BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Program Augmentations and Associated Funding for the Years 2013 through 2014.	Application 12-12-XXX (Filed on December 21, 2012)

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M) FOR APPROVAL OF DEMAND RESPONSE PROGRAM AUGMENTATIONS AND ASSOCIATED FUNDING FOR THE YEARS 2013 THROUGH 2014

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December 21, 2012

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I.
INTRODUCTION

In compliance with the California Public Utilities' Commission's ("Commission" or "CPUC") Rules of Practice and Procedures ("Rules") and D.12-04-045, dated April 19, 2012, and as modified by D.12-08-023, dated August 20, 2012, as well as pursuant to the direction reflected in the November 16, 2012 letter from Mr. Edward Randolph, Director, Energy Division (then "November Letter"). San Diego Gas & Electric Company (SDG&E) submits this Application (the "Application") for approval its Demand Response Program ("DRP") augmentation budgets for the years 2013 and 2014 and revision to selected DR programs previously adopted by D.12-0404, D.12-08-023, Resolutions E-4502 and E-4511.

As discussed in greater detail below and in the testimony served concurrently herewith and incorporated by reference, the Application seeks Commission authority to: 1) implement the revisions to selected DR programs; and, 2) approve the corresponding budgets and fund shifting to implement these program revisions.

In addition to direction to file the Application, the November Letter included an attachment entitled, "Energy Division Guidance for Post Summer 2012 DR Evaluation and 2013/2014 Summer Planning containing questions to which SDG&E was required to respond ("ED Questions"). The November Letter instructed SDG&E to include the responses to the ED Questions in this Application. SDG&E provides its responses as Appendix X. The information included in Appendix X is not referenced in witness Costello's testimony, nor does Appendix X have any direct relevance to the 2013-2014 DRP program proposal requested by SDG&E in this Application.

II.
BACKGROUND

A. 2012 Summer

In early 2012, Units 2 and 3 of the San Onofre Nuclear Generating Station ("SONGS") were taken out of service as a result of various operational concerns. Those units have remained out of service throughout 2012 (although SONGS operator Southern California Edison Company ("SCE") has submitted a proposed plan for partial restart of Unit 2 to the Nuclear Regulatory Commission), and at the present time their return to service is unknown.

As a result of the anticipated outage of SONGS Units 2 and 3 during the summer months of 2012, on April 25, 2012, Mr. Edward Randolph - Director, Energy Division, directed that SCE and SDG&E "…submit Tier 3 advice letters ("ALs") proposing [DR] program augmentations and improvements…" and that "…SCE and SDG&E should focus their efforts on areas potentially affected by the SONGS outage…with programs to be effective no later than July 1, 2012." Mr. Randolph's direction further provided that, in order to address the potential reliability issues that may arise during the summer months of 2012 as a result of the SONGS outage, and because of the shortened time frame and expedited nature of the request, the advice letters be submitted by April 30, 2012, with protests due on May 3 and replies due on May 4.

While receipt of the Energy Division letter on April 27, 2012 did not allow for an extended period of time to develop and evaluate a variety of program augmentation and enhancement proposals, SDG&E filed its AL 2351-E on April 30, 2012. This was done following collaboration between SDG&E and stakeholders, as well as consultation with Energy Division staff. AL 2351-E proposed modifications to its existing PTR program, and the establishment of a new SummerGen 2012 program, utilizing on-site, customer-owned generation facilities. The proposed modifications to PTR sought to expand the program's applicability (previously approved for residential customers only) to include SDG&E's small Commercial and Industrial customer segments. SDG&E also proposed funding of its proposed revisions through budget fund-shifting guidelines established by D.12-04-045. SDG&E's proposed revisions to PTR, and the associated funding, were approved by Commission Resolution E-4502 on May 24, 2012. SDG&E's proposed SummerGen 2012 program was deferred for separate consideration, and due to concerns over required San Diego County Air Pollution Control District permit modifications, dispatch protocols and other operating provisions, SDG&E subsequently withdrew the SummerGen 2012 proposal by letter dated June 7, 2012.

SDG&E filed AL 2370-E on June 1, 2012, proposing the Demand Bidding 2012 ("DBP") program following direction from Energy Division staff and discussions between SDG&E, stakeholders, some SDG&E's larger customers. The proposed DBP program would offer incentives to non-residential customers for reducing energy consumption and demand during a program event, and would be available to those customers capable of providing at least 5 MW of load reduction. SDG&E also proposed funding 2012 DBP through budget fund-shifting as established by D.12-04-045. The Commission approved AL 2370-E through Resolution E-4511, dated July 12, 2012. SDG&E subsequently filed the DBP 2012 customer contract form to implement DBP 2012 by AL 2386-E, dated July 20, 2012.

On June 14, 2012, SDG&E filed its AL 2373-E, submitting certain tariff revisions in compliance with D.12-04-045, which adopted SDG&E's 2012 – 2014 DRP portfolio and budgets. Among the DRP portfolio revisions adopted by D.12-04-045 was SDG&E's proposal to terminate its then-existing Critical Peak Pricing-Emergency ("CPP-E") program. SDG&E has proposed elimination of CPP-E for a variety of reasons, including the small number of participating customers and the desire to transition those customers onto other DR programs. Although D.12-04-045 adopted SDG&E's proposal to eliminate CPP-E, it did delegate to Energy Division staff the authority to "…enable program changes to go into effect starting in 2013 and to continue to 2012, leaving 2012 unmodified if needed." (see D.12-04-045, pages 132-133, and SDG&E's AL 2373-E, page 2). Following discussions with Energy Division staff, and in light of the SONGS outage, SDG&E proposed in AL 2373-E the deferral of the closure of CPP-E to December 31, 2012, thereby preserving the availability of the program through 2012. This would allow SDG&E to take advantage of the available load reduction potential from CPP-E. AL 2373-E was subsequently approved as a Tier 1 compliance filing, effective June 24, 2012.

These DR program augmentations and enhancements, as well as the associated funding proposals reflected in SDG&E's ALs 2351-E, 2370-E and 2386-E reflected program revisions and funding, and approved by Resolutions E-4502 and E-4511 are effective only for 2012.

B. 2013-2014 Outlook

SDG&E has examined the resources and outlook for the summer of 2013. As a result, and given the outlook for generation, transmission, and anticipated customer loads, SDG&E concludes that based on ongoing efforts of SDG&E, SCE and the CAISO that SDG&E will be able to meet loads even under transmission contingency situations in 2013. Only in the case involving the AES Huntington Beach Units 3 and 4 synchronous condenser project not being placed in service by mid-2013 does SDG&E foresee shortages in meeting planning criteria. Furthermore, the results of SDG&E's program augmentations for Summer 2012 confirmed that there should not be any significant reliance on short-term incremental load reductions through Demand Response Programs to offset the Huntington Beach synchronous condenser project. In this scenario incremental load reductions would be so small as to be insignificant to mitigate the overall consequences should this synchronous condenser project not go forward. In his November Letter, Mr. Randolph expressed his concern over the ongoing outage of SONGS and indicated that he is, "…initiating further commission consideration of utility demand response (DR) programs in the SCE and SDG&E service territories for the summers of 2013 and 2014." He further indicated that, "…SDG&E should submit Application(s) proposing program improvements and augmentations to (their) existing demand response (DR) program portfolios." Accordingly, SDG&E hereby submits hereby submits this DR Application.

III.
SUMMARY OF APPLICATION

The Application is supported by SDG&E witness Michelle Costello, Demand Response Manager. The witness' prepared direct testimony is served concurrently herewith, incorporated in the Application by reference, and summarized below:

A. Purpose

SDG&E witness Costello describes the purpose of this application, 2012 DRP changes to support identified needs resulting from the uncertainties of SONGs and the outlook for 2013 and 2014.

B. 2013-2014 DRP Proposal

This section describes the following specific program proposals:

- Continuation of a modified Demand Bidding Program;
- Issuance of a new request for proposals for load control product(s);
- Continuation of its Community Partners and expansion to include south Orange County community based organizations;
- Discussion of program budgets required to support these requests; and
- Changes to tariffs to reflect program changes.

C. Cost Effectiveness

This section presents the results of the cost effectiveness analysis for the proposed program changes.

D. Cost Recovery Mechanism

This section discusses the cost recovery mechanism that will be used to record and recover expenses incurred for these programs.

IV.
RATE AND REVENUE IMPACTS

A. Current Cost Recovery Mechanism

Consistent with D.12-04-045 and its testimony in A.11-03-002, the regulatory accounting and cost recovery treatment for the requested augmented budget in this application is described below.

- SDG&E currently records all program costs associated with its existing demand response programs and its current and future DRP bilateral contracts[1] in its Advanced Metering and Demand Response Memorandum Account ("AMDRA"). SDG&E will continue then transfer the existing disposition of the AMDRA balances to SDG&E's Rewards and Penalties Balancing Account (RPBA") on an annual basis for amortization in SDG&E's electric distribution rates over 12 months, effective on January 1st of each year, consistent with SDG&E's adopted tariffs.
- SDG&E will continue to record in AMDRA authorized demand response program costs related to DR Operation and Maintenance ("O&M") expenses, capital related costs (i.e., depreciation, return and taxes), customer capacity incentive payments, and all other costs, not recovered through SDG&E's General Rate Case ("GRC").
- The one exception to the way SDG&E records demand response programs costs in AMDRA is the recording of the energy component of the DRP customer incentive payments in its Energy Resource Recovery Account ("ERRA").

[1] SDG&E's existing bilateral contracts are its Summer Saver and Demand Smart programs.

The current and proposed electric rates of SDG&E's proposal in years 2014 and 2015 are noted in the tables below:

SAN DIEGO GAS & ELECTRIC®
DEMAND RESPONSE PROGRAMS - ELECTRIC
ILLUSTRATIVE ELECTRIC RATE IMPACT
2014

Customer Class	9/1/2012	2014	Change	
	¢/kWh	¢/kWh	¢	%
(a)	(b)	(c)	(d)	(e)
Residential	18.324	18.325	0.001	0.01%
Small Commercial	18.001	18.002	0.001	0.01%
Med & Lg Commercial/Industrial	14.305	14.306	0.001	0.01%
Agriculture	17.509	17.509	0.000	0.00%
Street Lighting	14.868	14.868	0.000	0.00%
System Total	16.154	16.155	0.001	0.01%

SAN DIEGO GAS & ELECTRIC
DEMAND RESPONSE PROGRAMS - ELECTRIC
ILLUSTRATIVE ELECTRIC RATE IMPACT
2015

Customer Class	9/1/2012	2015	Change	
	¢/kWh	¢/kWh	¢	%
(a)	(b)	(c)	(d)	(e)
Residential	18.324	18.333	0.009	0.05%
Small Commercial	18.001	18.010	0.009	0.05%
Med & Lg Commercial/Industrial	14.305	14.312	0.007	0.05%
Agriculture	17.509	17.517	0.008	0.05%
Street Lighting	14.868	14.875	0.007	0.05%
System Total	16.154	16.162	0.008	0.05%

The monthly winter bill for a typical residential customer living in the inland climate zone using 500 kWh will change from $83.52 at present rates to $83.53 in 2014 and $83.54 in 2015 respectively.

V.
STATUTORY AND PROCEDURAL REQUIREMENTS

A. Proposed Category, Issues to be Considered, Need for Hearings and Proposed Schedule

SDG&E proposes to categorize this Application as a "rate-setting" proceeding within the meaning of Rules 1.3(e) and 7.1. SDG&E does not believe hearings will be necessary but respectfully requests that the Commission adopt a final decision by the first quarter of 2013 to enable SDG&E to have ample time to implement these programs effective January 1, 2013. Therefore, SDG&E proposes the following schedule:

<u>Schedule</u>

Filing of Application	December 21, 2012
Protests and Responses to Application	January 17, 2013
Replies to Protest or Responses	January 22, 2013
Pre-Hearing Conference	February 5, 2013
Intervenor Testimony Due	February 11, 2013
Proposed Decision	February 19, 2013
Comments on Proposed Decision	March 11, 2013
Final Decision	March 21, 2013

B. Statutory Authority – Rule 2.1

This Application is made pursuant to Sections 451, 701, 702 , 728, and 729 of the Public Utilities Code of the State of California; the Commission's Rule of Practice and Procedure; and the other relevant prior decisions, orders, and resolutions of the Commission.

C. Legal Name, Place of Business/Incorporation – Rule 2.1(a)

Applicant's legal name is San Diego Gas & Electric Company. SDG&E is a public utility corporation organized and exiting under the laws of the State of California, with its principal place of business at 8830 Century Park Court, San Diego, California 92123.

D. Correspondence – Rule 2.1(b)

Correspondence or communications regarding this application should be addressed to:

Joy C. Yamagata
Regulatory Case Administrator for
San Diego Gas & Electric Company
8330 Century Park Court
San Diego, California 92123
Telephone: (858) 654-1755
Facsimile: (858) 654-1788
E-Mail: JYamagata@semprautilities.com

With a copy to:

Steven D. Patrick
Attorney For
San Diego Gas & Electric Company
555 West 5th Street, Suite 1400
Los Angeles, CA 90013
Telephone: (213) 244-2954
Facsimile: (213) 629-9620
E-Mail: SDPatrick@semprautilities.com

E. Articles of Incorporation - Rule 16

SDG&E is incorporated under the laws of the State of California. A certified copy of the restated Articles of Incorporation, as last amended, currently in effect and certified by the California Secretary of State, was filed with the Commission on October 1, 1998 in connection with SDGE&E' Application No. 98-10-012, and is incorporated herein by reference.

F. Financial Statement, Balance Sheet, and Income Statement - Rule 3.2(a)(4)

Appendix A to this Application is SDG&E's Financial Statement, Balance Sheet and Income Statement as of as of September 30, 2012.

G. Rates – Rules 3.2(a)(2) and 3.2(a)(3)

Illustrative electric distribution rate impacts for years 2014-2015 resulting from the proposed DR budgets are presented in Section IV.

H. Property and Equipment – Rule 3.2(a)(4)

A general description of SoCalGas and SDG&E's respective properties was filed with the Commission on October 5, 2001, in connection with Application 01-10-005, and is being incorporated herein by reference. Appendix B to this Application is a statement of SDG&E's Costs of Property and Depreciation Reserve Applicable Thereto as of September 30, 2012.

I. Summary of Earnings – Rules 3.2(a)(5)

Appendix C to this Application is a Summary of Earnings for SDG&E for the 3 months ended September 30, 2012.

J. Depreciation – Rule 3.2(7)

For financial statement purposes, depreciation of utility plant has been computed on a straight-line remaining life basis at rates based on the estimated useful lives of plant properties. For federal income tax accrual purposes, SDG&E generally computes depreciation using the straight-line method for tax property additions prior 1954, and liberalized depreciation , which includes Class Life and Asset Depreciation Range Systems, on tax property additions after 1954and prior 1981. For financial reporting and rate-fixing purposes, "flow through accounting" has been adopted for such properties. For tax property additions in years 1981 through 1986, SDG&E has computed its tax depreciation using the Modified Accelerated Cost Recovery Systems and, since 1982, has normalized the effects of the depreciation differences in accordance with the Economic Recovery Tax Act of 1981 and the Tax Reform Act of 1986.

K. Proxy Statement – Rule 3.2(a)(8)

A copy of SDG&E's most recent proxy statement, dated April 27, 2012, was mailed to the California Public Utilities Commission on May 2, 2012.

L. Pass Through of Costs – Rule 3.2(a)(10)

The changes that SDG&E seeks in this Application reflect estimated costs to SDG&E, and SDG&E proposes to pass through to customers only costs that SDG&E incurs for the services and commodities it furnishes.

M. Service and Notice – Rule 3.2(b)

SDG&E is serving this Application on all parties in A.11-03-001, A.11-03-002 and A.11-03-003. Within ten days of filing this Application, SDG&E will mail notice of this Application to the State of California and to cities and counties that SDG&E will post the notice in its offices and publish the notice in newspapers of general circulation in each county in its service territory. In addition, SDG&E will include notices with the regular bills mailed to all customers affected by the proposed rate changes. The service list of state and government agencies is attached hereto as Appendix D.

VI.
RELIEF REQUESTED

For the reasons set forth in this Application and accompanying testimony, SDG&E respectfully asks the Commission to:

1. Approve an increase to SDG&E approved 2012-2014 DRP budget by an incremental amount of $1,631,108, to fund its Demand Bidding Program ("DBP") and Customer Education, Awareness and Outreach ("CEAO") program proposals.
2. Approve the fund shift of $4,983,649 of unspent authorized budget from Peak Time Rebate ("PTR") program back to its Capacity Bidding Program ("CBP").
3. Authorize the continuation of SDG&E's DBP approved by Resolution E-4511, with revisions, most notably, the establishment of a new, day-of, 30-minute notice product. DBP would be funded through the budget fund-shift authorized by Resolution E-4511.
4. Authorize SDG&E to issue a Request for Proposals ("RFP") solicitation, to seek proposals from third-party vendors for new programs and technologies to implement load control programs, intended to augment and expand existing technologies and programs within SDG&E's service territory.
5. Authorize SDG&E's proposed Community-Partners initiative element of its CEAO program to continue and expand to include south Orange County CBOs.
6. Authorize SDG&E's proposed revisions to the tariff language for Schedules DBP and PTR that incorporate the proposed program enhancements.

WHEREFORE, SDG&E respectfully requests the Commission grant its Application as filed.

Dated this 21st day of December, 2012.

Respectfully submitted,

/s/ Caroline A. Winn

Caroline A. Winn
Vice President – Customer Solutions
San Diego Gas & Electric Company

/s/ Steven D. Patrick

Steven D. Patrick
Attorney for
San Diego Gas & Electric Company

VERIFICATION

I am an officer of San Diego Gas & Electric Company, and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing Application are true and to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 21st day of December, 2012 at San Diego, California.

/s/ Caroline A. Winn

Caroline A. Winn
Vice President – Customer Solutions
San Diego Gas & Electric Company

APPENDIX A
Financial Statement, Balance Sheet and Income Statement

SAN DIEGO GAS & ELECTRIC COMPANY
FINANCIAL STATEMENT
SEPTEMBER 30, 2012

(a) Amounts and Kinds of Stock Authorized:

Preferred Stock	1,375,000	shares	Par Value $27,500,000
Preferred Stock	10,000,000	shares	Without Par Value
Preferred Stock	Amount of shares not specified		$80,000,000
Common Stock	255,000,000	shares	Without Par Value

Amounts and Kinds of Stock Outstanding:

PREFERRED STOCK			
5.0%	375,000	shares	$7,500,000
4.50%	300,000	shares	6,000,000
4.40%	325,000	shares	6,500,000
4.60%	373,770	shares	7,475,400
$1.70	1,400,000	shares	35,000,000
$1.82	640,000	shares	16,000,000
COMMON STOCK	116,583,358	shares	291,458,395

(b) Terms of Preferred Stock:
Full information as to this item is given in connection with Application Nos. 93-09-069, 04-01-009, 06-05-015 and 10-10-023 to which references are hereby made.

(c) Brief Description of Mortgage:
Full information as to this item is given in Application Nos. 08-07-029,10-10-023 and 12-03-005 to which references are hereby made.

(d) Number and Amount of Bonds Authorized and Issued:

First Mortgage Bonds:	Nominal Date of Issue	Par Value Authorized and Issued	Outstanding	Interest Paid in 2011
6.8% Series KK, due 2015	12-01-91	14,400,000	14,400,000	979,200
Var% Series OO, due 2027	12-01-92	250,000,000	150,000,000	7,612,500
5.85% Series RR, due 2021	06-29-93	60,000,000	60,000,000	3,510,000
2.539% Series VV, due 2034	06-17-04	43,615,000	43,615,000	2,562,373
2.539% Series WW, due 2034	06-17-04	40,000,000	40,000,000	2,349,999
2.516% Series XX, due 2034	06-17-04	35,000,000	35,000,000	2,056,249
2.832% Series YY, due 2034	06-17-04	24,000,000	24,000,000	1,409,999
2.832% Series ZZ, due 2034	06-17-04	33,650,000	33,650,000	1,976,936
2.8275% Series AAA, due 2039	06-17-04	75,000,000	75,000,000	134,561
5.35% Series BBB, due 2035	05-19-05	250,000,000	250,000,000	13,375,000
5.30% Series CCC, due 2015	11-17-05	250,000,000	250,000,000	13,250,000
6.00% Series DDD. due 2026	06-08-06	250,000,000	250,000,000	15,000,000
Var Series EEE, due 2018	09-21-06	161,240,000	161,240,000	324,863
6.125% Series FFF, due 2037	09-20-07	250,000,000	250,000,000	15,312,500
6.00% Series GGG, due 2039	05-14-09	300,000,000	300,000,000	18,000,000
5.35% Series HHH, due 2040	05-13-10	250,000,000	250,000,000	13,375,000
4.50% Series III, due 2040	08-15-10	500,000,000	500,000,000	21,812,500
3.00% Series JJJ, due 2021	08-18-11	350,000,000	350,000,000	0
3.95% Series LLL, due 2041	11-17-11	250,000,000	250,000,000	0
4.30% Series MMM, due 2042	03-22-12	250,000,000	250,000,000	0
Unsecured Bonds:				
5.9% CPCFA96A, due 2014	06-01-96	129,820,000	129,820,000	7,659,380
5.3% CV96A, due 2021	08-02-96	38,900,000	38,900,000	2,061,700
5.5% CV96B, due 2021	11-21-96	60,000,000	60,000,000	3,300,000
4.9% CV97A, due 2023	10-31-97	25,000,000	25,000,000	1,225,000

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
ASSETS AND OTHER DEBITS
SEPTEMBER 30, 2012

	1. UTILITY PLANT	2012
101	UTILITY PLANT IN SERVICE	$13,487,237,954
102	UTILITY PLANT PURCHASED OR SOLD	13,548,294
104	UTILITY PLANT LEASED TO OTHERS	85,194,000
105	PLANT HELD FOR FUTURE USE	8,151,201
106	COMPLETED CONSTRUCTION NOT CLASSIFIED	-
107	CONSTRUCTION WORK IN PROGRESS	644,811,836
108	ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT	(4,891,310,393)
111	ACCUMULATED PROVISION FOR AMORTIZATION OF UTILITY PLANT	(256,001,359)
118	OTHER UTILITY PLANT	696,958,732
119	ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF OTHER UTILITY PLANT	(194,217,472)
120	NUCLEAR FUEL - NET	114,909,686
	TOTAL NET UTILITY PLANT	9,709,282,479

	2. OTHER PROPERTY AND INVESTMENTS	
121	NONUTILITY PROPERTY	6,313,633
122	ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF NONUTILITY PROPERTY	(546,049)
123	INVESTMENTS IN SUBSIDIARY COMPANIES	-
124	OTHER INVESTMENTS	-
125	SINKING FUNDS	-
128	OTHER SPECIAL FUNDS	891,855,963
	TOTAL OTHER PROPERTY AND INVESTMENTS	897,623,547

Data from SPL as of November 29, 2012

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
ASSETS AND OTHER DEBITS
SEPTEMBER 30, 2012

3. CURRENT AND ACCRUED ASSETS

		2011
131	CASH	217,557
132	INTEREST SPECIAL DEPOSITS	-
134	OTHER SPECIAL DEPOSITS	-
135	WORKING FUNDS	500
136	TEMPORARY CASH INVESTMENTS	-
141	NOTES RECEIVABLE	-
142	CUSTOMER ACCOUNTS RECEIVABLE	233,612,683
143	OTHER ACCOUNTS RECEIVABLE	20,081,947
144	ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS	(2,863,738)
145	NOTES RECEIVABLE FROM ASSOCIATED COMPANIES	-
146	ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES	16,778,226
151	FUEL STOCK	2,305,557
152	FUEL STOCK EXPENSE UNDISTRIBUTED	-
154	PLANT MATERIALS AND OPERATING SUPPLIES	78,537,372
156	OTHER MATERIALS AND SUPPLIES	-
163	STORES EXPENSE UNDISTRIBUTED	(1,162)
164	GAS STORED	124,296
165	PREPAYMENTS	225,125,013
171	INTEREST AND DIVIDENDS RECEIVABLE	4,010,076
173	ACCRUED UTILITY REVENUES	62,753,000
174	MISCELLANEOUS CURRENT AND ACCRUED ASSETS	187,504,106
175	DERIVATIVE INSTRUMENT ASSETS	44,776,045
	TOTAL CURRENT AND ACCRUED ASSETS	872,961,478

4. DEFERRED DEBITS

181	UNAMORTIZED DEBT EXPENSE	35,714,172
182	UNRECOVERED PLANT AND OTHER REGULATORY ASSETS	2,571,278,815
183	PRELIMINARY SURVEY & INVESTIGATION CHARGES	5,106,648
184	CLEARING ACCOUNTS	976,020
185	TEMPORARY FACILITIES	-
186	MISCELLANEOUS DEFERRED DEBITS	23,303,759
188	RESEARCH AND DEVELOPMENT	-
189	UNAMORTIZED LOSS ON REACQUIRED DEBT	17,089,535
190	ACCUMULATED DEFERRED INCOME TAXES	557,872,815
	TOTAL DEFERRED DEBITS	3,211,341,764
	TOTAL ASSETS AND OTHER DEBITS	14,691,209,268

Data from SPL as of November 29, 2012

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
LIABILITIES AND OTHER CREDITS
SEPTEMBER 30, 2012

5. PROPRIETARY CAPITAL

		2011
201	COMMON STOCK ISSUED	($291,458,395)
204	PREFERRED STOCK ISSUED	(78,475,400)
207	PREMIUM ON CAPITAL STOCK	(592,222,753)
210	GAIN ON RETIRED CAPITAL STOCK	-
211	MISCELLANEOUS PAID-IN CAPITAL	(479,665,368)
214	CAPITAL STOCK EXPENSE	25,688,571
216	UNAPPROPRIATED RETAINED EARNINGS	(2,786,794,413)
219	ACCUMULATED OTHER COMPREHENSIVE INCOME	9,755,579
	TOTAL PROPRIETARY CAPITAL	(4,193,172,179)

6. LONG-TERM DEBT

221	BONDS	(3,536,905,000)
223	ADVANCES FROM ASSOCIATED COMPANIES	-
224	OTHER LONG-TERM DEBT	(253,720,000)
225	UNAMORTIZED PREMIUM ON LONG-TERM DEBT	-
226	UNAMORTIZED DISCOUNT ON LONG-TERM DEBT	11,834,550
	TOTAL LONG-TERM DEBT	(3,778,790,450)

7. OTHER NONCURRENT LIABILITIES

227	OBLIGATIONS UNDER CAPITAL LEASES - NONCURRENT	(674,680,029)
228.2	ACCUMULATED PROVISION FOR INJURIES AND DAMAGES	(31,028,287)
228.3	ACCUMULATED PROVISION FOR PENSIONS AND BENEFITS	(330,278,239)
228.4	ACCUMULATED MISCELLANEOUS OPERATING PROVISIONS	0
230	ASSET RETIREMENT OBLIGATIONS	(727,777,372)
	TOTAL OTHER NONCURRENT LIABILITIES	(1,763,763,927)

Data from SPL as of November 29, 2012

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
LIABILITIES AND OTHER CREDITS
SEPTEMBER 30, 2012

8. CURRENT AND ACCRUED LIABILITES

		2011
231	NOTES PAYABLE	(1,700,000)
232	ACCOUNTS PAYABLE	(355,445,678)
233	NOTES PAYABLE TO ASSOCIATED COMPANIES	-
234	ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES	(19,711,480)
235	CUSTOMER DEPOSITS	(62,850,929)
236	TAXES ACCRUED	(23,942,687)
237	INTEREST ACCRUED	(62,692,511)
238	DIVIDENDS DECLARED	(1,204,917)
241	TAX COLLECTIONS PAYABLE	(5,403,831)
242	MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES	(393,906,897)
243	OBLIGATIONS UNDER CAPITAL LEASES - CURRENT	(36,831,314)
244	DERIVATIVE INSTRUMENT LIABILITIES	(190,728,539)
245	DERIVATIVE INSTRUMENT LIABILITIES - HEDGES	0
	TOTAL CURRENT AND ACCRUED LIABILITIES	(1,154,418,783)

9. DEFERRED CREDITS

252	CUSTOMER ADVANCES FOR CONSTRUCTION	(13,656,727)
253	OTHER DEFERRED CREDITS	(496,869,300)
254	OTHER REGULATORY LIABILITIES	(1,133,746,949)
255	ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(26,152,469)
257	UNAMORTIZED GAIN ON REACQUIRED DEBT	-
281	ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED	(5,201,256)
282	ACCUMULATED DEFERRED INCOME TAXES - PROPERTY	(1,723,457,126)
283	ACCUMULATED DEFERRED INCOME TAXES - OTHER	(401,980,102)
	TOTAL DEFERRED CREDITS	(3,801,063,929)
	TOTAL LIABILITIES AND OTHER CREDITS	($14,691,209,268)

Data from SPL as of November 29, 2012

SAN DIEGO GAS & ELECTRIC COMPANY
STATEMENT OF INCOME AND RETAINED EARNINGS
NINE MONTHS ENDED SEPTEMBER 30, 2012

1. UTILITY OPERATING INCOME

400	OPERATING REVENUES		$3,128,104,838
401	OPERATING EXPENSES	$1,985,711,620	
402	MAINTENANCE EXPENSES	150,491,317	
403-7	DEPRECIATION AND AMORTIZATION EXPENSES	340,416,565	
408.1	TAXES OTHER THAN INCOME TAXES	66,916,393	
409.1	INCOME TAXES	(60,648,307)	
410.1	PROVISION FOR DEFERRED INCOME TAXES	692,026,077	
411.1	PROVISION FOR DEFERRED INCOME TAXES - CREDIT	(439,860,104)	
411.4	INVESTMENT TAX CREDIT ADJUSTMENTS	349,575	
411.6	GAIN FROM DISPOSITION OF UTILITY PLANT	-	
	TOTAL OPERATING REVENUE DEDUCTIONS		2,735,403,136
	NET OPERATING INCOME		392,701,702

2. OTHER INCOME AND DEDUCTIONS

415	REVENUE FROM MERCHANDISING, JOBBING AND CONTRACT WORK	-	
417.1	EXPENSES OF NONUTILITY OPERATIONS	(2,338)	
418	NONOPERATING RENTAL INCOME	279,720	
418.1	EQUITY IN EARNINGS OF SUBSIDIARIES	-	
419	INTEREST AND DIVIDEND INCOME	3,433,840	
419.1	ALLOWANCE FOR OTHER FUNDS USED DURING CONSTRUCTION	61,143,049	
421	MISCELLANEOUS NONOPERATING INCOME	441,574	
421.1	GAIN ON DISPOSITION OF PROPERTY	-	
	TOTAL OTHER INCOME	65,295,845	
421.2	LOSS ON DISPOSITION OF PROPERTY	-	
426	MISCELLANEOUS OTHER INCOME DEDUCTIONS	2,269,819	
	TOTAL OTHER INCOME DEDUCTIONS	2,269,819	
408.2	TAXES OTHER THAN INCOME TAXES	385,776	
409.2	INCOME TAXES	(50,028,891)	
410.2	PROVISION FOR DEFERRED INCOME TAXES	0	
411.2	PROVISION FOR DEFERRED INCOME TAXES - CREDIT	9,150,462	
	TOTAL TAXES ON OTHER INCOME AND DEDUCTIONS	(40,492,653)	
	TOTAL OTHER INCOME AND DEDUCTIONS		103,518,679
	INCOME BEFORE INTEREST CHARGES		496,220,381
	NET INTEREST CHARGES*		118,248,320
	NET INCOME		$377,972,061

**NET OF ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION, (25,593,864)*

Data from SPL as of November 29, 2012

SAN DIEGO GAS & ELECTRIC COMPANY
STATEMENT OF INCOME AND RETAINED EARNINGS
NINE MONTHS ENDED SEPTEMBER 30, 2012

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3. RETAINED EARNINGS

RETAINED EARNINGS AT BEGINNING OF PERIOD, AS PREVIOUSLY REPORTED	$2,412,437,103
NET INCOME (FROM PRECEDING PAGE)	377,972,061
DIVIDEND TO PARENT COMPANY	-
DIVIDENDS DECLARED - PREFERRED STOCK	(3,614,751)
OTHER RETAINED EARNINGS ADJUSTMENTS	
RETAINED EARNINGS AT END OF PERIOD	$2,786,794,413

APPENDIX B
Statement of Original Cost & Depreciation Reserve

SAN DIEGO GAS & ELECTRIC COMPANY

COST OF PROPERTY AND
DEPRECIATION RESERVE APPLICABLE THERETO
AS OF SEPTEMBER 30, 2012

No.	Account	Original Cost	Reserve for Depreciation and Amortization
	ELECTRIC DEPARTMENT		
302	Franchises and Consents	$ 222,841	$ 202,900
303	Misc. Intangible Plant	77,353,474	5,956,882
	TOTAL INTANGIBLE PLANT	77,576,315	6,159,782
310.1	Land		46,518
310.2	Land Rights	14,526,518	0
311	Structures and Improvements	0	28,099,799
312	Boiler Plant Equipment	83,488,783	48,112,447
314	Turbogenerator Units	163,231,924	31,835,664
315	Accessory Electric Equipment	112,838,130	24,629,097
316	Miscellaneous Power Plant Equipment	81,935,410	5,570,451
	Steam Production Decommissioning	25,801,345	0
	TOTAL STEAM PRODUCTION	481,822,111	138,293,977
320.1	Land	0	0
320.2	Land Rights	283,677	283,677
321	Structures and Improvements	275,650,545	270,613,381
322	Boiler Plant Equipment	556,559,852	419,749,061
323	Turbogenerator Units	142,381,272	137,165,063
324	Accessory Electric Equipment	173,236,427	167,695,922
325	Miscellaneous Power Plant Equipment	314,945,328	238,404,313
107	ICIP CWIP	0	0
	TOTAL NUCLEAR PRODUCTION	1,463,057,102	1,233,911,417
340.1	Land	143,476	0
340.2	Land Rights	2,428	2,428
341	Structures and Improvements	19,292,858	3,354,334
342	Fuel Holders, Producers & Accessories	20,348,101	4,219,943
343	Prime Movers	84,174,818	18,425,712
344	Generators	327,819,991	79,806,403
345	Accessory Electric Equipment	31,708,394	6,932,035
346	Miscellaneous Power Plant Equipment	23,517,224	9,161,900
	TOTAL OTHER PRODUCTION	507,007,290	121,902,754
	TOTAL ELECTRIC PRODUCTION	2,451,886,502	1,494,108,147

No.	Account	Original Cost	Reserve for Depreciation and Amortization
350.1	Land	$ 40,792,766	$ 0
350.2	Land Rights	136,915,589	12,620,732
352	Structures and Improvements	285,526,462	37,969,416
353	Station Equipment	963,037,139	160,020,003
354	Towers and Fixtures	657,533,430	90,481,482
355	Poles and Fixtures	264,238,315	52,963,522
356	Overhead Conductors and Devices	405,736,207	173,636,915
357	Underground Conduit	296,317,703	26,013,364
358	Underground Conductors and Devices	322,821,442	27,238,624
359	Roads and Trails	189,171,960	7,688,134
	TOTAL TRANSMISSION	3,562,091,012	588,632,193
360.1	Land	16,176,228	0
360.2	Land Rights	75,238,482	33,153,382
361	Structures and Improvements	3,496,653	1,430,921
362	Station Equipment	400,242,232	83,103,282
364	Poles, Towers and Fixtures	514,829,210	227,985,908
365	Overhead Conductors and Devices	406,981,539	161,271,509
366	Underground Conduit	961,943,312	372,398,607
367	Underground Conductors and Devices	1,275,571,386	750,853,056
368.1	Line Transformers	493,734,055	83,730,898
368.2	Protective Devices and Capacitors	15,811,184	(8,073,411)
369.1	Services Overhead	120,817,092	123,018,731
369.2	Services Underground	307,165,451	216,444,427
370.1	Meters	202,595,561	(10,090,946)
370.2	Meter Installations	48,973,286	(25,352,981)
371	Installations on Customers' Premises	6,513,419	11,287,058
373.1	St. Lighting & Signal Sys.-Transformers	0	0
373.2	Street Lighting & Signal Systems	24,682,390	17,871,226
	TOTAL DISTRIBUTION PLANT	4,874,771,482	2,039,031,669
389.1	Land	7,523,627	0
389.2	Land Rights	0	0
390	Structures and Improvements	31,037,336	18,531,828
392.1	Transportation Equipment - Autos	0	49,884
392.2	Transportation Equipment - Trailers	58,146	2,554
393	Stores Equipment	17,466	16,139
394.1	Portable Tools	19,375,183	6,089,238
394.2	Shop Equipment	328,720	192,373
395	Laboratory Equipment	302,226	43,595
396	Power Operated Equipment	92,162	149,134
397	Communication Equipment	167,869,475	68,724,500
398	Miscellaneous Equipment	1,367,470	198,274
	TOTAL GENERAL PLANT	227,971,811	93,997,520
101	TOTAL ELECTRIC PLANT	11,194,297,122	4,221,929,310

No.	Account	Original Cost	Reserve for Depreciation and Amortization
GAS PLANT			
302	Franchises and Consents	$ 86,104	$ 86,104
303	Miscellaneous Intangible Plant	0	0
	TOTAL INTANGIBLE PLANT	86,104	86,104
360.1	Land	0	0
361	Structures and Improvements	43,992	43,992
362.1	Gas Holders	0	0
362.2	Liquefied Natural Gas Holders	0	0
363	Purification Equipment	0	0
363.1	Liquefaction Equipment	0	0
363.2	Vaporizing Equipment	0	0
363.3	Compressor Equipment	0	0
363.4	Measuring and Regulating Equipment	0	0
363.5	Other Equipment	0	0
363.6	LNG Distribution Storage Equipment	2,052,614	695,087
	TOTAL STORAGE PLANT	2,096,606	739,079
365.1	Land	4,649,144	0
365.2	Land Rights	2,218,045	1,216,581
366	Structures and Improvements	11,541,403	9,549,587
367	Mains	133,850,631	60,133,947
368	Compressor Station Equipment	80,292,125	58,124,223
369	Measuring and Regulating Equipment	18,728,435	14,690,619
371	Other Equipment	0	0
	TOTAL TRANSMISSION PLANT	251,279,782	143,714,957
374.1	Land	102,187	0
374.2	Land Rights	8,118,693	6,032,451
375	Structures and Improvements	43,447	61,253
376	Mains	559,330,462	320,306,907
378	Measuring & Regulating Station Equipment	15,057,081	6,731,152
380	Distribution Services	242,910,503	280,997,186
381	Meters and Regulators	138,989,796	37,776,302
382	Meter and Regulator Installations	86,311,288	25,839,727
385	Ind. Measuring & Regulating Station Equipme	1,516,811	1,015,741
386	Other Property On Customers' Premises	0	0
387	Other Equipment	5,223,272	4,676,902
	TOTAL DISTRIBUTION PLANT	1,057,603,539	683,437,621

No.	Account	Original Cost	Reserve for Depreciation and Amortization
392.1	Transportation Equipment - Autos	$ 0	$ 25,503
392.2	Transportation Equipment - Trailers	74,501	74,501
394.1	Portable Tools	7,177,745	3,059,517
394.2	Shop Equipment	76,864	29,005
395	Laboratory Equipment	283,094	235,131
396	Power Operated Equipment	162,284	92,500
397	Communication Equipment	1,541,611	945,501
398	Miscellaneous Equipment	198,325	54,067
	TOTAL GENERAL PLANT	9,514,423	4,515,725
101	TOTAL GAS PLANT	1,320,580,454	832,493,487

COMMON PLANT

No.	Account	Original Cost	Reserve for Depreciation and Amortization
303	Miscellaneous Intangible Plant	191,146,549	103,690,346
350.1	Land	0	0
360.1	Land	0	0
389.1	Land	5,612,511	0
389.2	Land Rights	1,080,961	27,275
390	Structures and Improvements	238,943,754	102,545,650
391.1	Office Furniture and Equipment - Other	18,852,648	9,705,372
391.2	Office Furniture and Equipment - Computer E	69,378,197	33,175,342
392.1	Transportation Equipment - Autos	33,942	(338,930)
392.2	Transportation Equipment - Trailers	33,369	1,801
393	Stores Equipment	144,926	84,549
394.1	Portable Tools	1,193,702	133,992
394.2	Shop Equipment	248,289	139,109
394.3	Garage Equipment	969,973	(70,516)
395	Laboratory Equipment	2,236,234	866,738
396	Power Operated Equipment	0	(192,979)
397	Communication Equipment	103,048,288	46,815,016
398	Miscellaneous Equipment	2,440,895	870,667
118.1	TOTAL COMMON PLANT	635,364,239	297,453,433
	TOTAL ELECTRIC PLANT	11,194,297,122	4,221,929,310
	TOTAL GAS PLANT	1,320,580,454	832,493,487
	TOTAL COMMON PLANT	635,364,239	297,453,433
101 & 118.1	TOTAL	13,150,241,816	5,351,876,230
101	PLANT IN SERV-SONGS FULLY RECOVER	$ (1,164,131,236)	$ (1,164,131,236)
101	PLANT IN SERV-ELECTRIC NON-RECON Electric	$ (5,884,704)	$ 0

No.	Account	Original Cost	Reserve for Depreciation and Amortization
101	PLANT IN SERV-ASSETS HELD FOR SALE		
	Electric	$ (23,714,257)	$ (600,716)
	Common	(8,861,299)	$ 0
		(32,575,555)	(600,716)
101	PLANT IN SERV-LEGACY METER RECLASS		
	Electic	$ (23,070,475)	$ 66,831,561
101	PLANT IN SERV-SUNRISE FIRE MITIGATION		
	Electic	$ 0	$ 0
118	PLANT IN SERV-COMMON NON-RECON		
	Common - Transferred Asset Adjustment	$ (2,894,035)	$ (2,894,035)
101	Accrual for Retirements		
	Electric	$ (1,625,051)	$ (1,625,051)
	Gas	(1,166,032)	(1,166,032)
	TOTAL PLANT IN SERV-ACCRUAL FOR RE	(2,791,083)	(2,791,083)
102	Electric	0	0
	Gas	0	0
	TOTAL PLANT PURCHASED OR SOLD	0	0
104	Electric	85,194,000	738,033
	Gas	0	0
	TOTAL PLANT LEASED TO OTHERS	85,194,000	738,033
105	Plant Held for Future Use		
	Electric	8,151,201	0
	Gas	0	0
	TOTAL PLANT HELD FOR FUTURE USE	8,151,201	0
107	Construction Work in Progress		
	Electric	691,573,134	
	Gas	46,045,820	
	Common	60,506,228	
	TOTAL CONSTRUCTION WORK IN PROGRESS	798,125,183	0
108	Accum. Depr SONGS Mitigation/Spent Fuel Disallowance		
	Electric	0	221,468

No.	Account	Original Cost	Reserve for Depreciation and Amortization
108.5	Accumulated Nuclear Decommissioning Electric	0	800,593,254
	TOTAL ACCUMULATED NUCLEAR DECOMMISSIONING	0	800,593,254
101.1	ELECTRIC CAPITAL LEASES	778,390,265	74,999,690
118.1	COMMON CAPITAL LEASE	25,803,159	17,682,391
		804,193,424	92,682,081
120	NUCLEAR FUEL FABRICATION	62,963,775	40,861,208
143	FAS 143 ASSETS - Legal Obligation	116,218,782	(688,610,630)
	FIN 47 ASSETS - Non-Legal Obligation	72,842,470	30,051,014
143	FAS 143 ASSETS - Legal Obligation	0	(1,335,631,302)
	TOTAL FAS 143	189,061,252	(1,994,190,918)
	UTILITY PLANT TOTAL	$ 13,866,583,564	$ 3,189,195,847

APPENDIX C
Summary of Earnings

SAN DIEGO GAS & ELECTRIC COMPANY
SUMMARY OF EARNINGS
NINE MONTHS ENDED SEPTEMBER 30, 2012
(DOLLARS IN MILLIONS)

Line No.	Item	Amount
1	Operating Revenue	$3,128
2	Operating Expenses	2,735
3	Net Operating Income	$393
4	Weighted Average Rate Base	$5,738
5	Rate of Return*	8.40%

*Authorized Cost of Capital

APPENDIX D
Service List of State and Government Agencies

State of California
Attorney General's Office
P.O. Box 944255
Sacramento, CA 94244-2550

State of California
Attn. Director Dept of General Services
PO Box 989052
West Sacramento, CA 95798-9052

United States Government
General Services Administration
300 N. Los Angeles
Los Angeles, CA 90012

Naval Facilities Engineering Command
Navy Rate Intervention
1314 Harwood Street SE
Washing Navy Yard, DC 20374

Alpine County
Attn. County Clerk
99 Water Street, P.O. Box 158
Markleeville, CA 96120

Borrego Springs Chamber of Commerce Attn. City Clerk
786 Palm Canyon Dr
PO Box 420
Borrego Springs CA 92004-0420

City of Carlsbad
Attn. City Attorney
1200 Carlsbad Village Drive
Carlsbad, CA 92008-19589

City of Carlsbad
Attn. Office of the County Clerk
1200 Carlsbad Village Drive
Carlsbad, CA 92008-19589

City of Chula Vista
Attn: Office of the City Clerk
276 Fourth Avenue
Chula Vista, California 91910-2631

City of Chula Vista
Attn. City Attorney
276 Fourth Ave
Chula Vista, Ca 91910-2631

City of Coronado
Attn. Office of the City Clerk
1825 Strand Way
Coronado, CA 92118

City of Coronado
Attn. City Attorney
1825 Strand Way
Coronado, CA 92118

City of Dana Point
Attn. City Attorney
33282 Golden Lantern
Dana Point, CA 92629

City of Dana Point
Attn. City Clerk
33282 Golden Lantern
Dana Point, CA 92629

City of Del Mar
Attn. City Attorney
1050 Camino Del Mar
Del Mar, CA 92014

City of Del Mar
Attn. City Clerk
1050 Camino Del Mar
Del Mar, CA 92014

City of El Cajon
Attn. City Clerk
200 Civic Way
El Cajon, CA 92020

City of El Cajon
Attn. City Attorney
200 Civic Way
El Cajon, CA 92020

City of Encinitas
Attn. City Attorney
505 S. Vulcan Ave.
Encinitas, CA 92024

City of Encinitas
Attn. City Clerk
505 S. Vulcan Ave.
Encinitas, CA 92024

City of Escondido
Attn. City Clerk
201 N. Broadway
Escondido, CA 92025

City of Escondido
Attn. City Attorney
201 N. Broadway
Escondido, CA 92025

City of Fallbrook
Attn. City Clerk
233 E. Mission Road
Fallbrook, CA 92028

City of Fallbrook
Attn. City Attorney
233 E. Mission Road
Fallbrook, CA 92028

City of Imperial Beach
Attn. City Clerk
825 Imperial Beach Blvd
Imperial Beach, CA 92032

City of Imperial Beach
Attn. City Attorney
825 Imperial Beach Blvd
Imperial Beach, CA 92032

Julian Chamber of Commerce
P.O. Box 1866
2129 Main Street
Julian, CA

City of Laguna Beach
Attn. City Clerk
505 Forest Ave
Laguna Beach, CA 92651

City of Laguna Beach
Attn. City Attorney
505 Forest Ave
Laguna Beach, CA 92651

City of Laguna Niguel
Attn. City Attorney
30111 Crown Valley Parkway
Laguna Niguel, California 92677

City of Laguna Niguel
Attn. City Clerk
30111 Crown Valley Parkway
Laguna Niguel, California 92677

City of Lakeside
Attn. City Clerk
9924 Vine Street
Lakeside CA 92040

City of La Mesa
Attn. City Attorney
8130 Allison Avenue
La Mesa, CA 91941

City of La Mesa
Attn. City Clerk
8130 Allison Avenue
La Mesa, CA 91941

City of Lemon Grove
Attn. City Clerk
3232 Main St.
Lemon Grove, CA 92045

City of Lemon Grove
Attn. City Attorney
3232 Main St.
Lemon Grove, CA 92045

City of Mission Viejo
Attn: City Clerk
200 Civic Center
Mission Viejo, CA 92691

City of Mission Viejo
Attn: City Attorney
200 Civic Center
Mission Viejo, CA 92691

City of National City
Attn. City Clerk
1243 National City Blvd
National City, CA 92050

City of National City
Attn. City Attorney
1243 National City Blvd
National City, CA 92050

City of Oceanside
Attn. City Clerk
300 N. Coast Highway
Oceanside, CA 92054-2885

City of Oceanside
Attn. City Attorney
300 N. Coast Highway
Oceanside, CA 92054-2885

County of Orange
Attn. County Counsel
P.O. Box 1379
Santa Ana, CA 92702

County of Orange
Attn. County Clerk
12 Civic Center Plaza, Room 101
Santa Ana, CA 92701

City of Poway
Attn. City Clerk
P.O. Box 789
Poway, CA 92064

City of Poway
Attn. City Attorney
P.O. Box 789
Poway, CA 92064

City of Ramona
Attn. City Clerk
960 Main Street
Ramona, CA 92065

City of Ramona
Attn. City Attorney
960 Main Street
Ramona, CA 92065

City of Rancho San Diego - Jamul
Attn. City Clerk
3855 Avocado Blvd.
Suite 230
La Mesa, CA 91941

City of San Clemente
Attn. City Clerk
100 Avenida Presidio
San Clemente, CA 92672

City of San Clemente
Attn. City Attorney
100 Avenida Presidio
San Clemente, CA 92672

City of San Diego
Attn. Mayor
202 C Street, 11th Floor
San Diego, CA 92101

County of San Diego
Attn. County Clerk
P.O. Box 121750
San Diego, CA 92101

City of San Diego
Attn. City Attorney
1200 Third Ave.
Suite 1620
San Diego, CA 92101

County of San Diego
Attn. County Counsel
1600 Pacific Hwy
San Diego, CA 92101

City of San Diego
Attn. City Clerk
202 C Street, 2nd Floor
San Diego, CA 92101

City of San Marcos
Attn. City Clerk
1 Civic Center Dr.
San Marcos, CA 92069

City of San Marcos
Attn. City Attorney
1 Civic Center Dr.
San Marcos, CA 92069

City of Santee
Attn. City Clerk
10601 Magnolia Avenue
Santee, CA 92071

City of Santee
Attn. City Attorney
10601 Magnolia Avenue
Santee, CA 92071

City of Solana Beach
Attn. City Attorney
635 S. Highway 101
Solana Beach, CA 92075

Spring Valley Chamber of Commerce
Attn. City Clerk
3322 Sweetwater Springs Blvd, Ste. 202
Spring Valley, CA 91977-3142

Valley Center Chamber of Commerce
Attn. City Clerk
P.O. Box 8
Valley Center, CA 92082

City of Vista
Attn. City Attorney
200 Civic Center Drive, Bldg. K
Vista, CA 92084

City of Vista
Attn. City Clerk
200 Civic Center Drive
Vista, CA 92084

City of Aliso Viejo
12 Journey
Aliso Viejo, CA 92656

APPENDIX X

APPENDIX X

San Diego Gas & Electric Company

Response to Energy Division Guidance
for Post Summer 2012 DR Evaluation and 2013/2014 Summer Planning

1. Demand Response Program Performance

a) Load impact (MWs) and participation

Data: provide the load impact, enrollment and number of participants' information for each of DR programs categorized by: 1) Monthly Nominated Programs, 2) Other Price-Responsive, and 3) Emergency[1] Programs; and by program types (Day Ahead/Day of). The DR program listed under each of these categories should be consistent with the programs referred to in the IOUs DR Weekly Forecasts/Daily Reports that have been submitted to the CPUC and CAISO in summer 2012.

- Provide the load impact, enrollment, and number of participants for each DR event and a summary table for each of the five summer months (June, 2012 to October, 2012). The monthly value should be determined by the highest load impact (MWs) of the DR events in a given month (similar to the RA monthly load impact). Provide the temperature and system peak load in the utility's service territory for each event day.
- If separate subgroups of the enrolled customers within a program were dispatched in different DR event hours, the load impact for that event day should be the aggregate of all of the customers triggered. For example, SCE may have dispatched three different groups of residential AC cycling customers in three different event hours; the load impact for the residential AC cycling customers should be the sum of the load impact from each group of customers.
- The number of participants is defined as the number of customers or accounts that were used to determine the load impact in the seven day results reports submitted to the CPUC and CAISO in 2012. The number of participants may be fewer than the total number of customers enrolled under each program. For example, for SCE's residential default Peak Time Rebate (PTR) program, the total enrollment for this program is the total residential population that is eligible to receive a rebate, but SCE may use the number of customers who signed up for the notification as the number of participants.

[1] As categorized in the DR Daily Reports and the Weekly Forecasts. Some programs are referred to as Reliability Programs such as the Base Interruptible Program (BIP) and others are referred to as price-responsive programs such as AC cycling.

- For SCE, provide the Ex Post load impact and number of participants for the South of Orange County and South of Lugo. These two areas should be defined consistent with the same areas identified by the CAISO in the Daily DR Report.

- **Data source**: use the hourly load impact data that were relied upon for the seven-day result reports submitted to the CPUC and CAISO in 2012. Provide a brief summary of the methodologies that describe how the hourly load impact (MWs) were developed.
    - The utility should also provide an update of the load impact and number of participants based on the settlement billing data for each DR event and a summary of the monthly load impact.
    - The utilities may provide an update when the Ex Post load impact data based on the Load Impact Protocols becomes available (no later than January 31, 2013). Provide a brief summary of the methodologies describing how the Ex Post hourly load impact (MWs) were developed.
    - By February 2013, for each DR program provide a historical monthly load impact comparison (for the summer months only) between the seven day results reports provided to the CPUC and CAISO, settlement billing data, and the Ex Post data for 2010 to 2012.

SDG&E Response: Table 1 contains a monthly summary of total demand response load impacts achieved in 2012. A monthly summary of the total demand response load impact must be interpreted carefully because not all programs were called every month, and even in months where programs were called, not all programs were called on the same day. The "maximum load reduction from programs triggered" column contains the sum of the maximum load reductions from the month for each program called at any time during the month. The column "load reduction on the highest overall load reduction day" contains the results for programs called on the event date during the month which had the highest total load impact for the month. For example, the 119 MW value for August is the sum of the maximum results for all programs triggered at any time during August, whereas the 65 MW value includes results only from programs that were triggered on August 10^{th}, which was the event date for which the total demand response load reduction was the highest in August.

Table 1 Prelminary 2012 Load Impacts by Month (MW)				
	Maximum Load Reduction from Programs Trigged	Load Reduction Highest Overall Load Reduction day	Programs Triggered on Highest Overall Load Reduction Day	Programs Triggered at any time during the month
June	0	0	none	none
July	13	13	PTR	PTR
August	119	65	ACSAVER, CBP-DA, PTR	ACSAVER,CBP,CPP,CPP-E, DBP,PTR
September	103	54	ACSAVER, BIP,CBP,CPP-E,DBP	ACSAVER,BIP,CBP, CPP-D,CPP-E, DBP,PTR
October	51	33	ACSAVER,CPP, CBP-DA,DBP	ACSAVER,CBP,CPP-D

Tables 2 through 6 contain the average load impacts from the CAISO reports for each program for each event along with the event times, maximum temperature Fahrenheit, enrollment, the daily demand response forecast, the system peak, and program category. For events that lasted from 11 a.m. – 6 p.m., the average load reduction from 1 p.m. - 6 p.m. is also provided. For events that were less than 5 hours, only the average load reduction from the event period is provided since data is not available for all hours between 1 p.m. and 6 p.m. Event times are reported using hour ending notation. For example, an event that starts hour 14 and ends hour 17 starts at 1:00 p.m. and ends at 5:00 p.m.

Settlement results are provided for the Capacity Bidding Program (CBP), Demand Bidding program (DBP), PTR Residential (PTR-Res) and PTR Small Commercial (PTR-A), since these are the programs for which payments to customers/aggregators are calculated using baselines. Note that for CBP and DBP the settlement results are simply the load impacts using the settlement baselines not the load impacts paid for. The CBP payments are capped at the value nominated by the aggregator and the load reduction paid for is less than the baseline results when the aggregator achieves less than 90% of their nominated value. The DBP settlements are capped at 150% of the customer's nomination. These caps and comparisons to nominations are not included in these settlement calculations; therefore, the load reduction paid for will be less than or equal to the load impacts calculated according to the settlement baselines. Since we use the settlement baselines for the CAISO reporting for CBP and DBP, the final settlement load impacts and CAISO report load impacts are either equal or very close. For PTR-Res and PTR-A there are no caps or nominations to take into account therefore the settlement load impacts presented are equal to the load impacts paid for.

For residential and small commercial programs, we use a one day baseline with a same day adjustment to calculate the load impacts for the CAISO report. The baseline day is not always the day immediately preceding the event day. It is the day we judge to be the most comparable to the event day based on temperature and day of the week. For DBP, we also use a one day baseline with a same day adjustment. For all other programs, we use a 10 day baseline with a same day adjustment. There are limited exceptions to these approaches. For example, a 1 day baseline was used to analyze the CPP-D September 15th Saturday event.

								Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp F	Event Start	Event end	Enrollment	(event hours)	(1pm-6pm)	Load Reduction Settlements (MW)	Forecast	System Peak Hour	System Peak Load (kW)
Price-Responsive	PTR Res	DAY AHEAD	7/20/12	87	12	18	1,218,623	13.3	15.5	160.1	25.0	17	3,527
Price-Responsive	PTR Com	DAY AHEAD	7/20/12	87	12	18	111,805	0.1	0.1	31.2	1.2	17	3,527

Table 2 Preliminary July Load Impacts by Event

Table 3 Preliminary August Load Impacts by Event part 1

								Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrollment	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	8/8/12	89	13	16	28,500	13.7			26.0	16	3,989
Monthly Nominated	CBP-DO	DAY OF	8/8/12	89	14	17	318	11.2		11.5	11.7	16	3,989
Price-Responsive	CPP	DAY AHEAD	8/9/12	88	12	18	1,181	20.9	19.3		13.6	17	3,931
Monthly Nominated	CBP-DA	DAY AHEAD	8/9/12	88	14	17	79	9.3		9.4	7.5	17	3,931
Price-Responsive	PTR Res	DAY AHEAD	8/9/12	88	12	18	1,218,334	26.1	27.6	202.8	12.6	17	3,931
Price-Responsive	PTR Com	DAY AHEAD	8/9/12	88	12	18	111,704	0.3	0.3	27.4	1.1	17	3,931
Price-Responsive	ACSAVER	DAY OF	8/10/12	92	17	18	28,500	19.8			27.0	16	4,112
Monthly Nominated	CBP-DA	DAY AHEAD	8/10/12	92	15	18	79	9.5		9.5	7.5	16	4,112
Price-Responsive	PTR Res	DAY AHEAD	8/10/12	92	12	18	1,218,037	28.1	29.7	196.6	12.2	16	4,112
Price-Responsive	PTR Com	DAY AHEAD	8/10/12	92	12	18	111,682	8.0	6.9	37.5	0.8	16	4,112
Price-Responsive	CPP	DAY AHEAD	8/11/12	91	12	18	1,170	12.3	11.8		11.1	16	3,701
Price-Responsive	PTR Res	DAY AHEAD	8/11/12	91	12	18	1,207,881	33.6	35.9	231.1	12.9	16	3,701
Price-Responsive	PTR Com	DAY AHEAD	8/11/12	91	12	18	111,288	0.0	0.0	26.2	0.8	16	3,701
Price-Responsive	ACSAVER	DAY OF	8/13/12	91	14	17	28,502	18.2			33.0	16	4,266
Monthly Nominated	CBP-DO	DAY OF	8/13/12	91	14	17	318	10.6		10.6	11.7	16	4,266
Emergency Program	CPPE	DAY OF	8/13/12	91	14	18	4	1.5			2.0	16	4,266

Table 4 Preliminary August Load Impacts by Event part 2

								Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrollment	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	CPP	DAY AHEAD	8/14/12	88	12	18	1,169	27.1	25.4		14.0	16	4,136
Price-Responsive	CBP-DA	DAY AHEAD	8/14/12	88	15	18	79	8.3		8.5	9.0	16	4,136
Price-Responsive	DBP	DAY AHEAD	8/14/12	88	14	18	1	7.6			5.0	16	4,136
Price-Responsive	PTR Res	DAY AHEAD	8/14/12	88	12	18	1,216,871	6.9	7.1	240	12.8	16	4,136
Price-Responsive	PTR Com	DAY AHEAD	8/14/12	88	12	18	111,691	4.8	4.5	30	1.2	16	4,136
Price-Responsive	ACSAVER	DAY OF	8/17/12	94	14	17	28,528	20.6			19.3	15	4,266
Price-Responsive	CPP	DAY AHEAD	8/21/12	83	12	18	1,166	20.0	19.5		16.0	16	3,638
Price-Responsive	PTR Res	DAY AHEAD	8/21/12	83	12	18	1,217,877	10.0	11.3	1,003	22.4	16	3,638
Price-Responsive	PTR Com	DAY AHEAD	8/21/12	83	12	18	111,806	4.5	4.5	62	1.2	16	3,638
Price-Responsive	CPP	DAY AHEAD	8/30/12	90	12	18	1,164	20.3	19.4		16.0	16	3,962

Table 5 Preliminary September Load Impacts by Event

								Ave. Load Reduction CAISO report (MW)					
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrollment	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	9/13/12	81	15	18	27,973	12.8			16.0	17	3,783
Monthly Nominated	CBP-DO	DAY OF	9/13/12	81	15	18	321	10.5		10.7	12.1	17	3,783
Price-Responsive	ACSAVER	DAY OF	9/14/12	109	14	17	27,973	21.5			16.0	17	4,592
Emergency Program	BIP A	DAY OF	9/14/12	109	14	17	11	1.3			0.3	17	4,592
Monthly Nominated	CBP-DA	DAY AHEAD	9/14/12	109	15	18	78	5.8		5.9	12.1	17	4,592
Monthly Nominated	CBP-DO	DAY OF	9/14/12	109	15	18	321	9.9		10.1	9.0	17	4,592
Emergency Program	CPPE	DAY OF	9/14/12	109	14	17	4	1.4			1.6	17	4,592
Price-Responsive	DBP	DAY AHEAD	9/14/12	109	14	18	1	9.1		9.1	5.0	17	4,592
Price-Responsive	ACSAVER	DAY OF	9/15/12	104	14	17	27,973	3.1			9.0	16	4,313
Price-Responsive	CPP	DAY AHEAD	9/15/12	104	12	18	1,147	5.5	4.7		11.1	16	4,313
Price-Responsive	PTR Res	DAY AHEAD	9/15/12	104	12	18	1,217,877	45.8	48.0	297.6	32.3	16	4,313
Price-Responsive	PTR Com	DAY AHEAD	9/15/12	104	12	18	111,806	0.0	0.0	32.8	0.9	16	4,313
Monthly Nominated	CBP-DA	DAY AHEAD	9/17/12	84	15	18	78	8.0		8.4	9.0	17	3,681

Table 6 Preliminary October Load Impacts by Event														
								Ave. Load Reduction CAISO report (MW)						
Category	Program	Type of Program	Date	Temp	Event Start	Event end	Enrollment	(event hours)	(1pm-6pm)	Load Reduction Settlement (MW)	Forecast (MW)	System Peak Hour	System Peak Load (kW)
Price-Responsive	ACSAVER	DAY OF	10/1/12	92	15	18	16,231	9.2			15.0	17	4,155.5
Monthly Nominated	CBP-DA	DAY AHEAD	10/1/12	92	15	18	78	7.0		7.3	12.1	17	4,155.5
Monthly Nominated	CBP-DO	DAY OF	10/1/12	92	15	18	323	9.5		9.5	9.0	17	4,155.5
Price-Responsive	CPP	DAY AHEAD	10/2/12	98	12	18	1,133	16.1	16.7		16.0	16	4,146.3
Monthly Nominated	CBP-DA	DAY AHEAD	10/2/12	98	15	18	78	8.0			9.0	16	4,146.3
Price-Responsive	DBP	DAY AHEAD	10/2/12	98	15	18	1	8.4		8.4	5.0	16	4,146.3

- **Averaging period**: for programs that have different hourly load impact, produce two sets of data to determine the daily value for each DR event: 1) the event hours and 2) the RA measurement hours (1 p.m.-6 p.m.)

SDG&E Response: Please see Table 7.

Table 7 2012 RA Comparison

Month	Program	2012 RA forecast (MW)	2012 Load Impact Event Period (MW)	2012 Load Impact 1 p.m. - 6 p.m. (MW)	RA forecast Maximum Temperature	2012 Event Date Temperature
July	PTR Res	70	13	16	91	87
July	PTR Com		0	0	91	87
August	ACSAVER	15	21		88	94
August	CBP-DA	10	10		88	92
August	CBP-DO	22	11		88	89
August	CPP-D	12	27	25	88	88
August	CPP-E		2		88	91
August	DBP		8	8	88	88
August	PTR Res	69	34	36	88	91
August	PTR Com		8	7	88	92
September	ACSAVER	17	22		96	109
September	BIP	11	1		96	109
September	CBP-DA	10	8		96	84
September	CBP-DO	23	11		96	81
September	CPP-D	12	6	5	96	104
September	CPP-E		1		96	109
September	DBP		9	9	96	109
September	PTR Res	63	46	48	96	104
September	PTR Com		0	0	96	91
October	ACSAVER	18	9		96	92
October	CBP-DA	10	8		96	98
October	CBP-DO	23	10		96	92
October	CPP-D	14	16	17	96	98
October	DBP		8		96	98

Note: When program event hours were shorter than the RA hours only the load impact for the event period is provided since it is not possible to calculate an average load impact from 1 p.m. to 6 p.m.

- **Comparison analysis:**

  Q.1: How does the DR program load impacts compare with the 2012 DR allocation for RA for each of the summer months (June, 2012 to October, 2012)? Please provide a table that includes all programs.

Response: Table 7 compares the 2012 adopted demand response RA allocation which was based on the demand response forecast filed on April 1st, 2011 to the 2012 load impact values.

The Summer Saver program (ACSAVER) 2012 load impact results are higher than the RA estimates in August and September, which makes sense given that event day temperatures were higher on the 2012 event day compared to the RA forecast's assumed temperatures. The Summer Saver load impact for October is lower however than the RA estimate. Demand response load impacts have been consistently lower in October for the Summer Saver program than they are for August and September, even when October temperatures are high. It may be possible that this could be explained by more detailed weather information, hourly temperature, humidity, cloud cover and so forth instead of just the daily maximum temperature or may be simply that customers have a different mindset as they head into fall and do not use their air-conditioning as often. The CBP day-ahead load impacts are similar to the RA forecast.

Q.2: How does the DR program load impact compare with the 2012 DR allocation for RA, taking into account up-to-date information such as enrollment and weather changes? In other words, did the DR programs perform as expected when the programs were triggered? Please provide a comparison table that includes all programs.

Response: Table 7 compares the 2012 adopted demand response RA allocation which was based on the demand response forecast filed on April 1st, 2011 to the 2012 load impact values.

BIP and CBP day-of both have lower enrollments than were predicted for the RA forecast, which explains the difference between the RA forecast and the 2012 actual load impacts. In August and October, the CPP-D load impact is higher than the RA forecast; however, the CPP-D load impacts for September are lower than the RA forecast because the only September CPP-D event occurred on September 15th - a very hot Saturday. Therefore, CPP-D impacts may be lower because the event was on a Saturday and there may also be measurement error in the load impact estimate itself because there were no non-event Saturdays in 2012 or 2011 or 2010 with temperatures as high as September 15th to use for a baseline. Demand Bidding and Small Commercial PTR forecast were not included in the 2012 RA forecast because these programs are new, and CPP-E was not included because we had proposed to cancel it in 2012 at the time the RA forecast was created.

Q. 3: Did the utility observe any evidence of customer fatigue as a result of consecutive DR events on multiple days? If the answer is yes, how much did the customer fatigue affect the load impact?

Response: Effects of customer fatigue on load impacts are difficult to estimate because even when several event days are called in a row, those event days occur on different days of the week and occur at different temperatures, so it can be difficult to discern whether or not changes in load impact are due to the multiple event days or to other factors. PTR events were called 08/09/2012, 08/10/2012, 08/11/2012 and 08/14/2012, and preliminary load impacts were lowest on 08/14/2012, which may possibly be due to customer fatigue. For all other programs, no evidence of customer fatigue shows up in the load impacts. This does not mean that customer fatigue does not exist, just that it wasn't measurable relative to all the other variations in load impacts between events using baseline methods.

a) DR operation

- **DR program information:** provide a summary of all DR program availability (maximum hours/events per month/year), triggering criteria, by the same categories as in 1.a).

  Provide a summary of the DR programs events including total number of hours and events triggered and the list of triggering conditions in comparison with the program maximum hours and events.. For example, if a DR program is has a maximum of 180 hours and it was triggered a total of 22 hours, the comparison should show both 22 triggered and 180 maximum hours.

Response: Please see Table 8.

Table 8 2012 Demand Response Events

Program	Type	Program Season	Available Annual Events/Hours	Available Monthly Events/Hours	Available Weekly Events/Hours	Available Daily Events/Hours	# of Events Triggered	Available Remaining	Trigger Criteria	Trigger Condition
Critical Peak Pricing-Default (CPP-D)	Day Ahead	Year Round	18 Events	No Limit	No Limit	1 Event Always 7 Hours (11am-6pm)	7 Events	11 Events	**Temperature and system load** *Monday: 86º; 3472 MW *Tues-Fri: 84º; 3837 MW *Saturday: 86º; 3837 MW	Met trigger criteria for all 7 events
Capacity Bidding Program (CBP)	Day Ahead	May-Oct Mon-Fri	No Limit	44 Hours	No Limit	1 Event Up to 8 Hours (11am-7pm)	Aug-12 Hours Sep-8 Hours Oct-8 Hours	Aug-32 Hours Sep-36 Hours Oct-36 Hours	**Price:** *Mon - Friday only *Market Price equal to or greater than 15,000 btu/kWh heat rate *Other Statewide or local system conditions	Mitigate potential price spikes and load forecast above 4000 MW
Capacity Bidding Program (CBP)	Day Of	May-Oct Mon-Fri	No Limit	44 Hours	No Limit	1 Event Up to 8 Hours (11am-7pm)	Aug-7 Hours Sep-8 Hours Oct-4 Hours	Aug-37 Hours Sep-36 Hours Oct-40 Hours	**Price:** *Mon - Friday only *Market Price equal to or greater than 15,000 btu/kWh heat rate *Other Statewide or local system conditions	Mitigate potential price spikes and load forecast abolve 4000 MW and/or Real Time Load came in higher than Day Ahead forecast
Base Interruptibile Program (BIP)	Day Of - 30 minute	Year Round	120 Hours	10 Events		1 Event Up to 4 Hours	3 Events 14 Hours	86 Hours	CAISO forecasts a Stage 1 CAISO declares a Stage 2 CAISO calls for interruptible load Extreme weather or system demands or at SDGE discretion.	1 ComplianceTest 2 Met trigger criteria

Table 8 2012 Demand Response Events

Program	Type	Program Season	Available Annual Events/Hours	Available Monthly Events/Hours	Available Weekly Events/Hours	Available Daily Events/Hours	# of Events Triggered	Available Remaining	Trigger Criteria	Trigger Condition
Summer Saver	Day Of	May-Oct Holidays Excluded	15 Events or 120 Hours	40 Hours	3 Events	1 Event Noon to 8 pm Min 2/Max 4 Hours	Aug-15 Hours Sep-10 Hours Oct-4 Hours	Aug-25 Hours Sep-30 Hours Oct-36 Hours Annual 96 Hours	**Temperature and system load** *Monday - Friday: 3800 MW *Saturday - Sunday - Optional Participation *CAISO Stage 1 or 2 *Local or system emergency	Mitigate potential price spikes and load forecast abolve 4000 MW and/or Real Time Load came in higher than Day Ahead forecast
Reduce Your Use	Day Ahead	Year Round	18 events	No Limit	No Limit	1 Event Always 7 Hours (11am-6pm)	7 Events	11 Events	**Temperature and system load** *Monday: 86º; 3472 MW *Tues-Fri: 84º; 3837 MW *Saturday: 86º; 3837 MW	Met trigger criteria for all 7 events
Critical Peak Pricing- Emergency (CPP-E) Terminates Dec 31	Day Of 30 minute	Year Round	80 Hours	40 Hours	4 Events	1 Event	Aug-1 Event (4 Hours) Sep-1 Event (4 Hours)	72Hours	Local utility emergency with intent to avoid any firm load curtailment CAISO calss for interruptible load	Conditions warranted by Utility
Demand Bidding	Day Ahead	Jul - Dec 2012 only	No Limit	No Limit	No Limit	No Limit	1 Event 5 Hours	N/A	CAISO 1,2,or 3 Emergency Transmission or imminent system emergency or as warranted by the utility	Conditions warranted by Utility
Flex Alerts in Effect							Aug-10 Aug-14			

- **Comparison analysis:**

  <u>Q.1: How often was each of the DR programs triggered as compared to the corresponding program availability? Provide a comparison between the program's operating limit and its actual events and hours per month/year.</u>

Response: Please see Table 8.

<u>Q. 2: What were the reasons for any of the DR programs operated under the operating limit, e.g., triggering conditions, customers' annoyance, system load and resource conditions, etc.</u>

Response: Please see Table 8.

<u>Q. 3: Provide a comparison of the DR program summer historical operational data for each DR program organized by the three categories listed in I.1.a) from 2006 to 2012: actual number of DR events vs. maximum events, actual total event hours/month or summer vs. maximum event hours/month or summer.</u>

Response: Tables 9 through 11 contain the maximum annual number of events allowed for each program along with the number of events called for each year from 2006-2012. Some programs, like CBP and BIP, have monthly limits on the number of events that can be called as well.

Table 9 Number of Events Monthly Nominated Programs					
Category	Program	Year	Maximum Hours per year	Number of Event hours called	Number of Events Called
Monthly Nominated Program	CBP-Day Ahead	2006	144	0	0
Monthly Nominated Program	CBP-Day Ahead	2007	144	38	8
Monthly Nominated Program	CBP-Day Ahead	2008	144	4	1
Monthly Nominated Program	CBP-Day Ahead	2009	144	24	6
Monthly Nominated Program	CBP-Day Ahead	2010	144	28	7
Monthly Nominated Program	CBP-Day Ahead	2011	144	19	5
Monthly Nominated Program	CBP-Day Ahead	2012	144	24	6
Monthly Nominated Program	CBP-Day Of	2006	144	0	0
Monthly Nominated Program	CBP-Day Of	2007	144	45	12
Monthly Nominated Program	CBP-Day Of	2008	144	6	1
Monthly Nominated Program	CBP-Day Of	2009	144	37	7
Monthly Nominated Program	CBP-Day Of	2010	144	50	12
Monthly Nominated Program	CBP-Day Of	2011	144	28	7
Monthly Nominated Program	CBP-Day Of	2012	144	20	5

Table 10 Number of Events Emergency Programs					
Category	Program	Year	Maximum Hours per year	Number of Event hours called	Number of Events Called
Emergency Program	BIP	2006	120	2	1
Emergency Program	BIP	2007	120	4	1
Emergency Program	BIP	2008	120	No events	0
Emergency Program	BIP	2009	120	No events	0
Emergency Program	BIP	2010	120	4	1
Emergency Program	BIP	2011	120	4	1
Emergency Program	BIP	2012	120	4	1
Emergency Program	CPP-E	2006	80	7	2
Emergency Program	CPP-E	2007	80	14	3
Emergency Program	CPP-E	2008	80	No events	0
Emergency Program	CPP-E	2009	80	No events	0
Emergency Program	CPP-E	2010	80	No events	0
Emergency Program	CPP-E	2011	80	No events	
Emergency Program	CPP-E	2012	80	9	2

Table 11 Number of Events Price Responsive Programs					
Category	**Program**	**Year**	**Maximum Hours per year**	**Number of Event hours called**	**Number of Events Called**
Price-Responsive	CPP-D	2006	98	70	10
Price-Responsive	CPP-D	2007	98	63	9
Price-Responsive	CPP-D	2008	126	No events	0
Price-Responsive	CPP-D	2009	126	56	8
Price-Responsive	CPP-D	2010	126	28	4
Price-Responsive	CPP-D	2011	126	14	2
Price-Responsive	CPP-D	2012	126	49	7
Price-Responsive	PTR	2006	Unlimited	No events	0
Price-Responsive	PTR	2007	Unlimited	No events	0
Price-Responsive	PTR	2008	Unlimited	No events	0
Price-Responsive	PTR	2009	Unlimited	No events	0
Price-Responsive	PTR	2010	Unlimited	No events	0
Price-Responsive	PTR	2011	Unlimited	32	5
Price-Responsive	PTR	2012	Unlimited	49	7
Price-Responsive	Summer Saver	2006	120	24	8
Price-Responsive	Summer Saver	2007	120	43	12
Price-Responsive	Summer Saver	2008	120	8	2
Price-Responsive	Summer Saver	2009	120	30	7
Price-Responsive	Summer Saver	2010	120	44	11
Price-Responsive	Summer Saver	2011	120	22	6
Price-Responsive	Summer Saver	2012	120	30	8
Price-Responsive	DBP	2006	Unlimited	16	4
Price-Responsive	DBP	2007	Unlimited	41	9
Price-Responsive	DBP	2008	Unlimited	The program was cancelled	0
Price-Responsive	DBP	2009	Unlimited	The program was cancelled	0
Price-Responsive	DBP	2010	Unlimited	The program was cancelled	0
Price-Responsive	DBP	2011	Unlimited	The program was cancelled	0
Price-Responsive	DBP	2012	Unlimited	14	3

Q. 4: Provide a comparison of the historical operational data for the utility's peaker plants, e.g, combustion turbines from 2006 to 2012: actual dispatched hours vs. maximum hours allowed by permit.

Response: Historical operational data for our peaker plants are listed in Table 12.

Table 12 – SDG&E's Historical Peaker Plant Operational Hours								
	Cuyamaca		El Cajon Energy Center		Miramar		Orange Grove	
	Run Hours	Emission Allowance	Run Hours	Emission Allowance	Run Hours	Emission Allowance	Run Hours	Emission Allowance
2006					200	5000		
2007					250	5000		
2008	373	N/A			671	5000		
2009	625	N/A			1919	5000		
2010	481	N/A	438.9	2500	2946	5000		
2011	667	N/A	432.8	2500	4306	5000		
2012	1621	N/A	973.9	2500	4805	5000	2147.9	6400

*Please note: some data is missing for certain peaker plants either because they were not in existence at the time or because the plant has not provided the data. The Cuyamaca peaker plant does not have an emission allowance.

2. CAISO Markets

a) Price spikes

- Provide a mapping of the day-ahead or real time wholesale energy price spikes and the DR events for each of the summer months (June, 2012 to October, 2012).

Response: Please see "Attachment F – Price Spikes".

b) Market analysis

Q.1: Were price-responsive DR programs used to avoid paying for and mitigating these price spikes? If not, why not?

Response: No, price-responsive DR programs are not able to mitigate the price spikes in the real time market. Bidding for the Day-Ahead Market closes at 10AM the day before the trading day and consists of a sequence of processes that determine the hourly Market Clearing Prices for Energy (including physical and Virtual Bids) and Ancillary Services, as well as the incremental procurement in RUC while also mitigating Bids from to address non-competitive constraints. These processes are co-optimized to produce a Day-Ahead Schedule at least cost while meeting local reliability needs.

Bidding for the Real-Time Market (RTM) and Hour-Ahead Scheduling Process (HASP) closes 75 minutes before the beginning of each Trading Hour (which, in turn, begins at the top of each hour). A sequence of processes determines the Marketing Clearing Prices for each Trading Hour. The prices resulting from these processes are used for the HASP and Real-Time Market Settlement. HASP is performed immediately after the Real-Time Market Power Mitigation. All HASP Schedules for the Trading Hour are published approximately 45 minutes before the start of each Trading Hour.

Q.2: If the answer to Q.1 is yes, did the utility observe any change in market prices or impact on supply constraints or congestion experienced in the market?

Response: Not applicable.

Q.3: If the answer is to Q.1 is no, are there any current DR programs that could be modified to address the price spikes (day-ahead or real time)? What are the specific modifications and does it make sense to make those changes?

Response: Due to the timing of the market closing and other processes that determine the hourly market clearing process for energy, it is very difficult to align with the real time market price spikes that occur. We are proposing a 30 minute product for those customers that can contribute large loads, which gets us closer to responding to the hourly pricing. We have noted in our response to question 2.a that for the most part, our programs and processes have done a fairly accurate job of predicting the spikes and the need for load even on a day ahead basis.

Q.4: For DR programs that have a price trigger, was the trigger set too high or too low? Was it reasonable?

Response: Our only DR program with a price trigger is Capacity Bidding Program (CBP). CBP uses a 15,000 btu/kWh heat rate for a proxy. This is a reasonable proxy.

3. **Customers' Experience**

- **Alignment between DR program operation & design and customers' expectations:**

Q. 1: What was the utility's overall customer experience with the DR programs in summer 2012?

Response: Overall, the customer experience for the summer was very positive. Programs worked hard to deliver notifications to customers earlier than required. These helped customers, both commercial and residential, prepare for the event day. Critical Peak Pricing Default (CPP-D) noticed notification bounce-backs decreased compared to previous years. Peak Time Rebate (PTR) introduced the ability to view event day results online for residential customers. This new experience encountered some issues or confusion that will be clarified through educational efforts about PTR, peak hours, energy consumption, demand response, and our online presentment tool in 2013. Preliminary survey results indicate that most customers reacted positively to the program, and only 129 complaints (0.01% of the eligible population) were received by the Customer Contact Center. We also had 718 calls (0.06%) from customers who wanted clarification on the program. About 28% of the calls were regarding online presentment through My Account.

Q.2: What feedback (complaints or problems) did the utility receive from customers about the DR events?

Response: CPP-D received some customer complaints regarding the various channels of notification. Some customers that were signed up for notification through multiple channels may not have received all of their notifications by 3pm due to firewalls on customer's IT servers.

More than half of the feedback for Summer Saver customers was due to uncomfortable temperatures from the A/C cycling.

For PTR, almost a quarter of customer complaints (24%) were from customers expressing the desire to add outbound dial alerts. A few customers were confused about how the CRL was calculated and displayed in My Account. Since the PTR credit is awarded for whole kilowatt hours, some customers who did not receive a credit felt they deserved a credit for partial kWh reduction below their CRL. A number of callers also wanted the CSR to inform them of their CRL instead of logging in to My Account to view it. PTR also experienced an issue with customers not receiving their alerts on time due to a firewall policy on the internet service provider's (ISP) side. No feedback was received from small commercial customers on PTR.

We were very concerned about potential confusion between Flex Alerts and Reduce Your Use days. We saw the need for very careful education about the difference between the two wherever possible, in order to mitigate customer complaints under the scenario where a Flex Alert could be called, Reduce Your Use not called, and then the customers expect to get a bill credit based on their conservation. The following messaging was crafted and posted to our website as well as distributed via outreach training and the media to help combat customer confusion:

> *Reduce Your Use days vs. Flex Alerts: What's the difference?*
>
> *A Reduce Your Use day is broadcast by SDG&E, and in return for saving energy, we credit you with a reward on your bill when you conserve on these specific days. A Flex Alert is issued by the state of California, and while there is no incentive for participating in a Flex Alert, it is important to help the California Independent System Operator (CAISO) maintain reliability by saving energy when one is called.*

In the end, we decided to always call a Reduce Your Use day event if Flex Alerts were called by CAISO so that customers would not encounter this particular issue.

The following section is redacted.

Q.3: Based on the feedback received by the utility, did any of the customers (and the percentage) feel that there were too many DR events last summer?

Response: Preliminary survey results indicated some Critical Peak Priding Default customers have stated “It costs us a lot of money to have multiple events consecutively.” Some customers are concerned that they are going to pay more than they would on an alternative rate and may end up opting out next year. No other programs have received customer feedback regarding the number of events called in the summer of 2012.

Q.4: Did any of the customers (and the percentage) feel that the incentives they received were too low or unfair?

Response: A very small number of residential customers, and were unhappy with incentive levels. Only 10 (>1%) Summer Saver customers out of 28,755 left the program because they felt the incentives were too low or unfair. Based on customer feedback received by the Customer Contact Center, a very small percentage of PTR customers (0.0001%) felt that either the credits for only whole kWh was unfair, or that the credit amount of $0.75 was too low.

Limited commercial customer and aggregator feedback indicates that incentive levels may be lower than customers would like. Aggregators for the Capacity Bidding Program suggest there is potential for increased enrollment in Capacity Bidding Program if the incentives were increased. Higher incentives could potentially create economic viability for enrolling customers with smaller load shed capabilities where it does not exist at today’s levels. Two Demand Bidding customers (six accounts), representing 100% of the program population have indicated that incentive levels for the program were not high enough.

Q.5: Are there any lessons learned from the customer perspective particularly for AC cycling, Peak Time Rebate, Demand Bidding Program, Capacity Bidding Program, Critical Peak Pricing, 10-in-10 program?

Response: PTR customers gave us some insight into how residential customers feel about demand response, and how much they know about their energy usage. Some customers were under the impression that we have real–time energy usage data available. This led to some confusion surrounding the availability of the Customer Reference Levels before events, and results after events.

Preliminary analysis on customer participation and reduction levels indicates that awareness of the program and events are key to a customer's success on event days. Customers who actively signed up for event alerts, along with customers who were enrolled in a special program (San Diego Energy Challenge, HAN program or Pilot, etc.) had much higher average reduction levels than those customers who either received an alert as a result of being registered in My Account or who received no alert. We will continue to focus on increasing customer awareness, and thus participation in 2013 and 2014. Many customers requested an outbound dial option to alert them of events. Although that was not available in 2012, it is something that we are working on for 2013 and beyond.

The addition of PTR for Small Commercial customers in 2012 gave us the chance to evaluate the reaction of non-residential customers to this type of program. These customers signed up for alerts at a much lower rate than residential customers, and provided less load reduction. This is likely due to the structure of the program, and their limited ability to reduce their energy use between the hours of 11:00 am and 6:00 pm.

The 2012 Summer Saver program (AC Cycling) exhibited patterns that were consistent with previous year's responses. There are several program controls in place to help mitigate customer concerns surrounding these findings.

- **Customer awareness and participation:** provide an analysis of the Peak Time Rebate program on customer participation and free ridership.

  Q. 1: Which group(s) of customers (those who signed up for notification, those who received notification through My Account, those without direct notification) provided the most load reduction under each DR program and what was the reason(s)?

Response: Customers who signed up for notification provided the most load reduction. Differences in load impacts between customer enrolled in My Account and those without direct notification were not large enough to be measured with preliminary estimation methods. However, one should not conclude that there was no difference in load impacts between these two groups of customers until formal measurement and evaluation results are available.

Q.2: Were the DR event notification systems effective?

Response: PTR event notifications were largely effective, enabling program staff to alert customers via email or text message in a timely matter the day before an event. Customers who received the email through an action on their part (signing up) produced the most load reduction, compared to those who received the alerts by default, or those who received no alerts.

During the 2012 season, 3,565,858 pre-event alerts were sent to residential customers for PTR, and 124,073 were sent to commercial customers.

One email provider's system held and throttled our emails, resulting in quite a few customers receiving their email alerts late (up to a few days after the event). This issue could not be resolved with the provider, but a workaround was established between us and the alert vendor.

- **Program Evaluation**: it is our understanding that SCE is doing a program evaluation of its 10-in-10 program and SDG&E is doing an evaluation of its Peak

Time Rebate program. To the extent that these evaluations are available by January 2013, the utilities should submit these reports to the CPUC for consideration.

Response: We will submit the evaluation of our Peak time Rebate program to the CPUC for consideration as soon as it is available.

4. Coordination with CAISO and Utility Operations

- Daily and Weekly DR Reporting

Q.1: From the IOUs' perspective, was the daily and weekly DR reporting helpful to the utility? What could be improved?

Response: Initially, the demand response forecast reporting requirements for 2012 summer were difficult to provide by the times that the ISO and ED wanted. Our software was not configured to provide output in the format that the ISO and ED desired. Once initial changes were designed and implemented the process went relatively smoothly, until the next change was identified by the ISO and ED. The software that we use to prepare our DR forecast is in a production environment and requires programming and testing as it resides on a server supported by our IT group. All changes (even seemingly small ones) must go through IT's processes for testing before going into production. Therefore, we request 30 day-ahead notification for any changes to the DR forecast template.

When the day-ahead events are triggered, the DR forecast is updated near the end of the work day and provided to our internal distribution. The DR program area then sends the forecast to the ISO, ED and CEC. The forecast that is provided before 8am daily only has information from the prior day (for any day ahead events that may have been triggered). Therefore, when the DR Program and/or the electric procurement groups initiate the triggering for our "day of" programs, it is appropriate that those groups send the updates out to the external groups when the decision to trigger the event has been made.

We would like to recommend that the group where the forecast originates (Load Analysis) send the initial DR forecast that it provides to the ISO, ED and CEC. This would alleviate some of the redundancy that currently exists in the process. Currently, the Load Analysis group sends the DR Forecast to our internal personnel, and then the DR program personnel, in turn, provide it to the external groups: ED, CEC and ISO personnel.

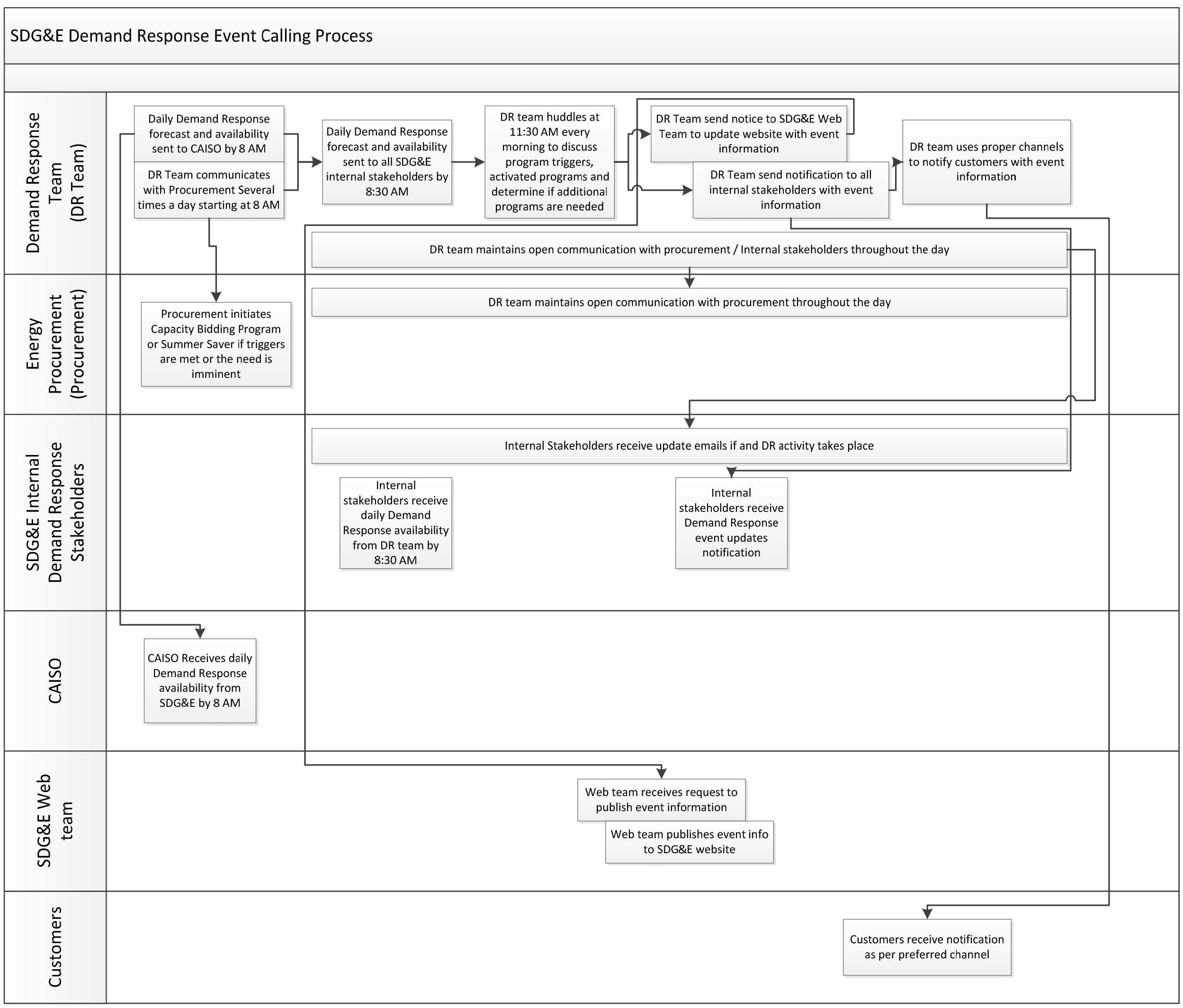
We also recommend that the weekend DR forecast be sent on Friday afternoon and that it covers the forecast days: Saturday Sunday and Monday. Additionally, we propose that this weekend forecast will only be updated in the event that DR events are triggered for Saturday, Sunday or Monday (day of for Saturday and Sunday and day ahead programs for Sunday and Monday). The normal weekday DR Forecast process would resume Monday mornings.

Q.2: Please describe communication and coordination efforts between utility DR program staff and utility procurement staff and grid operation staff on day-to-day usage of demand response programs.

Response: The Demand Response (DR) team sends out daily forecasts for demand response availability to CAISO by 8 a.m. The DR team also distributes email communication containing information regarding available demand response resources and any program activation to all internal stakeholders by 9 a.m. Updated communications are sent out as situations change. DR staff also monitors San Diego Gas & Electric's website to ensure correct event information is posted and/or removed at the correct time.

The DR team starts communication with energy procurement at 8 a.m. every day and maintains an open communication channel with multiple contacts throughout the day. At 8 a.m. procurement informs the DR team of the need to activate Capacity Bidding Program day-of or Summer Saver program. If the programs need to be activated, the DR team will ask the San Diego Gas & Electric web team to publish event information on the website. The DR team then updates all internal stakeholders with event information and sends out customer notifications through proper program based channels.

The DR team huddles at 11:30 a.m. every day to discuss program triggers, currently activated programs and determine if additional programs need to be activated. If the situation warrants, the DR team requests changes made to the website, notifies internal stakeholders and send out appropriate customer notifications.



- DR coordination/communication

<u>Q.3: What are the utility's internal operational procedures for the DR programs (price responsive and emergency)? Provide examples of how the utility triggered and communicated DR events with its energy center and grid operator for August 8, 9, 10, & 14, 2012, September 14, 2012, and October 2, 2012.</u>

Response: Please see the response to Q2. The processes for price responsive and emergency programs are the same as all other programs.

<u>Q.4: Were the DR forecast communicated to the utility's energy center and grid operation consistent with what had been reported to the CAISO in the Daily DR Reports? If not, why?</u>

Response: Our DR forecast is the same forecast file that is provided internally and externally and is consistent with what is reported to the CAISO.

<u>Q.5: Are there other coordination/communication issues between the IOUs and CAISO that the Commission should address by summer 2013?</u>

Response: In our responses to question 6 "Flex Alerts", we address coordination/communication issues specific to Flex Alerts. As outlined below, there is a lack of understanding and coordination between the IOUs and CAISO on triggers for Flex Alerts and how/why they may be called. For this reason, we requests that CAISO provide specific triggers for how/when Flex Alerts are called, as well as provide advanced notification of at least two hours before the information is distributed to the media and general public so that we can adequately prepare our own systems and coordination with local media.

5. **Emergency DR Dispatch Order**

Dispatch order: Under the CAISO's current emergency operational procedure (No.4420, Section 3.3.2) and pursuant to the Settlement Agreement adopted in D.10-06-034), the utilities' Base Interruptible Program (BIP) and SCE's API program and commercial AC cycling program cannot be dispatched until after the CAISO dispatches non-RA resources and canvases other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties.

<u>Q.1: If CAISO's dispatch order was revised such that non-RA resources and other entities /balancing authorities are dispatched AFTER BIP, AP-I, and commercial AC cycling programs are dispatched, would that revision have resulted in additional BIP, AP-I and commercial AC cycling events in 2012? If so, how many events, and on what days?</u>

Response: In order to fully answer this question we would need the number of times and days that the CAISO had to dispatch non-RA resources and canvas other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties in San Diego service territory. We have requested this information from the CAISO and have yet to receive the data.

<u>Q.2: Should this dispatch order be moved up in the operational procedure so the CAISO can dispatch the emergency DR before dispatching non-RA resource and canvassing resources from outside of its system? If the answer</u>

is no, explain why emergency DR (which is an RA resource) should be dispatched after the CAISO dispatches non-RA resources.

Response: At this time the load reduction capabilities of Base Interruptible Program (BIP) are very small and we do not see the value that would be gained from modifying the Settlement that was reached in Resolution E-4220. BIP has had all of its individual marketing dollars disallowed, so it is unlikely that we can effectively grow this program to a size that would have a significant impact on this discussion.

Q.3: If the answer is yes, how can the dispatch ordered be changed? What is the best process to address this issue?

Response: Not applicable.

6. **Flex Alert (If the utility needs additional time for the analysis, it can be provided in the January 31, 2013 updates or supplemental testimony).**

- **Effectiveness:** provide a mapping of the CAISO's Flex Alert(s) and the utility's DR events. For the Flex Alert(s) that coincided with the utility's DR event(s), provide the utility's best estimate of the load impact that can be attributed to the Flex Alert(s).

Response: Please see Table 8.

If there was no DR event during a Flex Alert, provide the utility's best estimate of the load reduction that it observed, that can be attributed to the Flex Alert(s).

Response: In order to avoid customer confusion, PTR events were called on all flex alert days so there were no flex alert days without demand response. An alternate method of attempting to quantify the effects of flex alert day in theory would be to look at the load reductions on PTR event days when no flex alert was issued compared to PTR days when a flex alert was issued. However, the three PTR event days for which a flex alert was not called are not comparable to the 4 PTR events when a flex alert was also called[2]. Two event days had significantly cooler temperature than the flex alert PTR days, and the third was the extremely hot Saturday, September 15th, which is a very unique event with no comparable non-event days available that will be difficult to estimate. In addition, preliminary results indicate that PTR load reductions were 4% or less, and the difference in load impacts between a PTR event with a flex alert and a PTR event without a flex alert will be even smaller and there are limits on how precisely load impacts can be measured.

Provide the methodology (ies) for the estimates, e.g., methods similar to the Ex Post load impact analysis.

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[2]Strictly speaking there were only 2 flex alert days August 10th and August 14th. However, a flex alert was originally issued on August 9th for August 10th-Augsut 12th but the Aug 11th and 12th alerts were later canceled. Therefore SDG&E does not believe it would be valid to treat the PTR events on August 9th and August 11th as non flex alert days for the purposes of load impact analysis.

Q 1: What was the utility's experience with the Flex Alert? Was there any communication between the CAISO and the utility prior to the issuance of the Flex Alert and coordination for the DR events?

Response: The CAISO media/information office held weekly 30 minute conference calls beginning in early July that ended at the end of September. During those calls, the media/information office would share a weather forecast for the upcoming week and some general comments about whether or not they felt that Flex Alerts were potentially on the horizon. We requested specific Flex Alert triggers from CAISO on several occasions, but never received that information. The biggest gap in communication came when the two Flex Alerts this summer were actually triggered on 8/9 (for 8/10, 11 and 12) and on 8/13 (for 8/14). The IOUs did not receive any kind of official advanced notification that Flex Alerts would be called; we only received the same media alert (email and phone call) as the news media, the general public, etc. The same situation occurred when CAISO ended up cancelling the Flex Alert for 8/11 and 8/12. We received no advanced notification from CAISO, only the same media release that was issued statewide. This caused a good amount of confusion both internally at SDG&E as well as with the local media who were trying to decipher whether or not conservation was still necessary based on messages coming from CAISO regarding Flex Alerts and messages coming from us regarding the concurrently running Reduce Your Use days.

Q.2: What was the customers overall experience with Flex Alert? Were there any customer confusions between the Flex Alert and the utility DR event notifications?

Response: We have not yet officially evaluated customer confusion between Flex Alerts and Reduce Your Use days (or other DR programs). However, internal discussions have focused on the difficulty of educating the media, stakeholders and customers regarding the difference. As addressed in Question 3 on Customer Experience, we crafted a message point for distribution to help differentiate the two programs, but it was apparent through watching news stories and via social media monitoring that a good level of understanding was not there. We would recommend that a formal evaluation take place on customer understanding of the differences between local demand response programs, like Reduce Your Use, and Flex Alerts in order to help inform both the IOUs and CAISO on future messaging and differentiation.

Q.3: Should the Flex Alert be continued for 2013 and 2014? If so, are there ways to improve the effectiveness of the Flex Alert program?

Response: We have requested funding for continuation of the Flex Alert program in 2013 and 2014 as part of the Statewide Marketing, Education and Outreach (SW MEO) application, A. 12-08-009. The funding requested for two years is $2M, which was based on the authorized amount of $1M for 2012 in D. 12-04-045. Based on the success of our local outreach effort, as described further below, we are formally requesting with this application that we move $200,000 currently requested for Flex Alerts from the Statewide Marketing, Education and Outreach proceeding (A. 12-08-009) for continuation of the Conservation Partners campaign, as described below.

Based on our support of SCE's proposals regarding continuation of Flex Alerts that they describe in A.12-08-008, funding for Flex Alerts could entirely be removed from the SW MEO applications and management oversight be transferred back to the DRP proceeding, so that the Commission and IOUs would be able to appropriate direct, measure and evaluate the effectiveness of any further Flex Alert efforts. SDG&E will make this consideration A.12.08-009.

Based on experience from the summer of 2012, we are proposing one modification to the Flex Alert program as proposed in A. 12-08-009. In May of 2012, the Commission expressed a clear objective regarding the need to educate lower income and hard-to-reach communities on the need for conservation. The contractor/implementer of the Flex Alert campaign, who also happens to own the trademark to the Flex Alert brand name, expressed an inability to effectively undertake the requested community outreach. At an April 23, 2012 meeting with CAISO, Commissioner Sandoval and staff, representatives from the Commission's Energy Division, Public Information Office and Business Community Outreach offices, and the three electric IOUs, it was agreed that SDG&E and SCE would implement this community outreach in their respective service territories. Based on this direction, we budgeted $100,000 and created the "Community Partners" program. Through this program we requested local community-based organizations (CBOs) to submit proposals on how they could best communicate with their own constituencies. We scored the proposals based on demographic reach, the organizations ability to meet education objectives, their creativity and a proposed timeline.

Thirty-six CBOs received a total of $91,000 in funding from us to promote education around conservation, including both Reduce Your Use days and Flex Alerts. The remaining $9,000 was used to fund the creation and distribution of flyers, posters and videos, and the costs associated with training days for the CBOs. The agencies were all brought together in July 2012 for a training session, where the materials were provided. The agencies then took the materials and used them to execute their own tactical plans, including contests and games for children, extensive social media outreach, videos, blogs, education for disabled adults and other grassroots outreach through events and media. On Reduce Your Use and Flex Alert days, the agencies were able to use their own extensive social networks to tweet and post messages about the need for conservation during that day.

Campaign results indicate that we reached 250,000 additional hard-to-reach customers through the social media efforts of the CBOs, including total daily reach of 44,000 customers through Facebook on event days, increased reach through Twitter, 5,000 video views of Flex Alert ads in Vietnamese, and 12,000 listeners hearing Vietnamese translated Flex Alert ads five times on the one in-language radio station in the San Diego media market.

With regard to continuation of Flex Alerts as a mass media campaign, we support SCE's recommendations in their SW MEO testimony for A.12-08-007 as outlined in testimony, Chapter 3, Section E (page 25.)

> **"E. Long-Term Planning for Statewide Emergency Alert Program**
>
> Although the IOUs are committed to continue funding for statewide emergency alerts (i.e., Flex Alert) in 2013-2014, SCE suggests that the Commission reevaluate beginning in 2015 whether CAISO should take over full control of the statewide emergency alert program. Since its inception in 2004, the IOUs have provided exclusive funding for both messaging and operations of the program although there has only been one emergency alert event called in the previous five years (in 2007). A key reason for0 this declining need for emergency alerts is due to the growth in IOU DR programs, which have1 positively impacted grid reliability. Additionally, energy use has decreased as an outcome of the economic downturn.

In those historical instances where an event was called, the statewide emergency alert program benefitted not only CAISO, but also the other load serving entities (LSEs) throughout the *entire* State of California. SCE has determined that the current funding mechanism for CAISO's emergency alert program is detrimental to California IOU ratepayers, because neither the CAISO nor the other LSEs within the state contribute any funding for the management and messaging of the program.

As such, SCE recommends that beginning in 2015 the Commission no longer direct the IOUs to fund operations of the CAISO's statewide emergency alert program and should fully transition the responsibility to the CAISO. This will allow sufficient time for the Commission to evaluate and implement the transition to CAISO such that it may seek funding through its Grid Management Charge (GMC) cost recovery. This will provide equity to all California ratepayers that everyone is contributing to the statewide emergency alert messaging. This inequity with emergency alerts does not exist with IOU local programs because not all LSEs have DSM programs.

Furthermore, CAISO supports the sole use of the existing emergency alert brand (i.e., Flex Alert), whereas the IOUs are open to alternatives. CAISO has recommended, and the Commission has directed, that the IOUs continue to use the existing brand. However, this limits the IOUs' ability to contract the marketing functions because the ownership of the trademark does not reside with either the IOUs or the Commission. Rather, the contractor that initially established the campaign in 2004 owns the trademark. As a result, the IOUs are currently funding a program name to which they have no claim or legal authority. Unless CAISO supports a different brand name, the IOUs will be required to continue a sole source contract with the owner of the existing statewide emergency alert brand and trademark.

Additionally, IOUs managing the statewide emergency alert program do not have the discretion of when to launch the program. Since CAISO is the only entity that can launch the program, the IOUs' role is limited and thus highlights the need for CAISO to assume total ownership.

Finally, managing the program to accommodate CAISO's desired scope while balancing IOU specific regulatory constraints can be difficult. For instance in summer 2012, CAISO requested the IOUs share statewide emergency alert messaging with the Federal Electricity Commission (CFE) in Baja, Mexico, in an effort to promote energy conservation in that region, despite the fact that the existing ratepayer-funded statewide emergency alert program messaging would air outside of the IOUs' service territories.

For these reasons, SCE recommends the Commission remove the requirement for the IOUs to solely fund the CAISO's statewide emergency alert program after December 31, 2014. SCE further recommends that the Commission defer this authority to CAISO. This transition should be directed to occur during the 2013-2014 bridge cycle to address the funding and operational challenges for the IOUs highlighted above and to provide the CAISO the opportunity to seek funding in its GMC cost recovery."[3]

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[3] A.12-08-008. SCE testimony of Kazuko "Marti" Ochiai. Section 3E, page 25.