Decision **PROPOSED DECISION OF ALJ FUKUTOME (Mailed 12/22/2009)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of its 2009 Rate Design Window Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation (U39E).	Application 09-02-022 (Filed February 27, 2009; amended March 13, 2009)

DECISION ON PEAK DAY PRICING FOR PACIFIC GAS AND ELECTRIC COMPANY

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DECISION ON PEAK DAY PRICING FOR PACIFIC GAS AND ELECTRIC COMPANY

1. Summary

This decision continues implementation of the Commission's policy to make dynamic pricing available for all electric customers by adopting and implementing default and optional critical peak pricing and time-of-use rates (together, referred to as Peak Day Pricing) beginning May, 1, 2010 for Pacific Gas and Electric Company. This decision also adopts appropriate customer outreach and education activities and measures to ensure customer awareness and understanding of the new rates and options.

Among other things, this decision determines that:

- Large commercial and industrial customers will be defaulted to Peak Day Pricing rates on May 1, 2010 unless they proactively choose to opt out to a time-of-use rate. Optional Peak Day Pricing tariffs will be available on that date for those small and medium commercial and industrial, and agricultural customers who have already received the necessary metering equipment.
- Peak Day Pricing will become the default tariff for medium and small commercial and industrial and large agricultural customers beginning February 1, 2011. These customers however will not be defaulted to the Peak Day Pricing tariff until 12 months of recorded interval billing data is available for use in determining their best Peak Day Pricing options. They can also choose to opt out to time-of-use rates.
- Time-of-use rates will be the default tariff for small agricultural customers beginning February 1, 2011.
- The current SmartRate option available to residential customers will remain in effect until 2011 at which time SmartRate customers will either transition to residential Peak Day Pricing rates or revert to non-time differentiated residential tiered rates.

- There will be between 9 and 15 Peak Day Pricing event days per calendar year.
- All customers that are defaulted to, or choose, Peak Day Pricing rates will be afforded bill stabilization for the first year, unless they choose to waive such protection.
- The costs of bill stabilization and any under- or over-collections related to the variation in the number of Peak Day Pricing events will be allocated to all customers within specific customer classes.
- All Customers subject to Peak Day Pricing will have a hedging option to reduce bill volatility. The larger customers will have a capacity reservation option, while the smaller customers will have an option where they would be subject to Peak Day Pricing on alternating event days.
- Customers who are on Peak Day Pricing rates may opt out any time during the first year they are on such rates.
- Incremental cost recovery for Peak Day Pricing implementation, amounting to $92,072,000 for the years 2008 through 2010, is reasonable. The revenue requirement associated with these costs will be included in rates through Pacific Gas and Electric Company's Annual Electric True-up advice letter filing.
- Recovery of potential cost overruns, including those related to contingencies, and costs of the conversion of Customer Care and Billing Version 1.5 to Version 2.2 are deferred to after-the-fact reasonableness review applications.
- Peak Day Pricing implementation costs for 2008 through 2010 should be classified as distribution costs and should be allocated by distribution equal percentage of marginal cost allocators to all distribution customers, including direct access customers. Such allocation for 2011 and beyond should be decided in future General Rate Case Phase 2 proceedings.
- Pacific Gas and Electric Company should (1) work with the Commission's Business and Community Outreach Branch to determine how the group can assist in outreach efforts to small and medium customers and (2) hold quarterly meetings, two with Energy Division and two open to the public.

- Pacific Gas and Electric Company should be subject to a number of reporting requirements in order for the Commission to gather information and to provide a means for parties to express concerns and a means to address any such concerns.

2. Background

Pacific Gas and Electric Company (PG&E) filed this application in compliance with Decision (D.) 08-07-045, which ordered PG&E to propose certain time-differentiated electric rates (generally called dynamic pricing) for customers as part of its 2009 Rate Design Window and to seek recovery of incremental expenditures required to implement dynamic pricing.[1] The Commission's dynamic pricing principles seek to increase customer involvement in (a) managing California's energy supply, (b) reducing greenhouse gas emissions, and (c) managing future power plant development costs, by providing real economic incentives to reduce electric demand during peak periods.

As ordered in D.08-07-045, PG&E now proposes default and optional critical peak pricing (CPP) and time-of-use (TOU) rates, some of which will be effective for some customer classes by May 1, 2010 and others by February 1, 2011. PG&E will propose optional real time pricing (RTP) rates for all customer classes as part of its Test Year 2011 General Rate Case (GRC) Phase 2 Application that will be filed in March 2010.

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[1] D.08-07-045 adopted a dynamic pricing implementation timetable and associated rate design guidance for PG&E. It was issued on July 31, 2008 in the dynamic pricing phase of Application (A.) 06-03-005, PG&E's 2007 General Rate Case Phase 2 filing on marginal costs, revenue allocation and rate design. Among other things, the Commission ordered PG&E to propose various dynamic pricing rates in a Rate Design Window Application to be filed no later than February 28, 2009.

PG&E estimates that the incremental costs in 2008, 2009 and 2010 for the dynamic pricing proposals contained in this application will total $160.2 million, of which $110.5 million is for capital expenditures and $49.7 million is for expenses.[2] PG&E requests that the Commission find the estimated costs for its proposal to be reasonable.

2.1. Procedural Matters

A prehearing conference was held on April 22, 2009, and the Assigned Commissioner's Ruling and Scoping Memo was issued on May 5, 2009. Testimony in response to PG&E's application on issues other than information technology (IT) was served on or before July 31, 2009.[3] Testimony on IT-related issues was served on August 5, 2009.[4] Rebuttal testimony on non-IT-related issues was served on August 21, 2009.[5] Rebuttal testimony on IT-related issues was served by PG&E on August 26, 2009. Evidentiary hearings were held August 31, 2009 through September 4, 2009 and September 8, 2009. Opening

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[2] Costs are those reflected in PG&E's opening brief.

[3] Non-IT-related testimony was served by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), the California Large Energy Consumers Association (CLECA), the Building Owners and Managers Association of California (BOMA), the Agricultural Energy Consumers Association (AECA), the California Farm Bureau Federation (CFBF), the Direct Access Customer Coalition (DACC), the Energy Producers and Users Coalition (EPUC), and the Federal Executive Agencies (FEA); and jointly by the California Manufacturers & Technology Association (CMTA) and Energy Users Forum (EUF). Testimony was also served by EnerNOC, Inc. (EnerNOC). However, that testimony was withdrawn at evidentiary hearing on August 31, 2009.

[4] IT-related testimony was served by both DRA and FEA.

[5] PG&E, DRA, TURN, CLECA, and EPUC each served non-IT-related rebuttal testimony.

briefs were filed on September 28, 2009. Reply briefs were filed on October 5, 2009, at which time this proceeding was submitted for decision.

2.1.1. PG&E's Request for Expedited Partial Relief

On March 26, 2009, PG&E filed a Motion for Expedited Decision for Partial Relief. PG&E indicated that it had been incurring dynamic pricing implementation costs as early as 2008 and requested that the Commission authorize PG&E to recover in rates, those related expenses recorded in the Dynamic Pricing Memorandum Account (DPMA) as of November 30, 2009, subject only to review and verification that such expenditures were for dynamic pricing compliant activities. PG&E estimated that it would incur approximately $7 million in the DPMA by late November of 2009. PG&E proposed to incorporate the actual DPMA expense balance as of November 30, 2009 into the end-of-year 2009 Annual Electric True-up (AET) process for rate recovery beginning January 1, 2010. PG&E further requested that the Commission adopt a case schedule providing for a final decision on dynamic pricing proposals by the end of 2009. The motion was opposed by DRA.

In D.09-07-001, the Commission denied PG&E's request for partial relief, indicating that PG&E's ratemaking proposal did not provide an appropriate opportunity for the Commission to determine the reasonableness of the expenses before they were included in rates. It was determined that rate recovery of 2008 and 2009 expenses would instead be based on the amounts determined to be reasonable in the final decision for this proceeding. The decision also indicated that PG&E's request for an end of 2009 decision was addressed in the May 5, 2009 Scoping Memo for this proceeding.

2.1.2. Petition for Modification of D.08-07-045

In D.08-07-045, among other things, PG&E was ordered to propose one or more default CPP rates[6] for commercial and industrial (C&I) customers with maximum load less than 200 kilowatts (kW) (small and medium customers) that have had an advance metering infrastructure (AMI) meter for 12 months or more. The indicated effective date of the default rate(s) was to be on, or before, February 1, 2011.[7]

However, the Commission did leave open the possibility of changing the dynamic pricing timetable, as follows:

> This decision does not itself adopt any rates and does not commit the Commission to approve specific rates. Instead, this decision establishes dates when PG&E will be required to propose specified rates. We refer to these dates as the timetable. In the proceedings in which the Commission considers PG&E's specific rate proposals, the Commission could decide to adopt different rates or a different timetable based on the information presented to the Commission at that time. (D.08-07-045, pp. 8-9.)

On April 3, 2009, DRA, the California Small Business Association and California Small Business Roundtable (collectively, Petitioners) filed a Petition for Modification of D.08-07-045 (Petition). Petitioners requested that the Commission postpone the date by which CPP and other new rates are to become effective, for medium and small C&I customers, to no sooner than February

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[6] In this Rate Design Window filing, PG&E refers to such CPP rates, in conjunction with TOU rates, as Peak Day Pricing (PDP) rates.

[7] D.08-07-045, Ordering Paragraph 6.

2012.[8] Petitioners further requested that the Commission bifurcate the PG&E Rate Design Window proceeding, A.09-02-022, with Phase 1 devoted to rate design for large C&I and all agricultural customers, and Phase 2 devoted to rate design for small and medium C&I customers. The petition request was supported by TURN and opposed by PG&E.

In D.09-07-002, the Commission denied the petition for modification. The request that the effective date for default critical peak pricing rates for small and medium C&I customers be postponed from on, or before, February 1, 2011 to no sooner than February 2012 was denied without prejudice to the determination of such appropriate date in PG&E's ongoing Rate Design Window proceeding, A.09-02-022. Also, it was indicated that the request for bifurcation of A.09-02-022, and consideration of rate design for small and medium C&I customers in the second phase, was not adopted in that proceeding's Scoping Memo, was moot and should be denied.

3. PG&E's PDP Proposal

Under PG&E's proposal, the following rates will be effective May 1, 2010:

- For large C&I customers, default PDP rates that include TOU rates during non-peak periods.
- For agricultural, small and medium C&I, and residential customers with advanced meters, optional PDP rates that include TOU rates during non-peak periods.

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[8] Petitioners requested no change in the schedule for implementing dynamic pricing for large C&I customers, nor for agricultural customers.

By February 1, 2011, PG&E proposes the following rates will be effective:

- For large agricultural customers that have had an advanced meter for at least 12 months, default PDP rates that include TOU rates during non-peak periods.
- For small and medium C&I customers that have had an advanced meter for at least 12 months, default PDP rates that include TOU rates during non-peak periods. Flat rates will no longer be available to these customers.
- For small and medium agricultural customers that have had an advanced meter for at least 12 months, default TOU rates. Flat rates will no longer be available to these customers.

The specifics of PG&E's PDP rate proposal and cost recovery request are identified and discussed throughout this decision. With respect to implementation dates, DRA opposes the February 1, 2011 date for small and medium C&I customers, as discussed in Section 7.1.

4. Opposition to PG&E's PDP Proposal

A number of parties support the concept of PDP but have recommended various modifications to PG&E's rate, default implementation, and cost recovery proposals, which are addressed in this decision.

EUF/CMTA states that although they support the development of a portfolio of Demand Response (DR) programs that accesses all cost effective DR and enables all customers to respond meaningfully, they do not support implementation of PG&E's PDP tariff as presented. According to EUF/CMTA, PG&E's PDP tariff will inhibit or reduce response from some customers, will cause structural cost shifting, fails to address equity considerations and, as proposed, provides no net societal benefit.

After fully considering input and comments from a variety of parties in the dynamic pricing phase of PG&E's last GRC rate design proceeding, A.06-03-005, the Commission, in D.08-07-045, ordered PG&E to propose various default CPP rates. PG&E has complied with that order by filing its PDP proposal that is the subject of this proceeding. While we recognize that there are uncertainties and potential problems associated with the PDP program being adopted today, we are convinced that the program should go forward, in furtherance of our long term policy to provide dynamic pricing to all customers. We note the EUF/CMTA concerns, along with those of the other parties, and emphasize that the intent of our decision today is to implement a PDP program that fairly balances the risks and costs to various affected customers and customer classes while remaining generally consistent with the guidelines provided in D.08-07-045. As further discussed, we have found it necessary to modify certain elements of PG&E's proposed PDP program and the related cost recovery request.

5. Rate Design – All Classes

5.1. Rate Levels for PDP Rates

PG&E's original PDP rate proposal contained a $1.80 per kWh PDP period charge, with adjustments for residential, agricultural and small commercial customers. That PDP rate represented PG&E's initial interpretation of the Commission's Rate Guidance (Attachment A to D.08-07-045), which among other things states that TOU demand charges should be eliminated from the generation component of those tariffs that include generation demand charges. However, after reviewing other parties' testimony on this issue, PG&E revised its recommendation to give greater weight to another aspect of the Rate Guidance, which indicates that the PDP adder should be based more strictly on the marginal cost of generation capacity. PG&E also applied two standard adjustment factors identified by DRA to arrive at a PDP adder of $1.20 per kWh in rebuttal testimony. By further applying its initial proposed adjustments to the $1.20 PDP charge, PG&E indicates that the agricultural and standard residential PDP adders would be reduced to $1.00 per kWh (to reflect rate design considerations unique to these two rate classes), and the small Commercial PDP adder would become $0.60 per kWh (based on the same bill impact mitigation considerations first described in its original testimony). Also, under its new alternative for residential customers discussed later in this decision, the residential PDP adder would become $0.50 per kWh.

There is no opposition to PG&E's revised PDP rate levels.[9] They are reasonable and are adopted.

5.2. TOU Rates

Except for two specific exceptions, PG&E has not proposed to change its TOU rates in this proceeding. The two exceptions are the TOU rates that would be combined with PDP for small and medium C&I customers and for residential customers. First, for customers on Schedule A-1, the new TOU version of Schedule A-1 would become the "backstop" TOU rate for those A-1 customers who do not accept default to the PDP rate. Similarly, the PDP version of Schedule A-6 TOU would become the default rate for customers taking optional TOU service on this schedule.

Second, in response to DRA's recommendation that residential PDP be offered in combination with the standard non-TOU Schedule E-1 residential tariff, PG&E's rebuttal testimony presented a residential PDP rate with TOU prices that are less steeply time-differentiated than those offered under the

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[9] As specified in Exhibit 7, Tables 2-3 through 2-5, and Table 2-6, Alternative 1.

residential Schedule E-6 tariff. This rate would only be offered in conjunction with residential PDP.

With the changes contained in PG&E's rebuttal testimony, no party opposes PG&E's TOU rate proposals in this case, although DRA has expressed strong interest in development of more greatly time-differentiated TOU rates, especially for medium C&I customers in future cases. The TOU rates for PDP, as now proposed by PG&E,[10] are reasonable and are adopted. The need for, and structure of, more greatly time-differentiated TOU rates for medium C&I customers can be raised as issues in future cases.

5.3. Number of PDP Events

All parties that have addressed the number of PDP events support an annual minimum of 9 and a maximum of 15 PDP calls.[11] There is general agreement that adoption of these minimum and maximum numbers mitigates the problem associated with over- and under-collections. Although PG&E presented testimony that the fixed temperature thresholds in its proposal would likely be met between 6 and 18 times in most years, PG&E states that the high degree of variability around the design basis of 12 years justifies adopting a somewhat narrower band on the number of annual PDP calls.

The Commission will adopt this consensus position on the minimum and maximum number of annual PDP calls, as well as PG&E's proposal for enforcing the bounds by raising or lowering the temperature thresholds. PG&E states that it should be possible to enforce the narrower bounds on the number of calls each

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[10] As specified in Exhibit 7, Tables 2-3 through 2-5, and Table 2-6, Alternative 1.

[11] Parties agreeing on this issue include PG&E, EUF/CMTA, CLECA, EPUC, FEA, CFBF, and DRA.

summer simply by raising or lowering the 98-degree weekday temperature threshold in 2-degree increments at monthly intervals over the course of the summer. According to PG&E, in most years, the threshold should not need to be adjusted more than one increment up or down over the course of the summer. The weekend and holiday threshold would be left fixed at 105 degrees.[12]

5.4. First Year Bill Stabilization/Protection

PG&E proposes to provide all non-residential customers with bill stabilization for the first year they are on the new PDP rates, whether they have been defaulted or opted in. The bill stabilization would protect the customer from a PDP bill for up to 12 cumulative months that exceeds the bill for the period under the customer's otherwise applicable tariff, such as TOU. For residential customers, PG&E proposes bill protection for the first year the customer is on PDP by not allowing the bill to exceed the annual bill under the tariff the customer was on previously, such as non-TOU Schedule E-1, as long as the tariff is available.

No party opposes PG&E's proposal to provide first year bill stabilization or protection. PG&E's first year bill stabilization/protection proposal is reasonable and is adopted. DRA has proposed extended bill stabilization for small C&I customers which is discussed further on in this decision.

5.5. Allocation of Over- and Under-Collections

The question of how to allocate over- and under-collections due to bill stabilization/protection and the variation in the number of PDP events from the PDP design number of 12 events was initially a contentious issue among a

[12] *See* Exhibit 7, p. 2-4.

number of the parties. Proposals included: (a) allocation to all customers under certain circumstances; (b) allocation to PDP participants only; (c) allocation by customer class giving rise to the over- or under-collection to all customers in the class; and (d) adoption of different allocation methods for under-collections due to bill protection/stabilization as opposed to over- and under-collections due to variations in the number of PDP events.

PG&E's initial proposal was to make annual adjustments to the generation revenues assigned to each principal customer class for the purpose of approximately adjusting the estimated under- or over-collections following any year in which the number of PDP events significantly differed from the 12 PDP events assumed for rate design purposes. The proposed adjustment would be applied following those years when there have been 9 or fewer PDP events or 15 or more PDP events. However, since a number of parties objected to this deadband recommendation, PG&E now recommends the adjustments should be made every year. PG&E does not expect the adjustments to be so large as to materially affect rates whether they are included or excluded.

With respect to under-collections due to bill stabilization, FEA states that participants alone cannot fund the bill protection because they are the ones who are being provided the protection. Therefore, all customers within each class must participate in funding any bill protection payments.

With respect to under- and over-collections due to the number of PDP events, FEA supports PG&E's revised proposal to allocate on a class basis to all customers so that it can be appropriately accounted for through rate design instead of being spread to all customers in all hours. FEA's associated rate design proposal is based on the fact that the dollars associated with any reconciliation of revenues resulting from more or less than 12 events is generation related and peak period specific. Accordingly, it is FEA's recommendation that, for each class, the reconciliation occur by applying a credit or a surcharge as appropriate to on-peak and mid-peak demand charges and energy charges. According to FEA, this approach matches the collections as nearly as practical with the periods in which the revenues were intended to be collected.[13]

FEA also indicates that purely from an equity standpoint, it would be preferable if the reconciliation occurred only across the participants, but there is a major practical problem with such an approach. The limitation is that with optional tariffs there could be the unintended consequence of either encouraging or discouraging participation because of the anticipated presence of a surcredit or surcharge in any given year.

CLECA also supports PG&E's revised approach, both for its simplicity and because the concept of visiting potentially large upward or downward adjustments on individual customers who actually sign up for this program is likely to create one more disincentive for participation. CLECA states that the Commission needs to encourage customers to participate by making the program understandable, relatively straightforward and by minimizing the perceived risks of participation. CLECA also notes that exclusion of non-

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[13] PG&E supports this recommendation. According to PG&E, these rate design adjustments to generation capacity related rate components are reasonable because these class level adjustments recognize variation in revenue collection of generation capacity based PDP charges due to variation in the number of PDP operations, and since these charges are generation capacity related, rate design adjustments to generation rate components that collect generation capacity costs are reasonable.

participants would necessitate tracking individual customers, but leaves it up to PG&E to determine whether that is operationally feasible.

DRA concurs with the view of the majority of the parties, that revenue reconciliation take place at the class level, both for revenue deviations due to annual bill stabilization/protection and, conditionally, for those due to variation in number of PDP events.

DRA's initial testimony advocated participant level reconciliation of PDP-related revenue deviations. DRA states that it changed its recommendation, based on the reduced revenue swings associated with the consensus recommendation of 9-15 PDP events and a maximum $1.20 per kWh PDP charge. Given this scenario, DRA no longer believes that the benefits of participant-level reconciliation outweigh the costs of its implementation.

Similarly, CFBF expressed its belief that it would be most appropriate to allocate the PDP over-/under-collection according to the class-specific enrolled load, but if the number of PDP events were restricted to between 9 and 15, the issue would be less important due to the reduced volatility.

Allocation to all customers by class is also supported by EPUC who, similar to FEA, noted that a participant only reconciliation in conjunction with an opt-out provision could lead to annual gaming of PDP rates.

TURN also indicates its support for allocation to all customers by class.

BOMA opposes the allocation to non-participants, stating that such a proposal contravenes the requirements of D.08-07-045 and is inconsistent with the settlement found reasonable in D.07-09-004.

BOMA refers to D.08-07-045 where the Commission stated that "Customers should have the opportunity to opt out of a dynamic pricing rate to another time-variant rate." According to BOMA, PG&E's proposal does not meet that standard. Under it, customers who opt out of the PDP Program to an applicable time variant rate, in order to avoid the financial risks of the PDP rate, will not actually escape those risks because PG&E will transfer PDP risks to the existing time variant rates.

BOMA also asserts that, in effect, through implementation of its E20 Secondary PDP rate, PG&E will actually change the revenue allocation and rate design of the existing E20 Secondary rate (which violates the terms of the Settlement Agreement, to which PG&E, FEA and BOMA were Parties, adopted in Decision 07-09-004). BOMA adds the FEA Proposal will further change the rate design of the Settlement by forcing all of the under-collection adjustments into peak period demand and energy charges, thus directly shifting revenue responsibilities from flat load customers to customers who use relatively higher proportions of the load during peak period hours.

According to BOMA the potential magnitude of the E20 Secondary summer rate increases that could be expected from under-collections could exceed 9% for 75% participation and three calls, and 1% with participation as low as 25% and nine calls. In BOMA's view, both figures represent cost shifts to customers that have "opted out" that are very significant. BOMA concludes that the potential risks that such transfers could occur under PG&E's PDP Plan are unacceptable, inconsistent with Commission precedent, and can be avoided by adopting BOMA's recommended alternative.

BOMA's alternative is derived from D.09-08-028 for the recent Southern California Edison (SCE) GRC Phase 2 filing (A.08-03-002), which states:

> …that the undercollection or overcollection resulting from the difference between actual called events and twelve events as designed shall be assigned to the summer on-peak and mid-peak periods as a flat cent per KWh surcharge in the subsequent annual

period for the CPP participants within each rate group that is responsible for the revenue imbalance.

BOMA states that by retaining revenue responsibility/credits within the subclass of E20 PDP Secondary, as specified in D.09-08-028, customers will be able to opt out to an E20 Secondary rate that is independent of the under- and over-collections of the PDP Program and avoid the financial risks and cost shifts associated with the PDP rates. Noting PG&E's arguments against this approach (in addition to their position that cost transfers will be small) which are that they do not know how to program the implementation of the approach, that it would be excessively costly to implement, and that they could not implement it by the May 2010 deadline, BOMA indicates that these arguments are unconvincing especially in light of the fact that SCE has committed to implement D.09-08-028. BOMA states that it does not accept PG&E's apparent premise that programming inconvenience should trump the basic principle of equity in rate setting.

EUF/CMTA also proposes that if the Commission adopts a PDP rate, it should limit distribution of the revenue deviation, whether positive or negative, to the PDP participants, to avoid the financial repercussions on those not on the PDP rate schedule. EUF/CMTA asserts that it would not be equitable to pass a rate impact on to a customer that did not participate in that program nor would it be equitable to the PDP participant group, and notes that distributing some of the revenue deviation to non-participants causes the PDP tariff not to be truly optional.

With respect to BOMA's argument that PG&E's proposed class level adjustments and rate design for under- or over-collections violate the settlement on revenue allocation and rate design approved by the Commission in D.07-09-004 for rate changes between GRCs,[14] PG&E acknowledges that Section 3 of Appendix B to D.07-09-004 establishes the revenue allocation and rate design guidelines for PG&E between GRCs and recognizes the potential deviation from those guidelines inherent in its recommendation, to the extent that the adjustments might increase (or decrease) the amount of revenue to be assigned to peak period demand and energy charges in some years. However, PG&E claims that these deviations would be small and are likely to be symmetric with respect to increases or decreases. Moreover, adjustments that increase the amount of revenue assigned to peak period charges in one year will be adjustments that make up for an under-collection of peak period revenue in the preceding year (and vice versa). According to PG&E, this means there would be no deviation from Section 3 of the D.07-09-004 Settlement Agreement if a multiple-year perspective is used. Lastly, PG&E asserts that BOMA's recommendation of participant-only adjustments could result in greater deviations from the Settlement Agreement than would PG&E's recommendations, because customers who opt out after enjoying the benefits of

[14] PG&E states that BOMA's brief does not explain which provisions of the seven separate settlement agreements attached to D.07-09-004 it believes would be violated by PG&E's proposed class level cost allocation and rate design adjustments. However, rate changes between GRCs are governed by Section 3 of the marginal costs and revenue allocation settlement agreement, which is at pp. 17-19 of Appendix B to D.07-09-004. PG&E indicates that there are two subsections of Section 3 which appear relevant to BOMA's argument. Subsection 3(A) provides in part that, "Each customer group will be held responsible for approximately the same percentage contribution to each component in rates (emphasis added); and subsection 3(G) holds that, "Non-residential rate changes will be implemented as equal percentage changes to demand and energy charges by component as necessary to collect revenue."

a year with a lower than expected number of PDP events would not have any allocation of under- and over-collections due to variation in PDP operations, while ongoing PDP participants would bear all the revenue requirement changes.

5.5.1. Discussion

No party disputes that under- and over-collections that are associated with bill stabilization should be allocated to all customers by class, and that principle will be adopted.

We will also adopt the principle of allocating under- and over-collections due to the number of PDP events by customer class to both participants and non-participants. While all parties appear to agree that such allocation should be by customer class, there is a difference in opinion, as described above, with respect to whether the allocation should be imposed on non-participants. A number of parties indicate that excluding non-participants would be preferable, but for a number of other reasons feel that inclusion of such customers in the allocation is either preferable or does not matter.

While BOMA's position is bolstered by Commission actions in D.09-08-028 in the SCE proceeding, settlements are not precedential. Also the record with respect to what was considered in the referenced settlement is not clear here in PG&E's proceeding. Here, with respect to excluding non-participants from the allocation, we agree there are potential gaming problems. At this point, there are also additional costs and difficulties in implementing such a proposal. While BOMA is concerned that the affects of allocating to all customers imposes a potentially large burden on non-participants, other parties explicitly state that such volatility effects would be largely mitigated by lowering the PDP rate, from that originally proposed by PG&E to what is now proposed by PG&E, and limiting the number of PDP events to between 9 and 15 per year, both of which are adopted in our decision today. We also note CLECA's point that whether or not under- and over-collections are substantial, imposing that risk on only those customers who actually sign up for PDP is likely to create one more disincentive for participation. Based on the weight of the evidence in this proceeding, we feel it is appropriate to allocate under- and over-collections due to the number of PDP events to both participants and non-participants.

Our decision on this issue reflects the position of a significant majority of the parties. The fact that such a majority of parties, representing the interests of a variety of different customer classes and groups, can agree on the issue is important. This is not to imply that a position should be disregarded or demeaned in any way simply because its support is in the minority. However, to the extent that parties are satisfied with an outcome, it is more likely that potential problems that may concern the customers they represent will be minimized. The more that happens and the more that perceived problems are minimized, the more likely it is that a program such as PDP will be successful.

With respect to BOMA's use of D.08-07-045 to support its position, by the PDP program adopted today, customers can opt out of a PDP rate to a time-variant rate (for non-residential customers) as required by D.08-07-045. In D.08-07-045, the Commission does not state that non-participants in dynamic pricing programs are necessarily immune from all costs of the program, such as the allocation of certain under- and over-collections. It is the Commission's prerogative to adopt a program such as PDP and assign associated costs, on a case-by-case basis, in a manner that is consistent with the record and consistent with furthering its goals and policies. With respect to costs here in this section, it is reasonable for non-participants to share in a portion of the risk and costs of the

PDP program, since its purpose is to lower rates for all customers in the long term.

With respect to FEA's recommendation that, within each class, the reconciliation should occur by applying a credit or a surcharge as appropriate to on-peak and mid-peak demand charges and energy charges, the only parties that addressed it were PG&E and BOMA. PG&E supports this recommendation, while BOMA opposes it.

With respect to BOMA's claim that the FEA/PG&E proposal violates the Settlement in D.07-09-004, according to PG&E the equal cents per kWh surcharge approach suggested by BOMA (and adopted but not yet implemented for SCE) would deviate further from the 2007 GRC settlement than the approach endorsed by FEA and PG&E, because it would assign recovery of all peak-period revenue under- and over-collections to an undifferentiated cents-per-kWh charge.

However, we also note PG&E's statement that:

> While PG&E endorses the FEA approach, the company indicates that if the Commission wishes to take an approach to rate design that is fully compliant with the settlement approved by D.07-09-004, it would make no distinction in rate design for these under- and over- collections. In that event, the adjustments would be spread on an even percentage basis among all generation demand and energy charges. Rate design guidelines provided by D.07-09-004 are somewhat different in the residential class to comply with the rate restrictions of AB 1X. (PG&E, Reply Brief, p.8, footnote 6.)

We prefer to maintain the settlement approved by D.07-09-004 to the extent reasonably possible, as long as it does not impede our efforts regarding implementation of dynamic pricing. With respect to this particular issue, as indicated by PG&E, maintaining the principles reached in that settlement is a viable alternative to FEA's proposal and to BOMA's proposal. For this reason only, we will require that adjustments, to the extent possible, be consistent with the Settlement in D.07-09-004 and, for non-residential customers, be spread on an even percentage basis among all generation demand and energy charges. The merits of the FEA/PG&E proposal or the BOMA proposal can be addressed in future proceedings, as appropriate.

6. Rate Design – Large C&I Customers

As required by the Rate Guidance, PG&E has proposed a capacity reservation option for customers that take service on Schedules E-19, E-20 and AG-5C.[15] The capacity reservation option allows customers to pay fixed charges for a portion of their usage, while being exposed to higher PDP prices for only the portion above their fixed reservation level. This allows the customer a means to mitigate bill volatility, by choosing the degree of exposure to high PDP-period prices that is most appropriate for its own business.

PG&E states that its approach is similar to the approach taken by San Diego Gas & Electric Company's (SDG&E) default CPP tariff. This approach limits the application of the capacity reservation charge option to those schedules that include generation demand charges that recover all (or nearly all) assigned generation capacity costs. Therefore, the capacity reservation option is limited to C&I and agricultural customers or customers served on Schedules E-19, E-20 and AG-5C. These customers will be able to elect a capacity reservation level anywhere from zero to 100% (limited to an integer). For customers who make no election, the default capacity reservation subscription will be 50% of the

[15] Customers on these schedules are generally larger, but customers less than 200 kW may take service on Schedules E-19 and AG-5C.

customer's most recent average peak-period maximum demand during the summer billing months before they are assigned to the new tariff.

By PG&E's proposal, the capacity reservation may not be changed for 12 months. In its prepared testimony EUF/CMTA proposed to allow the customers to change their capacity reservation before 12 months has passed on a one-time basis, in order to allow the change to take effect prior to their second summer season on PDP.[16] PG&E opposes this EUF/CMTA proposal. According to PG&E, maintaining the 12 month period before the capacity reservation subscription level can be changed is necessary to align the timing and messaging to customers concerning other features such as bill stabilization and to reduce the volume and impacts of too many changes. PG&E also argues that the proposal would adversely impact costs and schedule.

6.1. Discussion

With the exception of the EUF/CMTA proposal that would allow customers to change their capacity reservation before 12 months has passed on a one-time basis, there is agreement among the affected parties that PG&E's capacity reservation proposal should be adopted.

Generally, the EUF/CMTA proposed change is not necessary, since most customers will have made their initial capacity reservation choice prior to the May 2010 implementation of PDP and would be able to change their capacity reservation prior to the 2011 summer season or any time after that. For the relatively fewer new customers that take service during the summer season and

[16] While this recommendation was not included in EUF/CMTA's opening brief and EUF/CMTA did not file a reply brief, it is assumed that EUF/CMTA still supports this recommendation.

who would not be able to change until some time during the next summer season, that inconvenience must be weighed against the additional costs and potential delays that might be incurred in implementing the EUF/CMTA proposal. After taking these factors into consideration, we determine that PG&E's capacity reservation proposal, including the condition that the capacity reservation may not be changed for 12 months is reasonable and should be adopted.

7. Rate Design – Small and Medium Customers

7.1. Default Date for Small and Medium C&I Customers

PG&E's proposal to offer PDP by May 1, 2010 to all customers with appropriate interval meters and to impose PDP/TOU rates on a default basis, for specific customer classes, which would begin either on May 1, 2010 or February 1, 2011, is consistent with the timeline determined by the Commission in D.08-07-045.

DRA's primary recommendation is to default small and medium commercial customers with a 12-month advanced meter history to TOU rates beginning February 1, 2011, and to transition such customers to default PDP/TOU rates after they have been on TOU rates for one year.

However, if the Commission does not adopt DRA's primary recommendation, then DRA's secondary recommendation is to default small and medium C&I customers with a 12-month advanced meter history to PDP/TOU rates beginning February 1, 2012.

DRA states that delaying the implementation of full PDP rates by one year to February 1, 2012 for small and medium C&I customers will ease the transition for some 490,000 business customers, which make up approximately 85% of the non-residential sector. DRA states that the one-year delay is desirable for small and medium commercial customers, given that there is something of a "chicken and egg" problem, since the requisite notification equipment may not be marketed unless a significant percentage of customers are on dynamic rates. Yet, according to DRA, such rates for such customers can be sufficiently onerous to lead to excessive opt-out rates without such equipment. DRA believes the best tradeoff is to delay the implementation of PDP rates for small and medium businesses for one year, noting that PG&E's own witnesses expect such equipment to be on the market in 2012.

PG&E states that, under DRA's primary proposal, customers would face two changes within one year: mandatory TOU beginning in 2011 and default PDP beginning in 2012, which would require two waves of messaging, the first one about TOU and a second one about PDP a year later. Moreover, if DRA's proposal were adopted, customers would face evaluating their business process first for TOU and then a year later, a second time for PDP.

PG&E believes that ways to be successful with a customer's energy consumption under TOU may or may not lead to ways that are successful with the CPP portion. PG&E also believes it is not appropriate to ask customers to go through and reevaluate their business processes to understand how to be successful on TOU and only one year later to come back and say the rules of the road have changed again and, now that they have gotten accustomed to TOU, they need to also get accustomed to CPP. It is PG&E's position that the Commission should implement the TOU and PDP changes together, and not separate them by a mere 12 months. Therefore, PG&E urges the Commission to reject DRA's proposal and adopt the February 1, 2011 implementation date for PDP combined with mandatory TOU, as reflected in PG&E's proposal and the schedule in D.08-07-045.

7.1.1. Discussion

For the reasons cited by PG&E, we believe that defaulting small and medium C&I customers first to TOU rates and then one year later defaulting them to CPP rates is not appropriate. The proposed transition process may lead to customer confusion and frustration, resulting in reduced participation in the PDP program. Therefore, it will not be adopted.

PG&E is silent on the specifics of DRA's secondary recommendation to defer the February 1, 2011 PDP default date for small and medium C&I customers to February 1, 2012. However, as requested by PG&E, we will maintain the February 1, 2011 date and not delay the default process for one year. DRA argues notification devices may be more readily available under its proposal, but it is not clear what percentage of customers will ultimately rely on such devices for notification or to what extent, if any, it is necessary to have access to such devices before subjecting customers to the default process. PG&E proposes that small and medium C&I and agricultural, with maximum demands less than 200kW, and residential customers will be notified by telephone or e-mail through automatic notification from PG&E. PG&E also states for such customers who have a SmartMeter, PG&E will utilize the existing SmartRate curtailment notification process to notify customers when a PDP event occurs. There is no evidence to support DRA's suggestion that without to-be-developed notification equipment, the PDP rate would become sufficiently onerous to lead to excessive opt-out rates.

Furthermore, as discussed further on in this decision, we are providing funding for PG&E to accelerate the development of notification devices to increase the likelihood that such devices will be commercially available for small and medium C&I customer use by 2011.

At this point, we see no compelling reason to delay the February 1, 2011 default date for small and medium C&I customers. With respect to this date, our primary concern is that customer outreach and education may be, in some way, lacking such that customers are not fully informed about of PDP and the default process, or customers are unable to make optimal choices with respect to the process. Customer outreach and education is discussed later in this decision. In adopting and supplementing various aspects of PG&E's proposals, we expect that customer outreach and education will be successful.

7.2. Options for Reducing Bill Volatility

7.2.1. PG&E

For those residential, small and medium C&I and agricultural customers who are subject to the PDP tariffs, and who are not served under tariffs where a capacity reservation charge is an option (i.e., Schedules E-19, E-20 and AG-5C), PG&E proposes that customers instead be allowed to choose between different options for PDP event duration and limits on consecutive-day PDP operations. According to PG&E, these options will serve the same purpose of mitigating customer bill volatility as is to be served by capacity reservation subscriptions for larger customers. In particular, customers will be offered the following two options:

Limit on Consecutive PDP Operations

Customers choosing this option will never be subject to PDP prices on consecutive days. Instead, customers requesting service under this PDP option will be divided into two groups (of approximately equal size) and PDP prices will be in effect on alternating PDP event days for these customers. Because customers requesting service under this option will expect to be called upon for only one-half of the total number of PDP event days each summer, their offsetting PDP rate credits will also be reduced by one-half.

<u>Choice of Event Duration</u>

PG&E's standard PDP pricing period for all non-residential rate schedules will be the four-hour period between 2:00 p.m. and 6:00 p.m. However, non-residential customers will be offered the choice of paying somewhat lower per-kWh PDP prices (by a factor of one-third) if they request a six-hour PDP event period (noon to 6:00 p.m.) rather than the standard four-hour period. Residential customers will not have this option as the current SmartRate five-hour event duration (2:00 p.m. to 7:00 p.m.), which falls between the two options described above, is being retained for the class.

The proposed default assignment for all non-residential customers will be to service that is subject to no limit on consecutive operations and the standard four-hour PDP pricing period. The default assignment for residential customers will be no limit on consecutive day events, with a standard five-hour event duration (and no options for changing the standard residential PDP period).

PG&E states that if the Commission wants customers to respond to PDP prices, the customers need to consider actively how they can change their energy usage to respond to the new rates. According to PG&E, its two options would encourage the customers to think about which choice is best for them, which by necessity involves considering their business operations, energy demands, and what they can change.

Also, in rebuttal testimony to DRA's "soft cap" proposal, PG&E indicated that its Balanced Payment Plan (BPP) program is an existing service option which is available for all residential and small commercial customers. PG&E states that it will continue making the BPP available for small commercial customers accepting assignment to the default PDP tariffs, so this is an existing service option which will already exist and will afford protections similar to those that would be afforded by DRA's more complex system of monthly and increasing annual bill caps.

TURN supports PG&E's proposed mechanisms that allow customers to hedge the risk of bill volatility.

DRA asserts that PG&E's alternating PDP day and six-hour PDP window proposals add complexity, from both the customer perspective and from the utility perspective with respect to customer outreach, PDP event notification, and billing, adding that in deciding whether to endorse these proposals, the Commission must weigh the value provided by these proposals against the cost and complexity of implementing them.

With respect to the value provided, DRA argues that PG&E's proposals are inferior, compared to the other monthly bill volatility mitigation proposals on the record, specifically DRA's "soft cap" and PG&E's BPP proposals, and there is no evidence that PG&E's alternating day and six-hour window present sufficient value to the customer to offset their complexity.

Also, DRA states that there is no evidence on the record that PG&E surveyed its customers about alternating day or six-hour PDP window options for mitigating bill volatility or that PG&E made any effort to assess potential customer interest in having such options available.

In DRA's opinion, the Commission should rank the alternating PDP day and six-hour PDP window options last among the three monthly bill volatility options presented on the record.

With respect to the BPP, DRA states that it has the advantage over the other options in that it is already implemented and therefore there is no incremental cost except for possible costs of notifying PDP customers of their eligibility and explaining the potential pros and cons of accepting that option. On the other hand, DRA argues that a PDP customer electing BPP will experience a severely attenuated PDP price signal by PDP charges being spread over 12 months or payable up to six months after the summer season.

7.2.2. DRA

DRA recommends that PG&E offer a "soft cap" for summer monthly bills for A1-PDP and A6-PDP customers, based on a "monthly average energy rate limiter" of 110% of the average summer A1-TOU or A6-TOU rate, respectively. PG&E should then roll forward any unbilled PDP revenue to the following month's bill. Unbilled PDP revenue would continue to roll forward until headroom under the 110% cap permits collection. DRA asserts that this mechanism would dampen monthly bill volatility without any loss of PDP revenue and without imposing complex additional decision analysis on small and medium customers.

According to DRA, while its soft cap proposal causes some PDP signal attenuation, unlike the BPP any bill in a month with more than the average number of PDP events will show an immediate increase in the amount due and payable, and in most cases, PDP charges would be fully collected by the end of the summer season. Thus, DRA believes that its soft cap proposal is superior to PG&E's BPP for the purpose of mitigating monthly PDP customer bill volatility.

PG&E opposes DRA's monthly soft cap proposal arguing that DRA's 110% monthly limiter would be a major change adding significant costs and delay to the PDP project, and may even be beyond the capability of Customer Care and Billing (CC&B) version 2.2. PG&E is also concerned that DRA's 110% monthly cap will add complexity to bills and confuse customers.

7.2.3. Discussion

We will adopt PG&E's alternating day and six-hour window options to mitigate bill volatility for those customers that do not have a capacity reservation option. We prefer PG&E's proposal, because, similar to the capacity reservation charge, it provides customers with an incentive to choose or stay on PDP rates by offering an option to reduce their exposure to potential increases related to those rates. On the other hand, the "soft cap" and BPP are mechanisms that spread the effect of monthly rate increases over a longer timeframe. PG&E's proposal also does more to encourage customers to evaluate how they use electricity as well as what they can do to, and how likely they would, reduce or shift their usage. Certainly this is a more complex and potentially confusing exercise when compared to simply being subject to DRA's proposed soft cap or the current BPP. However, with appropriate and comprehensive customer education, we believe PG&E's proposal which enhances customer choice can be implemented successfully.

7.2.4. Medium C&I Customers

We have approved PG&E's capacity reservation proposal as indicated above, but believe it is necessary to also consider the concept for medium commercial customers on Schedule A-10, in the context of bill volatility for such customers who are defaulted onto PDP rates.

A-10 customers are the only ones that have a PDP default where 100% of peak time usage would be set at the $1.20 /kWh charge. The E-20 and other large customer classes will only be subject to 50% of their peak time usage at the PDP rate because a 50% capacity reservation charge will be the default amount. The PDP rate for the A-1 customer is set at $.60 /kWh, and the residential/small agricultural PDP rates are opt-in rates.

To provide comparable bill volatility protection for PDP default A-10 customers, we will extend a form of the capacity reservation charge to A-10 customers, which is simpler to implement and understand than that for larger customers. The PDP default rate will include a 50% capacity reservation charge thereby reducing bill volatility and putting defaulted medium commercial customers on the same footing as defaulted large commercial customers. However, with respect to making a choice of a capacity reservation amount, A-10 customers will only be able to choose either to maintain the 50% amount or to reduce the amount to 0%. We feel this is appropriate, because many customers in this class may not have as much knowledge and understanding of how to determine the optimal capacity reservation charge for their particular circumstances[17] as opposed to that of larger customers who will also be individually contacted by customer service representatives.

However, we will retain the alternate day and six-hour window options proposed by PG&E for the A-10 customers to provide other bill volatility mitigation options. For instance, if a customer is willing to stay on PDP but with less bill volatility exposure, that customer could choose the alternating day option in addition to maintaining the 50% capacity reservation. While we could have used the alternating day option as the means for reducing bill volatility for defaulted A-10 customers (instead of the simplified capacity reservation charge), there is a question of whether these particular customers would know when they would or would not be subject to PDP, since they would not have affirmatively made the choice for the option. Without affirmatively making the choice for the

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[17] PG&E should be prepared to explain the limited options simpler and more basically than they would explain the more complex options for larger customers.

alternating day option, there is a probability of increased confusion over bills and charges for particular event days and not for others.

7.3. Additional Bill Stabilization/Protection

DRA recommends that PG&E be directed to offer a second and third year of modified annual bill stabilization to small commercial customers, with an increasing cap of 110% of the otherwise applicable TOU bill in the second year of PDP service, and 120% in the third year. According to DRA, special treatment is merited for small customers because they have the least resources to deal with rate design change and because most of these customers have never been on time-varying prices. DRA also proposes that further annual bill capping should be re-evaluated in PG&E's 2014 GRC.

PG&E opposes DRA's proposal for additional bill stabilization/protection, indicating that DRA does not provide any additional testimony or documentation to support its proposal for second and third year bill stabilization, or to allow the Commission and other parties to evaluate whether this extra protection for small C&I customers is warranted. Also, when considering the effects of second and third year bill stabilization, along with the effects of the monthly energy limiter of 110%, PG&E anticipates that the combined effect of DRA's monthly and annual bill mitigation proposals would compound the difficulty for customers to understand their bills. PG&E states that this is a major change to its proposal that would be very costly and would adversely impact the project schedule. PG&E is also unsure whether its CC&B would support this structure prior to the version 2.3 upgrade.

7.3.1. Discussion

We will not extend the bill stabilization/protection beyond the first year. We make this determination with the understanding that there will be appropriate and comprehensive customer education with respect to understanding the PDP program and customer options.

We recognize that bill stabilization reduces the risk for participants to enter or remain in the program. However, extending bill stabilization beyond one-year must be balanced against our determination that it is reasonable for non-participants to share in the risk of a new rate program if its purpose is to lower rates for all customers in the long term. However, the extent to which non-participants bear the participants' costs should be limited to what is necessary to effectively implement the PDP rate.

We will ensure that the vast majority of customers will have at least 12 months of historic usage available when deciding their PDP options or when being defaulted to a PDP rate. The first year of bill stabilization will protect customers who are on PDP rates by allowing them to experience the actual effects of such rates without facing financial harm over that period, if the PDP is disadvantageous when compared to the otherwise applicable TOU rate. We believe this is a sufficient duration for all PDP customers to understand that peak period usage when there are PDP events will be significantly more expensive than before.

This belief is especially true for customers who affirmatively choose PDP. We assume these customers have evaluated their situations in choosing PDP. A year of actual experience should be sufficient for such customers to decide whether or not their evaluation was correct and to adjust accordingly.

We feel somewhat less confident about customers, who are defaulted onto PDP rates, especially smaller and potentially less sophisticated customers with respect to rate matters. Such customers may not have evaluated their options before being subject to PDP rates. However, they also will have experienced a number of PDP events and the monthly rate effect of PDP rates with respect to their actual usage during the bill stabilization period. If, during the first year, it becomes obvious that they should opt out of PDP, they can do so and with bill stabilization not experience a long term financial impact. We do not see what benefit a second and third year of bill stabilization will provide and are not convinced that the extension is necessary.

Again we must emphasize the importance of customer outreach and education. Especially for defaulted customers, it is extremely important that, as their first year on PDP progresses, customers become well aware of the PDP program, the details that affect their rates, their options to opt out or remain in the program and the requirements for switching rates in the future. As previously indicated, if customer outreach and education problems arise, it may be necessary to delay certain aspects of PDP implementation.

7.4. Up-Front Lump Sum Credit for Notification Information

For A1-PDP customers, PG&E now proposes a 1.096 cent per kWh PDP credit, applicable to all summer period energy usage. DRA proposes a one-time up-front lump sum PDP credit for small and medium C&I customers newly defaulting to A1-PDP rates in order to provide a more visible incentive to remain on PDP and to facilitate PG&E's collection of customer contact information for PDP event notification. Under this proposal, customers must be on a PDP rate by May 1, and would have to repay the credit if they opt out before October 31 of the same year. Also, the lump sum credit would be subject to true-up if a customer's actual usage is at variance with the usage assumed for purposes of setting the lump sum amount.

PG&E opposes this proposal, noting that this lump sum credit could interact in unanticipated ways with other elements of the rate and program design. In addition, PG&E states that the provision of a customer's credits in a lump sum, up-front credit means that, in later months, customers will only see the high PDP charges in the monthly bill amounts due, without the offsetting effect of the credits for the month, which could give customers an inaccurate perception of PDP charges. Moreover, PG&E indicates that DRA's recommendation would not solve the problem of maintaining accurate customer contact information, which tends to change over time. Lastly, PG&E asserts that DRA's lump sum proposal would have substantial impacts on cost and scheduling.

7.4.1. Discussion

There may well be impacts on costs and scheduling associated with DRA's proposal. However, the reason that we will not adopt it is because of the potential for customer confusion as to what are the real effects of being on PDP. As PG&E indicates, by taking the energy usage credit up front, customers will only see the high PDP charges in the monthly bill amounts due, without the offsetting effect of the credits for the month. Artificially high monthly bills may be confusing to customers who are trying to determine whether to remain on PDP or to opt out of the program as they experience the effects of the program. We feel it is more important to ensure that customers understand how their usage affects their rates rather than to incent a customer to stay on PDP for a full season by offering the up-front credit as proposed by DRA.

As to facilitating the collection of customer contact information, there is value in that. However, it is not clear that proactive efforts by PG&E to obtain such information will be insufficient or lacking in some manner. Success in obtaining the information should be monitored and maximized as PDP is implemented. At this time, we do not feel the potential benefit of additional customer contact information by implementing DRA's proposal outweighs the downside of potential inaccurate perceptions of the effects of PDP.

7.5. Multi-Year Amortization

DRA proposes that revenue shortfalls resulting from annual bill stabilization should be amortized over multiple years, for specific rate classes, if recovery in one year would cause rates to rise by more than 1%. DRA states that generation-related revenues are already significantly volatile, prior to the widespread adoption of PDP. A history of generation-related over- and under-collections shows that since 2004, under-collections of 1%, 6%, and 8% have occurred, along with over-collections of 1% and 2%.

PG&E opposes DRA's recommendation. PG&E states that DRA did not provide any analysis to support its recommendation, while PG&E's analysis shows that it is very unlikely that the 1% threshold would be triggered. According to PG&E, in a summer of 12 or fewer PDP events, customer bill projections provided in their work papers show that even if 100% of the customers in each rate class were simultaneously subjected to first-year bill protection, the 1% threshold would not be reached. In addition, in scenarios with larger bill protection shortfalls (summers with larger numbers of PDP events), the shortfalls would occur only in concert with significant PDP revenue over-collections as a consequence of the large number of PDP calls -- which are likely to involve a net decrease to rates.

7.5.1. Discussion

We will not implement DRA's proposal. PG&E has provided evidence that it is unlikely that the 1% threshold will be triggered. More importantly, the Commission already has the latitude to impose multiple-year amortizations when it feels it is necessary to do so, when looking at all rate changes that are happening concurrently, as well as considering what has happened in the near past and what may happen in the near future. A 1% or 2% increase in rates, when viewed in isolation, may not require multiple-year amortizations. If the increase becomes much larger due to other increases, the Commission can, and in the past has, extended the amortization period. We will leave it up to future Commission actions to decide if and when multi-year amortizations are appropriate when looking at all rate changes in the timeframe that those changes will happen, rather than now imposing amortization requirements for one narrow aspect of potential rate increases.

8. Rate Design – Agricultural Customers

8.1. Agricultural Customer Access to Information

CFBF and AECA identify the need for the availability of adequate interval data to agricultural customers before such customers default or make decisions about PDP. Both want agricultural customers to default to the new rates only after they have had comprehensive access to meaningful interval data for at least 12 months. In addition, AECA urges that such information be made available in one downloadable aggregated format for multiple meters, before requiring a migration to default dynamic rates or mandatory TOU rates. CFBF requests that after the 12 months of information is available, there should be four months before the customer must make a decision. In addition, CFBF states that farmers should not be required to decide these important issues during planting, growing or harvesting seasons (approximately April through October).

CFBF also has proposed that agricultural customers receive 12 months of bill analysis or "shadow bills," which would show, for the same usage as the current bill, the bill expected under the relevant dynamic pricing option. CFBF proposes that this information also be available at least an additional four months on top of the proposed 12 months before the customer must make a decision.

PG&E agrees with the general principle that customers need access to interval usage information, but takes issue with the agricultural intervenors' specific proposal for access to 12 months of interval data. According to PG&E, the only agricultural customer subject to default PDP are large customers; and approximately 700 of these customers currently have or can have access to interval data via the InterAct tool on PG&E's website. Also, on average, customers receiving SmartMeters are getting access to interval usage data within 30 days of meter installation. Thus, customers will have sufficient data to make informed decision and there is no need to depart from PG&E's proposal to use the one-year anniversary of SmartMeter installation to determine when the customer becomes subject to default PDP. In addition, PG&E argues that starting the 12-month clock based on AMI interval data availability would have a major negative impact on cost and schedule for PDP.

With respect to AECA's multiple meter request, PG&E states that its proposed CSOL changes in this proceeding will make data for multiple accounts accessible and downloadable with a single login, and the request is unnecessary and will adversely affect cost and schedule.

With respect to "shadow bills," PG&E objects to this request because it will be providing tools on CSOL that customers can use to run their own bill analyses. Unlike the CSOL tools, hard copy shadow bills would not enable the customer to do "what if" analyses, to test what happens with various changes in its energy demands under different rates and scenarios. PG&E asserts that the CSOL tools will be superior to "shadow bills" for that reason. PG&E also notes that CFBF's "shadow bill" proposal would add significant costs and delay to PDP implementation.

8.1.1. Discussion

Under PG&E's proposal that the choice should be made 12 months after the meter is installed, it appears that most affected customers would have to make a choice with respect to opting out of the PDP program while having only 10 or 11 full months of interval data. Depending on which months are missing, full bill analyses with respect to when PDP rates would apply may be difficult or not possible. The consequence of such limitations may well be that customers would choose to opt out of the program rather than assume an unknown risk. As a general matter, we feel it is appropriate and reasonable that a customer have access to 12 months of interval data before having to make a choice. However, we see this as a problem more for the smaller customers than for the larger customers.

The first default date for PDP is May 1, 2010 and affects large C&I customers. Such customers already have access to 12 months of billing quality interval data on which to make a decision regarding PDP rates. Additionally, these customers will have the benefit of direct contact and interaction with a customer service representative to aid in this process. There may well be some newer customers who will have to either make a choice with respect to, or be defaulted onto, PDP rates with only 10 or 11 months of interval data. Depending on which months are missing, bill analyses with respect to the time period when PDP rates would apply may be difficult. In such situations, we expect that PG&E's customer representatives would be able to provide the necessary assistance in order to overcome this obstacle to customers' full understanding of their situations and options.

For the February 1, 2011 default date, large agricultural and medium and small C&I customers will face default to PDP and small agricultural customers will face default to mandatory TOU. Having 12 months of interval data available before requiring choices related to these defaults is much more important than for large C&I customers. While large agricultural customers already have interval meters, most medium and small C&I and small agricultural customers will be subject to time varying rates for the first time. For these customers, access to the full 12 months of interval data prior to making default choices is the most critical. The lack of such information can be problematical with respect to fully understanding their situations and options with respect to PDP. As indicated previously, if certain historic usage during PDP periods is not available, the effect of PDP rates and the need to change usage patterns may not be fully understood, and customers may simply choose to opt out of PDP to reduce high bill risks. While there will be customer outreach and education as well as the opportunity to contact customer representatives, the type of assistance afforded to all large customers through direct customer representative contact will not be the norm for the smaller customers. The least we can do is ensure that customers subject to the February 1, 2011 default date have 12 months of interval data before being subject to that process. Therefore, with respect to the February 1, 2011 default date, PG&E shall not default any affected customers to PDP/TOU rates until it is able to provide access to 12 months of recorded interval data at least 45 days prior to the default date.

We do not agree that agricultural customers require an additional four months to make their decision regarding PDP/TOU defaults and options. There is no convincing evidence to support the proposition that in this respect they require more time than those in the other affected customer classes who will have 45 days to make their decisions. Likewise, we will not require that farmers be allowed to defer their decisions during planting, growing and harvesting seasons.

With respect to AECA's request regarding the availability of information in one downloadable aggregated format for multiple meters, PG&E does not object to the request because of the need for such information, but asserts that its proposed CSOL functionality will address AECA's concern. We agree with PG&E, and, as discussed later in this decision, note that the PG&E proposal to implement such CSOL functionality is approved. We therefore expect that the CSOL feature to aggregate information will be available to the large agricultural customers before they are subject to being defaulted to PDP. PG&E should not default such customers with multiple accounts to PDP until this feature is available.

Likewise, with respect to CFBF's "shadow bill" proposal, PG&E objects to the proposal but does not object to the need for such bill analysis. PG&E argues that its proposal for enhanced CSOL functionality will provide such analysis as well as analyses using varying scenarios. Again, we agree with PG&E, and, as discussed later in this decision, note that the PG&E proposal to implement such CSOL functionality is approved. Again, we expect that this feature will be available to agricultural customers before they are subject to being defaulted to PDP. We also note that this CSOL feature to calculate bills under varying scenarios is very important and necessary not only for agricultural customers, but for all customers, to evaluate the effects of PDP and make appropriate choices. PG&E should not default any customers to PDP until this feature is available.

8.2. Other Agricultural Customer Issues

In this proceeding, AECA recommended an alternative dynamic pricing scheme similar to an SCE rate that provides a table of TOU prices on a year-ahead basis, which is adjusted for weather. AECA states it would offer significantly more flexibility and would encourage voluntary participation within the agricultural class.

PG&E opposes this recommendation indicating that it is impractical. PG&E alleges that AECA mischaracterized the SCE proposal, the SCE proposal is being discontinued, AECA's proposal would have large cost and schedule impacts, and it would needlessly complicate customers' choices.

AECA also states that SmartMeter installation and the emergence of dynamic pricing creates the opportunity to virtually master meter farm operations' multiple accounts in ways that could fundamentally transform agricultural energy management practices, providing significant system benefits. AECA recommends that the Commission develop programs that enable growers to virtually aggregate multiple meters.

PG&E states that the proposal is moot, because, in effect, agricultural customers will receive the benefit of virtual master metering through the PDP rate design. PG&E adds that to the extent that AECA wants virtual master metering for purposes other than PDP, the issue belongs in the rate design phase of a GRC.

In its opening brief, AECA states that both of its proposals require significant study and analysis and, given the limited scope of the rate design window, concedes that consideration of such topics are likely better determined in PG&E's next GRC. AECA now requests that the Commission order PG&E to raise both issues in their next GRC for consideration.

In its reply brief, PG&E renewed its objections to the proposals and indicated that while parties are free to raise such issues in the rate design phase of GRCs, PG&E should not be required to do so.

8.2.1. Discussion

Since AECA is withdrawing consideration of both proposals in this proceeding, we will not rule on the merits of the proposals at this time. Also, we note PG&E's responsive testimony and objections and we will not require PG&E to raise either issue in its next or future Phase 2 GRC proceedings. However, at such times, parties are free to raise and support such issues on their own.

9. Rate Design - Residential Customers

PG&E's current residential CPP rate, SmartRate, allows the PDP surcharge to be added to non-TOU rates. However, the Rate Design Guidance in D.08-07-045 requires residential PDP to be combined with TOU in non-event hours. Consequently, PG&E's original testimony proposed to terminate its current residential CPP rate or SmartRate Program on Schedule E-RSMART on or before May 1, 2010, giving these customers the option of choosing the new PDP rate or defaulting to a non-PDP rate. According to PG&E, because Schedule E-6 includes relatively steep TOU pricing incentives, bill comparison results indicated that many residential customers currently served on non-TOU rates would incur significant bill increases simply from moving to the TOU component of the PDP rate (without even considering the effect of the PDP price signal). Also, the proposed compliant PDP rate is significantly different than the current SmartRate option available to residential customers. The new PDP rate would have a PDP price signal set at a level approximately two-and-one-half times the current SmartRate price signal.[18] PG&E indicated that it would only assign a residential SmartRate customer to PDP if the customer affirmatively elects that option.

In its prepared testimony, DRA stated its belief that a PDP rate would work better with a TOU schedule that has a more gradual differential between peak and off-peak rates. DRA also recommended that Schedule E-RSMART be closed to new customers and that existing customers be grandfathered on this schedule indefinitely.

In its prepared testimony, TURN recommended that the Commission authorize PG&E to design its residential PDP rate on top of non-TOU inverted tiered rates to encourage customer participation in hotter inland climates and to increase demand response and reduction from PDP rates.

In response to DRA and TURN concerns, PG&E presented two alternatives for residential customers in its rebuttal testimony. In its Alternative 1 proposal, PG&E responded to concerns about adverse bill impacts by including TOU rates that are less steeply time-differentiated than those offered under the Schedule E-6 tariff. If Alternative 1 were approved, PG&E states that it would extend the existing residential SmartRate tariff for one additional year for both existing and new enrollees, and then implement the revised residential PDP rate design for all residential dynamic pricing participants beginning in 2011. PG&E states that by approving Alternative 1, the Commission would facilitate a smooth transition of existing residential customers to the revised PDP rate.

[18] Calculated using the originally proposed PDP charge of $1.50/kWh.

Alternative 2 is PG&E's original proposal, which combines PDP with the existing time-differentiated E-6 TOU rates. SmartRate would end after 2009 under Alternative 2 and existing SmartRate customers could opt into Alternative 2 PDP. The fully compliant PDP residential tariff, however, would have severe bill impacts for many of the early SmartRate participants due to the relatively steep TOU differentials in Schedule E-6.

Both DRA and TURN indicate that PG&E's Alternative 1 responds to their concerns and recommend that it be adopted. PG&E also agrees that Alternative 1 is the superior residential PDP proposal. No other party addressed this issue. The alternative 1 proposal is reasonable and will be adopted.

10. Tariff Revisions and Requirements

10.1. Opt-Out and Switching Proposals

10.1.1. PG&E

PG&E has proposed default, opt-out provisions that comply with the dates and directions in D.08-07-045. Normally, customers will be given 45 days from the day they qualify for a default PDP rate to opt out of the PDP rate. If they do not opt out, they will be defaulted to PDP rates on their next billing period which is at least five days after the 45-day period. For the May 1, 2010 default date for large C&I customers, the opt-out period will begin 45 days before May 1, 2010. However, in the first year that default PDP is applicable to an individual customer, PG&E intends to allow the customer to opt out of PDP, if the customer has not previously taken any action that indicates it has made an affirmative choice relative to PDP.

In general, PG&E plans to let customers opt out of PDP during the first year beginning with the date they become eligible for default PDP, if the customer has not taken any affirmative action concerning PDP. After the customer's first year on PDP, the customer could opt out of PDP consistent with PG&E's normal rules governing customer switching from one rate schedule to another.

10.1.2. DRA

It is DRA's position that customers should be allowed to opt out of PDP rates to an applicable TOU rate schedule at any time, subject to a limit of one opt-out per season. Customers opting out during the summer season (May-October) would be required to repay any PDP credits they have received since May 1 of the year in which they opt out. Winter season opting out would carry no financial penalty.

DRA also recommends that customers opting in to PDP rates must provide updated contact information, or otherwise arrange with the utility for event notification. Customers should be allowed to opt in to PDP rates at any time during the summer season, provided they have not previously opted out during the same season. Such customers would receive PDP credits and be subject to PDP charges as of the effective date of beginning service under PDP rates. Customers should be allowed to opt in once during the winter season.

DRA states that its motivation is to allow customers greater flexibility to adapt to new rate designs and potential changes to business circumstances than allowed by PG&E's proposed 45-day opt-out period. The additional flexibility granted by DRA's proposed switching rules might prompt some customers to accept default PDP status when they might otherwise opt out due to PG&E's proposed 45-day provision. At the same time, DRA believes that customers, who are on PDP rates as of May 1 of a given year but opt out before October 31 of the same year, should pay a financial penalty. Further, the appropriate penalty would be forfeiture of PDP credits earned from May 1 until the opt-out date.

This provision would discourage customer gaming by timing a decision to opt out in advance of a forecasted heat wave, thereby capturing partial summer PDP credits but avoiding late summer PDP costs.

10.1.3. EnerNOC

EnerNOC recommends that, if PG&E's PDP proposal is approved PG&E's PDP tariff should be modified to allow PG&E customers to opt-out of PDP at any time if they opt out to enroll in another DR program.

According to EnerNOC, such a change will not create any disruptions to the program, and customers will still have an incentive to modify energy usage behaviors to reduce peak usage or reduce the need to build additional generation capacity, whether they are on PDP or a DR program. EnerNOC adds that its proposed modification will benefit customers by providing them with a wider range of options, while, at the same time, maintaining the customer's commitment to DR and increasing customer satisfaction for customers who belatedly understand that PDP does not work well for them.

As a matter of principle, PG&E believes that EnerNOC's proposal has merit. However, according to PG&E, this functionality would not be available on May 1, 2010, and whether it could be available in 2011 is debatable.

10.1.4. Discussion

For the first year under PDP rates, PG&E recommends that customers who affirmatively choose to be on such rates must remain on the rates for 12 months. Customers who did not affirmatively choose to be on PDP but who were defaulted onto such rates can opt out any time during the first year and would be afforded bill stabilization for the time they are PDP rates. After the first year, consistent with its current rules, customers would be limited to switching once a year.

We will extend PG&E's first year opt-out provision to all customers including those who affirmatively choose to opt in. We believe it is appropriate to provide the immediate opt-out provisions for customers who, for whatever reason, are on PDP and who, for whatever reason, realize that they no longer want to be on PDP. We believe this is reasonable for several reasons. Customer outreach and education may not be perfect. Defaulted customers may experience significant bill increases just because they did not realize they were on PDP or realize what the effects might be. For customers who affirmatively chose to be on PDP, their analyses with respect to benefits and costs of being on PDP or their analyses and plans with respect to how their usage might be reduced or shifted may have been flawed to the degree that there may be significant adverse financial consequences by remaining on PDP. Even with first year annual bill stabilization, such customers may want to immediately opt-out of PDP for cash flow, convenience or other reasons. The imposition of PDP is significant and there is no good reason to require customers to remain on PDP just because they failed to make a decision or where they made the wrong decision.

Because of the first year bill stabilization provisions, strict enforcement of a 12-month wait period would have no overall financial consequences with respect to how much a customer might actually pay during that time period. However, there is the potential downside of needless customer dissatisfaction related to wanting to change schedules but not being able to do so.

We believe that one year is sufficient for customers on PDP to realize that (1) they are on such a schedule, (2) there are consequences for using electricity during peak periods on PDP event days, and (3) there are options to mitigate bill increases. Customers would have experienced the monthly bill effects of between 9 and 15 PDP events in conjunction with whatever bill volatility protection they have and would have had the opportunity to react accordingly. At some point customers must make an informed choice and should be held responsible for that choice. The first year of experiencing the rate effects is a reasonable and appropriate timeframe for that to happen. After this first year, it is reasonable that customers should be limited to switching rate schedules once a year, which is consistent with PG&E's current rules on such switching.

In some respects our determinations of being able to opt out any time during the first year and on annual basis thereafter are not too different from that proposed by DRA. Under DRA's proposal, customers would be able to opt in or opt out of PDP one time per season, although it is not clear how many times customers can opt in or opt out during a year. We do note DRA's recommendation for a financial penalty for those customers who are on PDP as of May 1 and opt out before October 31. We will not impose this provision at this time, because it is not clear that it is necessary. However, PG&E should monitor the situation, and if it is determined that there is a significant amount of customer gaming with respect to opting in or out of PDP, PG&E should propose a solution as proposed by DRA or alternatively determined in an appropriate future rate design proceeding.

Also, for the reasons cited by EnerNOC we will adopt its recommendation that PG&E customers should be allowed to opt out of PDP at any time, if they opt out to enroll in another DR program. However, we will not hold up the May 1, 2010 implementation of PDP to accommodate this revision to PG&E's proposal, but will require that PG&E incorporate the change as soon as possible.

10.2. Dual Participation in PDP and Demand Response Programs

The Commission addressed the general issue of dual participation in DR programs in D.09-08-027. That decision allows customers to participate concurrently in one program that provides an energy payment and one that provides a capacity payment. The decision also states it is reasonable to consider Critical Peak Pricing to be an energy payment program.[19]

Ordering Paragraph 30 of D.09-08-027 directs the utilities to file Tier 2 advice letters on dual participation, stating:

> In the case of simultaneous or overlapping events called in two programs, a single customer enrolled in those two programs shall receive payment only under the capacity program, not for the simultaneous event for the energy payment program. Critical Peak Pricing shall be considered to provide an energy payment for the purposes of these dual program participation rules.

PG&E states that although D.09-08-027 treats CPP as an energy payment program, the details of PG&E's PDP rate as developed in compliance with D.08-07-045 were not included in the record for that decision. For example, while current CPP rates might possibly be identified as an "energy payment" program because CPP credits were applied only as energy credits (per kWh), even though a capacity valuation ($/kW-year) was originally used to establish these credits. However, D.08-07-045 called for the new PDP credits to be adopted here to be applied on a demand basis (per kW) for all rate schedules where generation capacity costs are currently recovered through demand charges. PG&E states that its PDP rate proposals were all developed in compliance with

[19] *See* D.09-08-027, pp. 154-155.

this requirement. It is PG&E's position that because the PDP credits are based on reduced generation demand charges, it is not accurate to characterize it as an energy payment program.

PG&E also states that it, along with CLECA and EUF/CMTA, recognizes that if dual participation in PDP and a separate capacity program is allowed, there is a dual incentive problem, because PG&E's proposed PDP rate provides a capacity incentive, rather than an energy incentive, and dual participation will result in double incentive payments.

PG&E requests that the Commission find in this case that PDP is a capacity payment program due to the way it treats demand charge revenues. In the event the Commission continues to treat PDP as an energy payment program, PG&E states it would need to redesign PDP to ensure the total amount of avoided generation capacity cost does not go below zero.

CLECA also believes that the Commission's decision is problematic in that while the PDP program expresses the incentive as an energy payment, it does so by grouping what are clearly generation capacity costs into a relatively small number of hours for recovery through the PDP energy rate. Expressing the generation capacity costs as an energy rate does not change their fundamental nature. Thus, a customer that participates in both base interruptible program (BIP) and PDP events at the same time will cause the utility to avoid one set of generation capacity costs, but could be compensated twice for the one set of costs.

While the Commission is clear that it will require the utilities to develop tariff provisions that ensure that such double recovery will not occur, CLECA states this is not easy to accomplish. CLECA adds that customers might have very little incentive to participate in both programs if the customer would either lose all of the PDP credits or lose all of the BIP credits in the event there were multiple PDP events and also a simultaneous BIP event. That is because participation in these events creates costs for customers – their businesses are disrupted and their production of goods is interrupted, sometimes for a longer period than the electric interruption. Thus, participation in dual programs could result in discounted incentives for participation and customers are unlikely to look upon that favorably.

EnerNOC states that the dual participation determination by the Commission in D.09-08-027 is consistent with the position that has been continuously taken by EnerNOC in Commission DR proceedings, including as a participant in the California Demand Response Coalition in A.08-06-001, et al. It is EnerNOC's position that PDP is compatible with mandatory capacity payments programs, and, as such, the Commission's findings in D.09-08-027 that dual participation should be allowed in such programs apply to PG&E's PDP proposed in this application. EnerNOC also asserts that the determination that CPP programs such as PDP are energy, rather than capacity, payment programs was fully and appropriately considered in D.09-08-027.

EnerNOC also states that it has also consistently advocated that a customer enrolled in both a dynamic pricing tariff like PDP and a dispatchable DR program should not receive an additional energy payment from the DR program on a day when events are called in both programs for the same hours. The Commission appropriately found in D.09-08-027 that dual participation can be accommodated while also ensuring that customers do not receive two energy payments for the same curtailment activity.

EnerNOC asserts that it is inescapable that modification of PG&E's PDP proposal here is now required to ensure consistency with the Commission's directives in D.09-08-027. EnerNOC believes that D.09-08-027 makes clear that, in allowing dual participation, it is not the intent of the Commission to replace existing DR programs with a non-dispatchable TOU program, such as the PDP proposed by PG&E, but rather to ensure that the move to dynamic pricing complements existing programs.

It is EnerNOC's position that the combination in PG&E's PDP proposal of defaulting all commercial and industrial customers to PDP, while not allowing these customers to opt into another DR program or participate concurrently in a dispatchable capacity-based program, defeats and conflicts with the Commission's intent and directions in D.09-08-027. In addition, these provisions will make it impossible for DR providers either to maintain existing contracted DR levels in existing PG&E programs or to reach contracted ramp rates in contracts already approved by this Commission.

Therefore, EnerNOC recommends that, to the extent that PG&E's PDP proposal is approved by the Commission, such approval be conditioned on PG&E amending that proposal consistent with D.09-08-027. Specifically:

> PG&E's PDP tariff should be modified to allow PG&E customers to participate in both the PDP and Day-of dispatchable demand response programs at the same time, to conform to the Commission's rules for dual participation established in D.09-08-027.

PG&E acknowledges that should the Commission continue to treat PDP as an energy payment program, PG&E's proposed PDP initiative would need to be revised. PG&E does not believe, however, that these revisions are properly within the scope of this case and states that it plans to address these requirements in compliance with the Ordering Paragraphs of D.09-08-027. Moreover, PG&E asserts that there is no record in this case to base a new PDP rate that complies with D.09-08-027, since that decision only came out a few days before PDP hearings began, which did not allow sufficient time for parties to develop and propose a PDP rate that would comply with the directives in D.09-08-027.

10.2.1. Discussion

This decision is not the appropriate vehicle for modifying previous Commission determinations in D.09-08-027 with respect to dual participation or the consideration of CPP as an energy payment program. At this point, any desired changes to these determinations should be addressed through modification of D.09-08-027 by suitable means.

Therefore, at this time, we agree with EnerNOC's recommendation that PG&E's PDP tariff should be modified to allow PG&E customers to participate in both the PDP and Day-of dispatchable demand response programs at the same time, to conform to the Commission's rules for dual participation established in D.09-08-027.

Also, unless and until D.09-08-027 is modified as discussed above, we agree with PG&E, CLECA and EnerNOC that the PDP proposal needs to be revised to address the double payment problem. We also agree with PG&E that the record in this proceeding is inadequate to make the necessary revisions at this time. We will therefore authorize PDP implementation without making such revisions. PG&E states that it plans to address this when complying with the ordering paragraphs of D.09-08-027. That is satisfactory, if it is feasible to do so. Alternatively, appropriate revisions can be considered in PG&E's 2011 Phase 2 GRC or a subsequent rate design window. In any event, to the extent that PDP is implemented before the revisions are made, PG&E should collect data to understand and evaluate how the payments overlap and use that information in determining how best to revise the PDP program.

10.3. Automated Demand Response

CLECA stresses the importance of automated demand response (Auto-DR), noting that having access to technology that facilitates response to dynamic pricing may well encourage customers not to opt out of such rates. CLECA states there should be provisions of customer information as to the availability of such technology and incentives for installing it as long as it is cost-effective. CLECA notes that Utility Technology assessment/Technology Incentive programs are one source of funding for larger customers and suggests that funding should be available for smaller customers as well, as long as the programs are cost-effective.

PG&E states that it supports Auto-DR and has an Auto-DR program for large customers in its 2009-2011 Demand Response programs. However, according to PG&E, the technologies that facilitate Auto-DR for large customers are currently too costly for mass market applications, and technology suitable for small and medium customers is not sufficiently developed to implement CLECA's proposal at this time.

According to PG&E, an open Auto-DR standard is in development, with use cases and business requirements expected around October 31, 2009. Subsequent technical requirements for the protocol must be developed. The draft technical requirements document is expected in 2010. The draft technical requirements would then go to the International Electrotechnical Commission, where the standard would be finalized as an international standard for DR. For customers with loads less than 200kW, PG&E states that it may present an Auto-DR program in the 2012-2014 DR program cycle with the expectation that by that time the standards will be in place and vendors will have developed technologies for smaller customers. However, PG&E adds that the present dynamic pricing case is not the right forum to consider CLECA's proposal.

10.3.1. Discussion

In general, the Commission supports programs such as Auto-DR that cost-effectively facilitate customer responses to dynamic pricing. With respect to Auto-DR for smaller customers, there is insufficient evidence to implement any such program at this time. We agree with PG&E's position that Auto-DR is being addressed and should continue to be addressed in the demand response proceedings.

11. Incremental Cost Recovery

11.1. PG&E

PG&E is seeking authorization to recover the incremental costs it incurs from 2008 through 2010 to implement the default and optional PDP and TOU rates presented in this application.[20]

PG&E indicates that (1) the incremental nature of PG&E's forecasted costs is assessed relative to cost estimates previously adopted by the Commission in other proceedings; (2) costs that are not incremental, that have been approved in other proceedings, will be tracked and recorded in accordance with the cost recovery adopted on those proceedings; and (3) only the incremental costs are

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[20] Such recovery is in accordance with D.08-07-045, Ordering Paragraph 14, which states that: "PG&E shall seek recovery of incremental expenditures required to implement dynamic pricing incurred before 2011 in the application(s) in which PG&E proposes the specific dynamic pricing rates and shall provide the necessary justification."

requested to be treated in accordance with PG&E's DPMA ratemaking proposal that is discussed later in this decision.

PG&E retained an independent external consultant, Pricewaterhouse Coopers LLC (PwC), to perform an analysis of PG&E's cost estimates to assess the incremental nature of the requested costs in this proceeding. According to PG&E, PwC applied a two-step approach to test whether PG&E's cost estimates included in the application were incremental to cost estimates approved by the Commission in prior proceedings, or were being considered by the Commission in then ongoing proceedings. PwC evaluated both the incremental nature of the activities underlying the cost estimates, and the incremental nature of the cost estimates relative to costs previously approved by the Commission in prior proceedings. PwC identified seven other proceedings for possible overlap with this proceeding in terms of incremental cost recovery:

- 2003 GRC (A.02-11-017),
- 2007 GRC (A.05-12-002),
- AMI Pre-Deployment (A.05-03-016),
- AMI (A.05-06-028),
- Demand Response (DR) 2006-2008 Program Years (A.05-06-006),
- DR 2009-2011 Program Years (A.08-06-003), and
- SmartMeter Program Upgrade (A.07-12-009).

PG&E further states that in order to evaluate the incremental nature of PG&E's cost request in this proceeding, PwC (1) undertook not only a review of the Commission decisions in each of the possibly related proceedings, but also undertook a detailed review of PG&E's submitted testimony and workpapers, prepared briefs, hearing transcripts and other documentation, including intervenor testimony and various filed reports as necessary; (2) developed a matrix of cost categories for each of the proceedings; and (3) conducted interviews with the witnesses and their supporting staff to understand the specific assumptions included in their respective costs estimates, and to reconcile these assumptions to the information presented in prior relevant proceedings and associated Commission decisions.

11.2. DRA

DRA states that it is not clear what, if any, analysis PG&E (or PwC) has done to determine how ratepayer funds PG&E has received in the past for Customer Education/ Outreach/ Service/ Notification and IT activities were actually used for those activities, or whether PG&E has spent the funds effectively to implement dynamic pricing. DRA asserts that what is clear is that the Commission has already authorized vast sums of ratepayer money to fund Customer Outreach/ Education/ Service/ Notification and IT capital and expense projects for PG&E to implement dynamic pricing, and PG&E has offered little other than generalities and unsubstantiated conclusions to justify adding another $160.2 million. DRA, therefore, recommends that the Commission approve zero ratepayer funding for Customer Education and Outreach, zero ratepayer funding for development of Notification Equipment, reduce PG&E's request for IT costs by $14 million in this case, and remove what DRA expects will be a $28 million IT request from PG&E's upcoming GRC.

IT costs and the development of notification equipment are discussed further in this decision. With respect to customer outreach costs, DRA notes that, for Customer Outreach and Education Activities, PG&E's request of $32.4 million from 2008 through 2010 in this proceeding is over and above $300 million PG&E was authorized in Customer Outreach and Education costs in the two AMI proceedings, the 2006- 2007 GRCs, and Demand Response programs for budget years 2008 and 2009 through 2011. Also, PG&E will be seeking still more ratepayer funding for Customer Education and Outreach in its 2011 GRC.

According to DRA, PG&E's testimony, workpapers and data request responses provide little, if any, verifiable information to determine whether PG&E's Customer Outreach and Education cost estimates are truly incremental or should be adjusted. Consequently, DRA reviewed the monthly and semi-annual AMI reports PG&E is required to file with the Commission. DRA states that it sought to determine whether costs PG&E seeks for activities in this case overlap with funding PG&E has received in other cases. According to PG&E's January 2009 AMI Semi-Annual Assessment Report, as of December 31, 2008, 42% of the budgeted SmartMeter project costs had been spent, while only 24% of the marketing and operations funds ($191 million) had been spent. According to the SmartMeter Steering Committee Update of June 19, 2009, 73% of the Customer costs for the budget year 2009 were still unspent as of May 2009. DRA indicates that PG&E still has $75 million in unspent funds from the AMI proceedings for Customer Acquisition and Marketing, and recommends no additional funding should be ordered here.

In rebuttal PG&E states that DRA's recommended reduction of Customer Education and Outreach costs contains several major errors including:

- DRA inappropriately compares PG&E's PDP estimate for Customer Education and Outreach efforts to costs for a different, broader scope of customer and marketing activities included in PG&E's SmartMeter Program. With respect to the $75 million identified by DRA, the Commission adopted PG&E's forecast of $54.8 million for SmartMeter customer acquisition, of which $11.9 million had been spent through June 2009.
- DRA fails to differentiate between PG&E's education and outreach activities for different customer classes such as residential, small and medium C&I, and large C&I.

- DRA fails to consider the planned timing of PG&E's estimated customer acquisition costs (i.e., relative to SmartMeter endpoint deployment) anticipated at the time of PG&E's original AMI filing.
- DRA misrepresents the amount of PG&E's "unspent budget" for customer and marketing costs included in PG&E's SmartMeter Program budget and fails to acknowledge the significant residential customer acquisition costs that will necessarily be incurred as PG&E completes its full deployment of SmartMeter endpoints.

In response DRA asserts the following:

- If the $75 million figure is comprised of costs for activities that are not comparable to the Customer Education and Outreach estimates in this PDP application, PG&E was authorized $54.8 million for activities that even PG&E says are "potentially comparable." According to PG&E, $11.9 million of that had been spent as of July 2009, thus, PG&E still has approximately $42.9 million left.
- There are, or should be, synergies between AMI and PDP. PG&E could use those synergies and apply the unspent Customer Acquisition and Marketing and Outreach and Education funds from the AMI decisions to the Peak Day Pricing program. If, and when, those funds are exhausted, PG&E can file an application to request more.
- PG&E has pointed to nothing in the Commission's AMI decisions that states that the funding cannot be applied as DRA recommends.
- PG&E's track record for "planned timing" supports Commission adoption of DRA's recommendation.

11.3. TURN

TURN indicates that it did not devote the resources necessary to fully evaluate PG&E's incremental cost analysis, but its limited inspection of customer outreach and education showed that PG&E's incremental cost methodology maximized the calculation of additional incremental costs.

TURN notes that DRA focused on actual expenses on customer acquisition in the AMI proceeding and as a result recommended that the entire $32.4 million was unnecessary due to the over $40 million in unspent funding for SmartRate customer acquisition activities. Based on a review of the record, TURN supports DRA's recommendation and offers the following points:

- It is a general principle of utility ratemaking that the utility has discretion to shift funds among projects and cost categories, absent specific Commission direction that funds earmarked for a particular purpose must be recorded in a memorandum account and cannot be shifted to another purpose without authorization. For example, the Commission has imposed fund shifting limitations on energy efficiency and demand response programs.
- TURN is not aware of any fund-shifting limitations imposed in the AMI decision, D.06-07-027. Indeed, upon further questioning PG&E's witness admitted that his statement was based merely on the fact that the Commission adopted a stipulation in the AMI case that identified $54 million for marketing costs. The Commission adopted a total cap on costs for purposes of reasonableness and cost sharing.
- TURN believes that the cost cap does not prevent PG&E from spending the money on other activities, but rather requires that PG&E keep accurate track of the costs spent on activities authorized pursuant to the AMI decision.

In the event that DRA's recommendation is not adopted, TURN proposes two alternatives.

First, TURN notes PG&E's methodology for determining the overlap with the AMI decision for small and medium C&I customer outreach and education, where PwC took a forecast of $17.6 million for total customer acquisition spending in 2010 and Jan/Feb 2011 and multiplied it by 9.2%, the percentage of small and medium C&I and agricultural customers the SmartRate program that PG&E plans to market. TURN asserts that it is inaccurate to multiply the total spending by a "percentage of customers" number because the unit acquisition costs are very different. Per customer acquisition costs for residential customers were forecast at $90, while per customer acquisition costs for C&I customers were forecast at $225. Multiplying total spending on both classes by number of customers to calculate the overlap of just the C&I costs ignores this basic difference. TURN also notes that in the original AMI case PG&E had forecast that C&I customers would represent 5.1% of the total number of customers accepting the SmartRate, but marketing costs for C&I customers represented 11.9% of total marketing costs. Therefore, TURN recommends that, at a minimum, the adjustment should be based on the 11.9%, which results in a reduction of $2.09 million, or $470,000 more than PG&E.

However, rather than this $2.09 million reduction, TURN believes it would be more appropriate to use a $2.49 million reduction based on the original AMI budget forecast. TURN states that PG&E had forecast $6.522 million for customer acquisition expenses for small C&I customers in the AMI proceeding, and this was the amount embedded in the $54.8 million and if one used the authorized costs in an incremental cost analysis, one would most likely disallow the $2.490 million forecast in the AMI case for C&I customer acquisition in 2010, plus some portion of the $0.487 million forecast for 2011.

In its reply brief, PG&E states that it would agree to the $2.09 million reduction proposed by TURN, but not the alternative proposal of a $2.490 million reduction. It appears that PG&E disagrees with the larger reduction because it is at odds with PwC's analysis which incorporated the use of judgment to modify authorized AMI amounts by the use of more recent budgets.

11.4. Discussion

In general, we agree with the customer class differentiation argument that PG&E offered regarding DRA's proposal to eliminate funding in this proceeding for customer outreach and education. In the AMI filing PG&E's forecast of customer acquisition costs of $54.8 million was adopted and according to PG&E, approximately $48.2 million (88%) was anticipated to be used for residential customers.[21] By imputing its adjustment whereby $32.4 million in PDP costs for customer education and outreach for non-residential customers would be taken from the approximate $42.9 million remaining in the AMI authorization for customer acquisition, the DRA proposal would leave only $10.4 million (24%) for residential customer acquisition activities.

We are not convinced that, in this case, it is reasonable to redirect previously authorized acquisition funds for residential customers to non-residential customers merely because of the availability of unspent funds. It might be reasonable, if it were determined that certain amounts previously authorized for residential related activities would ultimately not be necessary. Certainly PG&E has the obligation to spend ratepayer provided money in an optimal, cost effective manner, and the Commission should encourage such redirection of funds if necessary. However, in this case, it has not been shown that it is necessary. DRA is not advocating that education and outreach to residential customers be limited or reduced in any way. Its recommendation is based primarily on the fact that there are unspent AMI funds available at this time. However, PG&E has presented convincing evidence that the actual

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[21] Exhibit 7, p. 48, Table 4-1.

spending of customer acquisition costs authorized by its AMI decision has been delayed due to delays in the deployment of SmartMeters. Without good cause, we do not believe it is an effective use of the Commission's resources to deplete previously authorized funds for residential customer acquisition activities, and then have PG&E request the same funding in a later proceeding. We will not adopt DRA's proposal to fund all customer outreach and education for PDP from unspent AMI funds.

However, in considering the evidence on this issue, we are not convinced that PG&E's quantification of $1.62 million as the overlap between this proceeding and the AMI proceeding, with respect to small and medium C&I customer acquisition costs, is reasonable. By PG&E's own evidence, the AMI decision incorporated PG&E's forecasted budget of $2.49 million for small and medium C&I customer acquisition activities for 2010. The record is scant as to why this adjustment should be reduced. PG&E is not arguing that the total amount of $6.522 million budgeted at that time for small and medium C&I customer acquisition activities should be modified in any way, but rather that the $2.49 million amount for 2010 was based on an assumed timing of electric meter deployment that was subsequently modified and an adjustment which reflects a revised AMI budget should be used.

We do not know the details of PG&E's AMI budget changes that may have impacted its $1.62 million proposed adjustment, which was calculated by multiplying a $17.6 million forecast times 9.2%, and we are concerned with the result that appears illogical. As PG&E has indicated, customer acquisition expenditures authorized by its AMI decision have been delayed due to delays in the deployment of SmartMeters. Assuming that it is true that expenditures were not eliminated but delayed, it is logical to conclude that there would likely be more money, not less, available in 2010 for small and medium C&I customer acquisition activities than the $2.49 million originally forecasted by PG&E. Therefore, we believe it is reasonable to increase rather than decrease the $2.49 million amount to better estimate what should be reflected as AMI funding for small and medium C&I customer acquisition activities in 2010, and to reflect that better estimate in determining incremental costs for this proceeding.

PG&E's revised SmartMeter deployment forecast indicates that 1,662,000 meters will be deployed in 2010, as opposed to 1,037,000 meters indicated in the original meter deployment forecast.[22] That is, the delay in meter deployment would result in an approximate 60% increase in the number of meters that would be deployed in 2010. To reflect the revised meter forecast, the associated delay in customer acquisition expenditures, and the likely availability of more small and medium C&I customer acquisition funds for 2010, we will increase the originally forecasted small and medium C&I customer acquisition expenditure amount of $2.49 million for 2010 by the same 60% and deduct the resulting amount of $3.98 million in determining incremental costs for 2010 in this proceeding.

In all other respects, we conclude that PG&E's incremental analysis, including that related to (1) foundational work and (2) large C&I and large agricultural customers, is reasonable.

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[22] *See* Exhibit 7, p. 4-9, Figure 4-1.

12. Customer Outreach and Education – Foundational Activities and Costs Common to All Classes

12.1. PG&E's Proposal

PG&E proposes foundational work that includes customer research, educational materials design, training program development and facilitation, staffing, and database operations enhancement. PG&E estimates the related incremental cost to be $5.90 million for the 2008-2010 time period. PG&E considers all foundational costs to be incremental.

Customer Research

PG&E will employ focus groups, interviews, and quantitative-based telephone and online interviews to identify segment-specific business needs and communication preferences. Efforts will include determining customers' baseline understanding of PDP and TOU rates, researching how best to reach out to them according to their industry and size, determining the optimal communication channels by customer segment, testing outreach materials for clarity and effectiveness, testing usability of decision and energy analysis tools, deciding the most effective notification methodologies, testing prototype notification devices, conducting customer satisfaction surveys, and conducting ongoing tracking studies to drive improvements in outreach.

With this information PG&E will be able to take a targeted approach to assisting customers in making their rate decisions, and states that it will incorporate research results with customer feedback so that outreach efforts over time will increasingly reflect actual customer experiences and preferences. Using cost estimates from previous research projects, PG&E estimates these incremental research costs to be $1.70 million.

Educational Materials Design

PG&E will use input from customer research to design, test and refine educational materials, indicating that the materials will become more sector-specific over time as PG&E gains additional customer insights. PG&E estimates these incremental materials design costs to be $0.30 million.

Training Program Development and Facilitation

Using the information in the educational materials, PG&E will develop internal training materials, design training modules and deliver training to Account Managers, Customer Service Representatives (CSR), and Dynamic Pricing Specialists so they will be able to assist customers with the new rates. Training will vary according to the needs of the employee audience. PG&E estimates these incremental training development and facilitation costs to be $0.55 million.

Staffing

PG&E plans to hire three incremental Research Managers (two in 2010) to implement the customer research efforts described above; and one incremental dynamic pricing program Outreach Supervisor, who will spend two-thirds of his or her time managing overall implementation of customer outreach. Based on the average cost per internal employee, PG&E estimates these incremental labor costs to be $0.95 million.

Database Operations

In order effectively to implement customer outreach, PG&E indicates that it needs to expand and enhance its business customer database to include new fields to collect information on meter status and customer default eligibility, rate impacts based on usage patterns, outreach efforts, responses and rate decisions for each customer. These enhancements will allow PG&E to segment customers with like usage patterns, identify customers most in need of education on the PDP implications for their businesses, select role models in various industry sectors who have learned to manage their energy usage more effectively, and tailor customer messaging. Costs include database management; database enhancements to allow for notification and response tracking, loading data to the database, pulling data from the database, and building incremental customer reports; and on-going database maintenance. These costs are specific to enabling targeted customer outreach and are separate from the incremental IT work discussed later in this decision. PG&E estimates these incremental costs to be $2.40 million.

12.2. Discussion

DRA has indicated that it does not dispute these costs. No other party addressed this issue. The activities proposed by PG&E and the associated costs are reasonable. In addition, as discussed above, PG&E's analysis of the incremental nature of these costs is also reasonable. Therefore, PG&E's estimate of the incremental foundational costs common to all customers, which amounts to $5.90 million, is adopted. Contingencies related to these adopted costs are discussed further on in this decision.

13. Customer Outreach and Education – Large Customers

According to PG&E, there are currently approximately 10,000 large C&I customers and approximately 1,250 large agricultural customers. Approximately 20% of these large C&I customers are in DR programs and, under PG&E's proposal, would not be subject to PDP default. While almost all of the rest are currently subject to mandatory TOU rates, few have significant experience with CPP rates. Thus, according to PG&E, most of these large customers will need assistance with PDP rate selection in time for the May 1, 2010 (large C&I

customers) and February 1, 2011 (large agricultural customers) default dates if they are to avoid unexpected bill volatility and dissatisfaction.

13.1. PG&E's Proposal

PG&E proposes incremental costs specific to large C&I and agricultural customers that consist of account services staffing for Person-to-Person outreach, and various activities related to Awareness and Education, for a total incremental cost estimate of $5.92 million.

Person to Person Outreach

PG&E proposes to deploy existing Account Managers and incremental personnel to work directly with large customers to analyze new rate structures. The incremental account services personnel will consist of 25 Dynamic Pricing Specialists to augment the existing Account Manager staff and work with customers individually on PDP issues such as rate selection. PG&E will also hire one incremental Account Manager. The Account Manager will work with large customers in the Business Customer Center helping existing Account Managers involved in dynamic pricing-related work. Under PG&E's proposal, these personnel will later shift to assisting small and medium commercial and agricultural customers. PG&E estimates these additional labor costs to be $3.30 million through 2010, with $2.93 million being considered incremental for purposes of determining this proceeding's rate increase.

Awareness and Education

PG&E indicate that it will augment its Person-to-Person outreach with a direct mail and e-mail campaign to alert large customers who will default to new rates that a significant change is coming that requires their attention. The campaign will include an industry-specific component aimed at industries that may face the most severe impacts from PDP. There will also be outreach to large customers enrolled in DR programs and not eligible for default to PDP, to make sure they do not stop participating in DR programs due to confusion over messaging.

The specific Awareness and Education activities proposed by PG&E are:

- direct outreach (e-mail, direct mail, bill inserts, graphic design and printing),
- educational materials and collateral, online content development (writing the educational content and designing the graphic design for the web),
- staffing (two and one/third incremental employees to oversee development and implementation of customer outreach), and
- customer recognition (to acknowledge customers who participate in successful energy management strategies and adopt demand shifting behavior).

PG&E estimates these additional labor costs to be $3.29 million through 2010, with $2.99 million being considered incremental for purposes of determining this proceeding's rate increase.

13.2. Discussion

The activities proposed by PG&E and the associated costs are unopposed and reasonable. In addition, as discussed above, PG&E's analysis of the incremental nature of these costs is also reasonable. Therefore, PG&E's estimate of the incremental cost for large customer outreach and education which amounts to $5.92 million is adopted. Contingencies related to these adopted costs are discussed further on in this decision.

14. Customer Outreach and Education – Small and Medium Customers

According to PG&E, there are currently approximately 75,000 medium-sized (maximum demand less than 200 kW but greater than 20 kW) C&I

customers, approximately 415,000 small C&I customers (maximum demand less than 20 kW), and approximately 80,000 small agricultural customers (maximum demand less than 200 kW), for a total of about 570,000 smaller business customers. Virtually all of these customers are subject to defaulting to new rates on or after February 1, 2011; C&I customers onto PDP and agricultural customers onto TOU. Approximately half of the small agricultural customers are already on TOU rates, half are not. Few smaller C&I customers have experience with CPP rates. PG&E indicates that approximately 300,000 of these customers will default to new rates before October 2011 and therefore will receive some direct outreach through efforts outlined and costs reflected in this application.

14.1. PG&E's Proposal

PG&E states that it expects the outreach effort for these smaller customers to be more challenging than for large customers, due to factors such as smaller customers' lack of experience with anything other than flat rates, PG&E's inability to reach most of these customers on a one-on-one basis, smaller customers' lack of familiarity with their energy use, and, in some situations, their lack of facility with English. Costs specific to these customers relate to account services staffing for Person-to-Person and general awareness outreach, and various activities related to Awareness and Education, and total $22.20 million of which PG&E considers $20.58 million to be incremental.

<u>Person to Person Outreach</u>

PG&E proposes to provide more support for inbound customer calls requesting advice on rate selection, energy management, bill fluctuations, use of web-based rate analysis tools, etc. PG&E notes that CSRs who work in PG&E's Business Customer Service Center will receive updated dynamic pricing training. Also, in May 2010, after the default date for large C&I customers has passed, PG&E plans to deploy an additional 15 Dynamic Pricing, for a total of 40, and an additional 20 Account Managers, for a total of 21 to support the broad customer awareness campaigns targeted at these customers, as well as to help with individualized rate analyses. PG&E estimates these additional labor costs to be $3.70 million through 2010, all of which would be incremental.

Awareness and Education

According to PG&E, its outreach to smaller customers will necessarily focus heavily on a broad Awareness and Education campaign consisting of direct outreach, educational materials and collateral, online content development, paid media (e.g., off-line and on-line business and trade journals and geo-targeted media), earned or unpaid media (e.g., contributing to trade journal articles about dynamic pricing), staffing, and customer workshops for those most at risk of significantly negative bill impacts. This awareness campaign will be geographically specific in accordance with SmartMeter roll out and will alert customers to the rate change and direct them to self-help resources, including the PG&E web site and call centers. PG&E also proposes to provide a variety of ways for customers to respond, including on-line forms and self-mailer response cards, with call center support.

Direct outreach timed to customer default dates will involve the design, production and distribution of multiple and in-language versions of email, direct mail, and bill inserts. PG&E's 2010 forecast for this work is $6.45 million. However, incremental costs for this activity are $1.6 million less, or about $4.9 million. Development, production and refinement of educational materials and collateral, in-language translation, and revisions are estimated to cost an incremental $3.075 million.

Additions to the company's web site will include information on and timing of the new rates, rate comparison tools, industry or segment-specific dynamic pricing rate explanations, and case studies of customers who have successfully shifted load to realize the benefits of DR. PG&E states it will make information available off-line upon request. Developing and designing the new online content is estimated to cost an incremental $0.60 million.[23]

Paid media work, including creative development and design of targeted awareness campaigns, and planning to determine the off-line and online magazines, newsletters and other trade publications that will reach the desired audience, will cost an estimated incremental $5.00 million.

Staffing will involve creation of an outreach awareness and education team devoted to these smaller customers. The team will include one Dynamic Pricing Outreach Supervisor, one and one-fifth Dynamic Pricing Project Managers, and two Dynamic Pricing Coordinators, costing an estimated incremental $0.875 million through 2010. All the incremental Dynamic Pricing Specialists and Account Managers will be team participants.

Customer workshops will help to actively engage smaller customers who are difficult to reach or unresponsive to direct outreach. Costs, including event management agency fees, administration and production, travel expenses, event sponsorship and community involvement fees, etc., will be an incremental $2.50 million in 2010.

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[23] Cost recovery related to customer web presentment infrastructure upgrades and development of online rate selection tools are discussed separately in this decision.

PG&E estimates total 2009-2010 Awareness and Education costs associated with medium and small C&I and small agricultural customers to be $18.50 million with the incremental costs amounting to $16.88 million.

14.2. Discussion

Issues relating to DRA concerns regarding commercial customers with loads less than 20kW (small commercial), and DRA proposals for an Independent Evaluator and an Outreach Advisory Panel, along with our concerns regarding measurement and evaluation, are discussed later in this decision. Other than that, no party objects to any specific activities or total costs (as opposed to incremental costs) related to PG&E's proposal, as described above, and we determine that they are reasonable for setting the revenue requirement in this proceeding. However, we have previously determined in this decision that PG&E's analysis of the incremental nature of these costs is not reasonable and will reduce the total $18.50 million cost of Awareness and Education by $3.98 million, rather than $1.62 million as proposed by PG&E, to determine the incremental cost amount of $14.52 million for this category. This results in our adoption of $22.20 million total costs and $18.22 million incremental costs for outreach and education for medium and small C&I and small agricultural customers. Contingencies related to these adopted costs are discussed further on in this decision.

15. Customer Outreach and Education – Residential Customers

Residential customers become eligible to opt in to PDP in May 2010. PG&E makes no request in this proceeding for incremental cost recovery for outreach and education for residential customers. PG&E states that outreach costs for the residential optional PDP rate program will be covered by customer acquisition cost recovery authorized in the AMI decision. PG&E also states that it plans to leverage experience from SmartRate outreach to reduce residential customer acquisition costs and increase their participation rates.

16. Customer Outreach and Education – SmartRate Customers

All costs associated with customer outreach and education/acquisition for the voluntary SmartRate program, either in its current form or after the date the underlying rate changes to PDP, were authorized in the AMI Decision through the period of meter deployment and therefore are not requested by PG&E in this proceeding. These costs include marketing to residential customers and to a segment of medium and small C&I customers, and transitional education of customers enrolled in SmartRate to migrate to PDP.

17. Small Commercial Customer Distinctions

DRA notes that in D.08-07-045, the Commission found and concluded the following:

- Large C&I customers with maximum load greater than 500 kW have been on mandatory TOU rates since the late 1970's or early 1980's, depending on the size of the customer. (Finding of Fact 8.)
- Large C&I customers have been on TOU rates for between five and thirty years. (Finding of Fact 10.)
- Small commercial customers require more time for customer Outreach and Education than do large and medium C&I customers." (Finding of Fact 22.)
- It is reasonable to subdivide commercial and industrial customers with maximum load less than 200 kW into two subgroups: those with maximum demand between 20 kW and 200 kW, referred to as medium C&I, and those with maximum demand below 20 kW, referred to as small commercial." (Conclusion of Law 11.)

Based on this, DRA states "Despite the Commission's clear expression of concern about how best to conduct Customer Outreach and Education to small commercial customers, PG&E did not separate its program costs for small commercial customers from those for its medium commercial and industrial customers." (DRA Opening Brief, p. 41.) DRA recommends that PG&E be required to track its spending on small commercial customer outreach separately from such spending for medium C&I, and large C&I customer outreach.

It is also DRA's understanding that, PG&E's preliminary approach to Outreach and Education for Small and Medium C&I and Small Agricultural customers will be mostly through direct mail, bill inserts, email, personalized letters, customized direct mail, and brochures, while, for its larger customers, PG&E has opted more for workshops, focus groups, education by the use of the internet, and direct person-to-person Outreach and Education. According to DRA, these activities are more costly and largely account for PG&E spending at least 18 times more on Outreach and Education for each large customer than for each small and medium customer.

PG&E argues that DRA's concerns regarding small customers are misplaced for the following reasons:

- Conclusion of Law 11 concerns the development of draft timetables for customer defaults, and refers to a discussion in D.08-07-045 starting at p. 21. An earlier Ruling in the case grouped together all small and medium C&I customers below 200 kW demand for purposes of the draft default timetable. PG&E recommended subdividing this group into those with maximum demand above and below 20 kW, and delaying dynamic pricing for those below 20 kW. (*Id.*, at 21.) The Commission adopted PG&E's recommendation to subdivide the group, but ultimately determined that both medium and small C&I customers would have the same default schedule.

- With respect to Finding of Fact 22 of D.08-07-045, which states that small commercial customers require more time for customer education and outreach than do large and medium C&I customers, on a cumulative basis, given the relative vast number of small commercial customers, this statement may be true. To the extent time correlates to spending, PG&E estimates that it will cost far more to conduct outreach to small and medium customers than to large ones – $20.6 million versus $5.9 million in 2008-2010, and $17.9 million versus $3.2 million after 2010. However, Finding of Fact 22 does not mean an individual small customer necessarily takes longer to reach a decision than an individual larger customer. There are circumstances where it will take much longer to assist a large company than a small one.
- PG&E's small C&I customers are predominantly served under the Schedule A-1 and A-6 tariffs, while medium C&I customers predominantly take service under either Schedule A-10 or E-19V. PG&E has recognized and given considerable weight to differences between the needs and usage characteristics of its small versus medium C&I customers, and has developed significantly different default PDP rate proposals for these two groups of customers versus the large C&I PDP proposal. PG&E's communications and on-line support tools for these customers will also distinguish between small versus medium C&I customers, because, these communications and support tools will distinguish between customers based on the tariffs under which they currently take service. In this respect, PG&E's rate proposals and customer education plans are fully compliant with any requirements that might be inferred from Finding of Fact 22 or Conclusion of Law 11.
- DRA's observation that through 2010 PG&E plans to spend considerably more on outreach and education for each large customer than for each small or medium customer leaves out of its analysis that spending on outreach to medium and small C&I customers will not really begin until half way through 2010, after most large customers have defaulted and at a time when PG&E will be adding account services resources.

With respect to DRA's recommendation that PG&E be required to track its spending on small commercial customer outreach separately from such spending for medium C&I, and large C&I customer outreach, PG&E argues that it is a new recommendation made in opening briefs and should be disregarded. PG&E indicates that had it had the opportunity to address this issue during or prior to the hearing, it would have provided testimony on the difficulty and uselessness of such tracking.

PG&E also argues that DRA's request is untimely. Resolution E-4210 ordered PG&E to provide monthly DPMA cost tracking reports to DRA. Subsequently, PG&E and DRA agreed upon ongoing DPMA reporting requirements that did not include DRA's latest request. According to PG&E, it has been providing DRA with the DPMA reports in the previously agreed-to format since the beginning of 2009, and DRA has even provided feedback that it was satisfied with the template for reporting the incremental expenditures, and has not requested additional changes along the lines it now requests. According to PG&E, providing this kind of breakdown would be overly burdensome, particularly considering its limited to nonexistent usefulness; and it is not even clear that PG&E could do so, since many expenditures cannot be clearly identified by customer class.

17.1. Discussion

While information regarding only small commercial customers might be valuable in some respects, we will not require the separate reporting requirement as recommended by DRA. Regardless of how Commission determinations in D.08-07-045 are interpreted, we are certainly concerned about the effectiveness of outreach and education for small commercial customers, especially since most have never been on a time varying rate of any kind.

However it is not clear what aspects of customer outreach and education, if any, would be improved by tracking costs in the manner recommended by DRA. According to PG&E, the DPMA cost reporting that is already going on is at least somewhat satisfactory. Moreover, what is important is not the necessarily the accounting but the results of the efforts that are put forth. PG&E has proposed outreach and education measures that differ for certain classes of customers and that may well be appropriate. Ultimately, we expect that all customers will be adequately informed and educated and will base any conclusion on the success of PG&E's efforts based on what is done, what is or is not effective and what else could and should have been done. For these reasons, the further segregation of costs for small commercial customers will not likely be that revealing with respect to our outreach and education goals.

18. Outreach Advisory Panel

DRA recognizes that PG&E's plan for Outreach and Education is subject to change because PG&E has not yet performed the foundational research necessary to determine how to best reach different customer segments effectively. However, as to Customer Outreach and Education to small commercial customers, DRA states that it does not seem that PG&E has any specific plan to most effectively use the ratepayer funding it seeks. For example, DRA suggests that PG&E could do more to make use of the internet for communicating with small customers.

DRA states that the Commission should be concerned about the vagueness of PG&E's plans for Customer Outreach and Education to its small commercial customers noting that if PG&E's Customer Outreach and Education program for small commercial customers is inadequate, many of them will begin receiving bills that are higher and less predictable than before, and for reasons they do not fully understand. This, in turn, could undermine the success of the Commission's dynamic pricing initiative.

To assist PG&E in providing effective outreach to the small commercial business community, DRA recommends that the Commission direct PG&E to establish an Outreach Advisory Panel. The goal of the Outreach Advisory Panel would be to monitor and evaluate the effectiveness of PG&E's Outreach and Education programs on an on-going basis. DRA states that it can include participants from consumer groups, Chambers of Commerce, Energy Division, local small business organizations, intervener groups representing small businesses, and nonprofit community based organizations which represent small business customers.

Under DRA's proposal, the Outreach Advisory Panel would be provided the opportunity to make recommendations for improvements before PG&E launches its Outreach and Education efforts for small commercial customers and to recommend changes to the Outreach and Education effort on an ongoing basis; the costs for the Outreach Advisory Panel would be met from the unspent marketing and customer costs PG&E has received in the AMI proceedings; and the burden of using the Outreach and Education dollars in a manner which is most beneficial to the customer would be on PG&E.

PG&E opposes DRA's Advisory Panel recommendation. While PG&E agrees that soliciting input from a wide spectrum of sources can increase the relevance and effectiveness of outreach, and appreciates the particular outreach challenges presented by small business customers, PG&E asserts that its outreach plans already address those challenges. For example, incremental Dynamic Pricing Specialists added to meet the needs of defaulting large customers will be retained and new Specialists and Account Managers hired during the roll out of dynamic pricing to smaller customers. A total of 40 incremental Specialists and 21 incremental Account Managers will be available to assist smaller business customers, especially those who could be adversely impacted by PDP were they not to take action to change their energy usage. PG&E argues that by interacting with various types of small business customers, these representatives will be able to provide a valuable feedback on how the program can be made more relevant and effective as the outreach continues over a two-year period. Moreover, engaging with relevant groups is already part of PG&E's outreach planning. For example, PG&E's customer workshops will entail partnering with industry and community groups, and PG&E will be engaging with various groups through pilot studies and customer interviews that have already begun.

PG&E state that it is concerned that pre-approval of outreach and educational materials for small commercial customers by an Advisory Panel (Panel) would delay development of materials and increase the amount of time necessary to implement outreach campaigns. Also, it is unclear what such a specialized Panel would contribute and thus difficult to justify the time and money involved. Other concerns relate to unknown specifics of DRA's proposal including the number of Panel members, how they would be selected, exactly whom they would represent, how the Panel would be governed, exactly what it would review, how often it would meet, and what costs would be involved. Also, for reasons it already addressed with respect to incremental funding, PG&E states that it would not be appropriate, as DRA suggests, to fund such a Panel from residential outreach dollars approved in the AMI case.

PG&E notes that the main example of the specificity that DRA contends is lacking in PG&E's plan is with respect to use of the internet. PG&E assumes that a high percentage of small and medium customers do have access to the internet and states that one of the many things it already plans to do is DRA's suggestion that PG&E include in every mailing a request that the customer provide an email address.

18.1. Discussion

PG&E's concern that pre-approval of outreach and educational materials might result in delay is valid. Also, there appear to be certain aspects of PG&E's planned efforts, such as customer workshops and partnering with industry and community groups, which would duplicate what an advisory panel might accomplish. For these reasons, we will not adopt DRA's Outreach Advisory Panel proposal. However, in order to help facilitate input from the smaller customers, business groups and community groups, we will require that PG&E work with the Commission's Business and Community Outreach Branch to determine how the group can assist PG&E in outreach efforts to small and medium customers. The Business & Community Outreach group can be a resource in raising PDP awareness and also ensuring the Commission policy is being implemented effectively. To the extent that the Business & Community Outreach Branch participates in this process, we expect that it will keep the Energy Division informed of its activities and evaluations of the ongoing process.

Also, we will require PG&E to hold quarterly meetings that coincide with its quarterly reports on its outreach and education efforts (s*ee* Section 19.1). Two of the quarterly meetings should be with Energy Division and two of the meetings should be open to the public and posted on appropriate service lists. These meetings will provide opportunities for parties and the public to provide ongoing input into PG&E's outreach plans.

19. Evaluation of Outreach and Education Efforts

DRA notes that PG&E has received over $300 million in Customer Outreach and Education costs in the two AMI proceedings, the 2006-2007 GRC and demand response programs for budget years 2002-2008 and 2009-2011, over and above what it is seeking in this case. DRA recommends that, before the Commission authorizes any additional ratepayer funding for this PDP outreach, it establish performance measures. DRA indicates that PG&E's testimony as to how it intends to conduct effective outreach to small commercial and medium C&I customers, is so vague as to be virtually meaningless. DRA states that given the vagueness of PG&E's plans for small commercial customers, measuring the effectiveness of PG&E's Outreach and Education efforts is critical and that performance measures can be used to improve the efficiency and effectiveness of Outreach and Education activities and strategies to help achieve key objectives and ensure that ratepayer money is not wasted.

Therefore, DRA recommends that the Commission order PG&E to retain a reputable, independent impact assessment firm to measure and evaluate PG&E's Outreach efforts, and report on those efforts periodically to its proposed Outreach Advisory Panel and to the Commission. Further, DRA recommends that PG&E be directed to use unspent funds, previously authorized in the AMI case, to pay for the contract with impact assessment firm, and should include the Energy Division in the hiring process to ensure the independence of the evaluator.

At this time, DRA suggests the following goals for the independent impact evaluation firm:

- Representative surveys of a sample of customers who have been targeted by Outreach and Education efforts to measure the effectiveness of the outreach;

- Assessment of progress towards goals of Outreach and Education activities, i.e., increased understanding of new rates, ability to make informed choices, ability to avoid rate shock.

Under DRA's proposals, the Commission and the Outreach Advisory Panel would receive survey results directly from the impact evaluation firm and provide guidance for changes to PG&E's Outreach and Education effort. DRA indicates that while ratepayer funds need to be spent on this effort, doing so will maximize the effectiveness of how the total budget for Outreach and Education is spent.

PG&E opposes DRA's independent evaluator recommendation. PG&E agrees that measuring and evaluating the awareness levels achieved by outreach are key to any effective marketing plan, especially one built on the principle of continuous improvement. PG&E also agrees that tracking studies and surveys are a critical component of outreach. Nor does PG&E oppose submitting to the Commission periodic reports on customer outreach. However, it appears to PG&E that DRA's recommendation is based largely on its lack of sufficient expertise to evaluate PG&E's outreach plan, not on any failing in the plan itself. PG&E states that is presumably why DRA's recommendation ignores PG&E's foundational research proposal and therefore represents an unnecessary and duplicative expense in the range of $120,000 to $150,000 annually.

PG&E states that it has already built measurement and evaluation into its outreach plans, specifically in the customer research component, and that research will be an important way for PG&E to measure the success of its customer outreach, and make modifications as needed.

Further, for reasons similar to that expressed with respect to funding in Section 11, PG&E asserts that it would not be appropriate, as DRA suggests, to fund an assessment firm from residential outreach dollars approved in the AMI case.

19.1. Discussion

We feel it is important that PG&E is able, in a transparent way, to demonstrate that it will evaluate its outreach and education efforts and, if necessary, that it will modify its efforts appropriately. We agree with DRA's assertion that PG&E has not provided sufficient details on how this would be done. However, with respect to DRA's recommendation, we are concerned that hiring an independent evaluator will necessitate a formal evaluation, in which the evaluator would look at a snapshot of PG&E's efforts and then provide feedback based on that moment in time, rather than facilitating a process of providing ongoing feedback on, and proposed modifications of, PG&E's outreach and education activities as it continues the roll out of SmartMeters and the implementation of the PDP default process. We direct PG&E to work with the Demand Response Evaluation and Measurement Committee (DRMEC) to conduct an evaluation in 2011 of the effectiveness of customer education and outreach efforts of small and medium customers. We will additionally impose certain reporting requirements on PG&E to elicit information and to provide a means for parties to express concerns and a means to address any such concerns. PG&E shall:

- File an advice letter within 120 days of this final decision clearly identifying and describing the specific performance measurements, for each of its customer classes, which it will use to determine that its outreach and education campaign is successful.
    - Possible examples of measurements could include, but should not be limited to, quantifying benchmarks of successful outreach efforts such as: number of workshops held,

minimum participants attended, number of customers signed up for "My Account," number of customers that respond to the utility indicating they will stay on or opt out of PDP, and maximum number of customers calls or complaints after a PDP event.

PG&E should also include a detailed plan with a timeline to develop customer surveys for each customer class. The plan should include a description of the information the utility will gather from customers through survey questions to measure the success of its outreach.

- Prepare a monthly report to be provided to the Energy Division and posted on a public website. This monthly report should include a breakdown of cost categories and money spent on education and outreach as well as a narrative description that describes the costs. PG&E should work with the Energy Division to design an appropriate format for the reports.
- Provide a semi-annual written progress report to all parties on the service list, which includes foundational research conducted and findings, all outreach activities that have occurred, lessons learned from interactions, performance measurements that have or have not been met and if necessary modifications to outreach efforts going forward. The form and content of the report should be coordinated with the Energy Division and should be modified as necessary on an ongoing basis.
- Hold quarterly progress report presentations. Two of the meetings shall be open to DRA and the Energy Division. Two of the meetings shall be in conjunction with the semi-annual written reports and open to all parties on the service list.
- Provide, to the Commission's Business and Community Outreach Branch, PG&E's schedule of outreach events, at which PG&E staff will be educating customers about PDP and TOU rates. (Events include workshops, industry meetings, and meetings with members of Chambers of Commerce etc.). To the extent possible, PG&E should coordinate such events with the Business and Community Outreach Branch.

- After each of the presentations to parties on the service list, file an Advice Letter that includes a workshop report describing recommendations and issues raised and how PG&E will proceed as a result of the discussions and recommendations.

If the Commission finds, based on the information 1) in the monthly quarterly or semi-annual reports, 2) through the advice letter process, 3) through feedback from the Business and Community Outreach Branch, or 4) through the DRMEC evaluation that PG&E's methods of education and outreach are failing to satisfactorily education customers, it may be necessary for the Commission to order PG&E to redirect its customer outreach and education efforts and funding or, in the extreme, delay the further implementation of default PDP rates.

20. Incremental Customer Inquiry Activities/Costs

PG&E requests $2.306 million in customer inquiry costs associated with the new TOU and PDP rates. PG&E states that additional inquiries are likely to be generated by the new rates from all customer groups, including calls about event notification and contact information updates; calls in response to marketing efforts and calls to opt-in or opt-out of the new rates. Costs related to the increased contact center volumes amount to $1.947 million. PG&E also includes $0.358 million for training contact center and local office CSRs to handle all types of inquiries related to the implementation of dynamic pricing.

None of the parties oppose the customer inquiry activities proposed by PG&E. However, TURN objects to including $281,600 to fund calls from residential and small and medium C&I customers subject to SmartRate conversion. According to TURN, the Commission authorized the AMI project based on a projection of $2.7 million in annual benefits due to reduced "customer contact" costs, based on the notion that residential and small commercial customers would not need to contact the call center as often with billing inquiries after deployment of smart meters. TURN argues that funding this portion of PG&E's request, in the amount of $281,600 chips away at that promised benefit.

In disagreeing with TURN's proposed adjustment, PG&E states that while the Commission did approve $2.7 million for savings associated with the implementation of SmartMeter, these savings were based on the assumption that customers would make fewer calls regarding:

1) high bills ($617,000),
2) delayed bills ($125,000),
3) estimated bills ($1,472,000) and,
4) meter reading concerns ($189,000).

Also, there was an additional $301,000 in projected savings due to shortened calls associated with high bill complaints.

According to PG&E, TURN has incorrectly assumed that the $281,600 was part of the AMI funding, and the Commission should reject TURN's proposed disallowance.

20.1. Discussion

In general, we agree with PG&E's position that SmartRate conversion inquiries are new types of calls that were not anticipated when the Commission adopted the $2.7 million savings amount. PG&E has accounted for the majority of the savings, and the types of savings indicated do not appear to encompass savings related to SmartRate conversions. We will therefore not adopt TURN's adjustment or any portion of the adjustment for the reasons cited by TURN. However, we are concerned with the inclusion of the $281,600 amount for SmartRate conversion calls for another reason.

With respect to these particular inquiries, PG&E states the following:

> As of December 1, 2008, PG&E had approximately 10,000 residential and small and medium C&I customers on the three current CPP tariffs (E-CPP, E-CSMART and E-RSMART). By May 1, 2010, PG&E estimates that approximately 61,900 residential and small and medium C&I customers will be on these rates. With the implementation of the new rates, all of the residential customers will have the opportunity to opt-in to the new PDP rate for summer 2010. Otherwise, they will default to the non-PDP tariff.
>
> Either way, the transition from the existing SmartRate to the new PDP rate will generate customer inquiries. PG&E estimates that 75 percent of those customers on SmartRate as of May 1, 2010 (the date the new PDP rates would be available to customers), will make these calls. PG&E estimates these calls to be similar to an account inquiry call. Based on an account inquiry call averaging 3 minutes, 55 seconds (2007 average), this cost estimate is $281,600 for 2010. (Exhibit 3, p. 3-5)

PG&E's cost estimate for 2010 is premised on customer inquiries associated with a May 1, 2010 date for transitioning residential, as well as small and medium C&I, SmartRate customers to the applicable PDP tariff. However, based on the residential PDP rate design adopted by this decision, the existing residential SmartRate tariff will be extended by a year for both existing and new enrollees, and then the residential PDP for all residential dynamic pricing participants will begin in 2011. Since this transition for residential customers has been delayed by one year, it is reasonable to assume the associated costs would be delayed by one year as well. As such, it would be outside of the cost recovery timeframe requested by PG&E for this proceeding. However, it is not clear what incremental inquiry costs might be incurred in 2010 with respect to small and medium C&I customers who are not subject to the one year delay. Since there are significantly more residential customers than small and medium C&I customers, we will assume that most of the anticipated costs relate to residential customers and should be excluded. Without better evidence, we will include

$50,000 for SmartRate conversion calls for small and medium C&I customers in 2010 and exclude the remainder from cost recovery in this proceeding.

21. Incremental Customer Notification Activities/Costs

For 2010, PG&E proposes to continue its current activities for managing and implementing event notification to its non-residential customers, primarily its large C&I and large agricultural customers and estimates the cost to $1.173 million. The related activities include overseeing and managing the customer service agreements for the increased number of customers on PDP, obtaining new notification contact information and updating outdated information, and utilizing InterAct for event notification and provision of interval usage data and DR analytic tools to large C&I customers. Notification to small and medium C&I, agricultural and residential customers will continue through the system currently used for SmartRate. Other customer notification related activities in 2010 include preparing and providing information to the California Independent System Operator in connection with PDP events.

No party has opposed these event notification activities or the associated cost estimate as originally presented by PG&E. They are reasonable and the $1.173 million cost estimate will be adopted and included in determining the revenue requirement for this proceeding.

22. Effect of D.09-08-027 on Incremental Customer Notification

In update testimony, dated August 31, 2009,[24] PG&E requests an additional $1.170 million in incremental notification costs. PG&E explains that in D.09-08-027, the Commission approved the voluntary CPP program costs, but

[24] August 31, 2009 was the first day of evidentiary hearing.

stated that the funding would end if CPP (PDP is a form of CPP) is approved in A.09-02-022. PG&E states that the amount of funding that would not continue for 2010 is $1.165 million. PG&E also indicates that it clearly stated in its original testimony that if full funding for voluntary CPP program was not approved in the 2009-2011 DR application, additional funding would be needed for implementation of PDP. Since the 2010 authorization in D.09-08-027 terminates with Commission approval of PDP, PG&E asserts that it now needs to have that funding reinstated as an incremental cost in this case.[25]

To the extent that there may be a disconnect between the Commission's underlying treatment of CPP costs in D.09-08-027 and the nature of incremental costs in this case, DRA and TURN indicate that it would be appropriate to address any error in a petition to modify D.09-08-027. According to DRA, what is not appropriate is for PG&E to inject issues from another case into this one without proper notice. Without affording all parties to this case the opportunity to review the record in D.09-08-027 and, if necessary, conduct discovery, submit testimony, and cross examine, DRA asserts that the Commission should not assume that PG&E's characterization of cost disallowances in D.09-08-027 is correct.

TURN states that even if PG&E is correct that nothing in D.09-08-027 hinders it from requesting additional money in this case, its request for another $1.2 million in notification costs, which doubles its original PDP notification cost request, is excessive. According to TURN there are 715 large customers on the

[25] Of the $1.165 million authorized in D.09-08-027, PG&E indicates that $0.101 million is no longer necessary, but added a 10%, or $0.106 million contingency to the remaining costs.

voluntary CPP tariff. CPP customers comprise 6.4% of all large customers and 12.5% of the large customers that PG&E expects to enroll onto the PDP rates. TURN questions the need to double its budget to notify and assist just these customers. If the Commission does not reject PG&E's request entirely, TURN suggests that at most the Commission should allow an additional 12.5% of the original incremental request, which amounts to $150,000.

In response, PG&E states that TURN's recommendation is not consistent with PG&E's estimates for the amount of work that is needed for large customer notification, as explained in its testimony.

22.1. Discussion

In its update testimony, PG&E lists three categories of costs related to this update request.

One category relates to $0.106 million for contingencies. As discussed in Section 31 of this decision, contingencies are excluded from cost recovery in this proceeding, and PG&E's request will be reduced by $0.106 million for that reason.

A second category relates to $0.407 million that was identified as part of the 2010 PDP costs, included in the detailed description of the estimated cost components, and specifically excluded from the total customer notification costs requested in this application. Parties thus had the opportunity to review the reasonableness of the activities related to these costs. As noted above, no party opposed any of the event notification activities or the associated cost estimate as presented by PG&E. It is reasonable to include these costs as part of this proceeding, since they appear reasonable and have been excluded from the cost recovery originally anticipated by PG&E.

The third category of costs relates to $0.657 million for work that PG&E asserts continues to be needed to support customer notification when the voluntary CPP program is replaced with PDP. As opposed to the $0.407 million request, these costs were not specifically identified as part of PG&E's 2010 PDP costs, were not included in the detailed description of the estimated cost components, and were not specifically excluded from the total customer notification costs requested in this application. Since these costs were not specifically included in the total PDP notification costs estimated by PG&E, it is difficult to understand why they are necessary now.[26] In its update, PG&E states that the $0.657 million amount is comprised of non-demand response labor (e.g., account services, supervision and oversight overhead and other administrative costs) that supports large customer CPP activities such as notification and information gathering, which will continue under PDP. However, due to the timing of the update and the associated request, parties did not have the opportunity to fully review these costs. Also, we do not find PG&E's update description of the costs to be compelling for the purpose of determining reasonableness or the extent that these specific costs were included or excluded in D.09-08-027.

Therefore, for additional customer notification costs, we will only include the $0.407 million that was specifically identified as part of the 2010 PDP costs and specifically excluded from the total customer notification costs requested in this application. However, PG&E is not precluded from recording any of the

[26] It is our understanding that, in general, PG&E estimated total PDP costs for various categories of expense, and those amounts were reduced by any costs that were being recovered in other proceedings.

actual remaining costs in the DPMA. To the extent that these actual costs drive total project costs over the forecast cost cap, PG&E can, by its cost recovery proposal, seek recovery of the excess costs through an after-the-fact reasonableness review.

23. Notification of Event Cancellation

In its testimony PG&E indicates that it will notify customers of a PDP event the day before it occurs, or as appropriate, notify customers if the PDP event is cancelled. PG&E intends to notify customers of a PDP event by 2:00 p.m. the day before the event, but does not indicate when it would notify customers of a PDP event cancellation.

In its prepared testimony, TURN recommended that PG&E be prohibited from canceling PDP events after customers have received day-ahead notification to protect participating customers from inconvenience, confusion, frustration and hardship and to increase the desirability and effectiveness of PDP tariffs.

In response, PG&E indicated that it needs the latitude to cancel a PDP event in the case of unforeseen occurrences such as notification system technical problems, public telephone network failures, or some human error in initiating the event in the first place. Under such circumstances, PG&E states that it may need to cancel the event so that customers will not incur higher PDP energy charges for events of which they had no notice and therefore could not make arrangements.

In its opening brief, TURN recommended that the Commission prohibit PG&E from canceling a PDP event after 4:00 p.m. on the day before the event. This would give PG&E two hours from the 2:00 p.m. notification deadline to detect the need for and communicate an event cancellation.

To support the reasonableness of its revised recommendation, TURN cites the cross examination of PG&E witness Chan who agreed that PG&E should not be able to cancel a PDP event at any time. Chan also testified that in his personal opinion, "it would not be a bad statement to put in our tariffs to let a customer know that if we do cancel an event, when we should notify them."[27] Moreover, Chan clarified that PG&E would only cancel a PDP event under very limited circumstances, and those identified by him would be obvious to PG&E in time for the event to be cancelled during the same afternoon as event notification.

TURN argues that its proposal reasonably balances PG&E's concerns about being able to react to a very narrow set of rare events that could support event cancellation, and the concerns of PDP customers in avoiding inconvenience, frustration, and/or hardship from event cancellation

In its reply brief, PG&E indicated its agreement with TURN that a cancellation notice should go out as soon as possible, and that it has no objection to a reasonable cut-off time. However, PG&E argues that TURN's choice of a 4:00 p.m. cut-off is arbitrary, and states that for reasons not on the record, since TURN did not raise its new proposal until after the record closed, 4:00 p.m. is too early.

PG&E proposes that the Commission order that this matter be resolved by including the issue in an advice letter PG&E will file at the end of this proceeding. PG&E states that it will explain and support its current policy regarding cancellation cut-off time in the advice letter, to which TURN can file a protest if PG&E's explanation is not satisfactory.

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[27] PG&E, Chan, 3 RT 400.

23.1. Discussion

We agree with both TURN and PG&E that it would be reasonable to specify a cut-off time for PDP event cancellation in PG&E's tariffs.

Based on TURN's cross-examination of PG&E witness Chan, a 4:00 p.m. cut-off appears to be in a reasonable zone. However, as PG&E indicates, the record on what the appropriate time should be is limited by the lateness of TURN's proposal, which was made in its opening brief, long after the evidentiary record was closed. As suggested by PG&E, we will allow the company to file an advice letter to explain and support an alternative cut-off time. Parties will have the opportunity to respond. If no protests are filed, PG&E's proposed cut-off time will be adopted and should be included in PG&E's tariffs. If protested, the cut-off time will be determined by Commission resolution.

24. Incremental Notification Equipment Development

24.1. PG&E's Position

PG&E indicates that it is very concerned about defaulting small and medium C&I customers to PDP in 2011 without a way to send notice of a PDP event to the customer's premises that utilizes the SmartMeter. Currently there is nothing in the market or slated to come into the market for 2011 that can receive signals from PG&E's Home Area Network (HAN) without first being "tweaked" in PG&E facilities. Therefore, according to PG&E, "plug and play" devices compatible with PG&E's system are not expected to reach the market until 2012, at the earliest.

PG&E requests $1 million to accelerate the development of notification devices for small and medium C&I customers so devices with "plug and play" capability can reach the market in time for summer 2011. The dollars requested are to support nonrecurring engineering expenses to encourage the development of the devices and business requirements. PG&E indicates that it is not entering an unregulated market as an investor or vendor, but is merely ensuring that the market as a whole has timely access to the technology and standards needed to serve PG&E's small and medium C&I customers in the timeframe required by the PDP default implementation schedule laid out by the Commission.

PG&E will make that information available to the market by contributing any intellectual property rights, data and test results from the work supported by the requested funding to the Utility Communication Architecture International Users Group (UCAiug.) UCAiug has a creative commons policy pursuant to which all rights, data and results contributed to UCAiug are posted on its website and made available to anyone who wants to use the information, without charge. PG&E states that UCAiug is a top standard and technology forum in the industry and incorporates mature intellectual property right policies that define fair and reasonable use of the technologies that are included in the standards it develops.

According to PG&E, plug and play capability will require the devices to meet an SE 2.0 standard that should be developed by next year. PG&E states that there are substantial differences between the current standard, 1.0, and the new standard, 2.0. Because the normal sequence is for the standard to come out, and then the products are developed and tested, PG&E asserts that if that sequence happens, the products will not be ready by 2011. To accelerate product development, PG&E indicates that its proposed activities would compress the process and do things together in parallel, enabling devices compliant with SE 2.0 to reach the market in 2011.

PG&E anticipates working with entities that are selected through a competitive request for proposal process. The goal would be to fund development of devices at three levels. Tier 1 would be a simple device delivering intuitive lighting signals indicating when electricity is at low, medium or high demand. Tier 2 would communicate the current price of electricity, impending and current event notifications from PG&E, and potentially current premise electricity consumption in dollars and kWh. Tier 3 would provide the features found in Tier 2, plus the ability to send and receive control signals, optimize premise data for granular clarity, create control settings that can be triggered by pricing signals, and communicate with online optimization applications. PG&E seeks to support the nonrecurring engineering costs for these three tiers of SE 2.0 compliant devices because the C&I customer sector (up to 200kW) is very diverse, with very diverse needs.

24.2. DRA's Position

DRA recommends no ratepayer funding for the development of any of these products. It is DRA's position that PG&E's proposal to have its ratepayers fund the development of notification devices is too poorly conceived to justify ratepayer funding. According to DRA, while an unregulated market for HAN devices currently exists without the benefit of subsidies from captive ratepayers, it seems PG&E did not perform any analysis of the market to ascertain if the HAN devices it presumes its customers need, have been or are already being developed in a viable competitive market. Also, for small commercial customers, low-functionality customer notification devices already exist and are being used by customers of other utilities. DRA questions the need for devices with the higher functionality, stating that the low-functionality devices would be the least costly to produce and satisfy the need for basic notification.

DRA also states it is aware of no other utility demanding products made specifically to its individual rate design, nor has PG&E provided any evidence that PG&E's rate design is so unique or unorthodox as to require such special treatment before customers can operate notification devices.

DRA adds PG&E did not contact the Public Interest Energy Research (PIER) program, or the Electric Power Research Institute (EPRI) about developing customer notification equipment. Nor did PG&E contact other California utilities about sharing the cost of this development effort.

With respect to DRA's claim that the notification device design need not be designed to PG&E's PDP rate, PG&E states DRA ignores PG&E's testimony that given the dual participation rules adopted by D.09-08-027, the designs available in the market will not work, as far as informing customers whether a PDP or another DR program is being called. PG&E asserts that dynamic pricing requirements adopted by the Commission may require design modification of the device.

With respect to DRA's claim that devices already exist in the market, PG&E states that current products will not have "plug and play" capability under PG&E's AMI/HAN architecture, and are thus not suitable for PG&E's customers in 2011.

PG&E acknowledges that it did not propose joint development with EPRI or PIER or other utilities for the on-premise device project, indicating that the reason is that PG&E is under unique pressure to make such devices available by 2011 given the schedule in D.08-07-045. It has time pressure that other organizations do not share. PG&E indicates that it is still working with them on broader issues like development of standards associated with the use of, and communication with, such devices.

24.3. Discussion

We will adopt PG&E's estimated costs for notification equipment development, in the amount of $0.714 million.[28] We do this because we feel it is important to have such equipment available for 2011 when the PDP default process for small and medium C&I customers begins. While there are other means for notification, as discussed above, use of the AMI/HAN capabilities for this purpose can significantly enhance the notification process. We feel there is additional value in having devices that have "plug and play" capability as well as the ability to provide notification information consistent with the parameters of PG&E's adopted PDP program. The estimated $0.714 million amount is relatively small, and expenditure of such costs would be worthwhile if PG&E's efforts to facilitate the development of such devices by 2011 are successful. We will require that PG&E include the progress of this effort in the quarterly reports discussed in Section 19.1.

25. Incremental CSOL Activities

PG&E has identified two areas of change for its CSOL web presentment that are needed as a result of PDP.

First, PG&E indicates that it will need to modify tools for large C&I, small and medium C&I, agricultural and residential customers that already exist or are being built to incorporate aspects of PDP that are not in current rates. These changes include updating rate comparisons tools to include the PDP rates, as well as updating the rate comparison and load analysis tools to support the new rate structures.

[28] This excludes the associated 40% contingency requested by PG&E. Contingencies are discussed further on in this decision.

These new structures include the choice of two different event windows for small and medium C&I and residential customers, and the ability to elect non-consecutive or consecutive day PDP participation for these same customers. For large C&I customers, the tools need to incorporate reservation capacity optionality that allows the customer to select a base load demand to which PDP will not apply on event days. In addition to these changes to customer facing tools, PG&E states it will similarly need to modify its internal rate analysis tool for supporting rate comparison and analysis requests from customers via the Customer Contact Center.

PG&E has identified the CSOL "My Account" architecture as the second CSOL area requiring change for PDP. For the online tools to promote customer transition to the new PDP and TOU rates, PG&E states that the customer will need a seamless and integrated online experience that facilitates analysis of multiple accounts. According to PG&E, its current "My Account" architecture was not created to support energy management and analysis at the level now anticipated for default PDP.

In general we agree with the need for the additional CSOL activities that PG&E proposes. First of all, it is clear that updating rate comparisons tools to include the PDP rates, as well as updating the rate comparison and load analysis tools to support the new rate structures are necessary. Second, we agree that there is a need, especially as it relates to agricultural accounts, for CSOL to be able to group and analyze multiple accounts. Both changes are necessary to facilitate customers' understanding of their usage and the effects of the PDP program. Due to the importance of CSOL in successfully implementing PDP, we will require verification of the results of PG&E's activities in this regard. PG&E should file a Tier 2 advice letter after it has completed its proposed incremental

CSOL activities. PG&E should provide sufficient information for Energy Division staff to verify that the new PDP functionalities that PG&E has implemented on its website appropriately suit ratepayer needs.

26. Additional CSOL and Notification Requirements

We believe it is in the public interest to take the opportunity of this proceeding to implement certain CSOL and customer notification requirements that will provide benefits for residential customers who have SmartMeters and choose to not leave the existing Schedule E-1 tiered rate structure. SmartMeter functionality provides opportunities for such customers, to recognize their usage at different times of the month and with that information make informed decisions regarding their usage. Requirements in this regard are included in the discussion below which would provide features that PG&E may not be considering at this time

With respect to the upgraded CSOL system authorized by this decision, for the My Account web presentment, all customers should have access to a screen showing cumulative consumption and their bill to date in the current billing cycle. Additionally, customers on the E-1 tariff or any other tariffs that involve a tiered rate structure should be able to quickly and easily identify what tier they are in at any time during the month. These customers should also be able to review historic data that includes the tier they were at the end of the month. The web presentment should also include an easily accessible and brief description of the rate for each tier and the percentage over baseline that causes a customer to shift to the next tier.

Additionally, all customers should have access to a screen that predicts what their consumption and bill might be at the end of the current billing cycle by utilizing appropriate assumptions regarding their historic usage and applicable rates. This screen should recommend short-term options available to reduce the projected total in the current billing cycle. PG&E should also include tips for conservation, demand response and distributed generation and links that describe other rates or programs that customers may benefit from on a long term basis.

Also, while PG&E is planning to provide alerts to customers on time-varying rates, we will also require that all customers should be able to request alerts based on the conditions of their choice such as a target cumulative consumption threshold, a target cumulative cost threshold, and imminent cross-over into a higher tier rate. Customers should have the option of receiving these alerts via email, text message, or voicemail.

27. Incremental Billing, Revenue and Credit Activities/Costs

PG&E estimates $1,774,000 for incremental billing, revenue and credit costs to cover the impact of PDP and TOU deployment on activities associated with the billing process, particularly with billing adjustments, which will have added complexity due to the structure and features of PDP. Other specific cost items include: Quality Assurance Testing prior to deployment of the new rates; credit management challenges arising from the greater bill volatility that some customers may experience; and development and delivery of training for several customer bill-related employee groups, including incremental trainer and attendee labor, and materials. No party has opposed the billing, revenue and credit activities or the associated cost estimate. They are reasonable and the cost estimate will be adopted and included in determining the revenue requirement for this proceeding.

28. IT Costs

PG&E utilized its formalized PG&E Delivery Methods (PDM) process to assess and develop the IT functionality needed to meet its business stakeholders' requirements. As described in PG&E's testimony, the business requirements were developed by the stakeholders and communicated to the IT team responsible for this project. IT then began its own assessment of the IT changes that would be required, including an iterative process with the stakeholders to assess the impacts of the business requirements on the IT systems. To assist this process, the responsible business stakeholders facilitated the tracking and refinement of these new requirements and tracked the changes made. Through this process the business requirements were more specifically defined. Once this process was completed, the business users formally approved the final set of high-level business requirements, so that IT could then further distill the IT requirements. These requirements and costs were then broken down into specific workstreams and deliverables for the project.

Through this PDM planning process, PG&E identified three areas of work that needed to be completed as part of Dynamic Pricing Phase 1: billing system changes; CSOL changes; and the CC&B version upgrade to Version 2.2. PG&E indicates that it has devised a detailed plan to build the necessary rates needed for PDP, build the customer facing CSOL tools and capabilities for PDP and ultimately for RTP, and re-platform CC&B in time for RTP.

28.1. Billing System Changes

PG&E bills its customers through two primary systems. The Alternate Billing Service is used to bill approximately 20% of PG&E’s revenue; that encompasses about 20,000 monthly bills to mainly large C&I Customers. CC&B bills PG&E’s other customers, and thus, represents the majority of PG&E’s billing activity measured by monthly bills issued as well as by revenue. In order to implement new tariffs in these billing systems, PG&E states that it must (1) first update its billing systems to update the newly implemented rate schedules, including functionalities such as calculating bill protection amounts for different classes of customers and reservation capacity for others; (2) add new PDP-related adjustment types to its billing systems that allow for things such as the reversal of charges and cancel/re-bill of the associated PDP rates; and (3) must update the interfaces to and from dependent and related systems to recognize the PDP rates. PG&E indicates that it will also need to calculate unique adjustments to the bills sent to individual customers based upon these new rates, which must meet Revenue Reporting and Reporting Solution System reporting requirements associated with CPP and bill protection amounts.

PG&E estimates these billing system changes, excluding contingency, will cost $27,454,313 ($25,939,290 in capital for 2009 - 2010 and $1,515,023 in expense for 2008 - 2009) to implement. No party opposes PG&E's proposed billing system modification activities or the associated cost estimates. They are reasonable and the cost estimates will be adopted and included in determining the revenue requirement for this proceeding. Contingencies are discussed further on in this decision.

28.2. CSOL Update Changes

28.2.1. PG&E's Position

PG&E proposes to upgrade its CSOL systems for PDP implementation. According to the company, the Commission has made it clear that it wants tools and features that customers, faced with new dynamic tariffs, can use to effectively make informed decisions regarding their electric usage and applicable tariffs. PG&E describes two co-dependent improvements that it is making to its

CSOL systems -- the improvement of the tools and functionalities, and the CSOL re-platform. PG&E estimated these costs to be $23.3 million assuming it simultaneously re-platformed its CSOL system. Included in this amount are re-platforming costs of $10.7 million that reflect a foundation re-platform estimated at $7.4 million and a Middleware re-platform to BEA Systems (BEA) estimated at $3.3 million.

With respect to the re-platform, PG&E states that it made this decision after performing a cost comparison analysis and determining that it was less expensive to both build the tools and re-platform than to build the tools without re-platforming. Also, according to PG&E, the tools will better satisfy customer needs and expectations if built on a new platform.

PG&E presented the costs to provide new PDP tools and functionality on its website and other functionality that the Commission wanted, such as multilingual support and My Account upgrades. No party has disputed the need for this scope of work or PG&E's estimated costs for it.

As part of the CSOL work, PG&E determined that it would be cost neutral, if not less expensive, to re-platform CSOL at the same time it upgraded the tools. Further, PG&E determined that this plan would lower the implementation risk and increase the quality of the tools and other functionalities provided to customers. By conducting the CSOL re-platform now, PG&E indicates that it can provide the performance needed to service the higher transaction load that will be a result of PDP's more complex rates, rate features, and tools. This higher level of performance would allow PG&E to build tools that are more useful to its customers, thus furthering the Commission's goal of having appropriate tools to assist customers with making informed choices. According to PG&E, the old

CSOL platform would not be adequate to deliver this same level of customer experience, and no intervener group provided evidence to the contrary.

28.2.2. DRA's Position

According to DRA, review of PG&E's material shows that the approximate $10.7 million of PG&E's forecast related to re-platforming is not incremental in that it is not necessary to meet the requirements of D.08-07-045, has no support beyond the roughest of estimates, and/ or reflects costs for replacement of previously funded IT efforts which show premature inadequacy.

DRA's position on the CSOL rewrite is that it will need to be done at some point in the future, but the evidence does not show that the CSOL rewrite must be done to support D.08-07-045. According to DRA, PG&E has presented forecasts of web traffic that show up to only a 25% increase in average volume, and only 90% increase in peak volume, adding that these forecasts are based on PG&E's overly optimistic forecasts of meter deployment which, in turn, dictates the number of eligible customers. In light of this and PG&E's own testimony, DRA asserts that PG&E can build the needed tools for default customers while deferring the $10.7 million cost for re-platforming.

DRA indicates that the key driver for re-platforming seems to be PG&E's desire to capitalize on the opportunity to upgrade its web site to improve customer capabilities, prepare for future needs and improve quality of service, and that DRA recognizes the improvements that can accrue from the proposed change to WebLogic and BEA middleware. However, it is DRA's position that PG&E has not made a compelling case nor defined the specific functionality commensurate with the costs that justify authorizing recovery of those costs in this proceeding.

Furthermore, DRA argues that PG&E's desire to construct a new web site IT architecture reflects poor IT planning that has resulted in performance decay. DRA indicates that the stress imposition from the PDP decision will add complexity and volume, but the scale of change-outs proposed by PG&E results from presently inadequate systems with deficiencies that are highlighted by the lack of current functionalities necessary to carry out PDP. According to DRA, PG&E's assumptions relating to cost neutrality, call times, need for scalability and the increased computing volumes are speculative and without support. DRA, therefore, recommends that the Commission order PG&E to continue to develop necessary functionality, but defer the web re-platforming until it has been vetted through the GRC process.

DRA states that PG&E's assertion that it would be cost neutral, if not less expensive, to re-platform CSOL at the same time it upgraded the tools, is not supported by credible evidence. According to DRA, PG&E has exaggerated the user interface updating costs for not re-platforming. Specifically, the claim that the older platform requires about $7.8 million more to add the same incremental functionality, which translates to almost 6500 man-days of effort (at $1200/day) or 32 man years of effort, is unreasonable, and PG&E uses unsubstantiated costs that bias the analysis.

28.2.3. Discussion

We will adopt the elements and costs[29] of PG&E's CSOL upgrade proposal including that for re-platforming. Our understanding of the re-platforming issue is that while PG&E and DRA agree that that it should be done at some point and improvements can accrue from the change, PG&E would like to do it now in conjunction with updating CSOL functionality, while DRA prefers that it be deferred and considered in PG&E's next GRC. We further understand DRA's position that PG&E's analysis of cost-neutrality may be flawed and overstated. However, DRA has not provided an independent analysis of how much more, or less, it would cost to implement the same functionality on the current system rather than on the re-platformed system. In addition, agricultural customers have requested the ability to navigate the PG&E website with a single log in to access multiple meter data. This can only be accommodated on the re-platformed system. This is also apparently true for CSOL functionality that will be needed for RTP, which is scheduled to be offered as soon as May 1, 2011.

We note that DRA raised concerns regarding (1) website traffic volumes that do not justify high forecast costs, (2) difficulty in reconciling the gap between the functional capabilities mandated under the AMI previous rulemaking and those required to support PDP, (3) inadequate vetting of the current or future capabilities inherent in the previously selected AMI related systems and applications, and (4) CSOL functionality costs that far exceed simple incremental costs. We are however convinced by PG&E's responses which indicate that (1) the current site performs reasonably for today's needs, but PDP adds complexity that the current site cannot support, (2) with AMI a customer had access to historical information to see static usage with SmartRate, whereas with PDP customers will need the ability to analyze what-if scenarios for the future, (3) the current meter data management system is already running at

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[29] Adopted costs exclude contingencies. Contingencies are discussed further on in this decision.

capacity and cannot handle more functionality, and (4) enhanced CSOL functionality will cause greater web traffic than what was contemplated in the AMI proceeding, not only due to the increased number of visitors but also because CSOL has to perform more tasks per visit.

Based on the above considerations, we determine that it is reasonable for PG&E to perform the CSOL re-platforming in conjunction with updating the CSOL functionality for PDP purposes. We believe this will minimize the ultimate CSOL costs to ratepayers while providing improved CSOL capabilities for a longer period of time.

28.3. CC&B Version 2.2 Upgrade

28.3.1. PG&E's Position

PG&E seeks ratepayer funding to transition to a new version of the Customer Information System, known as Customer Care and Billing, (CC&B). Specifically, PG&E seeks funding to upgrade from its current Version 1.5 to Version 2.2 at a cost of $31.3 million, before contingency, in this case. PG&E states that it presented the $31.3 million in costs for this upgrade in this Rate Design Window (RDW) filing because it recognized that CC&B would have to be upgraded ahead of the RTP implementation deadline. PG&E adds that a later version, Version 2.3, will be installed on top of Version 2.2 in order to support RTP, but is not yet available. PG&E states that it intends to seek additional ratepayer funding to upgrade again to Version 2.3 for an additional $28 million, before contingency, in its 2011 GRC.

PG&E identified four risks that it argues could be avoided by upgrading to CC&B Version 2.2 now and upgrading to Version 2.3 later. According to PG&E, the desire to mitigate these risks drove PG&E's decision to upgrade first to Version 2.2 and then to Version 2.3. The identified risks are:

1. Version 2.3 does not exist at this time.
2. PG&E needs to mitigate the risk of moving to Version 2.3 functionality and RTP by operating and stabilizing the re-platformed CC&B prior to making the extensive changes for RTP.
3. There is a risk that PG&E's IT department will be oversubscribing itself, doing one large Version 1.5 to 2.3 upgrade plus the RTP upgrade, all at the same time.
4. Due to contractual terms, PG&E's Version 1.5 will not have vendor support after June 2011.

28.3.2. DRA's Position

DRA originally proposed that PG&E focus efforts on CC&B Version 2.3 instead of Version 2.2 and implement only the necessary CC&B enhancements in the interim. DRA recommended that the Commission remove the $31.2 million requested by PG&E in this proceeding and instead consider it along with the Version 2.3 upgrade in PG&E's 2011 GRC.

However, DRA states that after submitting its testimony, it learned from the vendor, Oracle, that Version 2.3 would have been ready in September 2009 but for modifications PG&E asked Oracle to make, and Version 2.3 will be available in December. DRA asserts this gives PG&E approximately 14 months to perform the upgrade and meet the schedule set forth in D.08-07-045. Having discussed the Version 2.3 timeline directly with Oracle, DRA now recommends that the Commission authorize ratepayer funding of the entire $31.3 million for the CC&B upgrade, but direct PG&E to apply it to Version 2.3 and remove any Version 2.3 funding requests from its 2011 GRC.

If the Commission is inclined to allow funding for Version 2.2, then DRA argues the amount of that funding should be significantly reduced. DRA states that the evidence shows that PG&E's cost per customer for installation far exceeds the $2 per customer that Oracle suggests, and that even if Oracle's estimate is tripled to $6 per customer, there would still be a $28 million savings from PG&E's estimate. According to DRA, PG&E's estimates for related storage costs are either excessively high or for large storage volumes that PG&E has not shown it needs, noting that storage costs can range from 10 cents a gigabyte at Best Buy, to $250 a gigabyte for very expensive, very high quality production storage units. It is DRA's position that PG&E has not justified the estimate of $1 million for storage, and it should be rejected.

DRA states that although it has modified its recommendations relating to the CC&B Version upgrade, its reasons for disagreeing with PG&E's proposal remain the same. First, PG&E's claimed need for immediate replacement of Version 1.5 reflects questionable IT planning to date. In its 2005 AMI proceeding, PG&E requested approximately $66 million to upgrade from Version 1.3 to 1.5. In February 2009, PG&E filed this application seeking over $31 million for an upgrade to Version 2.2 and will be filing a GRC application, probably in December 2009, seeking another upgrade, this time for more than $28 million, to Version 2.3. According to DRA, PG&E's ratepayer should not have to shoulder these costs which call into question PG&E's overall strategic IT planning and whether PG&E is making any effort to contain its IT costs.

A second and related DRA concern goes to the timing of PG&E's request and whether PG&E is using D.08-07-045 as a vehicle to justify IT infrastructure investment it either should have made before, or can defer until Version 2.3 is available. DRA states that by using D.08-07-045 as a vehicle, PG&E has selected possibly the most expensive way to address upgrading its CC&B system.

With respect to the PG&E claim that, due to contractual terms, PG&E's Version 1.5 will not have vendor support after June 2011, DRA states that considering that PG&E is working with Oracle to develop Version 2.3, it seems extremely unlikely that Oracle would refuse to work with PG&E to maintain its CC&B system while the Version 2.3 upgrade is performed. In any case, DRA asserts that Version 1.5 licenses can be renegotiated or PG&E can obtain IT from third parties in the 12 to 14 months it takes to perform the upgrade to a new version of the software.

28.3.3. Discussion

By DRA's proposal, the cost of $31.2 million to transition directly to Version 2.3 would be $28.5 million less than the amount estimated by PG&E to transition first to Version 2.2 and then to Version 2.3. It does not appear that PG&E contests the suggestion that DRA's strategy would save a significant amount of money. Rather, PG&E's opposition appears to be based on its perception of the risk of undertaking that strategy. This leaves the Commission in a difficult position.

Certainly, if it were known that particular risks identified by PG&E would materialize into actual problems (e.g., the release date for Version 2.3 turns out to be much later than anticipated, or oversubscription of resources results in unacceptable delays), it would be clear that DRA's strategy of directly transitioning to Version 2.3 should not be adopted. On the other hand, if it were known that such problems would not to materialize, the Commission would, by its responsibility to ensure just and reasonable rates, be required to adopt the least cost strategy proposed by DRA. Obviously, whether or not the identified risks will materialize into actual problems is not known, and there is nothing on the record which would indicate the probability of the risks materializing. A solution or strategy that balances cost risk and the implementation risk is needed to ensure that the appropriate transition from CC&B Version 1.5 to Version 2.3 is made and the recognized cost of implementing that transition is reasonable.

First of all, PG&E knows or should know its own billing systems and billing requirements better than other parties. Generally, it is reasonable to give the company the responsibility to determine how different Commission imposed mandates will affect their systems and requirements and provide the flexibility for the company to address such mandates in the most reasonable and cost effective manner possible. In providing the company flexibility to address the mandate, it is the Commission's responsibility to ensure that it is done most reasonably and cost effectively or, at least, that ratepayers only fund what is most reasonable and cost effective.

The Commission adopts estimates of, and provides cost recovery for, a number of different types of costs. For instance, there are costs estimated in GRCs that are estimated for future years and never trued up if recorded costs are higher or lower than the estimate; there are recorded costs in ERRA proceedings that are subjected to compliance rules and trued up or disallowed if necessary; there are recorded costs that are subject to a cost cap and reasonableness of review of costs in excess of that cost cap; and there are costs that are subjected entirely to reasonableness review before they are allowed final cost recovery. How the Commission treats costs is affected by its perception of the risks in determining whether specific projects or activities are reasonable and whether those projects or activities have been funded in the most cost effective manner. In situations where the Commission sees high degrees of risk, the inclination is to subject all recorded costs to an after the fact reasonableness review.

For the transition to CC&B Version 2.3 from Version 1.5, given the record in this proceeding, we see the risk for determining either the best alternative or determining what the ultimate cost should be to be extremely high. As indicated above, while there is a very significant difference in the costs of the DRA and PG&E proposals, PG&E has identified unquantifiable risks that must certainly be considered in determining the best alternative. Additionally DRA has identified a cost benchmark of $2 per customer that results in costs significantly lower than what PG&E estimates for the transition. Also, PG&E has requested cost recovery for transitioning from Version 1.5 to Version 2.2 in this proceeding, and will request cost recovery for transitioning from Version 2.2 to Version 2.3 in its test year 2011 GRC. In light of the potential to transition directly to Version 2.3, reviewing the transition first to Version 2.2 and then to Version 2.3 in separate proceedings complicates analyses and determinations of whether the ultimate transition Version 2.3 is being done most appropriately and cost-effectively.

For these reasons, we will subject all recorded costs that are incurred in the transition of the CC&B from Version 1.5 to Version 2.3 to an after the fact reasonableness review. PG&E will have the flexibility to make the CC&B transition in the manner that it sees is best, but will be fully responsible for its decisions in that regard. Therefore, PG&E will be ordered to file a reasonableness application within 60 days of completing the transition to CC&B Version 2.3. The reasonableness review will apply to all recorded costs incurred in transitioning from CC&B Version 1.5 to Version 2.3, whether that is done directly or by first transitioning to Version 2.2. As part of its showing, PG&E should identify all available options to transition to Version 2.3 and fully justify the option it chose. Any costs related to this transition should be removed from PG&E's test year 2011 GRC proceeding.

29. Incremental Load Impact Study Costs

PG&E forecasts $1.321 million (excluding contingencies) in incremental measurement and evaluation (M&E) spending to estimate annual load impacts for default PDP rates, to update enrollment forecasting models (also called discrete choice models) so they are consistent with the final decision in this case, and to complete the studies described in Ordering Paragraphs 11 and 12 of D.08-07-045.

The funding for M&E for PG&E's existing demand response programs are covered primarily in D.09-08-027 on PG&E's 2009-2011 demand response application, with the exception of PG&E's existing small and medium C&I and residential DR programs, SmartAC and SmartRate, for which load impact evaluation costs are covered by amounts approved in D.08-02-009 and D.06-07-027, respectively. PG&E indicates that it did not include additional costs for default PDP or new dynamic pricing rates in its 2009-2011 demand response application because Administrative Law Judge (ALJ) Hecht had directed that the utilities "[S]should not make proposals in their [2009-2011 DR] Applications that duplicate proposals that are under consideration in [A.06-03-005] or other proceedings."[30] Therefore, PG&E has included the incremental costs for updating its discrete choice models and its evaluation of load impact for default PDP in this proceeding.

[30] PG&E cites Administrative Law Judge Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications, R.07-01-041, February 27, 2008, p. 15.

No party opposes PG&E's incremental M&E activities or the associated cost estimate. They are reasonable and the cost estimate will be adopted and included in determining the revenue requirement for this proceeding.

30. Project Management Activities/Costs

PG&E estimates that project management office (PMO) capital costs that support the IT work will be $2.389 million (excluding contingencies). That amount, in total, is reflected in the IT capital cost estimates for 2009 and 2010. PG&E also estimates incremental PMO and external advisor expense costs of $2.397 million (excluding contingencies) that relates to planning, progress monitoring, quality control, risk, issue and change management, analyzing the incremental nature of the requested costs and the development of cost contingencies. That amount, in total, is reflected in the project management expense estimates for 2008, 2009 and 2010.

No party opposes PG&E's project management activities or the associated cost estimate. They are reasonable and the cost estimate will be adopted and included in determining the revenue requirement for this proceeding.

31. Contingency/Risk Based Allowance

31.1. PG&E's Position

PG&E states that implementation of a dynamic pricing rate design for default PDP is a multifaceted, large-scale project that will impact numerous interrelated workstreams and products, adding that uncertainties and risks in complex projects such as this are normal. According to PG&E, a contingency is an essential element of a capital project estimate that provides an allowance for unforeseeable elements in a defined work scope, and is integral in creating a total estimate value that reflects the best representation of what the defined project scope will ultimately cost.

PG&E requested PwC's assessment of the factors creating uncertainty in PG&E's cost estimates and the resulting cost contingencies and risk-based allowance are included in PG&E's PDP cost forecast.

In order to do this, PwC states that it analyzed the risk profile for each of PG&E's program elements with incremental costs. Nearly 50 program elements were investigated, with separate contingencies ranging from 0% to 40% assigned to them by PwC.

In total PG&E requests approximately $32.4 million for contingencies. The largest amount of $28.0 million relates to IT costs that are mostly capital expenditures. The next largest amount of $3.2 million relates to customer outreach expenses. The remaining $1.2 million in requested contingencies largely relate to other expense elements of PG&E's request.

31.2. FEA's Position

As a result of concerns about the magnitude of the IT contingency factor (33%) and the exposure of customers to paying higher costs than they should, FEA recommends that PG&E be required to undergo a reasonableness review, regardless of the level of project costs. As an alternative, FEA suggests that a maximum contingency allowance of 19% on the IT aspect of the project be permitted in order for PG&E to avoid a reasonableness review. FEA indicates that combining a 19% contingency allowance (the second highest of any requests for elements of the project) with the other proposed contingency allowances produces an overall contingency for the project of 16%, which is still larger than any contingency that the Commission previously has approved for PG&E PDP-related projects.

FEA recognizes that a contingency element is part of a reasonable cost estimation procedure. However, the presence of a large contingency on a project suggests to FEA that the project design is far from complete, and/or that there is a high potential for problems to be encountered in the implementation phase. Regardless, FEA asserts the high contingency factor, combined with PG&E's "free pass"[31] cost recovery proposal, puts customers at significant risk. FEA believes this is inappropriate, and that PG&E should assume a greater responsibility for careful and diligent project execution.

31.3. TURN's Position

TURN states that common sense suggests that the IT cost risk in this case should be lower than the risk in, for example, the AMI case. According to TURN, in this case, PG&E is modifying billing and IT systems to accommodate new default dynamic tariffs, but very similar dynamic tariffs have been available, at least to the large C&I customers, on a voluntary basis for several years, while in the AMI case, PG&E had to modify its billing and IT systems to accommodate the collection and processing of hourly meter data for over five million residential customers and about one-half million small commercial and industrial customers, thus requiring the processing of 8,760 data points for millions of customers, as opposed to 12 data points for these customers. TURN understands that there is a significant amount of IT work required to improve the on-line analyses tools that customers can access to evaluate their rate options, but on a basic common-sense level TURN does not understand the need to apply such a large IT contingency factor in this proceeding.

[31] By PG&E's cost recovery proposal, the Commission would find that all incremental costs authorized by this decision are reasonable so long as the actual costs are equal to or less than forecasted costs (including contingencies). Only actual costs in excess of the forecasted amounts would be subject to a traditional after the fact reasonableness review before being included in rates.

31.4. DRA's Position

PG&E included a 40% contingency for development costs for on-premise notification devices for small and medium C&I customers. If the Commission elects not to support DRA's proposal to eliminate these development costs, DRA recommends that the contingency be reduced to 20%, thereby reducing the contingency amount by $0.163 million. DRA understands that PG&E would be in the early stages of developing new notification equipment, however DRA asserts that the bulk of the features and components contained in these monitors are far from cutting edge. DRA indicates that signaling by light color is hardly new, and monitors have been equipped with liquid crystal display (LCD) printouts and programmable features for quite some time.

DRA also states that the contingencies associated with its adjustments to customer outreach and IT cost recovery in this proceeding should likewise be excluded from rates authorized by this decision.

31.5. Discussion

We will not include contingencies in the cost recovery authorized by this decision. PG&E's contingency request totals over $32 million, or approximately 25.6% of the forecasted costs. This represents a substantial amount of unspecified work that has not, and by PG&E's cost recovery proposal will have not, specifically been reviewed for reasonableness before being included in rates. We realize contingencies have been authorized and included in rates in prior Commission proceedings. For instance, in PG&E's AMI decision, the adopted costs reflected an overall contingency of 7.9%,[32] and in the SmartMeter Upgrade,

[32] D.06-07-027 in A.05-06-028.

adopted costs reflected an overall 12.9% contingency.[33] However, 25.6% is a significant increase over these amounts.[34] We are concerned that our regulatory obligation to ensure just and reasonable rates is being eroded by including such large portions of project costs in rates, without having determined the reasonableness of the costs. At this point, we do not know what amount of contingencies will actually be expended, and for any amounts expended, what the related activities or materials are, whether the related activities or materials are necessary and optimal, and whether the associated costs are reasonable.

By PG&E's cost recovery proposal, through December 2010, recorded expenses and the revenue requirement associated with recorded capital assets would be recorded in the DPMA and transferred on a monthly basis to the Distribution Revenue Adjustment Mechanism (DRAM), to be recovered in rates through the AET advice letter filing. Beginning January 2011, cost recovery would be through test year 2011 and subsequent GRC authorizations. Also, if overall actual costs exceed the adopted cost estimate, PG&E can seek recovery of the difference through a traditional after the fact reasonableness review. As discussed further in this decision, these elements of PG&E's cost recovery proposal are adopted.

With our understanding of this cost recovery, we see no compelling reason for authorizing any contingencies in this proceeding, especially in light of our

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[33] D.09-03-026 in A.07-12-009.

[34] We also note that contingencies in the AMI and SmartMeter cases serve an additional purpose in that those proceedings were comparing incremental costs to incremental benefits to evaluate whether the programs should go forward. In these cases it is important to reflect the contingencies up front so they can be included in the cost/benefit analysis. That is not the case in this proceeding.

concern regarding the magnitude of the contingencies and our regulatory responsibilities. The exclusion of the contingency allowance does not preclude PG&E from recovering reasonable actual costs that are in excess of the forecasted amount. This opportunity to do so is balanced by the fact that although costs are forecasted in this proceeding, only the actual costs (up to the cost cap based on the forecasted costs) and not the forecasted costs are reflected in rates.

By this decision, PG&E can recover costs above the forecasted amounts whether the excess is related to contingency risks or any other reason, as long as PG&E can demonstrate the need for, and the reasonableness of, the additional expenditures in a reasonableness review. This is consistent with our responsibility to ensure just and reasonable rates, and is thus preferable to building in a contingency amount and allowing PG&E to spend that amount without having to justify the need for, or the reasonableness of, the expenditures.

Additionally, the effect of not including contingencies in this proceeding is likely to be small because of the following considerations.

After 2010, cost recovery for incremental PDP expenditures will be through GRCs. With respect to capital coasts, in GRCs, the recorded plant balances are generally incorporated to the extent possible. Therefore, the actual capital costs (including costs in excess of the forecasted amounts) for the projects considered in this proceeding will likely be reflected in rates from 2011 forward.[35] Therefore, the vast majority of the capital related costs (depreciation,

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[35] In GRCs, capital project costs are forecasted and the authorized capital related costs are based on that amount until the next GRC, when the actual project costs would be reflected in the plant in service balances on which the annual capital related costs such as rate of return, income taxes and depreciation would be calculated.

rate of return and taxes) could be recovered based on the actual capital costs of the project over its depreciable life,[36] even without a reasonableness review filing by PG&E to recover costs in excess of forecasted. We note there is nothing to preclude other parties from challenging the reasonableness of recorded expenditures in GRCs. However, any rate adjustments to the capital related costs would be on a forward going basis only.

For expenses, we assume that PG&E has forecasted its costs for 2009 and 2010 based on the best information available at the time the forecasts are made. This is consistent with the way expenses are forecasted in GRCs where it is anticipated that actual costs could either be higher or lower than forecasted. Contingencies are not added to GRC forecasted expenses to fund perceived risks and uncertainties. We also note that PDP related expenses will likely be addressed in GRCs for the years 2011 and beyond. As such, explicit contingencies such as requested here will likely not be reflected for those years. In light of this, we see no overarching reason why contingencies related to annual PDP expenses are necessary, or even appropriate, in this proceeding.

Also, much of PG&E's reasoning for needing expense contingencies is not persuasive. For example, PG&E cites the possibility of delay, such as to CSOL implementation or SmartMeter deployment, and the need for additional costs to resolve the effects of such delay.[37] We note that recovery of expenses in this

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[36] That is, even if a $28 million contingency in capital costs were needed, the rate effect of excluding contingencies in this proceeding would only be the capital related costs associated with that amount, and it would only be for 2009 and 2010. From 2011 on the entire actual capital expenditure, including the additional $28 million, would be reflected in recorded plant balances and included in rates going forward.

[37] *See* Exhibit 3, pp. 2-28 and 2-29.

proceeding relate mainly to costs estimated to occur in 2010, while PDP implementation will last well into 2012. If there are any delays as suggested by PG&E, we do not see 2010 expenses necessarily going up. In fact they may go down due to reduced activity. Certainly under those circumstances, expenses for 2011 or 2012 may increase over what is now forecasted. However, the appropriate level for those costs is not the subject of this proceeding. That will be determined in PG&E's 2011 GRC based on what is known at the time when those costs are considered. Effects of delays may specifically be known at that time.

PG&E also cites uncertainties related to the breadth and complexity of customer outreach as well as to future materials and media costs, without explaining why these uncertainties would likely only increase costs. It appears such uncertainties could either increase or decrease costs, depending on what was assumed and what actually happens, and do not justify a contingency that only reflects increased costs.

For these reasons, the elimination of contingencies should have little effect on PG&E's ability to recover its costs for 2009 and 2010 with the rates authorized by this decision.

32. Revenue Requirements

Instead of the $160.2 million in incremental expenditures ($110.5 million for capital and $49.7 million for expense) estimated by PG&E, the adopted incremental expenditures indicated in the table below should be used in determining the revenue requirements for this decision.

Table 1
Adopted Incremental Expenditures

	2009	2010	2008	2009	2010	Total

	Capital	Capital	Expense	Expense	Expense	
			(Dollars in thousands)			
Customer Outreach						
Foundational			$ 54	$ 1,800	$ 4,050	$ 5,904
Large Customer			-	1,400	4,520	5,920
Small & Medium Customer			-	-	16,600	16,600
Customer Inquiry			-	-	2,074	2,074
Customer Notification			-	-	2,237	2,237
Billing, Revenue and Credit			-	-	1 774	1,774
Information Technology						
CC&B Billing Changes	$17,442	$ 8,497	347	1,169	-	27,455
CSOL Updates	21,023	2,246	15	3	-	23,287
CC&B Version 2 Upgrade	-	-	-	-	-	-
Project Management	1,491	898	-	-	-	2,389
Load Impact Studies	-	-	-	571	750	1 321
Project Management	-	-	410	1,421	575	2,397
Contingencies	-	-	-	-	-	-
Total Expenditures	$39,956	$11,641	$ 826	$ 6,355	$33,294	$92,072

PG&E uses its results of operations model and associated analysis to calculate the anticipated revenue requirements for 2008, 2009 and 2010 needed to fund PG&E's implementation of dynamic pricing rates as ordered in D.08-07-045. The revenue requirements are based on the incremental costs presented in this application that are not included in any other PG&E cost recovery filing, including all capital-related costs and operating expenses. PG&E states that, in determining the revenue requirements, it has used the methods and factors consistent with those used in its SmartMeter and GRC filings. Project cost recovery occurring beyond 2010 will roll into the 2011 GRC or other applicable filings.

No party has challenged PG&E's general methodology, results of operations model, or model assumptions for calculation of the revenue requirement. PG&E indicates that by its proposal, it expects to record a total of $33.3 million in PDP-related revenue requirements in the DPMA through 2010, reflecting an implementation cost of $160.2 million, which includes the impact of

D.09-08-027 on PG&E's incremental costs in this proceeding. However, this decision excludes certain costs requested by PG&E, specifically certain incremental customer education and outreach costs, costs to transition from CC&B Version 1.5 to Version 2.2, and estimated contingency costs. Therefore, the revenue requirements will need to be recalculated to conform to the costs adopted by this decision. The use of PG&E's results of operations model is reasonable for this purpose, and it should be used to calculate the revenue requirements related to the costs adopted by our decision today. PG&E should include details of the calculations when requesting PDP related rate recovery through its AET advice filing process.

33. Revenue Allocation

33.1. PG&E's Position

PG&E proposes to recover the incremental implementation costs through distribution rates. PG&E indicates that its proposal assigns and allocates the costs based on the function involved. Since the implementation costs are for things like the billing system, CSOL and customer services, which are distribution functions, PG&E assigns them to distribution and uses the distribution allocation factors, to allocate them to customer classes for recovery in distribution rates paid by bundled, direct access (DA) and community choice aggregation customers.

PG&E notes that similar dynamic pricing implementation costs have been unbundled as distribution in other cases. For example, all implementation costs for DR programs have been assigned to distribution for recovery. The same is true for all dynamic pricing implementation cost recovery related to the AMI and SmartMeter Update decisions. PG&E requests the Commission to approve the allocation treatment for incremental implementation costs in this proceeding that it has approved for the same activities in earlier proceedings. PG&E states that the activities to be funded in this proceeding differ from activities funded previously only in terms of their expanded size, larger scope and greater complexity, and there is no reason to treat allocation of these incremental costs for the same type of activities as in the AMI case differently than they are treated under existing programs.

33.2. DRA's Position

DRA's primary recommendation is to recover dynamic pricing implementation costs in rates paid by all users of PG&E's distribution grid, and allocate these costs by generation equal percentage of marginal costs (EPMC) in recognition of the primary role of generation in dynamic pricing cost causation. DRA states that this could be accomplished by establishing a separate rate component for dynamic pricing implementation costs, or, (preferably), by including dynamic pricing implementation costs as a subcategory of Public Purpose Program costs, analogous to Energy Efficiency program costs.

DRA's alternate recommendation differs from its primary recommendation only in proposing to allocate dynamic pricing implementation costs to all customers based on "equal percent of revenue", as was proposed by PG&E in its 2007 GRC for certain Public Purpose Programs such as Energy Efficiency and Renewables. According to DRA, such an allocation would reflect roles of both distribution and generation in dynamic pricing cost causation.

33.3. DACC's Position

DACC opposes PG&E's proposal to recover dynamic pricing implementation costs in distribution rates. It is DACC's position that, since the proposed dynamic pricing programs do not benefit DA customers or the energy service providers who serve them, the costs PG&E incurs to implement dynamic pricing should be recovered solely from PG&E's bundled service customers.

DACC states that a central tenet of DACC's participation in this proceeding is premised on the well established ratemaking principle that costs should be allocated on the basis of causation. It is DACC's position that, in the utility procurement context, the cost causation principle dictates that only those customers who have created the need for new programs and commitments should be required to pay for those commitments. Consistent with that principle, DACC's recommendations with respect to PG&E's dynamic pricing program proposal are as follows:

- The Commission should reject PG&E's proposal to have DA customers charged for costs incurred to provide a dynamic pricing program developed exclusively for bundled customers that DA customers are not qualified to receive.

- The Commission should adopt DACC's proposal to have the costs associated with regard to PG&E's dynamic pricing program collected solely from the bundled customers that are eligible to participate in the program.

33.4. CLECA's Position

CLECA believe that these implementation costs are either customer related or distribution type costs and that they should be allocated on the basis of distribution revenues. CLECA states these are not generation costs. They have nothing at all to do with generation. Rather, they are associated with PG&E's ability to render a bill for a new rate option and to explain that rate option to its customers. CLECA explains that these sorts of costs are normally considered to be distribution and/or customer-related costs and they are allocated to customer classes on the basis of distribution and customer allocators. CLECA also notes that the allocation of utility costs is normally an issue addressed in Phase 2 of a utility's general rate case and suggests deferring the question to PG&E's pending GRC.

It is CLECA's position that while these PDP implementation costs are customer and distribution related costs, they should not be allocated to DA customers, because DA customers are not eligible for this rate option – they do not take bundled service from the utility.

33.5. TURN's Position

TURN recommends that the costs at issue should be recovered in distribution rates but allocated between customer classes based on generation equal percent of marginal cost.

TURN notes that the nature and purpose of the costs in this case are very similar to the various implementation costs for demand response and advanced meter installation. The goal of dynamic pricing is to reduce peak load, which is exactly the goal of various demand response programs and of the advanced metering infrastructure. The nature of the costs involves primarily IT improvements and modifications, which was exactly a component of authorized AMI costs. The costs of demand response programs and the AMI infrastructure are all recovered in distribution rates pursuant to various Commission decisions.

It is TURN's position that the costs at issue in this proceeding should be allocated by a generation EPMC because their primary purpose is to facilitate reductions in generation capacity and energy costs. TURN adds that, while the recovery of implementation costs should be in the distribution rate component, it is important to note that the actual CPP charges and credits will apply to generation rates.

33.6. Discussion

To address this issue, we feel it is important to consider the following facts:

- Implementation cost recovery authorized in this proceeding is for 2008 through 2010 PDP related costs only.
- For the major electric utilities, revenue allocation, along with marginal cost and rate design, is a principal element of GRC Phase 2 filings. While generally contentious, this issue was settled in PG&E's last GRC Phase 2 proceeding, A.06-03-005. The uncontested Settlement Agreement on Marginal Cost and Revenue Allocation Settlement[38] was adopted by the Commission in D.07-09-004. That settlement also addressed rate changes between GRCs.
- Implementation cost recovery for 2011 and beyond will be determined in PG&E's 2011 and subsequent GRCs.
- Marginal cost, revenue allocation and rate design for 2011 and beyond will be determined in Phase 2 of PG&E's 2011 and subsequent GRCs.
- Similar revenue allocation issues were addressed in D.09-03-026, concerning PG&E's SmartMeter Upgrade proceeding (A.07-12-009).

PG&E estimates the revenue requirement in this proceeding will total $32.1 million for the years 2008-2010.[39] With the adjustments made in this decision, the revenue requirement authorized in this proceeding will be less than that amount. To put these amounts in context, D.07-09-004 reflected a settlement revenue allocation of $11,023.6 million, with $10,753.1 allocated to bundled customers and $270.5 million allocated to DA customers. The amounts

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[38] The settlement is included as Appendix B to D.07-09-004. There were 21 signatories to that settlement, including PG&E, DRA, DACC, CLECA, and TURN.

[39] Exhibit 5, Errata 03/13/09 (PG&E-3), p.10-2.

authorized and allocated by today's decision are therefore relatively small, 0.27% when compared to those total 2007 revenues. The use of different allocation percentages will have as small, or even smaller effect, on what is allocated to the different customer classes for 2010, which is the only revenue allocation being considered in this proceeding.

With respect to the costs themselves, CSOL, customer billing, and customer outreach costs are, by their nature, distribution and not generation costs. Such costs are normally allocated based on distribution-level EPMC.

Also, these costs for 2011 and beyond will be authorized in subsequent GRCs and will be allocated in that context. Cost responsibilities for customer classes will be evaluated on a more complete basis than what is being considered in this proceeding. CSOL and CC&B upgrade costs while necessary in the context of implementing PDP rates will be viewed in a more complete context of how the upgraded systems and new functions relate to the different classes of customers over time. Also, whether and to what extent certain customers should be exempted from certain costs will be evaluated when examining all costs to be allocated.

In PG&E's SmartMeter Upgrade proceeding, A.07-12-009, DRA recommended that distribution infrastructure and related operations and maintenance (O&M) costs be allocated by a generation allocator, because Upgrade costs were primarily justified on demand response and energy conservation benefits. Also, in that proceeding, the California City-County Street Light Association (CAL-SLA) argued that since SmartMeters are not necessary for streetlights and will not be installed on streetlights, street light customers should not pay for SmartMeters.

In D.09-03-026, concerning the SmartMeter Upgrade, the Commission stated:

> At this point, we will continue the use of the allocation methodology that applies to PG&E's original AMI authorization. In general, it is reasonable to allocate distribution infrastructure with distribution level EPMC related allocators, and PG&E's methodology is consistent with how SDG&E's AMI related costs are allocated. We will not preclude DRA, or any other party, from raising the issue in PG&E's next Phase 2 GRC proceeding. In fact, that would be a more appropriate forum for proposing such an allocation methodology that is based on principles which differ significantly from existing principles. (D.09-03-026, pp. 157-158.)
>
> There were a number of settlements in Phase 2 of PG&E's 2007 GRC, which addressed marginal costs, revenue allocation and rate design. In the particular settlement on marginal costs and revenue allocation, (footnote omitted) Section VII.3 addresses rate changes between GRCs. The Upgrade will result in a rate change between GRCs, so it is appropriate that the Section VII.3 principles in the marginal cost and revenue allocation settlement should be followed in determining the allocation of Upgrade costs to the various customer classes. PG&E should allocate the Upgrade revenue increases accordingly.
>
> CAL-SLA indicates that its primary recommendation does not comport with the Phase 2 GRC settlement but adds that SmartMeters were never identified in that proceeding as a cost to be allocated to street lights.
>
> We do not know what was assumed by the settling parties, including CAL-SLA, when the marginal cost and revenue allocation settlement agreement was reached. Settlements generally represent a compromise among the Settling Parties' respective litigation positions, in order to agree on a mutually acceptable outcome. What may not seem to be fair, when viewing a portion of the settlement in isolation, may be fair, when viewing the settlement in its entirety. We can only judge issues such as this by the plain language of the settlement. Authorization of the Upgrade necessitates a rate change between GRCs. The settlement provides principles for rate changes

> between GRCs. There is nothing in that section of the settlement that limits the application of those principles, if the increase is driven by SmartMeter costs or any other specific costs. There is nothing that states that certain customers can avoid an increase, if the reason for that increase does not directly benefit those customers. In order to honor the settlement process, we have no alternative but to impose the principles for rate changes between GRCs, as identified in PG&E's TY 2007 Phase 2 marginal cost and revenue allocation settlement, in allocating the Upgrade related revenues to customer classes. In doing so, street light customers will receive an allocation of Upgrade costs, although that allocation will be substantially lower than what was originally proposed by PG&E.
>
> By our determination today, we are not precluding CAL-SLA or any other party from raising the issue of how SmartMeter costs should be allocated in PG&E's next Phase 2 GRC proceeding. We expect such an issue would necessitate a fairly comprehensive analysis of what types of costs, beyond just SmartMeter costs, directly benefit or do not directly benefit the various customer classes and which of those costs should be assigned to particular customer classes. (D.09-03-026, pp. 160-161.)

As indicated previously, the revenue requirement increase for 2010 due to the implementation of the PDP program is relatively small. The effects of using different allocation factors or exempting certain classes from certain cost responsibilities are also small. At this point, we see no reason to deviate from the principles adopted in D.09-03-026. We will continue to allocate distribution related capital costs and related O&M costs by distribution level EPMC related allocators. The rate change for 2010 will apply to all distribution customers, including DA customers. We believe this is consistent with (1) how distribution costs are generally allocated, and (2) the marginal cost and revenue allocation settlement agreement adopted in D.07-09-004, with respect to rate changes between GRCs.

Parties can recommend different revenue allocation methodologies in PG&E's 2011 GRC Phase 2 proceeding, when the allocation of all costs are considered. It is a more appropriate proceeding for considering new or different revenue methodologies and for evaluating the need to exempt certain customer classes from specific cost responsibilities. Whether parties settle or the Commission decides, a more proper balance of parties' interests and a fairer outcome can be achieved when taking all of this into consideration with all other issues and factors in that GRC Phase 2 proceeding.

34. Cost Recovery Mechanism

PG&E proposes the following ratemaking treatment:

- Revenue requirements reflecting the actual incremental costs incurred to implement dynamic pricing will be recorded into the DPMA on a monthly basis through December 2010.
- Upon Commission approval of this Application each month through December 2010, PG&E will transfer the recorded balanced from the DPMA to the DRAM for subsequent recovery in rates through PG&E's AET advice filing process.
- The Commission will review forecast costs and associated revenue requirements for 2008-2010 in this Application, and as a result of that review, these forecast costs and associated revenue requirements will be deemed reasonable, and will not be subject to after-the-fact reasonableness review. If actual costs and associated revenue requirements recorded in the DPMA exceed the forecast, then PG&E proposes to file for recovery of the difference through a traditional after-the-fact reasonableness review application.
- Rate components covering the dynamic pricing project will be revised annually in the AET advice letters, or as otherwise authorized by the Commission. Cost recovery will occur through the DRAM and will be consolidated with the AET. Rates set to recover the DPMA costs will be determined in the same manner

as rates set to recover other distribution costs, using adopted methodologies for revenue allocation and rate design.

As discussed above in Section 33.6, this decision adopts PG&E's cost recovery proposal relating to the characterization of these incremental PDP costs as part of the distribution function and the methodology for allocating the revenue requirements to customer classes. It does not appear that there is any opposition to the other aspects of PG&E's proposed cost recovery mechanism, as described above.

In general, the mechanism is reasonable and will be adopted with the following clarification. This decision does not address the reasonableness of costs to transition from CC&B Version 1.5 to Version 2.3 and estimated contingency costs. Cost recovery of these items will be through an after-the-fact reasonableness review as described earlier in this decision. Also, to the extent that actual expenditures exceed the amounts authorized by this decision, PG&E can request cost recovery in an after-the-fact reasonableness review. Such review can be either combined with or separate from the CC&B reasonableness review.

Where costs approved in other proceedings will be used for PDP implementation, PG&E proposes that the actual costs approve for recovery in the earlier proceeding will be tracked and recorded as authorized in the earlier decision, but only up to the amount authorized for recovery in the earlier case. Amounts spent in excess of that amount for those activities will be recorded in the mechanisms approved for this case, the DPMA, for recovery as an incremental cost associated with the 2009 RDW. PG&E asserts that expenditures are accounted for as the Commission has approved them, and since PG&E is only recording actually incurred costs for recovery, PG&E will not over-collect its actual costs. PG&E's proposal to coordinate cost recovery where there is overlap between costs approved in earlier proceedings and the incremental costs in this proceeding is unopposed, reasonable and will be adopted.

PG&E also proposes that if the final decision in this case orders changes in PG&E's proposal for PDP that increase costs, PG&E will evaluate the cost, scope and timing implications of the changes approved by the Commission, and seek an increase to the level of cost recovery requested in this proceeding, as necessary. Rather than adopting PG&E's proposal, we direct that any such costs should be treated as cost overruns and requested in an after-the-fact reasonableness review, if necessary. At this point, there is no record on what the magnitude of such costs will be and whether the activities or projects that PG&E might undertake are optimal and reasonable. Rather than adopting costs that have not been fully litigated, we prefer to use the reasonableness review to ensure that only appropriate costs incurred in this manner are included in rates.

Finally, PG&E notes that if the Commission should change its view about the implementation of PDP or the scope of this project as proposed by PG&E in this application, then there is a possibility that parts of the dynamic pricing project may become stranded. To provide reasonable certainty that it will recover its costs, PG&E requests that the Commission adopt a policy that PG&E should be able to recover expenditures as long as the expenditures were made pursuant to, and consistent with, the specific dynamic pricing spending authority and guidance provided by the Commission. This proposal is apparently unopposed. We will grant PG&E's request with the provision that any such capital expenditures should be identified in PG&E's immediately following GRC. There should be an opportunity to determine whether those expenditures were reasonably incurred and PG&E acted reasonably when it became aware that any such parts of the project might be stranded.

35. Report on Bill Impacts for Agricultural Customers and TOU

AECA contends that, based on the extremely large number of agricultural customers currently on non-TOU rates that would be required to shift to TOU rates under PG&E's proposal, a more robust analysis is required to ensure that this large population of customers will not be inadvertently penalized by this migration. AECA proposed that PG&E provide analysis after 1,000 and 10,000 such customers were converted to SmartMeters to ensure that the analysis provided by PG&E was accurate enough to continue rate migration.

PG&E objected to that proposal and proposed an alternative recommendation in rebuttal testimony. In fall 2010, PG&E expects to have 12 months of available interval load information for at least 10,000 agricultural customers, with data from the AMI system. Using the most complete information available, PG&E proposes to develop an analysis of the projected bill impacts under TOU for this 10,000 customer sample of agricultural customers by November 2010.

In response, AECA stated its belief that the analysis proposed by PG&E will be robust enough to ensure adequate information for the Commission and parties to evaluate the migration. AECA requests that if the November 2010 analysis by PG&E illustrates a significant negative rate impact on existing non-TOU ratepayers, this issue remain pending and incorporated into PG&E's next GRC.

We will adopt PG&E's proposal to develop an analysis of the projected bill impacts under TOU for this 10,000 customer sample of agricultural customers by November 2010. The information should be provided to the Energy Division and AECA and the availability of the information should be made to the service list. If any party feels that the information necessitates a rate design modification, such recommendations should be presented in the next available rate design proceeding, whether it is a GRC Phase 2 or rate design window proceeding.

36. Request for Workshops on RTP

In its testimony, BOMA requests that workshops begin soon to consider the development of RTP tariffs. PG&E states that it has already started consulting with interested parties on RTP, including at a workshop on August 26, 2009 that was attended by parties to this proceeding. PG&E also notes that its RTP proposal must be filed on or before March 1, 2010, as part of its 2011 GRC Phase 2 showings, and that the development of its RTP proposal will therefore already be well underway by the time of the decision in this proceeding.

Appropriate discussions with other parties with respect to RTP tariffs have already begun, and they should continue. Nothing further is required at this time.

37. Cost-effectiveness Evaluation

EPUC recommends that once credible data is available to assess the impact of the PDP program on generation capacity procurement the program be evaluated. EPUC asserts that the program should be continued only if PG&E can demonstrate that the program results in measureable cost effective reductions in generation procurement cost that conclusively justify the continuation of the program as the default rates for PG&E's customers. EUF/CMTA also expressed a concern with respect to the difficulty in determining the cost effectiveness of PDP.

In response, PG&E points out that it is already under orders to assess the load impacts and financial benefits of its active and anticipated DR programs including D.08-04-050, D.09-03-026, D.08-07-045, D.08-02-009 and D.06-07-027.

PG&E notes that in D.09-03-026, Ordering Paragraph 10, the Commission directed PG&E to report annually the financial benefits of DR programs enabled by its AMI system, and, in D.08-04-050, PG&E was directed to assess the load impacts of each DR resource on an ex post and ex ante basis, annually. PG&E asserts, given the existing analyses and reporting requirements, there is no need for additional reporting requirements.

We agree there is no demonstrated need for additional cost effectiveness reporting requirements at this time. There should be sufficient information available for parties to analyze and make recommendations, with respect to the PDP program, in future appropriate proceedings.

38. Future Rate Design Proceedings

DRA recommends that PG&E be directed to file a 2012 RDW application in February 2012, to address the following:

- An assessment of the performance of the 2010 and 2011 summer season PDP programs, in terms of customer participation and achieved demand response, with proposed adjustments, if any, to improve program performance;
- Proposed adjustments to PDP charges and credits, to reflect marginal costs adopted in the 2011 GRC Phase 2.
- Proposed new TOU and TOU/PDP rates for medium C&I customers, intermediate in time-differentiation between the proposed A1-TOU and A6-TOU rate designs. The new rates should be available to medium C&I customers, and as an option for small commercial customers, on or before May 1, 2013. As of that date, A1-TOU and A1-PDP rates should no longer be available to medium C&I customers who have been on either A1 rate schedule for a full year.

In general, PG&E asserts that the 2014 GRC Phase 2 proceeding is the proper forum in which the Commission should consider changes to PDP and

TOU, principally because more useful data would be available for analysis at that time.

Based on the record, it is not clear whether the 2012 or 2013 RDW or the 2014 GRC Phase 2 proceeding is the more appropriate proceeding to consider PDP or TOU changes. A 2012 RDW window would be file in late November 2011. We note that implementation of PDP default provisions for certain customers will extend through 2012, possibly into 2013 depending on the actual deployment schedule for SmartMeters. It may well be important to make necessary changes that affect default provisions sooner rather than later. A 2012 RDW could accommodate that. Also, because this is a significant new program that can affect most customers in one way or another, a conservative approach for maintaining control of the program may be the most appropriate path to take. Again, this can be accommodated by a 2012 RDW which could identify program deficiencies or problems and address them in a timely matter. For these reasons, we will require PG&E to file a 2012 RDW to consider not only the DRA proposals indicated above, but whatever proposals parties think would be appropriate at the time of the RDW filing when considering the state and success, or lack of success, of the PDP program and its implementation. It should be recognized that even though such proposals may be brought up and considered at that time, the Commission may still decide that it would be better to defer some proposals to a later proceeding such as the 2014 GRC Phase 2. However, such decisions are better made at that time with consideration of a fully developed record.

DRA also recommends that consideration of a voluntary pilot RTP rate, available on a limited basis to nonresidential customers, should be delayed possibly to a 2013 RDW application. We believe it is premature to make a decision regarding such a delay. While DRA indicates that parties may be far apart on how best to implement such rates, PG&E will be proposing optional RTP rates for all customer classes as part of its 2011 GRC Phase 2, as ordered in D.08-07-045 (Ordering Paragraph 7). Whether or not it is necessary or desirable to delay the implementation of optional RTP rates should be determined based on a fully developed record in that proceeding.

39. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________, and reply comments were filed on __________________ by __________________.

40. Assignment of Proceeding

Rachelle B. Chong is the assigned Commissioner and David K. Fukutome is the assigned ALJ in this proceeding.

Findings of Fact

1. In D.08-07-045, the Commission ordered PG&E to propose various default CPP rates. PG&E has complied with that order by filing its PDP proposal that is the subject of this proceeding.
2. There is no opposition to PG&E's revised PDP rate levels.
3. In response to DRA's recommendation that residential PDP be offered in combination with the standard non-TOU Schedule E-1 residential tariff, PG&E's rebuttal testimony presented a residential PDP rate with TOU prices that are less steeply time-differentiated than those offered under the residential Schedule E-6 tariff.
4. With the changes contained in PG&E's rebuttal testimony, no party opposes PG&E's TOU rate proposals in this case.

5. The need for, and structure of, more greatly time-differentiated TOU rates for medium C&I customers can be raised as issues in future cases.

6. All parties that have addressed the number of PDP events support an annual minimum of 9 and a maximum of 15 PDP calls.

7. There is general agreement that adoption of 9 minimum and 15 maximum PDP calls mitigates the problem associated with over- and under- collections.

8. There is no opposition to PG&E's proposal for enforcing the PDP call bounds by raising or lowering the temperature thresholds.

9. No party opposes PG&E's proposal to provide first year bill stabilization or protection.

10. No party disputes that under- and over-collections that are associated with bill stabilization should be allocated to all customers by class.

11. There are potential gaming problems with respect to excluding non-participants from the allocation of under- and over-collections due to the variation in the number of PDP events.

12. There are additional costs and difficulties in implementing BOMA's recommendation to exclude non-participants from the allocation of under- and over-collections due to the variation in the number of PDP events.

13. Volatility effects are largely mitigated by lowering the PDP rate, from that originally proposed by PG&E to what is now proposed by PG&E, and limiting the number of PDP events to between 9 and 15 per year.

14. Whether or not under- and over-collections due to the variation in the number of PDP events are substantial, imposing that risk on only those customers who actually sign up for PDP is likely to create one more disincentive for participation.

15. FEA's recommendation that, within each class, the reconciliation of under- and over-collections should occur by applying a credit or a surcharge as appropriate to on-peak and mid-peak demand charges and energy charges is contrary to the settlement approved by D.07-09-004.

16. With the exception of the EUF/CMTA proposal that would allow customers to change their capacity reservation before 12 months has passed on a one-time basis, there is agreement among the affected parties that PG&E's capacity reservation proposal should be adopted.

17. Reconciliation of under- and over-collections should occur by spreading adjustments on an even percentage basis among all generation demand and energy charges.

18. Under DRA's primary proposal for implementing PDP for small and medium C&I customers, customers would face two changes within one year: mandatory TOU beginning in 2011 and default PDP beginning in 2012, which would require two waves of messaging, the first one about TOU and a second one about PDP a year later. Customers would face evaluating their business process first for TOU and then a year later, a second time for PDP.

19. There is no evidence to support DRA's suggestion that without to-be-developed notification equipment, the PDP rate would become sufficiently onerous to lead to excessive opt-out rates.

20. PG&E's alternating day and six-hour window options to mitigate bill volatility provide customers with an incentive to choose or stay on PDP rates, by offering an option to reduce their exposure to potential increases related to those rates.

21. DRA's "soft cap" proposal and the current BPP are mechanisms that spread the effect of monthly rate increases over a longer timeframe.

22. A-10 customers are the only ones that have a PDP default where 100% of peak time usage would be set at the $1.20/kWh charge.

23. The first year of bill stabilization/protection will protect customers who are on PDP rates by allowing them to experience the actual effects of such rates in situations where between 9 and 15 PDP events are called, without facing financial harm over that period, if the PDP is disadvantageous when compared to the otherwise applicable TOU rate.

24. Through customer outreach and education, it is extremely important that, as their first year on PDP progresses, customers (especially defaulted customers) become well aware of the PDP program, the details as they affect their rates, their options to opt out or remain in the program and the requirements for switching rates in the future.

25. With respect to DRA's up-front lump sum credit proposal for notification information, by taking the energy usage credit up front, customers will only see the high PDP charges in the monthly bill amounts due, without the offsetting effect of the credits for the month. Artificially high monthly bills may be confusing to customers who are trying to determine whether to remain on PDP or to opt out of the program as they experience the effects of the program.

26. The potential benefit of additional customer contact information by implementing DRA's up-front lump sum credit proposal is outweighed by the downside of potential inaccurate perceptions of the effects of PDP.

27. With respect to DRA's multi-year amortization proposal, PG&E has provided evidence that it is unlikely that the 1% threshold will be triggered.

28. The Commission already has the latitude to impose multiple year amortizations when it feels it is necessary to do so, when looking at all rate

changes that are happening concurrently, as well as considering what has happened in the near past and what may happen in the near future.

29. Under PG&E's proposal that certain customers should be subject to default PDP 12 months after their interval meter is installed, it appears that most affected customers would have to make a choice with respect to opting out of the PDP program while having only 10 or 11 full months of interval data.

30. Without 12 months of interval data, the effect of PDP rates and the need to change usage patterns may not be fully understood.

31. There is no convincing evidence to support the proposition that agricultural customers require an additional four months to make their decisions regarding PDP/TOU defaults and options.

32. There is no convincing evidence to support the proposition that farmers cannot make decisions regarding PDP/TOU defaults and options during planting, growing and harvesting seasons.

33. Enhanced CSOL functionality will address AECA's concerns regarding the availability of information in one downloadable aggregated format for multiple meters.

34. Enhanced CSOL functionality will address CFBF's "shadow bill" proposal by allowing customers to calculate bills under varying scenarios.

35. The enhanced CSOL functionality that will allow customers to calculate bills under varying scenarios is very important and necessary for all customers, including agricultural customers, to evaluate the effects of PDP and make appropriate choices.

36. AECA has withdrawn its recommendations regarding an alternative dynamic pricing scheme and the development of programs that enable growers to virtually aggregate multiple meters.

37. In response to DRA and TURN concerns, PG&E presented an Alternative 1 residential PDP proposal that includes TOU rates that are less steeply time-differentiated than those offered under the Schedule E-6 tariff and extends the existing residential SmartRate tariff for one additional year for both existing and new enrollees, and then implements the revised residential PDP rate design for all residential dynamic pricing participants beginning in 2011.

38. DRA, TURN and PG&E agree that the Alternative 1 residential PDP proposal should be adopted.

39. The imposition of PDP is significant and there is no good reason to require customers to remain on PDP for a full year because they either failed to make a decision or made the wrong decision.

40. One year on PDP rates is sufficient time for customers to make an informed decision regarding their desire to opt out of the PDP program.

41. While PG&E agrees in principle with EnerNOC's proposal that PG&E's PDP tariff should be modified to allow PG&E customers to opt out of PDP at any time if they opt out to enroll in another DR program, the required functionality in PG&E's PDP implementation processes will not be available until 2011 at the earliest.

42. The Commission addressed the general issue of dual participation in DR programs in D.09-08-027. That decision allows customers to participate concurrently in one program that provides an energy payment and one that provides a capacity payment and states that it is reasonable to consider Critical Peak Pricing to be an energy payment program.

43. PG&E's PDP proposal needs to be revised to address the double payment problem associated with dual participation in PDP and demand response programs.

44. With respect to Auto-DR for smaller customers, there is insufficient evidence to implement any such program at this time.

45. PG&E retained an independent external consultant, PwC, to perform an analysis of PG&E's cost estimates to assess the incremental nature of the requested costs in this proceeding.

46. By imputing DRA's adjustment whereby $32.4 million in PDP costs for customer education and outreach for non-residential customers would be taken from the approximate $42.9 million remaining in the AMI authorization for customer acquisition, the DRA proposal would leave only $10.4 million (24%) for AMI-related residential customer acquisition activities.

47. It has not been alleged or determined that customer acquisition costs previously authorized by PG&E's AMI decision for residential related activities should be significantly reduced.

48. PG&E has presented convincing evidence that the actual spending of customer acquisition costs authorized by its AMI decision has been delayed due to delays in the deployment of SmartMeters.

49. Assuming that it is true that customer acquisition costs authorized by PG&E's AMI decision were not eliminated but delayed, there is likely to be more money, not less, available in 2010 for small and medium C&I customer acquisition activities than the $2.49 million originally forecasted by PG&E.

50. PG&E's revised SmartMeter deployment forecast indicates that 1,662,000 meters will be deployed in 2010, as opposed to 1,037,000 meters indicated in the original meter deployment forecast, resulting in an approximate 60% increase in the number of meters that would be deployed in 2010.

51. PG&E's proposal for foundational customer outreach and education activities and the estimate of the associated incremental costs, which amounts to $5.90 million (excluding contingencies), are unopposed.

52. PG&E's proposal for large customer outreach and education activities and the estimate of the associated incremental costs, which amounts to $5.92 million (excluding contingencies), are unopposed.

53. PG&E's proposal for small and medium customer outreach and education activities and the estimate of the associated total costs, which amounts to $22.20 million (excluding contingencies), are unopposed.

54. Incremental costs for small and medium customer outreach and education, which is calculated by deducting the $3.98 million adjustment determined in Section 11.4 from the total costs of $22.20 million, amounts to $18.22 million (excluding contingencies).

55. Outreach and education costs for the residential optional PDP rate program will be covered by customer acquisition cost recovery authorized in the AMI decision.

56. All costs associated with customer outreach and education/acquisition for the voluntary SmartRate program, either in its current form or after the date the underlying rate changes to PDP, were authorized in the AMI Decision through the period of meter deployment and therefore are not requested by PG&E in this proceeding.

57. It is not clear what aspects of customer outreach and education, if anything, would be improved by segregating small commercial customer's costs as recommended by DRA.

58. Since the beginning of 2009, PG&E has been providing DRA with the DPMA reports in the previously agreed-to format, which does not segregate small commercial costs.

59. With respect to DRA's proposed outreach advisory panel, PG&E's concern that pre-approval of outreach and educational materials might result in delay is valid.

60. Certain aspects of PG&E's planned efforts, such as customer workshops and partnering with industry and community groups, would duplicate what an outreach advisory panel might accomplish.

61. The Business & Community Outreach group can be a resource in raising PDP awareness and also ensuring the Commission policy is being implemented effectively.

62. Quarterly meetings will provide opportunities for parties to provide ongoing input into PG&E's outreach plans.

63. DRA recommends that the Commission order PG&E to retain a reputable, independent impact assessment firm to measure and evaluate PG&E's Outreach efforts.

64. It is important that PG&E is able, in a transparent way, to demonstrate that it will evaluate its outreach and education efforts and, if necessary, that it will modify its efforts appropriately. PG&E has not provided sufficient details on how this would be done.

65. With respect to DRA's recommendation that the Commission order PG&E to retain a reputable, independent impact assessment firm to measure and evaluate PG&E's outreach efforts, hiring an independent evaluator will likely necessitate a formal evaluation, in which the evaluator would look at a snapshot of PG&E's efforts and then provide feedback based on that moment in time,

rather than facilitating a process of providing ongoing feedback on, and proposed modifications of, PG&E's outreach and education activities.

66. None of the parties oppose the customer inquiry activities proposed by PG&E.

67. SmartRate conversion inquiries are new types of calls that were not anticipated when the Commission adopted the $2.7 million savings amount for customer contact associated with the implementation of SmartMeter.

68. PG&E's customer inquiry cost estimate for 2010 is premised on customer inquiries associated with a May 1, 2010 date for transitioning residential, as well as small and medium C&I, SmartRate customers to the applicable PDP tariff.

69. Based on the residential PDP rate design adopted by this decision, the existing residential SmartRate tariff will be extended by a year for both existing and new enrollees, and then the residential PDP for all residential dynamic pricing participants will begin in 2011.

70. It is not clear what incremental inquiry costs related to conversions might be incurred in 2010 with respect to small and medium C&I customers who are not subject to the one year delay.

71. No party has opposed event notification activities or the associated cost estimate of $1.173 million, as originally presented by PG&E.

72. With respect to PG&E's requests for an additional $1.170 million in incremental notification costs due to the effect of D.09-08-027, $0.106 million relates to contingencies; $0.407 million relates to 2010 PDP costs that were included in the detailed description of the estimated cost components, and specifically excluded from the total customer notification costs requested in this application; and $0.607 million relates to work that PG&E asserts continues to be needed to support customer notification when the voluntary CPP program is

replaced with PDP the costs of which were not included in the detailed description of the estimated cost components, and were not specifically excluded from the total customer notification costs requested in this application.

73. It would be reasonable to specify a cut-off time for PDP event cancellation in PG&E's tariffs, but the record on what the appropriate time should be is limited by the lateness of TURN's proposal, which was made in its opening brief, long after the evidentiary record was closed.

74. Based on TURN's cross-examination of PG&E witness Chan, a 4:00 p.m. cut-off appears to be in a reasonable zone. However, as PG&E indicates, the record on what the appropriate time should be is limited by the lateness of TURN's proposal, which was made in its opening brief, long after the evidentiary record was closed.

75. While there are other means for notifying customers of PDP events, use of the AMI/HAN capabilities for this purpose can significantly enhance the notification process. There is additional value in having devices that have "plug and play" capability as well as the ability to provide notification information consistent with the parameters of PG&E's adopted PDP program.

76. The estimated $0.714 million to facilitate development of notification devices is relatively small, and expenditure of such costs would be worthwhile if PG&E's efforts result in the development of such devices by 2011.

77. With respect to CSOL, updating rate comparisons tools to include the PDP rates, as well as updating the rate comparison and load analysis tools to support the new rate structures, is necessary.

78. There is a need, especially as it relates to agricultural accounts, for CSOL to be able to group and analyze multiple accounts.

79. It is in the public interest to take the opportunity of this proceeding to implement certain CSOL and customer notification requirements that will provide benefits for residential customers who have SmartMeters and choose to not leave the existing Schedule E-1 tiered rate structure.

80. PG&E utilized its formalized PDM process to assess and develop the IT functionality needed to meet its business stakeholders' requirements. Through this PDM planning process, PG&E identified three areas of work that needed to be completed as part of Dynamic Pricing Phase 1: billing system changes; CSOL changes; and the CC&B version upgrade to Version 2.2.

81. No party opposes PG&E's proposed billing system modification activities or the associated cost estimates of $25,939,290 (excluding contingencies) in capital for 2009-2010 and $1,515,023 (excluding contingencies) in expense for 2008-2009.

82. Included in PG&E's proposed IT costs related to CSOL are re-platforming costs of $10.7 million that reflect a foundation re-platform estimated at $7.4 million and a Middleware re-platform to BEA estimated at $3.3 million.

83. Re-platforming should be done at some point and improvements can accrue from the change.

84. Certain CSOL functionality, such as the ability to navigate the PG&E website with a single login to access multiple meter data, can only be accommodated on the re-platformed system.

85. PG&E analysis indicates that it would be cost neutral, if not less expensive, to re-platform CSOL at the same time it upgraded the tools.

86. While DRA argues that PG&E's analysis of cost-neutrality may be flawed and overstated, DRA has not provided an independent analysis of how much

more, or less, it would cost to implement the same functionality on the current system rather than on the re-platformed system.

87. For its CC&B system, PG&E seeks funding to upgrade from its current Version 1.5 to Version 2.2 at a cost of $31.3 million (excluding contingencies) in this case. PG&E also intends to seek additional ratepayer funding to upgrade again to Version 2.3 for an additional $28 million (excluding contingencies) in its 2011 GRC.

88. CC&B Version 2.3, will be installed on top of Version 2.2 in order to support RTP.

89. The release of CC&B Version 2.3 is imminent.

90. In light of the potential to transition directly to Version 2.3, reviewing the transition first to Version 2.2 and then to Version 2.3 in separate proceedings complicates analyses and determinations of whether the ultimate transition to Version 2.3 is being done most appropriately and cost-effectively.

91. No party opposes PG&E's proposed incremental M&E activities or the associated cost estimate of $1.321 million (excluding contingencies) in expense for 2009-2010.

92. No party opposes PG&E's proposed project management activities or the associated cost estimates of $2.389 million (excluding contingencies) in capital for 2009-2010 and $2.397 million (excluding contingencies) in expense for 2008-2010.

93. PG&E requested PwC's assessment of the factors creating uncertainty in PG&E's cost estimates and the resulting cost contingencies and risk-based allowance are included in PG&E's PDP cost forecast.

94. In total, PG&E requests approximately $32.6 million for contingencies, or approximately 25.6%.

95. At this point, there is no way to determine what amount of contingencies will actually be expended, and for any amounts expended, what the related activities or materials are, whether the related activities or materials are necessary and optimal, and whether the associated costs are reasonable.

96. Beginning January 2011, PDP cost recovery will be through test year 2011 and subsequent GRC authorizations.

97. Contingencies are not added to GRC forecasted expenses to fund perceived risks and uncertainties.

98. The revenue requirements for this proceeding, as originally calculated by PG&E, will need to be recalculated to conform to the costs adopted by this decision.

99. No party has challenged PG&E's general methodology, results of operations model, or model assumptions for calculation of the revenue requirement.

100. In PG&E's last GRC Phase 2 proceeding, A.06-03-005, the uncontested Settlement Agreement on Marginal Cost and Revenue Allocation Settlement was adopted by the Commission in D.07-09-004. That settlement also addressed rate changes between GRCs.

101. PDP implementation cost recovery for 2011 and beyond will be determined in PG&E's 2011 and subsequent GRCs. Likewise, marginal cost, revenue allocation and rate design for 2011 and beyond will be determined in Phase 2 of PG&E's 2011 and subsequent GRCs.

102. CSOL, customer billing, and customer outreach costs are, by their nature, distribution and not generation costs.

103. With respect to PDP costs authorized by this decision, the effects of using different allocation factors or exempting certain classes from certain cost responsibilities are small.

104. Allocating 2010 distribution related capital costs and related O&M costs by distribution level EPMC related allocators, and applying that allocation to all distribution customers including DA customers, is consistent with (1) how distribution costs are generally allocated, and (2) the marginal cost and revenue allocation settlement agreement adopted in D.07-09-004, with respect to rate changes between GRCs.

105. Parties can recommend different revenue allocation methodologies in PG&E's 2011 GRC Phase 2 proceeding, when the allocation of all costs are considered. It is a more appropriate proceeding for considering new or different revenue allocation methodologies and for evaluating the need to exempt certain customer classes from specific cost responsibilities.

106. Other than the characterization of these incremental PDP costs as part of the distribution function and the methodology for allocating the revenue requirements to customer classes, there is no opposition to PG&E's cost recovery mechanism, as it relates to this decision.

107. PG&E's proposal to coordinate cost recovery where there is overlap between costs approved in earlier proceedings and the incremental costs in this proceeding is unopposed.

108. AECA proposes that PG&E provide analysis after 1,000 and 10,000 agricultural customers are converted to SmartMeters to ensure that the analysis of the effects of migration from non-TOU rates to TOU rates that was provided by PG&E is accurate enough to continue rate migration.

109. In fall 2010, PG&E expects to have 12 months of available interval load information for at least 10,000 agricultural customers, with data from the AMI system and proposes to develop an analysis of the projected bill impacts under

TOU for this 10,000 customer sample of agricultural customers by November 2010.

110. PG&E is already under orders to assess the load impacts and financial benefits of its active and anticipated DR programs including D.08-04-050, D.09-03-026, D.08-07-045, D.08-02-009 and D.06-07-027. Also in D.09-03-026, Ordering Paragraph 10, the Commission directed PG&E to report annually the financial benefits of DR programs enabled by its AMI system, and, in D.08-04-050, PG&E was directed to assess the load impacts of each DR resource on an ex post and ex ante basis, annually.

111. A 2012 RDW could review 2010 and 2011 PDP performance and identify any PDP program deficiencies or problems and address them in a timely matter, if necessary.

Conclusions of Law

1. The PDP program should go forward, in furtherance of the Commission's long term policy to provide dynamic pricing to all customers.

2. PG&E's revised PDP rate levels are reasonable.

3. The TOU rates for PDP, as now proposed by PG&E, are reasonable.

4. An annual minimum of 9 and a maximum of 15 PDP calls, as well as PG&E's proposal for enforcing the PDP call bounds by raising or lowering the temperature thresholds, are reasonable.

5. PG&E's first year bill stabilization/protection proposal is reasonable.

6. With respect to under- and over-collections due to first year bill stabilization/protection and the variation in the number of PDP events, it is reasonable for non-participants to share in a portion of the risk and costs of the PDP program, since its purpose is to lower rates for all customers in the long term.

7. It is reasonable that under- and over-collections due to first year bill stabilization/protection and the variation in the number of PDP events should be allocated to all customers by class.

8. The EUF/CMTA proposed change to PG&E's capacity reservation proposal is not necessary, since most customers will have made their initial capacity reservation choice prior to the May 2010 implementation of PDP and would be able to change their capacity reservation prior to the 2011 summer season or any time after that.

9. PG&E's capacity reservation proposal, including the condition that the capacity reservation may not be changed for 12 months is reasonable.

10. Defaulting small and medium C&I customers first to TOU rates and then one year later defaulting them to CPP rates may lead to customer confusion and frustration, resulting in reduced participation in the PDP program.

11. For small and medium C&I customers that have access to at least 12 months of interval billing data, default PDP rates that include time-of-use rates during non-PDP periods should be effective by February 1, 2011.

12. PG&E's alternating day and six-hour window options to mitigate bill volatility are preferable to DRA's "soft cap" proposal or PG&E's current BPP.

13. To provide comparable bill volatility protection for PDP default A-10 customers, it is reasonable to extend a form of the capacity reservation charge to A-10 customers, which is simpler to implement and understand than that for larger customers.

14. One year of bill stabilization/protection should be sufficient for all PDP customers to get the point that, when there are PDP events, any usage during the peak period will be significantly more expensive than before.

15. The proposal to extend bill stabilization/protection for two additional years for small commercial customers should not be adopted.

16. The proposal to provide an up-front lump sum credit for notification information for small and medium C&I customers should not be adopted.

17. The proposal that revenue shortfalls resulting from annual bill stabilization should be amortized over multiple years, for specific rate classes, if recovery in one year would cause rates to rise by more than 1%, should not be adopted.

18. Customers subject to the February 1, 2011 default date should have 12 months of interval data before being subject to that process.

19. The CSOL feature that would aggregate multiple meter information should be available to the large agricultural customers before they are subject to being defaulted to PDP.

20. The CSOL feature that would allow customers to calculate bills under varying scenarios should be available before any customer is subject to being defaulted to PDP.

21. The Alternative 1 residential PDP proposal is the most reasonable.

22. Customers should be allowed to opt out of the PDP program anytime during the first year that they are on PDP rates.

23. After the first year on PDP, it is reasonable that customers should be limited to switching rate schedules once a year, which is consistent with PG&E's current rules on such switching.

24. With respect to customers opting in or out during the peak season, PG&E should monitor the situation, and if it is determined that there is a significant amount of customer gaming with respect to opting in or out of PDP, PG&E should propose a solution in an appropriate future rate design proceeding.

25. PG&E customers should be allowed to opt out of PDP at any time, if they opt out to enroll in another DR program. PG&E should incorporate this revision to its proposal as soon as possible.

26. This decision is not the appropriate vehicle for modifying previous Commission determinations in D.09-08-027 with respect to dual participation or the consideration of CPP as an energy payment program.

27. PG&E's PDP tariff should be modified to allow PG&E customers to participate in both the PDP and Day-of dispatchable demand response programs at the same time, to conform to the Commission's rules for dual participation established in D.09-08-027.

28. Auto-DR is being addressed and should continue to be addressed in the demand response proceedings.

29. It is not an effective use of the Commission's resources to deplete previously authorized funds for residential customer acquisition activities, and then have PG&E request the same funding in a later proceeding.

30. DRA's proposal to fund all customer outreach and education for PDP from unspent AMI funds should not be adopted.

31. To reflect the revised meter forecast, the associated delay in customer acquisition expenditures, and the likely availability of more small and medium C&I customer acquisition funds for 2010 due to overlap with the AMI decision, it is reasonable to increase the originally forecasted small and medium C&I customer acquisition expenditure amount of $2.49 million for 2010 by 60%, the anticipated increase in 2010 meter installations over what was originally forecast, and deduct the resulting amount of $3.98 million in determining the small and medium C&I incremental costs for 2010 in this proceeding.

32. PG&E's incremental analysis related to (1) foundational work and (2) large C&I and large agricultural customers is reasonable.

33. PG&E's estimate of the incremental foundational costs for customer outreach and education, which amounts to $5.90 million (excluding contingencies), is reasonable.

34. PG&E's estimate of the incremental costs for large customer outreach and education, which amounts to $5.92 million (excluding contingencies), is reasonable.

35. An estimate of the incremental costs for small and medium customer outreach and education, which amounts to $18.22 million (excluding contingencies), is reasonable.

36. The further segregation of costs for small commercial customers will not likely be that revealing with respect to our outreach and education goals, and DRA's proposal to require such segregation will not be adopted.

37. Rather than establishing an outreach advisory panel, PG&E should (1) work with the Commission's Business and Community Outreach Branch to determine how the group can assist PG&E in outreach efforts to small and medium customers, and (2) hold quarterly meetings, two with Energy Division and two open to parties on the service list.

38. Rather than ordering PG&E to hire an independent evaluator, PG&E should be subject to a number of reporting requirements in order for the Commission to gather information and to provide a means for parties to express concerns and a means to address any such concerns.

39. PG&E should work with the DRMEC to conduct an evaluation in 2011 of the effectiveness of customer education and outreach efforts for small and medium customers.

40. Since this transition for residential customers has been delayed by one year, it is reasonable to assume the associated costs would be delayed by one year as well. As such, it would be outside of the cost recovery timeframe requested by PG&E for this proceeding.

41. Since there are significantly more residential customers than small and medium C&I customers, it is reasonable to assume that most of the anticipated costs relate to residential customers and should be excluded. Without better evidence, it is reasonable to include $50,000 for SmartRate conversion calls for small and medium C&I customers in 2010 and exclude the remaining $236,000 from cost recovery in this proceeding.

42. The event notification activities and the associated cost estimate of $1.173 million (excluding contingencies), as originally presented by PG&E, are reasonable.

43. With respect to PG&E's requests for an additional $1.170 million in incremental notification costs due to the effect of D.09-08-027, the $0.106 million contingency should be excluded consistent with how contingencies are treated in this decision; $0.407 million in 2010 PDP costs should be adopted since these costs were included in this application, parties had the opportunity to review the costs and no party opposed the costs; and $0.607 million to support customer notification when the voluntary CPP program is replaced with PDP should not be adopted since these costs never were part of this application and parties did not have the opportunity to review the costs.

44. It is reasonable to allow PG&E the opportunity to file an advice letter to explain and support an alternative cut-off time for notification of event cancellation.

45. PG&E's estimate of $0.714 million (excluding contingencies) to facilitate the development of notification devices is reasonable. PG&E should include the progress of this effort in the quarterly reports discussed in Sections 18.1 and 19.1 and ordered by this decision.

46. PG&E's proposed incremental CSOL activities are reasonable. Due to the importance of CSOL in successfully implementing PDP, PG&E should verify the results of its activities, by filing a Tier 2 advice letter after it has completed its proposed incremental CSOL activities. PG&E should provide sufficient information for Energy Division staff to verify that the new PDP functionalities that PG&E has implemented on its website appropriately suit ratepayer needs.

47. With respect to the upgraded CSOL system authorized by this decision, for the My Account web presentment, all customers should have access to a screen showing cumulative consumption and their bill to date in the current billing cycle. Additionally, customers on the E-1 tariff or any other tariffs that involve a tiered rate structure should be able to quickly and easily identify what tier they are in at any time during the month. These customers should also be able to review historic data that includes that tier they were in at the end of the month. The web presentment should also include an easily accessible and brief description of the rate for each tier and the percentage over baseline that causes a customer to shift to the next tier.

48. Additionally, all customers should have access to a screen that enables a determination of what their consumption and bill might be at the end of the current billing cycle by utilizing appropriate assumptions regarding their historic usage and applicable rates. This screen should recommend short-term options available to reduce the projected total in the current billing cycle. PG&E should also include tips for conservation, demand response and distributed

generation with links that describe other rates or programs that customers may benefit from on a long term basis.

49. Also, while PG&E is planning to provide alerts to customers on time-varying rates, we will also require that all customers should be able to request alerts based on the conditions of their choice such as a target cumulative consumption threshold, a target cumulative cost threshold, and imminent cross-over into a higher tier rate. Customers should have the option of receiving these alerts via email, text message, or voicemail.

50. PG&E's proposed billing system modification activities and the associated cost estimates of $25,939,290 (excluding contingencies) in capital for 2009-2010 and $1,515,023 (excluding contingencies) in expense for 2008-2009 are reasonable.

51. It is reasonable for PG&E to perform the CSOL re-platforming in conjunction with updating the CSOL functionality for PDP purposes.

52. PG&E's proposed CSOL update changes and the associated cost estimates of $23.270 million (excluding contingencies) in capital for 2009-2010 and $0.018 million (excluding contingencies) in expense for 2008-2009 are reasonable.

53. In light of the potential to transition directly to Version 2.3, reviewing the transition first to Version 2.2 and then to Version 2.3 in separate proceedings complicates analyses and determinations of whether the ultimate transition Version 2.3 is being done most appropriately and cost-effectively.

54. It is reasonable to subject all recorded costs that are incurred in the transition of CC&B from Version 1.5 to Version 2.3 to an after-the-fact reasonableness review.

55. PG&E's proposed incremental M&E activities and the associated expense estimate of $1.321 million (excluding contingencies) for 2009-2010 are reasonable.

56. PG&E's proposed project management activities and the associated cost estimates of $2.389 million (excluding contingencies) in capital for 2009-2010 and $2.397 million (excluding contingencies) in expense for 2008-2010 are reasonable.

57. In this case, due to the significant amount of PG&E's contingency request, it is reasonable to exclude contingency cost effects from rates authorized by this decision. To do otherwise, would be contrary to the Commission's responsibility to ensure just and reasonable rates.

58. The elimination of contingencies should have little effect on PG&E's ability to recover its costs for 2009 and 2010 with the rates authorized by this decision.

59. PG&E's general methodology and results of operations model assumptions for calculation of the revenue requirement are reasonable and should be used for determining the revenue requirement authorized by this decision.

60. Allocating 2010 distribution related capital costs and related O&M costs by distribution level EPMC related allocators, and applying that allocation to all distribution customers, including DA customer, is reasonable.

61. PG&E's proposed cost recovery mechanism, as it relates to this decision, is reasonable.

62. PG&E's proposal to coordinate cost recovery where there is overlap between costs approved in earlier proceedings and the incremental costs in this proceeding is reasonable.

63. With respect to any elements of this decision that change PG&E's PDP proposal and result in increased costs, any such costs should be treated as cost overruns and requested in an after-the-fact reasonableness review, if necessary.

64. With respect to potential stranded PDP capital costs, PG&E should be able to recover expenditures as long as the expenditures were made pursuant to, and

consistent with, the specific dynamic pricing spending authority and guidance provided by the Commission. Such expenditures should be identified in PG&E's immediately following GRC.

65. With respect to the PDP program, there is no demonstrated need for additional cost effectiveness reporting requirements at this time.

66. PG&E should file a 2012 RDW application in February 2012.

O R D E R

IT IS ORDERED that:

1. The following rates shall be effective by May 1, 2010:
   - For large commercial and industrial customers, default Peak Day Pricing rates that include time-of-use rates during non-Peak Day Pricing periods.
   - For agricultural and small and medium commercial and industrial customers with advanced meters, optional Peak Day Pricing rates that include time-of-use rates during non-Peak Day Pricing periods.
2. The following rates shall be effective by February 1, 2011:
   - For large agricultural customers that have access to at least 12 months of interval billing data, default Peak Day Pricing rates that include time-of-use rates during non-Peak Day Pricing periods.
   - For small and medium commercial and industrial customers that have access to at least 12 months of interval billing data, default Peak Day Pricing rates that include time-of-use rates during non-Peak Day Pricing periods. Flat rates will no longer be available to these customers.
   - For small and medium agricultural customers that have access to at least 12 months of interval billing data, default time-of-use rates. Flat rates will no longer be available to these customers.

- For residential customers with advanced meters, optional Peak Day Pricing rates that include time-of-use rates during non-Peak Day Pricing periods.

3. Peak Day Pricing rates and time-of-use rates, as specified in Exhibit 7, Tables 2-3 through 2-5, and Table 2-6, Alternative 1 are adopted.

4. An annual minimum of 9 and a maximum of 15 Peak Day Pricing calls, as well as Pacific Gas and Electric Company's proposal for enforcing the Peak Day Pricing call bounds by raising or lowering the temperature thresholds, are adopted.

5. Pacific Gas and Electric Company's proposed first year bill stabilization/protection proposal is adopted.

6. Under- and over-collections due to first year bill stabilization/protection and the variation in the number of Peak Day Pricing events shall be allocated to all customers by class, by spreading adjustments on an even percentage basis among all generation demand and energy charges.

7. Pacific Gas and Electric Company's proposed capacity reservation option and alternating day and six-hour window options to mitigate bill volatility for those customers that do not have a capacity reservation option are adopted. In addition a modified capacity reservation option is adopted for Schedule A-10 customers, where they will be able to choose either to maintain the 50% default amount or to reduce the amount to 0%.

8. The anticipated February 1, 2011 default process shall not begin until Pacific Gas and Electric Company's implementation processes meet the requirement that affected customers have access to 12 months of recorded interval billing data at least 45 days prior to their default date.

9. Pacific Gas and Electric Company's Alternative 1 residential Peak Day Pricing proposal is adopted.

10. Pacific Gas and Electric Company shall work with the Commission's Business and Community Outreach Branch to determine how the group can assist Pacific Gas and Electric Company in outreach efforts to small and medium customers.

11. Pacific Gas and Electric Company shall hold quarterly meetings that coincide with its quarterly reports on its outreach and education efforts. Two of the quarterly meetings shall be open to the Division of Ratepayer Advocates and the Energy Division and two of the meetings shall be open to parties on the service list.

12. Pacific Gas and Electric Company shall work with the Demand Response Evaluation and Measurement Committee to conduct an evaluation in 2011 of the effectiveness of customer education and outreach for small and medium customers.

13. Pacific Gas and Electric Company shall:

- File an advice letter within 120 days of this final decision clearly identifying and describing the specific performance measurements, for each of its customer classes, which it will use to determine that its outreach and education campaign is successful.
    - Possible examples of measurements could include, but should not be limited to, quantifying benchmarks of successful outreach efforts such as: number of workshops held, minimum participants attended, number of customers signed up for "My Account," number of customers that respond to the utility indicating they will stay on or opt out of Peak Day Pricing, and maximum number of customers calls or complaints after a Peak Day Pricing event.

  Pacific Gas and Electric Company should also include a detailed plan with a timeline to develop customer surveys for each customer class. The plan should include a description of the information the utility will gather from customers through survey questions to measure the success of its outreach.

- Prepare a monthly report to be provided to the Energy Division and posted on a public website. This monthly report shall include a breakdown of cost categories and money spent on education and outreach as well as a narrative description that describes the costs. Pacific Gas and Electric Company shall work with the Energy Division to design an appropriate format for the reports.
- Provide a semi-annual written report to all parties on the service list, which includes foundational research conducted and findings, all outreach activities that have occurred, lessons learned from interactions, performance measurements that have or have not been met and if necessary modifications to outreach efforts going forward. The form and content of the report should be coordinated with the Energy Division and should be modified as necessary on an ongoing basis.
- Hold quarterly progress report presentations. Two of the meetings shall be open to the Division of Ratepayer Advocates and the Energy Division. Two of the meetings shall be in conjunction with the semi-annual written reports and open to all parties on the service list.
- Provide to the Commission's Business and Community Outreach Branch, Pacific Gas and Electric Company's schedule of outreach events, at which Pacific Gas and Electric Company staff will be educating customers about Peak Day Pricing and time-of-use rates. (Events include workshops, industry meetings, and meetings with members of Chambers of Commerce, etc.). To the extent possible, Pacific Gas and Electric Company should coordinate such events with the Business and Community Outreach Branch.
- After each of the presentations to parties on the service list, file an Advice Letter that includes a workshop report describing recommendations and issues raised and how Pacific Gas and Electric Company will proceed as a result of the discussions and recommendations.

14. Within 60 days of the issuance of this decision, Pacific Gas and Electric Company shall file an advice letter to explain and support an alternative cut-off time for notification of event cancellation. Parties shall have the opportunity to respond. If no protests are filed, Pacific Gas and Electric Company's proposed cut-off time will be adopted and should be included in its tariffs. If protested, the cut-off time will be determined by Commission resolution.

15. Pacific Gas and Electric Company shall file a Tier 2 advice letter after it has completed its proposed incremental Customer Service On-line activities. Pacific Gas and Electric Company shall provide sufficient information for Energy Division staff to verify that the new Peak Day Pricing functionalities that Pacific Gas and Electric Company has implemented on its website appropriately suit ratepayer needs.

16. For cost recovery of Customer Care and Billing transition costs from Version 1.5 to Version 2.3, Pacific Gas and Electric Company shall file a reasonableness application within 60 days of completing the transition to Customer Care and Billing Version 2.3.

17. Any costs related to the Customer Care and Billing transition from Version 1.5 to Version 2.3 shall be removed from Pacific Gas and Electric Company's test year 2011 general rate case proceeding.

18. Pacific Gas and Electric Company shall use its results of operations model to calculate the revenue requirements related to the costs adopted by our decision today, and shall include details of the calculations when requesting rate recovery through its Annual Electric True-up advice filing process.

19. The adopted incremental expenditures that shall be used in determining the revenue requirements for this decision total $92,072,000 for the years 2008-2010.

20. Pacific Gas and Electric Company shall develop an analysis of the projected bill impacts under time-of-use rates for a 10,000 customer sample of agricultural customers by November 2010. The information should be provided to the Energy Division and the Agricultural Energy Consumers Association and the availability of the information should be made to the service list.

21. Pacific Gas and Electric Company shall file a 2012 Rate Design Window application in February 2012, to address the following:

- An assessment of the performance of the 2010 and 2011 summer season Peak Day Pricing programs, in terms of customer participation and achieved demand response, with proposed adjustments, if any, to improve program performance;
- Proposed adjustments to Peak Day Pricing charges and credits, to reflect marginal costs adopted in the 2011 General Rate Case Phase 2.
- Proposed new time-of use and time-of-use/Peak Day Pricing rates for medium commercial and industrial customers, intermediate in time-differentiation between the proposed A1-TOU and A6-TOU rate designs.

22. Application 09-02-022 is closed.

This order is effective today.

Dated _____________________________, at San Francisco, California.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated December 22, 2009, at San Francisco, California.

/s/ JOYCE TOM

Joyce Tom