BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs Allocate Revenues, And Design Rates.	Application 08-03-002 (Filed March 4, 2008)
In the Matter of the Application of Southern California Edison Company (U 338-E) for Authority to Make Various Electric Rate Design Changes.	Application 07-12-020 (Filed December 21, 2007)

COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON SCHEDULE TO DESIGN AND ADOPT DYNAMIC PRICING RATES

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs Allocate Revenues, And Design Rates.	Application 08-03-002 (Filed March 4, 2008)
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COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON SCHEDULE TO DESIGN AND ADOPT DYNAMIC PRICING RATES

Southern California Edison Company (SCE) hereby provides comments in accordance with the March 3, 2009 "Assigned Commissioner's Ruling Requesting Comments on Schedule to Design and Adopt Dynamic Pricing Rates for Southern California Edison Company" (hereinafter, "ACR").

I.

INTRODUCTION

The ACR states that SCE has filed settlement agreements which include critical peak pricing and real time pricing options for some customer groups, but that the Assigned Commissioner believes that such options "should be made available to all customers" to be consistent with the objectives previously identified by the Commission. The ACR concludes that "a plan should be established to ensure that SCE has dynamic pricing proposals for all customer classes when it files its 2012 General Rate Case Phase 2 Application."[1]

[1] ACR, p. 2.

Noting that the Commission has previously adopted a schedule for PG&E in Decision ("D.") 08-07-045 to develop and integrate dynamic pricing tariffs into its rates for all customers, the ACR asks parties for their comments on the following questions:

1. **Schedule for Proposing Dynamic Pricing Rates**: In D.08-07-045, the Commission adopted a timetable for Pacific Gas and Electric Company (PG&E) to propose dynamic pricing rates. If the Commission orders SCE to follow a comparable timetable, how should SCE's timetable differ from that adopted for PG&E? Should SCE propose additional dynamic pricing rates for certain customer classes prior to its 2012 General Rate Case Phase 2 Application? When should dynamic pricing tariffs be offered to each customer class?
2. **Guidance for Designing Dynamic Pricing Rates:** Do any of the principles and rate design guidance adopted for PG&E in D.08-07-045 "need to be changed before applying them to SCE to develop its dynamic pricing tariffs? If so, which ones and why?"

With only a few exceptions, the proposed settlement agreements already provide dynamic pricing options that will be available for most of SCE's customers by October 1, 2009, although CPP rates are generally not the default tariff. SCE will include dynamic pricing proposals for all applicable rate groups in its application for Phase 2 of its 2012 General Rate Case when that application is filed either in February or March 2011. Thus, SCE believes that its proposed schedule for proposing dynamic pricing options is not materially different from PG&E's and that no additional dynamic pricing rates need be proposed between now and time SCE files its application in Phase 2 of SCE's 2012 GRC.

The following Section II will address the timetable for proposed dynamic pricing options for each of SCE's rate groups based on the proposed settlement agreements in this proceeding, along with a comparison of these proposals to the dynamic pricing options and timetables adopted for PG&E in D.08-07-045. Then, in Section III, SCE will address whether any of the principles and guidance provided by D.08-07-045 should be changed with respect to dynamic pricing offerings for SCE's customers.

II.

THE PROPOSED SETTLEMENT AGREEMENTS PROVIDE DYNAMIC PRICING OPTIONS FOR SCE'S RATE GROUPS EFFECTIVE OCTOBER 2009

In this proceeding, SCE and the settling parties have filed four settlement agreements that comprehensively address rate design for all of SCE's rate groups — residential; small commercial; medium and large commercial; agricultural and pumping; street and area lighting.[2] The settlement agreements provide a default peak time rebate (PTR) for residential customers, default critical peak pricing (CPP) and mandatory time-of-use (TOU) for large (> 200 kW) commercial customers, and optional CPP or real time pricing (RTP) for each rate group to be implemented on October 1, 2009.[3] Table II-1, below, summarizes the timetable for SCE's implementation of dynamic pricing and TOU options set forth in the proposed settlement agreements by rate groups as well as a forecast of future proposals SCE expects to make in Phase 2 of its 2012 GRC. The column on the right side of Table II-1 summarizes the timetable that was adopted by the Commission in D.08-07-045 for PG&E.

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2 Two other settlement agreements were filed; one addressing revenue allocation and the other addressing submetering of commercial customers with proposed revisions to SCE's Rule 18.

3 Dynamic pricing is only applicable to bundled-service customers. Other exclusions include: Domestic master-metered accounts, Street Lighting and Traffic Control accounts, and Standby customers (for backup or maintenance service). In addition, customers on other demand response programs (*e.g.* BIP, APS) are also excluded from dynamic rate participation (*e.g.* CPP) to avoid double payment of avoided capacity.

Table II-1
Dynamic Pricing Options
Comparison of SCE's Proposed Implementation Schedule to D.08-07-045

Rate Group	Proposed Settlement Timetable and Schedule For Future Dynamic Pricing Rates	Schedule for Dynamic Pricing Rates Adopted for PG&E in D.08-07-045
Residential	**Default:** 5-tiered, non-time-differentiated, rate structure for Schedule D. Revenue increases allocated to Tiers 3 – 5. Schedule D-CARE has 3-tiered rate structure, with 20% discount from Schedule D and Tier 3 rate capped at 20 cents per kWh. No change to Basic Charges. **[Effective October 1, 2009]** Peak Time Rebate — Default overlay for customers on Schedule D and TOU-D schedules provided customers have advanced meters. Two-tiered incentive, with first tier set at $0.75/kWh but with incentive set at $1.25/kWh for technology-enabled device. Incentive provided for usage below customer-specific baseline. Year-round program, with events triggered by temperature, market prices, generation heat rates, or other system load conditions. **[Effective October 1, 2009]** **Optional Rates**: CPP — CPP event energy charge set at $1.36/kWh, with non-event credit set at $0.04/kWh for standard residential rates. **[Effective October 1, 2009 for customers with advanced meters.]** TOU — Schedule TOU-D-T will reflect a two-tiered TOU rate structure as well as TOU-TEV (electric vehicle). TOU-EV-1 modified to provide discounted off-peak charging rates. **[Effective October 1, 2009]** **Forecast: In Phase 2 of its 2012 GRC, SCE may propose optional RTP based on post-MRTU experience for customers with advanced meters. If AB1X protections removed or have materially changed to allow default or mandatory time-variant rates, SCE to propose default TOU and CPP for residential customers.**	**Default:** AB1X and other restrictions only permit a Peak Time Rebate option at this time. Restrictions imposed by AB1X currently limit any changes to default Tier 1 and Tier 2 rates and Basic Charge. Other legislative requirements apply to baseline and tiered rate structure. Peak Time Rebate — Default tariff for customers with advanced metering installations (AMI), provided design complies with AB1X. If AB1X protections removed or have materially changed to allow default or mandatory time-variant rates, PG&E to propose default TOU and CPP for residential customers. [D.08-07-045, p. 39.] **Optional Rates:** PG&E to offer TOU, CPP, and RTP as optional rates, with RTP made available to residential customers on or before May 1, 2011. [D.08-07-045, pp. 38 - 39.] Optional CPP should include TOU rates outside of CPP event periods and should be effective no later than May 1, 2010.

Table II-1
Dynamic Pricing Options
Comparison of SCE's Proposed Implementation Schedule to D.08-07-045

Rate Group	Proposed Settlement Timetable and Schedule For Future Dynamic Pricing Rates	Schedule for Dynamic Pricing Rates Adopted for PG&E in D.08-07-045
Small Commercial (< 20 kW demand)	**Default:** Implement new seasonal, non-time-differentiated rate structure. **[Effective October 1, 2009.]** **Optional Rates**: TOU — TOU-GS-1 and TOU-EV-3. **[Effective October 1, 2009]** CPP — Same energy charge and non-event credit as for Residential rate group, for customers with advanced meters. **[Effective October 1, 2009.]** **Forecast: In Phase 2 of its 2012 GRC, SCE to propose default TOU/CPP and mandatory TOU for customers with advanced meters, with optional RTP based on post-MRTU experience.**	**Default:** PG&E to implement default TOU/CPP rate starting May 2011 for small commercial customers who have had AMI meters for 12 months. [D.08-07-045, p. 26.] PG&E to file TOU rates applicable outside of CPP event periods to be effective no later than May 1, 2010. [D-07-08-045, p. 27.] Mandatory TOU rates for customers with advanced meters installed. [D-07-08-045, p. 26.] **Optional Rates:** PG&E to file optional RTP rate in Phase 2 of its 2011 GRC, with an effective date on or before May 1, 2011. [D-07-08-045, p. 27.]
Medium Commercial (20 to 200 kW)	**Default:** Retain current non-TOU rate structure, consisting of customer charge, seasonal energy charges, and demand charges except for Schedule TOU-GS-2. **[Effective October 1, 2009]** **Optional Rates:** TOU — GS-2 (TOU option A), GS-2 (TOU option B), and TOU-GS-2 (Option R). **[Effective October 1, 2009]** CPP — Optional overlay to Schedule GS-2 and GS-2 TOU (option B) schedules, with same CPP event energy charge as for Residential and Small Commercial rate groups. Non-event credits applied to summer, on-peak time-related demand charge, if applicable. **[Effective October 1, 2009]**	**Default:** PG&E to propose default TOU/CPP rate in its 2008 Rate Design Window, with implementation effective on or before February 1, 2011. Mandatory TOU pricing for customers who have had advanced meters for 12 months. [D-07-08-045, p. 24.] **Optional Rates:** PG&E to file optional RTP rate in Phase 2 of its 2011 GRC, with an effective date on or before May 1, 2011. [D-07-08-045, p. 24.] PG&E to file revised CPP rate coupled with TOU rates in its 2008 Rate Design Window, to be effective no later than May 1, 2010. [D-07-08-045, p. 24.]

Table II-1
Dynamic Pricing Options
Comparison of SCE's Proposed Implementation Schedule to D.08-07-045

Rate Group	Proposed Settlement Timetable and Schedule For Future Dynamic Pricing Rates	Schedule for Dynamic Pricing Rates Adopted for PG&E in D.08-07-045
Medium Commercial (20 to 200 kW)	**Forecast: In Phase 2 of its 2012 GRC, SCE to propose default TOU/CPP and mandatory TOU for customers with advanced meters, with optional RTP based on post-MRTU experience.**	
Large Commercial (> 200 kW)	**Default:** Mandatory TOU rates, with default TOU/CPP rate on TOU-GS-3 (Option B), and on TOU-8. **[Effective October 1, 2009]** **Optional Rates:** TOU — Options without CPP overlay, include TOU-8, Option A, Option B, and Option R. RTP option is available for > 500 kW customers. **[Effective October 1, 2009]** **Forecast: In Phase 2 of its 2012 GRC, SCE to propose a modified, optional RTP based on post-MRTU experience.**	**Default:** PG&E to file default TOU/CPP in its 2008 Rater Design Window to be effective on or before May 1, 2010. , with RTP by 2011. [D.08-07-045, p. 21.] **Optional Rates:** PG&E to file optional RTP in Phase 2 of its 2011 GRC to be effective on or before May 1, 2011. [D.08-07-045, p. 21.]
Small / Medium Agricultural (< 200 kW)	**Default:** Non-TOU schedules PA-1 and PA-2. **[Effective October 1, 2009]** **Optional Rates: [Effective October 1, 2009]** TOU — TOU-PA-1 and TOU-PA-2. CPP — Optional overlay for all TOU or non-TOU schedules with same CPP event energy charge as for Residential and Small Commercial rate groups. Non-event credits applied to either energy or demand components, depending upon where capacity costs are allocated on the otherwise applicable tariff. RTP — PA-RTP is available provided customer qualifies for TOU-PA-B. **Forecast: In Phase 2 of its 2012 GRC, SCE to propose**	**Default:** PG&E to propose default TOU to be implemented by 2011 for agricultural customers with advanced meters, provided they have had meters for 12 months. [D.08-07-045, pp. 31 – 32.] Mandatory TOU or other time-differentiated pricing after customers have had advanced meters for 12 months. [D.08-07-045, p. 32.] **Optional Rates:** PG&E to propose optional CPP/TOU in its 2008 Rate Design Window application, with rates effective on or before February 1, 2011. [D.08-07-045, p. 32.] PG&E to propose optional RTP in Phase 2 of its 2011 GRC, with effective date on or before May 1, 2011.

Table II-1
Dynamic Pricing Options
Comparison of SCE's Proposed Implementation Schedule to D.08-07-045

Rate Group	Proposed Settlement Timetable and Schedule For Future Dynamic Pricing Rates	Schedule for Dynamic Pricing Rates Adopted for PG&E in D.08-07-045
	mandatory TOU for customers with advanced meters, with optional CPP and RTP based on post-MRTU experience.	
Large Agricultural (> 200 kW)	**Default:** TOU-PA (Rate B). **[Effective October 1, 2009]** **Optional Rates: [Effective October 1, 2009]** CPP — Optional overlay to all schedules with same CPP event energy charge as for Residential and Small Commercial rate groups. Non-event credits applied to either energy or demand components, depending upon where capacity costs are allocated on the base rate. TOU-PA (Rate A), TOU-PA-5, TOU-PA-SOP. RTP — PA-RTP is available provided customer qualifies for TOU-PA-B **Forecast: In Phase 2 of its 2012 GRC, SCE to propose default CPP/TOU with optional RTP based on post-MRTU experience**	**Default:** PG&E to propose default CPP/TOU in early 2009, with default CPP implemented on or before February 1, 2011. [D.08-07-045, p. 31] **Optional Rates:** Optional RTP to be implemented on or before May 1, 2011. [D.08-07-045, p. 31]

The proposed settlement agreements, if approved by the Commission, are to become effective October 1, 2009. As Table II-1 illustrates, effective October 1, 2009, the settlement agreements reflect default or optional CPP rates for all rate groups, a new, default peak time rebate (PTR) for residential customers, and RTP options for agricultural and large commercial (>500 kW) customers.

The ACR asks whether SCE should propose additional dynamic pricing options for certain customer classes prior to SCE's application in Phase 2 of its 2012 GRC. SCE believes that the proposed settlement agreements include rate designs and options that meet, in large part, the default dynamic pricing objectives set forth in D.08-07-045 and that the balance of the dynamic pricing objectives should be achieved in Phase 2 of SCE's 2012 GRC. Other optional rate schedules may be proposed in the period between SCE's 2009 and 2012 GRCs within the context of SCE's rate design window (RDW). Under the rate case plan, for SCE's 2009 GRC cycle, RDW proposals may theoretically be filed in December 2009, December 2010, or December 2011. However, an RDW application made in December 2009 would have to be filed before any customer has had even one summer's experience on the rate design proposals accepted in the proposed settlement agreements. An RDW filing made in December 2010 would be comparable in timing to the filing SCE actually made in December 2007 (A.07-12-020). However, resolution of that application was deferred when it was consolidated with the March 2008 application in Phase 2 of SCE's 2009 GRC — an outcome that may likely reoccur in 2010. An RDW filing made in December 2011 would take place during the then-pending application in Phase 2 of SCE's 2012 GRC. Thus, the only limited opportunity for an SCE RDW filing to propose additional dynamic pricing rates is December 2010, with such proposals expected to become effective for the summer of 2011. However, SCE recommends not taking such action for two reasons. First, any mandatory changes differing from the settlement agreements would be inconsistent with the intent of the settling parties to make the default or mandatory rate design proposals contained in the proposed settlements effective through the three-year term of SCE's 2009 GRC, *i.e.,* from October 1, 2009 through September 30, 2012. Second, SCE believes that the three-year 2009 GRC cycle, which coincides with the installation period for advanced meters for both residential and small commercial customers, is best used as a transition period where operational and customer educational objectives are achieved.[4]

The issue implicitly raised by the ACR is when should CPP/TOU dynamic pricing be adopted as the ***default*** tariff for all of SCE's rate groups. For large commercial customers, by October 1, 2009, the default tariff will be CPP/TOU, with mandatory TOU pricing for all customers. By February 2011 (in the application for Phase 2 of SCE's 2012), SCE expects to propose to make CPP/TOU dynamic pricing the default tariff for residential (if AB1X restrictions are lifted); mandatory TOU and CPP/TOU the default tariff for small and medium commercial customers (dependent on installation of advanced meters and 12 months experience); mandatory TOU with optional TOU/CPP for small agricultural customers (again, dependent on installation of advanced meters and 12 months experience); and default CPP/TOU for large agricultural customers. At the same time, SCE would propose that most, if not all, rate groups have optional RTP based on post-MRTU experience achieved prior to February 2011.

III.

COMPARISON OF SCE'S PROPOSED DYNAMIC PRICING OPTIONS TO GUIDANCE PROVIDED BY D.08-07-045 AND POTENTIAL CHANGES TO GUIDANCE

The ACR asks whether any of the principles and rate design guidance adopted for PG&E in D.08-07-045 need to be changed before applying them to SCE to develop its dynamic pricing tariffs, and if so, which ones?[5] The Commission did not order SCE to adhere to the timetable or the rate design guidance adopted in D.08-07-045 for PG&E but recommended it be considered by SCE in its rate design proceedings.[6] Although D.08-07-045 was issued after SCE filed its

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[4] The current SCE SmartConnect deployment schedule results in less than 20 percent of SCE's customers having a year's worth of interval data by June 2011.

[5] ACR, pp. 2 – 3.

[6] D.08-07-045, p. 83.

application in this proceeding, many of the principles and guidance adopted in D.08-07-045 have already been reflected in the proposed settlement agreements or can be applied when SCE files its February 2011 application in Phase 2 of SCE's 2012 GRC. This can be seen by a comparison of the guidance to the principles reflected in the proposed settlement agreements. Table III-2, below, compares the rate design guidance offered in Attachment A and in the body of D.08-07-045 to the rate design principles reflected in the proposed settlement agreements, and how SCE expects to propose changes in its 2012 GRC to apply those principles and guidance or where SCE believes some changes are warranted.

Table III-1

Comparison of Rate Design Guidance in D.08-07-045 to SCE's Proposals

All Dynamic Pricing Rates – D.08-07-045	Reflected in Proposed Settlement Agreements?	Planned for SCE's 2012 GRC, Phase 2?
Rate design should promote efficient decision-making. To promote economically efficient decision-making, rates should be based on marginal cost.	Yes	Yes
Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.	Yes	Yes
Rates should also seek to provide stability, simplicity and customer choice.	Yes	Yes
If customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.	Yes	Yes
Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.	Not available.	Yes.
Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate	Yes	Yes
Utilities should offer optional bill protection to customers on default dynamic pricing rates	Yes, for customers on default CPP for the first 12 months	Yes, for customers on default CPP for the first 12 months
The utilities should bid demand reductions due to dynamic pricing into the California Independent System Operator's (CAISO's) day-ahead market	Details are provided in SCE's 2009-2011 Demand Response Application (A.08-06-001).	SCE will address after results obtained from pilot studies being conducted in summer 2009.

Critical Peak Pricing — D.08-07-045	Reflected in Proposed Settlement Agreements?	Planned for SCE's 2012 GRC, Phase 2?
CPP Event Price: The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period. Conclusion of Law 36.	Yes. The CPP event price reflects marginal capacity costs based on annualized cost of a new combustion turbine and the underlying energy rate reflects the marginal energy cost. Marginal energy costs are time differentiated for TOU rate schedules	CPP event price to be determined, but should balance demand response and rate stability objectives.
Summer Demand Charges: CPP rates should not have summer generation demand charges. Conclusion of Law 40	Proposed CPP rates include discounted summer on-peak and mid-peak generation demand charges based on the percentage of capacity that the CPP periods represent. Bill impacts are a concern, so a portion of the marginal generation costs are still reflected in summer generation demand charges	CPP rate designs will balance demand response and rate stability objectives.
Over/Under Collections: If customers reduce their usage, then they should see a commensurate reduction in their bills. Conclusion of Law 31	Yes. However, under- or over-collections resulting from the difference between actual and design number of CPP events will be assigned to CPP participants in the following year's summer on-peak and mid-peak periods as a flat cent per kWh surcharge. The minimum number of CPP events shall be nine	Yes
Number of CPP Events and Timing: Utilities should be able to call a variable number of CPP events each year, and the rate should be designed based on the number of events that would be called during a typical year. CPP events should be called any day of the week, year round. Conclusion of Law 42	Yes. CPP rates are designed based on 12 CPP events per year. A minimum of 9 and a maximum of 15 CPP events will be called each year. CPP events may be called from 2:00 p.m. to 6:00 p.m., on non-holiday, summer weekdays while PTR events may also occur on non-holiday, winter weekdays..	SCE will review the CPP and PTR event criteria.
CPP and TOU. CPP should include TOU rates during non-critical periods. Conclusion of Law 39	Yes. CPP rates can be applied in conjunction with both TOU and non-TOU rate options, when available For large commercial and industrial customers > 200 kW, the default TOU rate includes CPP. For customers < 200 kW, CPP is an optional overlay to either a TOU or non-TOU rate.	Yes, as TOU rates become mandatory for non-residential customers, the CPP overlay structure on non-TOU rates will no longer be available.

Real-Time Pricing	Reflected in Proposed Settlement Agreements?	Planned for SCE's 2012 GRC, Phase 2?
The energy charge should be indexed to the CAISO's day-ahead hourly market prices	Not applicable	To the extent feasible, SCE will propose pricing options that tie the energy charge to CAISO day-ahead hourly prices
At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered.	Not applicable. SCE's RTP offerings based on marginal cost of a combustion turbine (CT proxy method) allocated to hourly periods based on loss of load expectation (LOLE) methodology.	SCE's RTP proposals will incorporate any experience gained from MRTU deployment.
The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices	Not applicable	SCE's RTP proposals will incorporate any experience gained from the MRTU deployment.

There are three areas where SCE recommends additional review of, or changes to, the rate design guidance adopted in D.08-07-045. These three areas are: (1) the timing of CPP events, (2) the requirement that CPP rates should not have summer generation demand charges, and (3) the timing for implementation of new RTP options based on experience with MRTU. SCE believes that these issues are best considered in the context of Phase 2 of SCE's 2012 GRC.

D.08-07-045 provides that CPP events should be called any day of the week, year-round. The proposed settlements agreements restrict CPP events to summer weekdays only,[7] while PTR events may be called on weekdays throughout the year.[8] SCE believes that customer adoption of CPP would benefit if CPP events are called only in the summer at least initially. CPP events could be extended to all year after customers gain experience with the CPP rate and provided that the advent of MRTU reveals high price days occurring outside of summer weekdays. The restriction agreed to in the settlement agreements is reasonable given that there was only a single winter weekday (October 1, 2001) and two holiday/weekend days (September 1 and September 3, 2007) among SCE's 120 system peak load days in the last ten years (*i.e.* the top 12 system peak days in each year from 1998 - 2007). The design guidance provided by D.08-07-045 related to the timing of CPP events is an issue that should be considered in Phase 2 of SCE's 2012 GRC when SCE will determine how best to incorporate winter and weekend CPP events into its rate designs.

The requirement of D.08-07-045 that "CPP rates should not also have summer generation demand charges" is inconsistent with generally-accepted, cost causation and/or demand response program valuation principles. In R.07-01-041, joint comments filed by SCE and other parties stated:

> "For DR programs with constraints on their availability and/or how often they can be used, utilities will … take into consideration the capacity value of these DR programs during those … highest-valued periods in which the program is available and can be used. The value of the generation capacity in those periods will be determined by allocating the annual market value of generation capacity among the hours of the year ***in proportion to the relative need for capacity in***

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[7] *See e.g.,* Medium and Large Power Rate Design Settlement Agreement, p. 9.

[8] 2009 GRC Phase 2 Residential and Small Commercial Rate Design Settlement Agreement, p. 7; SCE/Garwacki, Ex.5, Appendix D, p. D-5.

those hours (e.g. in proportion to hourly LOLE or LOLP)."[9]
(Emphasis added.)

The CPP rate design proposed in the settlement agreements was based on these principles and is reasonable.[10] For SCE, the CPP event energy rate is designed to collect about 65 percent of the full annualized capacity value in a limited number of hours with the remaining 35 percent collected in generation demand charges.[11] This 35 percent represents the capacity value that cannot be obtained by limited call, time-period-specific, day-ahead programs. Market research has shown that customers strongly prefer CPP rate structures consistent with the proposed design in the settlement agreements. Moreover, if all of the generation capacity value were recovered in limited CPP event hours, it would be inconsistent with other guidance provided by D.08-07-045 that "deviation from marginal cost should be minimized."[12] Finally, the proposed CPP design mitigates concerns related to recovery of an inordinate amount of revenues from CPP events. The proposed settlement agreements assign about one-third of the generation marginal cost revenue responsibility to capacity charges. If this additional revenue were assigned to and collected based on a small number of CPP events, it could have unduly harsh customer bill impacts and could adversely affect utility revenue streams.

D.08-07-045 also discusses the development of RTP rates and correctly notes that any direct linkage to MRTU will require experience with MRTU and its related scarcity-pricing provisions that are expected to follow one year later in April 2010. The decision concludes that "It is reasonable to wait for two full summers of experience with MRTU before implementing RTP."[13] Until that occurs, the proposed settlement agreements would continue SCE's existing RTP-2 rate

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9 *See* "Joint Comments of . . . Recommending a Demand Response Cost Effectiveness Evaluation Framework," Attachment A, page 3, November 19, 2007 in R.07-01-041.

10 *See* SCE/Silsbee, Ex. 3, Appendix C.

11 For those rate schedules with summer generation demand charges, CPP rates reduce the summer generation demand charges by approximately 65% and recover this generation capacity revenue via high CPP period energy charges. SCE notes however that D.08-07-045 does not require all generation capacity costs to be included as CPP charges, only that there should not be summer generation demand charges. To the extent that the non-CPP period generation capacity costs are recovered from either capacity reservation charges or other seasonal/TOU energy charges, this discretion should be left to the utilities.

12 D.08-07-045, Attachment A, p. 1.

13 D.08-07-045, Finding of Fact No. 7.

structure, which uses hourly energy prices in conjunction with LOLE-allocated capacity to several different temperature-driven day types. Until the capacity issues associated with MRTU are fully understood, utilities should be able to implement CPP and RTP proposals that include capacity based on traditional LOLE allocation methodologies.

IV.

CONCLUSION

Based on the above comparisons and discussion, adoption of the proposed settlement agreements is reasonable as they will largely meet the timing requirements and guidance for dynamic pricing options adopted by the Commission in D.08-07-045. SCE believes there is no need to consider additional dynamic pricing options within the context of an SCE rate design window application, and that any differences between the rate design guidance provided by D.08-07-045 and the proposed rate design for dynamic pricing rates should be considered in Phase 2 of SCE's 2012 GRC.

Respectfully submitted,

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March 23, 2009

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of the COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON SCHEDULE TO DESIGN AND ADOPT DYNAMIC PRICING RATES on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **23rd day of March, 2009**, at Rosemead, California.

/s/ JENNIFER ALDERETE

Jennifer Alderete
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