distribution methodology. This charge is identical to bundled service and DA service. The average annual bill impacts would be the same for each of the 4 years in each scenario.

ALJ request

Pacific Gas & Electric Company

Expected Rate and Bill Impacts

Customer Class	Average Usage (kWh/Therm)	2007 Avg Rate**	2007 Avg Bill**	Scenario 5% of Annual $15.319 million / year over 3 years			Scenario 10% of Annual $30.637 million / year over 3 years			Scenario 15% of Annual $45.956 million / year over 3 years			Scenario 20% of Annual $61.275 million / year over 3 years		
				Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007
ELECTRIC															
Bundled															
Residential															
Sch E-1*	550	$0.13089	$71.99	$0.00008	$0.04	0.06%	$0.00015	$0.08	0.11%	$0.00023	$0.12	0.17%	$0.00030	$0.17	0.23%
Sch E-1*	850	$0.17595	$149.55	$0.00034	$0.29	0.20%	$0.00069	$0.58	0.39%	$0.00103	$0.88	0.59%	$0.00138	$1.17	0.78%
Class Avg	570	$0.15070	$85.88	$0.00025	$0.14	0.16%	$0.00049	$0.28	0.33%	$0.00074	$0.42	0.49%	$0.00099	$0.56	0.66%
SLP	1,562	$0.15853	$247.60	$0.00025	$0.39	0.16%	$0.00050	$0.78	0.32%	$0.00075	$1.17	0.47%	$0.00100	$1.56	0.63%
Medium	16,601	$0.14497	$2,406.67	$0.00015	$2.46	0.10%	$0.00030	$4.91	0.20%	$0.00044	$7.37	0.31%	$0.00059	$9.82	0.41%
E-19	80,959	$0.12887	$10,433.53	$0.00013	$10.57	0.10%	$0.00026	$21.14	0.20%	$0.00039	$31.71	0.30%	$0.00052	$42.27	0.41%
Streetlights	918	$0.16947	$155.62	$0.00044	$0.41	0.26%	$0.00089	$0.81	0.52%	$0.00133	$1.22	0.78%	$0.00177	$1.63	1.04%
Standby	73,878	$0.11658	$8,612.56	$0.00009	$6.42	0.07%	$0.00017	$12.84	0.15%	$0.00026	$19.26	0.22%	$0.00035	$25.68	0.30%
Agriculture	4,734	$0.12327	$583.54	$0.00024	$1.14	0.20%	$0.00048	$2.28	0.39%	$0.00072	$3.43	0.59%	$0.00097	$4.57	0.78%
E-20	964,042	$0.10263	$98,940.51	$0.00006	$56.48	0.06%	$0.00012	$112.96	0.11%	$0.00018	$169.44	0.17%	$0.00023	$225.92	0.23%
Direct Access															
Re Avg	466	$0.07602	$35.44	$0.00022	$0.10	0.30%	$0.00047	$0.22	0.62%	$0.00072	$0.33	0.94%	$0.00096	$0.45	1.27%
SLP	4,800	$0.06933	$332.81	$0.00021	$0.99	0.30%	$0.00041	$1.98	0.59%	$0.00062	$2.97	0.89%	$0.00082	$3.96	1.19%
Medium	43,655	$0.04637	$2,024.15	$0.00012	$5.12	0.25%	$0.00023	$10.25	0.51%	$0.00035	$15.37	0.76%	$0.00047	$20.50	1.01%
E-19	90,039	$0.04469	$4,023.67	$0.00012	$10.48	0.26%	$0.00023	$20.96	0.52%	$0.00035	$31.44	0.78%	$0.00047	$41.92	1.04%
Agriculture	62,540	$0.04288	$2,681.42	$0.00011	$6.79	0.25%	$0.00022	$13.59	0.51%	$0.00033	$20.38	0.76%	$0.00043	$27.17	1.01%
E-20	1,441,128	$0.02523	$36,363.28	$0.00004	$60.86	0.17%	$0.00008	$121.72	0.33%	$0.00013	$182.58	0.50%	$0.00017	$243.44	0.67%
BART Federal Preference Power	10,000,000	$0.00857	$85,695.52	$0.00002	$173.88	0.20%	$0.00003	$347.77	0.41%	$0.00005	$521.65	0.61%	$0.00007	$695.54	0.81%

* Baseline Territory X, Basic Service

** Rates effective March 1, 2007, filed in Advice 2975-E-A.

GAS				Scenario 5% of Annual $2,468 million / year over 3 years			Scenario 10% of Annual $4,937 million / year over 3 years			Scenario 15% of Annual $7,405 million / year over 3 years			Scenario 20% of Annual $9,874 million / year over 3 years		
Core Retail - Bundled (1)															
Residential	45	$1.382	$62.20	$0.00094	$0.04	0.07%	$0.00187	$0.08	0.14%	$0.00281	$0.13	0.20%	$0.00374	$0.17	0.27%
Commercial, Small	296	1.259	$372.96	$0.00057	$0.17	0.05%	$0.00115	$0.34	0.09%	$0.00172	$0.51	0.14%	$0.00229	$0.68	0.18%
Commercial, Large	32,092	1.011	$32,441.32	$0.00008	$2.57	0.01%	$0.00016	$5.13	0.02%	$0.00024	$7.70	0.02%	$0.00032	$10.27	0.03%
Core Retail - Transportation Only (2)															
Residential	53	0.475	$25.20	$0.00094	$0.05	0.20%	$0.00187	$0.10	0.39%	$0.00281	$0.15	0.59%	$0.00374	$0.20	0.79%
Commercial, Small	1,137	0.360	$409.56	$0.00057	$0.65	0.16%	$0.00115	$1.31	0.32%	$0.00172	$1.96	0.48%	$0.00229	$2.60	0.64%
Commercial, Large	3,751	0.147	$552.56	$0.00008	$0.30	0.05%	$0.00016	$0.60	0.11%	$0.00024	$0.90	0.16%	$0.00032	$1.20	0.22%
Noncore - Transportation Only (2)															
Industrial Distribution	42,999	0.133	$5,705.56	$0.00006	$2.58	0.05%	$0.00013	$5.59	0.10%	$0.00019	$8.17	0.14%	$0.00026	$11.18	0.20%
Industrial Transmission	N/A***														
Industrial Backbone	N/A***														
Electric Generation	N/A***														
EG Backbone	N/A***														
Wholesale - Transportation Only (2)															
Wholesale	N/A***														

Prepared July 18 2007

** Gas Rates effective July 1, 2007 (AL2840-G complying with Resolution M-4819). Present Rates in this example exclude the current $2.2 Million of CEE Incentives.

*** N/A indicates that that the allocated dollars were not sufficient to cause a rate change.

(1) Bundled core rates include: i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.76897 per therm adopted in PG&E's Public Purpose Program Surcharge filing (AL2769-G); ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(2) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

PG&E Proposal

Pacific Gas & Electric Company

Expected Rate and Bill Impacts

				Scenario 5% of Annual $11.489 million / year over 4 years			Scenario 10% of Annual $22.978 million / year over 4 years			Scenario 15% of Annual $34.467 million / year over 4 years			Scenario 20% of Annual $45.956 million / year over 4 years		
Customer Class	Average Usage (kWh/Therm)	2007 Avg Rate**	2007 Avg Bill**	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007	Rate Change vs. 2007	Bill Change vs. 2007	% Change vs. 2007
TRIC															
ed															
Residential															
Sch E-1*	550	$0.13089	$71.99	$0.00006	$0.03	0.04%	$0.00011	$0.06	0.09%	$0.00017	$0.09	0.13%	$0.00023	$0.12	0.17%
Sch E-1*	850	$0.17595	$149.55	$0.00026	$0.22	0.15%	$0.00052	$0.44	0.29%	$0.00077	$0.66	0.44%	$0.00103	$0.88	0.59%
Class Avg	570	$0.15070	$85.88	$0.00019	$0.11	0.12%	$0.00037	$0.21	0.25%	$0.00056	$0.32	0.37%	$0.00074	$0.42	0.49%
SLP	1,562	$0.15853	$247.60	$0.00019	$0.29	0.12%	$0.00038	$0.59	0.24%	$0.00056	$0.88	0.36%	$0.00075	$1.17	0.47%
Medium	16,601	$0.14497	$2,406.67	$0.00011	$1.84	0.08%	$0.00022	$3.68	0.15%	$0.00033	$5.52	0.23%	$0.00044	$7.37	0.31%
E-19	80,959	$0.12887	$10,433.53	$0.00010	$7.93	0.08%	$0.00020	$15.85	0.15%	$0.00029	$23.78	0.23%	$0.00039	$31.71	0.30%
Streetlights	918	$0.16947	$155.62	$0.00033	$0.30	0.20%	$0.00066	$0.61	0.39%	$0.00100	$0.91	0.59%	$0.00133	$1.22	0.78%
Standby	73,878	$0.11658	$8,612.56	$0.00007	$4.81	0.06%	$0.00013	$9.63	0.11%	$0.00020	$14.44	0.17%	$0.00026	$19.26	0.22%
Agriculture	4,734	$0.12327	$583.54	$0.00018	$0.86	0.15%	$0.00036	$1.71	0.29%	$0.00054	$2.57	0.44%	$0.00072	$3.43	0.59%
E-20	964,042	$0.10263	$98,940.51	$0.00004	$42.36	0.04%	$0.00009	$84.72	0.09%	$0.00013	$127.08	0.13%	$0.00018	$169.44	0.17%
Access															
Re Avg	466	$0.07602	$35.44	$0.00016	$0.08	0.21%	$0.00035	$0.16	0.46%	$0.00053	$0.25	0.70%	$0.00072	$0.33	0.94%
SLP	4,800	$0.06933	$332.81	$0.00015	$0.74	0.22%	$0.00031	$1.48	0.45%	$0.00046	$2.23	0.67%	$0.00062	$2.97	0.89%
Medium	43,655	$0.04637	$2,024.15	$0.00009	$3.84	0.19%	$0.00018	$7.69	0.38%	$0.00026	$11.53	0.57%	$0.00035	$15.37	0.76%
E-19	90,039	$0.04469	$4,023.67	$0.00009	$7.86	0.20%	$0.00017	$15.72	0.39%	$0.00026	$23.58	0.59%	$0.00035	$31.44	0.78%
Agriculture	62,540	$0.04288	$2,681.42	$0.00008	$5.10	0.19%	$0.00016	$10.19	0.38%	$0.00024	$15.29	0.57%	$0.00033	$20.38	0.76%
E-20	1,441,128	$0.02523	$36,363.28	$0.00003	$45.64	0.13%	$0.00006	$91.29	0.25%	$0.00010	$136.93	0.38%	$0.00013	$182.58	0.50%
BART Federal Preference Power	10,000,000	$0.00857	$85,695.52	$0.00001	$130.41	0.15%	$0.00003	$260.83	0.30%	$0.00004	$391.24	0.46%	$0.00005	$521.65	0.61%

Baseline Territory X, Basic Service
Rates effective March 1, 2007, filed in Advice 2975-E-A.

				Scenario 5% of Annual $1.851 million / year over 4 years			Scenario 10% of Annual $3.703 million / year over 4 years			Scenario 15% of Annual $5.554 million / year over 4 years			Scenario 20% of Annual $7.405 million / year over 4 years		
Retail - Bundled (1)															
Residential	45	$1.382	$62.20	$0.00070	$0.03	0.05%	$0.00140	$0.06	0.10%	$0.00211	$0.09	0.15%	$0.00281	$0.13	0.20%
Commercial, Small	296	1.259	$372.96	$0.00043	$0.13	0.03%	$0.00086	$0.25	0.07%	$0.00129	$0.38	0.10%	$0.00172	$0.51	0.14%
Commercial, Large	32,092	1.011	$32,441.32	$0.00006	$1.93	0.01%	$0.00012	$3.85	0.01%	$0.00018	$5.78	0.02%	$0.00024	$7.70	0.02%
Retail - Transportation Only (2)															
Residential	53	0.475	$25.20	$0.00070	$0.04	0.15%	$0.00140	$0.07	0.29%	$0.00211	$0.11	0.44%	$0.00281	$0.15	0.59%
Commercial, Small	1,137	0.360	$409.56	$0.00043	$0.49	0.12%	$0.00086	$0.98	0.24%	$0.00129	$1.47	0.36%	$0.00172	$1.96	0.48%
Commercial, Large	3,751	0.147	$552.56	$0.00006	$0.23	0.04%	$0.00012	$0.45	0.08%	$0.00018	$0.68	0.12%	$0.00024	$0.90	0.16%
ore - Transportation Only (2)															
Industrial Distribution	42,999	0.133	$5,705.56	$0.00005	$2.15	0.04%	$0.00010	$4.30	0.08%	$0.00015	$6.45	0.11%	$0.00019	$8.17	0.14%
Industrial Transmission	N/A***														
Industrial Backbone	N/A***														
Electric Generation	N/A***														
EG Backbone	N/A***														
esale - Transportation Only (2)															
Wholesale	N/A***														

Prepared July 18 2007
Gas Rates effective July 1, 2007 (AL2840-G complying with Resolution M-4819). Present Rates in this example exclude the current $2.2 Million of CEE Incentives.
N/A indicates that that the allocated dollars were not sufficient to cause a rate change.

Bundled core rates include: i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.76897 per therm adopted in PG&E's Public Purpose Program Surcharge filing (AL2769-G); ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

San Diego Gas & Electric Company - Electric Department

Five Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)
Residential												
Schedule DR*	500		72.18		0.06	0.09%		0.06	0.09%		0.06	0.09%
Schedule DR**	800		132.98		0.37	0.28%		0.37	0.28%		0.37	0.28%
Class Average	510	15.419	78.64	0.03375	0.07	0.09%	0.03375	0.07	0.09%	0.03375	0.07	0.09%
Small Commercial	1,490	16.279	242.55	0.02560	0.38	0.16%	0.02560	0.38	0.16%	0.02560	0.38	0.16%
Medium and Large C&I	43,421	12.630	5,484.25	0.01386	6.02	0.11%	0.01386	6.02	0.11%	0.01386	6.02	0.11%
Agricultural	1,956	15.397	301.18	0.02556	0.50	0.17%	0.02556	0.50	0.17%	0.02556	0.50	0.17%
Lighting	1,373	14.741	202.39	0.01745	0.24	0.12%	0.01745	0.24	0.12%	0.01745	0.24	0.12%

Ten Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)
Residential												
Schedule DR*	500		72.18		0.13	0.17%		0.13	0.17%		0.13	0.17%
Schedule DR**	800		132.98		0.73	0.55%		0.73	0.55%		0.73	0.55%
Class Average	510	15.419	78.64	0.06750	0.15	0.19%	0.06750	0.15	0.19%	0.06750	0.15	0.19%
Small Commercial	1,490	16.279	242.55	0.05120	0.76	0.3%	0.05120	0.76	0.3%	0.05120	0.76	0.3%
Medium and Large C&I	43,421	12.630	5,484.25	0.02772	12.04	0.2%	0.02772	12.04	0.2%	0.02772	12.04	0.2%
Agricultural	1,956	15.397	301.18	0.05113	1.00	0.3%	0.05113	1.00	0.3%	0.05113	1.00	0.3%
Lighting	1,373	14.741	202.39	0.03490	0.48	0.2%	0.03490	0.48	0.2%	0.03490	0.48	0.2%

*** Represents the monthly bill impact for a typical residential customer using 500 kWh per month, and reflects an average of coastal and inland climate zones.**
**** Represents the monthly bill impact for a residential customer with higher than typical usage of 800 kWh per month.**

<u>Data Sources</u>
Typical bill impacts are calculated based on current rates in effect 7/1/07, pursuant to Advice Letter 1900-E.
Average bills calculated using average usage times class average rate.

San Diego Gas & Electric Company - Electric Department

Fifteen Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)
Residential												
Schedule DR*	500		72.18		0.19	0.26%		0.19	0.26%		0.19	0.26%
Schedule DR**	800		132.98		1.10	0.83%		1.10	0.83%		1.10	0.83%
Class Average	510	15.419	78.64	0.10125	0.22	0.28%	0.10125	0.22	0.28%	0.10125	0.22	0.28%
Small Commercial	1,490	16.279	242.55	0.07679	1.14	0.5%	0.07679	1.14	0.5%	0.07679	1.14	0.5%
Medium and Large C&I	43,421	12.630	5,484.25	0.04158	18.06	0.3%	0.04158	18.06	0.3%	0.04158	18.06	0.3%
Agricultural	1,956	15.397	301.18	0.07669	1.50	0.5%	0.07669	1.50	0.5%	0.07669	1.50	0.5%
Lighting	1,373	14.741	202.39	0.05234	0.72	0.4%	0.05234	0.72	0.4%	0.05234	0.72	0.4%

Twenty Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)
Residential												
Schedule DR*	500		72.18		0.25	0.35%		0.25	0.35%		0.25	0.35%
Schedule DR**	800		132.98		1.47	1.10%		1.47	1.10%		1.47	1.10%
Class Average	510	15.419	78.64	0.13500	0.29	0.37%	0.13500	0.29	0.37%	0.13500	0.29	0.37%
Small Commercial	1,490	16.279	242.55	0.10239	1.53	0.6%	0.10239	1.53	0.6%	0.10239	1.53	0.6%
Medium and Large C&I	43,421	12.630	5,484.25	0.05545	24.08	0.4%	0.05545	24.08	0.4%	0.05545	24.08	0.4%
Agricultural	1,956	15.397	301.18	0.10225	2.00	0.7%	0.10225	2.00	0.7%	0.10225	2.00	0.7%
Lighting	1,373	14.741	202.39	0.06979	0.96	0.5%	0.06979	0.96	0.5%	0.06979	0.96	0.5%

*** Represents the monthly bill impact for a typical residential customer using 500 kWh per month, and reflects an average of coastal and inland climate zones.**
**** Represents the monthly bill impact for a residential customer with higher than typical usage of 800 kWh per month.**

Data Sources
Typical bill impacts are calculated based on current rates in effect 7/1/07, pursuant to Advice Letter 1900-E.
Average bills calculated using average usage times class average rate.

San Diego Gas & Electric Company - Electric Department

Five Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)	2011 Average Rate Change vs 2007 (¢/kWh)	2011 Average Bill Change vs 2007 ($)	2011 % Change vs 2007 (%)
Residential															
Schedule DR*	500		72.18		0.05	0.07%		0.05	0.07%		0.05	0.07%		0.05	0.07%
Schedule DR**	800		132.98		0.27	0.21%		0.27	0.21%		0.27	0.21%		0.27	0.21%
Class Average	510	15.419	78.64	0.02531	0.05	0.07%	0.02531	0.05	0.07%	0.02531	0.05	0.07%	0.02531	0.05	0.07%
Small Commercial	1,490	16.279	242.55	0.01920	0.29	0.12%	0.01920	0.29	0.12%	0.01920	0.29	0.12%	0.01920	0.29	0.12%
Medium and Large C&I	43,421	12.630	5,484.25	0.01040	4.51	0.08%	0.01040	4.51	0.08%	0.01040	4.51	0.08%	0.01040	4.51	0.08%
Agricultural	1,956	15.397	301.18	0.01917	0.38	0.12%	0.01917	0.38	0.12%	0.01917	0.38	0.12%	0.01917	0.38	0.12%
Lighting	1,373	14.741	202.39	0.01309	0.18	0.09%	0.01309	0.18	0.09%	0.01309	0.18	0.09%	0.01309	0.18	0.09%

Ten Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)	2011 Average Rate Change vs 2007 (¢/kWh)	2011 Average Bill Change vs 2007 ($)	2011 % Change vs 2007 (%)
Residential															
Schedule DR*	500		72.18		0.09	0.13%		0.09	0.13%		0.09	0.13%		0.09	0.13%
Schedule DR**	800		132.98		0.55	0.41%		0.55	0.41%		0.55	0.41%		0.55	0.41%
Class Average	510	15.419	78.64	0.05063	0.11	0.14%	0.05063	0.11	0.14%	0.05063	0.11	0.14%	0.05063	0.11	0.14%
Small Commercial	1,490	16.279	242.55	0.03840	0.57	0.2%	0.03840	0.57	0.2%	0.03840	0.57	0.2%	0.03840	0.57	0.2%
Medium and Large C&I	43,421	12.630	5,484.25	0.02079	9.03	0.2%	0.02079	9.03	0.2%	0.02079	9.03	0.2%	0.02079	9.03	0.2%
Agricultural	1,956	15.397	301.18	0.03834	0.75	0.2%	0.03834	0.75	0.2%	0.03834	0.75	0.2%	0.03834	0.75	0.2%
Lighting	1,373	14.741	202.39	0.02617	0.36	0.2%	0.02617	0.36	0.2%	0.02617	0.36	0.2%	0.02617	0.36	0.2%

*** Represents the monthly bill impact for a typical residential customer using 500 kWh per month, and reflects an average of coastal and inland climate zones.**
**** Represents the monthly bill impact for a residential customer with higher than typical usage of 800 kWh per month.**

Data Sources
Typical bill impacts are calculated based on current rates in effect 7/1/07, pursuant to Advice Letter 1900-E.
Average bills calculated using average usage times class average rate.

San Diego Gas & Electric Company - Electric Department

Fifteen Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)	2011 Average Rate Change vs 2007 (¢/kWh)	2011 Average Bill Change vs 2007 ($)	2011 % Change vs 2007 (%)
Residential															
Schedule DR*	500		72.18		0.14	0.20%		0.14	0.20%		0.14	0.20%		0.14	0.20%
Schedule DR**	800		132.98		0.82	0.62%		0.82	0.62%		0.82	0.62%		0.82	0.62%
Class Average	510	15.419	78.64	0.07594	0.16	0.21%	0.07594	0.16	0.21%	0.07594	0.16	0.21%	0.07594	0.16	0.21%
Small Commercial	1,490	16.279	242.55	0.05759	0.86	0.4%	0.05759	0.86	0.4%	0.05759	0.86	0.4%	0.05759	0.86	0.4%
Medium and Large C&I	43,421	12.630	5,484.25	0.03119	13.54	0.2%	0.03119	13.54	0.2%	0.03119	13.54	0.2%	0.03119	13.54	0.2%
Agricultural	1,956	15.397	301.18	0.05752	1.13	0.4%	0.05752	1.13	0.4%	0.05752	1.13	0.4%	0.05752	1.13	0.4%
Lighting	1,373	14.741	202.39	0.03926	0.54	0.3%	0.03926	0.54	0.3%	0.03926	0.54	0.3%	0.03926	0.54	0.3%

Twenty Percent Customer Class	Average Usage (kWh)	2007 Avg Rate (¢/kWh)	2007 Average Bill ($)	2008 Average Rate Change vs 2007 (¢/kWh)	2008 Average Bill Change vs 2007 ($)	2008 % Change vs 2007 (%)	2009 Average Rate Change vs 2007 (¢/kWh)	2009 Average Bill Change vs 2007 ($)	2009 % Change vs 2007 (%)	2010 Average Rate Change vs 2007 (¢/kWh)	2010 Average Bill Change vs 2007 ($)	2010 % Change vs 2007 (%)	2011 Average Rate Change vs 2007 (¢/kWh)	2011 Average Bill Change vs 2007 ($)	2011 % Change vs 2007 (%)
Residential															
Schedule DR*	500		72.18		0.19	0.26%		0.19	0.26%		0.19	0.26%		0.19	0.26%
Schedule DR**	800		132.98		1.10	0.83%		1.10	0.83%		1.10	0.83%		1.10	0.83%
Class Average	510	15.419	78.64	0.10125	0.22	0.28%	0.10125	0.22	0.28%	0.10125	0.22	0.28%	0.10125	0.22	0.28%
Small Commercial	1,490	16.279	242.55	0.07679	1.14	0.5%	0.07679	1.14	0.5%	0.07679	1.14	0.5%	0.07679	1.14	0.5%
Medium and Large C&I	43,421	12.630	5,484.25	0.04158	18.06	0.3%	0.04158	18.06	0.3%	0.04158	18.06	0.3%	0.04158	18.06	0.3%
Agricultural	1,956	15.397	301.18	0.07669	1.50	0.5%	0.07669	1.50	0.5%	0.07669	1.50	0.5%	0.07669	1.50	0.5%
Lighting	1,373	14.741	202.39	0.05234	0.72	0.4%	0.05234	0.72	0.4%	0.05234	0.72	0.4%	0.05234	0.72	0.4%

*** Represents the monthly bill impact for a typical residential customer using 500 kWh per month, and reflects an average of coastal and inland climate zones.**
**** Represents the monthly bill impact for a residential customer with higher than typical usage of 800 kWh per month.**

<u>Data Sources</u>
Typical bill impacts are calculated based on current rates in effect 7/1/07, pursuant to Advice Letter 1900-E.
Average bills calculated using average usage times class average rate.

SoCalGas
Bill Impact of Shareholder Incentives at various Earnings Rates
Incentives Amortized over 4 Years
v7-19-2007

Customer Class	Average Usage (therms/mo) A	2007 Average Rate ($/therm) B	2007 Average Bill ($/month) C	2008 Average Rate Change Vs 2007 ($/therm) D	2008 Average Bill Change Vs 2007 ($/month) E	2008 % Change Vs 2007 F	2009 Average Rate Change Vs 2007 G	2009 Average Bill Change Vs 2007 H	2009 % Change Vs 2007 I	2010 Average Rate Change Vs 2007 J	2010 Average Bill Change Vs 2007 K	2010 % Change Vs 2007 L	Annual Sales (mth/yr) M	No. Customers N	Average Usage per customer (th/yr) O
5% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00066	$0.03	0.06%	$0.00066	$0.03	0.06%	$0.00066	$0.03	0.06%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00066	$0.19	0.06%	$0.00066	$0.19	0.06%	$0.00066	$0.19	0.06%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00066	$3.24	0.08%	$0.00066	$3.24	0.08%	$0.00066	$3.24	0.08%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
10% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00132	$0.06	0.11%	$0.00132	$0.06	0.11%	$0.00132	$0.06	0.11%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00132	$0.38	0.12%	$0.00132	$0.38	0.12%	$0.00132	$0.38	0.12%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00132	$6.48	0.15%	$0.00132	$6.48	0.15%	$0.00132	$6.48	0.15%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00066	$1.20	0.08%	$0.00066	$1.20	0.08%	$0.00066	$1.20	0.08%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
15% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00199	$0.09	0.17%	$0.00199	$0.09	0.17%	$0.00199	$0.09	0.17%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00199	$0.58	0.17%	$0.00199	$0.58	0.17%	$0.00199	$0.58	0.17%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00198	$9.72	0.23%	$0.00198	$9.72	0.23%	$0.00198	$9.72	0.23%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
20% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00265	$0.12	0.22%	$0.00265	$0.12	0.22%	$0.00265	$0.12	0.22%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00264	$0.77	0.23%	$0.00264	$0.77	0.23%	$0.00264	$0.77	0.23%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00264	$12.96	0.31%	$0.00264	$12.96	0.31%	$0.00264	$12.96	0.31%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00067	$1.22	0.08%	$0.00067	$1.22	0.08%	$0.00067	$1.22	0.08%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664

Notes:
1) Core average rate includes procurement, transportation, and PPP costs
2) Non-Core average rate includes transportation and PPP costs
3) July 2007 core procurement rate of $0.681/therm used for all three years
4) Current transportation rates are used for all three years
5) NonCore C&I reflects distribution level service

SDGE Gas Department
Bill Impact of Shareholder Incentives at various Earnings Rates
Incentives Amortized over 4 Years
v7-19-2007

Customer Class	Average Usage (therms/mo)	2007 Average Rate ($/therm)	2007 Average Bill ($/month)	2008 Average Rate Change Vs 2007	2008 Average Bill Change Vs 2007	2008 % Change Vs 2007	2009 Average Rate Change Vs 2007	2009 Average Bill Change Vs 2007	2009 % Change Vs 2007	2010 Average Rate Change Vs 2007	2010 Average Bill Change Vs 2007	2010 % Change Vs 2007	Annual Sales (mth/yr)	No. Customers	Average Usage per customer (th/yr)
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
5% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00119	$0.05	0.09%	$0.00119	$0.05	0.09%	$0.00119	$0.05	0.09%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00042	$0.17	0.04%	$0.00042	$0.17	0.04%	$0.00042	$0.17	0.04%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00041	$0.46	0.05%	$0.00041	$0.46	0.05%	$0.00041	$0.46	0.05%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00015	$11.97	0.10%	$0.00015	$11.97	0.10%	$0.00015	$11.97	0.10%	86,211	90	957,900
10% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00238	$0.09	0.18%	$0.00238	$0.09	0.18%	$0.00238	$0.09	0.18%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00084	$0.33	0.07%	$0.00084	$0.33	0.07%	$0.00084	$0.33	0.07%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00082	$0.91	0.09%	$0.00082	$0.91	0.09%	$0.00082	$0.91	0.09%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00031	$24.75	0.20%	$0.00031	$24.75	0.20%	$0.00031	$24.75	0.20%	86,211	90	957,900
15% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00357	$0.14	0.27%	$0.00357	$0.14	0.27%	$0.00357	$0.14	0.27%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00127	$0.50	0.11%	$0.00127	$0.50	0.11%	$0.00127	$0.50	0.11%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00124	$1.38	0.14%	$0.00124	$1.38	0.14%	$0.00124	$1.38	0.14%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00046	$36.72	0.30%	$0.00046	$36.72	0.30%	$0.00046	$36.72	0.30%	86,211	90	957,900
20% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00476	$0.18	0.35%	$0.00476	$0.18	0.35%	$0.00476	$0.18	0.35%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00169	$0.67	0.15%	$0.00169	$0.67	0.15%	$0.00169	$0.67	0.15%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00165	$1.83	0.19%	$0.00165	$1.83	0.19%	$0.00165	$1.83	0.19%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00062	$49.49	0.41%	$0.00062	$49.49	0.41%	$0.00062	$49.49	0.41%	86,211	90	957,900

Notes:
1) Core average rate includes procurement, transportation, and PPP costs
2) Non-Core average rate includes transportation and PPP costs
3) July 2007 core procurement rate of $0.715/therm used for all three years of $0.715/therm
4) Current transportation rates are used for all three years
5) NGV reflects uncompressed service
6) Noncore C&I reflects high pressure service

SoCalGas
Bill Impact of Shareholder Incentives at various Earnings Rates
Incentives Amortized over 4 Years
v7-19-2007

Customer Class	Average Usage (therms/mo) A	2007 Average Rate ($/therm) B	2007 Average Bill ($/month) C	2008 Average Rate Change Vs 2007 ($/therm) D	2008 Average Bill Change Vs 2007 ($/month) E	2008 % Change Vs 2007 F	2009 Average Rate Change Vs 2007 G	2009 Average Bill Change Vs 2007 H	2009 % Change Vs 2007 I	2010 Average Rate Change Vs 2007 J	2010 Average Bill Change Vs 2007 K	2010 % Change Vs 2007 L	Annual Sales (mth/yr) M	No. Customers N	Average Usage per customer (th/yr) O
5% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00050	$0.02	0.04%	$0.00050	$0.02	0.04%	$0.00050	$0.02	0.04%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00050	$0.15	0.04%	$0.00050	$0.15	0.04%	$0.00050	$0.15	0.04%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00050	$2.45	0.06%	$0.00050	$2.45	0.06%	$0.00050	$2.45	0.06%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	($0.00016)	($0.29)	-0.02%	($0.00016)	($0.29)	-0.02%	($0.00016)	($0.29)	-0.02%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
10% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00099	$0.04	0.08%	$0.00099	$0.04	0.08%	$0.00099	$0.04	0.08%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00099	$0.29	0.09%	$0.00099	$0.29	0.09%	$0.00099	$0.29	0.09%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00099	$4.86	0.11%	$0.00099	$4.86	0.11%	$0.00099	$4.86	0.11%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
15% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00149	$0.07	0.13%	$0.00149	$0.07	0.13%	$0.00149	$0.07	0.13%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00149	$0.43	0.13%	$0.00149	$0.43	0.13%	$0.00149	$0.43	0.13%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00149	$7.31	0.17%	$0.00149	$7.31	0.17%	$0.00149	$7.31	0.17%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00050	$0.91	0.06%	$0.00050	$0.91	0.06%	$0.00050	$0.91	0.06%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664
20% Earnings Rate															
Residential	44	$1.19	$52.36	$0.00199	$0.09	0.17%	$0.00199	$0.09	0.17%	$0.00199	$0.09	0.17%	2,484,024	4,695,661	529
Core C&I	291	$1.14	$332.25	$0.00199	$0.58	0.17%	$0.00199	$0.58	0.17%	$0.00199	$0.58	0.17%	700,113	200,480	3,492
Gas Air Conditioning	4,907	$0.86	$4,233.51	$0.00198	$9.72	0.23%	$0.00198	$9.72	0.23%	$0.00198	$9.72	0.23%	1,060	18	58,889
Gas Engine	1,819	$0.87	$1,577.96	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	$0.00001	$0.02	0.00%	15,240	698	21,834
Noncore C&I	104,472	$0.12	$12,461.34	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	$0.00000	$0.00	0.00%	1,456,757	1,162	1,253,664

Notes:
1) Core average rate includes procurement, transportation, and PPP costs
2) Non-Core average rate includes transportation and PPP costs
3) July 2007 core procurement rate of $0.681/therm used for all three years
4) Current transportation rates are used for all three years
5) NonCore C&I reflects distribution level service

SDGE Gas Department
Bill Impact of Shareholder Incentives at various Earnings Rates
Incentives Amortized over 4 Years
v7-19-2007

Customer Class	Average Usage (therms/mo)	2007 Average Rate ($/therm)	2007 Average Bill ($/month)	2008 Average Rate Change Vs 2007	2008 Average Bill Change Vs 2007	2008 % Change Vs 2007	2009 Average Rate Change Vs 2007	2009 Average Bill Change Vs 2007	2009 % Change Vs 2007	2010 Average Rate Change Vs 2007	2010 Average Bill Change Vs 2007	2010 % Change Vs 2007	Annual Sales (mth/yr)	No. Customers	Average Usage per customer (th/yr)
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
5% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00089	$0.03	0.07%	$0.00089	$0.03	0.07%	$0.00089	$0.03	0.07%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00032	$0.13	0.03%	$0.00032	$0.13	0.03%	$0.00032	$0.13	0.03%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00031	$0.34	0.04%	$0.00031	$0.34	0.04%	$0.00031	$0.34	0.04%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00012	$9.58	0.08%	$0.00012	$9.58	0.08%	$0.00012	$9.58	0.08%	86,211	90	957,900
10% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00178	$0.07	0.13%	$0.00178	$0.07	0.13%	$0.00178	$0.07	0.13%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00063	$0.25	0.05%	$0.00063	$0.25	0.05%	$0.00063	$0.25	0.05%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00062	$0.69	0.07%	$0.00062	$0.69	0.07%	$0.00062	$0.69	0.07%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00023	$18.36	0.15%	$0.00023	$18.36	0.15%	$0.00023	$18.36	0.15%	86,211	90	957,900
15% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00268	$0.10	0.20%	$0.00268	$0.10	0.20%	$0.00268	$0.10	0.20%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00095	$0.37	0.08%	$0.00095	$0.37	0.08%	$0.00095	$0.37	0.08%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00093	$1.03	0.11%	$0.00093	$1.03	0.11%	$0.00093	$1.03	0.11%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00035	$27.94	0.23%	$0.00035	$27.94	0.23%	$0.00035	$27.94	0.23%	86,211	90	957,900
20% Earnings Rate															
Residential	38	$1.34	$51.35	$0.00357	$0.14	0.27%	$0.00357	$0.14	0.27%	$0.00357	$0.14	0.27%	326,207	711,899	458
Core C&I	394	$1.16	$458.04	$0.00127	$0.50	0.11%	$0.00127	$0.50	0.11%	$0.00127	$0.50	0.11%	129,794	27,466	4,726
NGV	1,112	$0.86	$960.96	$0.00124	$1.38	0.14%	$0.00124	$1.38	0.14%	$0.00124	$1.38	0.14%	4,030	302	13,344
Noncore C&I	79,825	$0.15	$12,197.52	$0.00046	$36.72	0.30%	$0.00046	$36.72	0.30%	$0.00046	$36.72	0.30%	86,211	90	957,900

Notes:
1) Core average rate includes procurement, transportation, and PPP costs
2) Non-Core average rate includes transportation and PPP costs
3) July 2007 core procurement rate of $0.715/therm used for all three years of $0.715/therm
4) Current transportation rates are used for all three years
5) NGV reflects uncompressed service
6) Noncore C&I reflects high pressure service

SHAREHOLDER INCENTIVE SCENARIOS
BASED ON TABLE 8A

SDG&E

Assumptions

PEB @ 100% of Goal	$297	
Electric Benefit	$556	90%
Gas Benefit	$61	10%

Earnings Rate	5%	10%	15%	20%
Electric Earnings	$13.38	$26.76	$40.15	$53.53
Gas Earnings	$1.47	$2.94	$4.40	$5.87
Total Earnings	$14.85	$29.70	$44.55	$59.40

Scenario 1: Equal Payments over 3 years

Earnings Rate	5%	10%	15%	20%
Electric Annual Payment	$4.46	$8.92	$13.38	$17.84
Gas Annual Payment	$0.49	$0.98	$1.47	$1.96
Total Annual Payment	$4.95	$9.90	$14.85	$19.80

Scenario 2: Equal Payments over 4 years

Earnings Rate	5%	10%	15%	20%
Electric Annual Payment	$3.35	$6.69	$10.04	$13.38
Gas Annual Payment	$0.37	$0.73	$1.10	$1.47
Total Annual Payment	$3.71	$7.43	$11.14	$14.85

Earnings Rate	5%	10%	15%	20%
SDGEgas				
Total	$1,468,152	$2,936,305	$4,404,457	$5,872,609
3 years	$489,384	$978,768	$1,468,152	$1,957,536
4 years	$367,038	$734,076	$1,101,114	$1,468,152
gas rate change 3 years				
Residential	$0.00119	$0.00238	$0.00357	$0.00476
Core C&I	$0.00042	$0.00084	$0.00127	$0.00169
NGV	$0.00041	$0.00082	$0.00124	$0.00165
Noncore C&I	$0.00015	$0.00031	$0.00046	$0.00062
gas rate change 4 years				
Residential	$0.00089	$0.00178	$0.00268	$0.00357
Core C&I	$0.00032	$0.00063	$0.00095	$0.00127
NGV	$0.00031	$0.00062	$0.00093	$0.00124
Noncore C&I	$0.00012	$0.00023	$0.00035	$0.00046

SoCalGas

Assumptions

PEB @ 100% of Goal	$135	
Electric Benefit	$20	5%
Gas Benefit	$357	95%

Earnings Rate	5%	10%	15%	20%
Electric Earnings	$0.36	$0.71	$1.07	$1.43
Gas Earnings	$6.37	$12.74	$19.10	$25.47
Total Earnings	$6.73	$13.45	$20.18	$26.90

Scenario 1: Equal Payments over 3 years

Earnings Rate	5%	10%	15%	20%
Electric Annual Payment	$0.12	$0.24	$0.36	$0.48
Gas Annual Payment	$2.12	$4.25	$6.37	$8.49
Total Annual Payment	$2.24	$4.48	$6.73	$8.97

Scenario 2: Equal Payments over 4 years

Earnings Rate	5%	10%	15%	20%
Electric Annual Payment	$0.09	$0.18	$0.27	$0.36
Gas Annual Payment	$1.59	$3.18	$4.78	$6.37
Total Annual Payment	$1.68	$3.36	$5.04	$6.73

Earnings Rate	5%	10%	15%	20%
SCG				
Total	$6,725,000	$13,450,000	$20,175,000	$26,900,000
3 years	$2,241,667	$4,483,333	$6,725,000	$8,966,667
4 years	$1,681,250	$3,362,500	$5,043,750	$6,725,000
gas rate change 3 years				
Residential	$0.00066	$0.00132	$0.00199	$0.00265
Core C&I	$0.00066	$0.00132	$0.00199	$0.00264
Gas Air Conditioning	$0.00066	$0.00132	$0.00198	$0.00264
Gas Engine	$0.00000	$0.00066	$0.00001	$0.00067
Noncore C&I	$0.00000	$0.00000	$0.00000	$0.00000
gas rate change 3 years				
Residential	$0.00050	$0.00099	$0.00149	$0.00199
Core C&I	$0.00050	$0.00099	$0.00149	$0.00199
Gas Air Conditioning	$0.00050	$0.00099	$0.00149	$0.00198
Gas Engine	($0.00016)	$0.00001	$0.00050	$0.00001
Noncore C&I	0	0	0	0

(END OF ATTACHMENT 10)