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July 30, 2014

To: Gil Wong and Greg Mandelman, PG&E

From: Aimee Savage, Stephen George, Nexant

Re: SmartRate Analysis Error

The purpose of this memo is to present final ex post and ex ante load impact estimates for PG&E's SmartRate program for program year 2013. These new estimates deviate slightly from the estimates provided in the April 1, 2014 report entitled *2013 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs.* The CPUC Energy Division and the DRMEC agreed that summarizing these small differences and the reasons underlying them in this memorandum was preferable to reissuing the full report. The new ex post load impact estimates are roughly 3% higher than the prior estimates for the typical event day and the new ex ante estimates differ by less than 1% from the prior values.

The remainder of this memo provides a brief overview of the SmartRate program and the impact estimation methodology. More details can be found in the April 1 report. These two sections are followed by a discussion of the nature of the error that occurred. The final two sections present the revised estimates and compare them with the prior values.

SmartRate Overview

SmartRate is a critical peak pricing (CPP) tariff that is an overlay on a customer's otherwise applicable tariff (OAT).[1] SmartRate pricing consists of an incremental charge that applies during the peak period on SmartDays and a per kilowatt-hour credit that applies for all other hours from June through September. For residential customers, the additional peak-period charge on SmartDays is 60¢/kWh. The SmartRate credit has two components, both of which apply only during the months of June through September. The first SmartRate credit, 3¢/kWh, applies to all usage other than peak-period usage on SmartDays. An additional credit of 1¢/kWh applies to Tier 3 and higher usage for residential customers regardless of time period.

Under SmartRate, there can be up to 15 SmartDays (also referred to as event days) during the summer season, which runs from May 1 through October 31. Unless a customer's underlying rate is also a time-of-use (TOU) rate, which is rare, prices vary by time of day on SmartDays only. The peak period on SmartDays is from 2 PM to 7 PM and customers are notified by 3 PM on the business day prior to the SmartDay.

Customers who enroll in SmartRate may also enroll in PGE&'s SmartAC program. SmartAC is a program in which customers receive a modest, one-time payment from PG&E in return for having their air

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1 Except for 5 E-7 customers and 20 E-6 customers, all other SmartRate customers have E-1 as their underlying tariff.

conditioner controlled at times of high system load. PG&E accomplishes this control through the use of switches that are installed directly on the customer's AC or through the use of programmable communicating thermostats that can receive a radio signal. Customers who enroll in both programs are given the option of having their AC controlled during the peak period on SmartDays. Choosing this option provides dually enrolled customers with an automatic boost to their savings due to reduced AC usage on SmartDays. At the end of 2013 there were roughly 119,000 customers enrolled on the SmartRate tariff, of which approximately 38,500 were also enrolled in the SmartAC program.

Ex Post Methodology

The primary source of reference loads, and hence impact estimates, is a series of matched control groups. These control groups are assembled from among the non-SmartRate population. The methods used to assemble the groups are designed to ensure that the control group load on event days is an accurate estimate of what load would have been among SmartRate customers on event days.

The fundamental idea behind the matching process is to find customers who were not subject to SmartRate events that have similar characteristics to those who were subject to SmartRate events. Two different control groups were assembled: one for the SmartRate-only population and one for the group of SmartRate customers also enrolled in SmartAC.

The control groups were selected using a propensity score match to find customers who had load shapes most similar to SmartRate customers. The match was performed within each LCA and usage quartile and was based on a set of variables that characterize load shape and the magnitude of electricity use on hot, non-event days.

Once the control groups were matched and validated, load impacts were estimated using a difference-in-differences methodology. This methodology calculates the estimated impacts as the difference in average loads between SmartRate and control customers on event days minus the difference between the two groups on hot, non-event days. This calculation controls for residual differences in load between the groups that are not eliminated through the matching process, thus reducing bias.

2013 Evaluation Error

Interval data for the 2013 analysis was provided to Nexant by PG&E. Most residential customers have meters that provide readings at the end of each hour. About 6% of SmartRate customers and their control counterparts have meters that record usage at fifteen minute intervals. Two separate interval data files were delivered to Nexant: one for 60-minute customers and one for 15-minute customers. In the 2012 analysis the units of measurement in the interval data files were kilowatts (kW). In 2013, customers who had 15-minute interval data were presented in kilowatt hours (kWh) rather than kilowatts.

To find an hourly kW value from 15-minute kW data, one must calculate the average of four 15-minute reads. To find an hourly kWh value from 15-minute kWh data, one must calculate the sum rather than the average. Some statistical programming code from the 2012 evaluation was used to process the 2013 interval data but the code was not updated to account for the change in units. This means that 6% of customers were analyzed assuming that their usage was ¼ of their true usage. Both SmartRate customers and the pool of potential control customers were affected by this error.

To correct this error, the raw interval data from PG&E was processed using revised code that took the sum rather than the average of the 15-minute data to estimate hourly values. This part of the analysis process occurred prior to control group selection so a new control group was developed based on the corrected 2013 load impact estimates.

Corrected 2013 Ex Post Load Impact Estimates

The programming error only had a minor effect on the ex post load impact estimates. Table 1 summarizes the corrected average load reductions across the five-hour event window provided by residential SmartRate-only customers on each event day during the summer of 2013. As shown, the average percent reduction ranged from a low of 13% on September 10 to a high of 19% on June 28. An average reduction of 16% was obtained across the 8 event days. The average load reduction per participant ranged from a low of 0.16 kW to a high of 0.34 kW. Aggregate average reduction in demand on Smart Days ranged from 13.3 MW to 28.2 MW. The aggregate load reduction averaged across all ex post event days equaled 21.1 MW. Prior to correcting for the data error, the aggregate load reduction was 20.5 MW, a difference of about 3%. Differences on individual event days ranged from a low of 1.5% to a high of 5.4%.

Table 1: SmartRate-only Ex Post Load Impact Estimates

Date	Enrolled participants	Avg. Reference Load (kW)	Avg. Load Reduction (kW)	Percent Load Reduction (%)	Aggregate Load Reduction (MW)	Daily Maximum Temp (°F)
7-Jun-13	76,855	1.52	0.25	17%	19.5	90
28-Jun-13	79,625	1.82	0.35	19%	28.2	94
1-Jul-13	79,740	1.87	0.30	16%	24.1	93
2-Jul-13	79,785	1.95	0.31	16%	24.4	93
19-Jul-13	80,495	1.44	0.22	15%	17.5	86
19-Aug-13	80,785	1.72	0.27	16%	21.5	89
9-Sep-13	80,744	1.55	0.25	16%	20.0	89
10-Sep-13	80,710	1.31	0.16	13%	13.3	83
Average Event Day	**79,842**	**1.65**	**0.26**	**16%**	**21.1**	**89**

Table 2 summarizes the corrected average load reduction for dually enrolled SmartRate customers on each 2013 event day and for the average event day. For this group, the average percent reduction ranged from a low of 22% on September 10 to a high of 33% on June 28. An average reduction of 29% was obtained across the 8 event days. The average load reduction per participant ranged from a low of 0.34 kW to a high of 0.83 kW. The aggregate ex post load reduction across all events ranged from 13.1 MW to 31.8 MW, with an average value of 24.3 MW. This is 2.5% higher than the value previously reported. The differences between the original and revised estimates ranged from 1.4% to 3.5% across event days.

Table 2: Dually Enrolled Ex Post Load Impact Estimates

Date	Enrolled participants	Avg. Reference Load (kW)	Avg. Load Reduction (kW)	Percent Load Reduction (%)	Aggregate Load Reduction (MW)	Daily Maximum Temp (°F)
7-Jun-13	37,909	1.97	0.63	32%	24.0	96
28-Jun-13	38,171	2.51	0.83	33%	31.8	99
1-Jul-13	38,179	2.61	0.77	29%	29.4	99
2-Jul-13	38,192	2.68	0.76	28%	29.2	99
19-Jul-13	38,315	1.82	0.49	27%	18.8	93
19-Aug-13	38,493	2.28	0.64	28%	24.7	95
9-Sep-13	38,576	2.04	0.58	29%	22.5	95
10-Sep-13	38,578	1.55	0.34	22%	13.1	85
Average Event Day	**38,302**	**2.18**	**0.63**	**29%**	**24.3**	**95**

Corrected 2014-2024 Ex Ante Load Impact Estimates

The effect of the programming error on the ex ante estimates was even smaller than for the ex post values. Table 3 shows the corrected per-customer and aggregate ex ante load impact estimates based on the estimated enrollment for 2014. For the typical event day, the revised ex ante estimates are nearly identical to the prior values. For the July system peak day, there is no difference under 1-in-10 year weather conditions. Under 1-in-2 year conditions, the new estimates are roughly 1% higher.

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Table 3: 2014 SmartRate Ex Ante Load Impact Estimates
By Weather Year and Day Type (1-6 PM)

Weather Year	Day Type	Mean Hourly Per Customer Impact (SmartRate Only) (kW)	Mean Hourly Per Customer Impact (Dually Enrolled) (kW)	Aggregate Mean Hourly Impact (SmartRate Only) (MW)	Aggregate Mean Hourly Impact (Dually Enrolled) (MW)	Aggregate Mean Hourly Impact (Full Program) (MW)
1-in-2	Typical Event Day	0.21	0.53	16.8	20.9	37.7
	May Monthly Peak	0.14	0.38	10.9	14.8	25.7
	June Monthly Peak	0.19	0.46	15.3	18.1	33.4
	July Monthly Peak	0.24	0.63	19.5	24.9	44.3
	August Monthly Peak	0.21	0.51	16.7	20.2	37.0
	September Monthly Peak	0.20	0.52	15.7	20.4	36.1
	October Monthly Peak	0.14	0.32	11.6	12.5	24.1
1-in-10	Typical Event Day	0.26	0.66	20.8	26.0	46.9
	May Monthly Peak	0.23	0.58	18.2	22.7	40.9
	June Monthly Peak	0.27	0.63	21.3	24.7	46.0
	July Monthly Peak	0.28	0.75	22.5	29.6	52.1
	August Monthly Peak	0.26	0.68	20.6	27.1	47.6
	September Monthly Peak	0.24	0.58	19.0	22.8	41.8
	October Monthly Peak	0.20	0.51	16.2	20.3	36.5