Docket:	:	A.11-06-007
Exhibit Number	:	DRA-01
Commissioner	:	Michael R. Peevey
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DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY ON SOUTHERN CALIFORNIA EDISON'S 2012 GENERAL RATE CASE, PHASE 2

A.11-06-007

San Francisco, California
December 20, 2011

571472

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CERTIFICATE OF SERVICE

MEMORANDUM

This report was prepared by the Division of Ratepayer Advocates (DRA) of the California Public Utilities Commission (Commission) in Application 11-06-007. In this report DRA presents its analysis and recommendations associated with the applicant's request.

Dexter Khoury and Cherie Chan served as DRA's project coordinators in this review, and are responsible for the overall coordination in the preparation of this report. DRA's witnesses' prepared qualifications and testimony are contained in Appendix A of this report.

EXECUTIVE SUMMARY

In this report, the Division of Ratepayer Advocates ("DRA") presents its testimony for Southern California Edison's ("SCE") General Rate Case ("GRC"), Phase II, Application ("A.") 11-06-007. This proceeding is intended to establish marginal costs, allocate revenues, design rates, and implement additional dynamic pricing rates.

DRA has been preparing its testimony during a period of a stagnant economy and an international debt crisis. People nationwide are unhappy with the direction of the economy and the pace of the recovery. In this environment, many customers continue to struggle in paying their bills, and all customer classes are experiencing difficulties. DRA thus recommends placing a cap on the revenue allocation equal to a maximum of 5% more than the system average change. DRA's revenue allocation recommendations would result in a 0.9% decrease in residential average rates and an 11.8% decrease in small commercial average rates.

DRA expended considerable time and effort examining SCE's underlying marginal costs, and has made several recommendations designed to improve the way SCE calculates marginal costs.

DRA happily notes that residential rate design should be less controversial than it was in PG&E's GRC Phase II last year, and DRA has made its recommendations that help reduce upper tier rates with fewer impacts to other residential customers.

DRA presents its Small Commercial Rates as well as its recommendations on time variant pricing for small commercial customers. DRA agrees with SCE that the transition to time variant pricing ("TVP") rates for small commercial customers should begin with Time of Use ("TOU") rates. DRA recommends a later transition date and less time differentiated TOU rates.

SUMMARY OF KEY DRA RECOMMENDATIONS

DRA made a number of significant recommendations and modifications to SCE's approach on how to calculate marginal costs.

A. Delivery Marginal Costs

DRA recommends the following:

1. Ten years of historical data should be used instead of the proposed fifteen in the regression analysis used to calculate Marginal Distribution Costs.
2. Actual capacity data should be used instead of planned capacity data to calculate Marginal Distribution Costs.

B. Marginal Energy Costs and Generation Capacity Costs

DRA recommends the following:

1. The level of SCE's Marginal Energy Costs should be increased by 24% to render them consistent with a current California Energy Commission natural gas forecast for 2012-2014.
2. For the marginal generation capacity cost, DRA recommends an annual value of $97.88 per kW-year, including a 15% resource adequacy adder, based on a modification of SCE's proposed RECC methodology to reflect lack of need for new generating capacity before 2017.

C. Marginal Customer Costs

DRA recommends the following:

1. The Commission adopt marginal customer costs ("MCCs") based on the NCO methodology which the Commission has adopted in nearly all litigated marginal cost decisions since 1992.
2. The Commission adjust the capital cost component of SCE's marginal customer cost downward by 10% to reflect customer or developer contributions (under Rules 15 and 16) to the costs of new customer connections to SCE's electric distribution grid.
3. The Commission adjust the capital cost component of SCE's residential marginal customer cost downward by an additional 5% to reflect lower cost connections not captured by SCE's methodology, such as infill connections.
4. In applying the NCO methodology, DRA proposes a uniform customer growth rate of 0.96% for all customer classes.

D. Revenue Allocation

DRA recommends the following:

1. The use of a total revenue allocator for demand response programs and AMI costs.
2. An equal cents per kWh allocation of California Solar Initiative ("CSI") and the public purpose programs ("PPP") costs.
3. Capping the revenue allocation so that no class would face an increase more than 5% above the system average rate percent change.

E. Residential Rate Design

DRA recommends the following:

1. SCE's proposal to reduce the number of residential rate tiers from 5 to 4 tiers by combining tiers 4 and 5 should be adopted.
2. SCE's proposal to decrease baseline allowances from 55% to 50% of average consumption should be rejected.
3. SCE's proposal to calculate separate baseline allowances for single family and multifamily residences should be rejected.
4. DRA recommends minimal changes to SCE's Schedule TOU-D-T.

F. Small Commercial Rate Design

DRA recommends the following:

1. The soonest any default time variant pricing ("TVP")[1] rates should be implemented for small commercial customers should be the Fall/Winter season of 2013, beginning October 1st.
2. Critical Peak Pricing or Real-time pricing should remain voluntary (opt-in) for small commercial customers, as SCE also recommends. However, if the Commission chooses to implement default CPP, it should not do so until customers have had two full summers of experience under TOU rates.
3. To mitigate bill impacts, the on-to-off-peak rate differentials for small commercial Time-of-Use customers should be initially limited to a "TOU-lite" rate, which would have lower on-to off-peak price differentials than SCE's.

[1] DRA defines TVP rates as including both 1) Time of Use rates as well as 2) Dynamic Pricing rate schedules such as CPP, in which prices are responsive to system conditions.

4. The current summer to winter energy charge differentials for small commercial customers on Schedule GS-1 should be maintained, as these customers will be subject to many other changes over the next few years.

List of DRA Witnesses and Respective Chapters

Chapter Number	Description	Witness
-	Executive Summary	
1	Marginal Cost Policy and Methodology	Robert Levin
2	Marginal Cost of Electric Generation	Robert Levin
3	Distribution Demand Marginal Cost	Louis Irwin
4	Customer Access Marginal Cost	Robert Levin
5	Revenue Allocation	Lee-Whei Tan
6	Residential Rate Design	Dexter Khoury
7	Small Commercial Rate Design	Cherie Chan

CHAPTER 1.

MARGINAL COST POLICY AND METHODOLOGY

(Witness Robert Levin)

I. INTRODUCTION

This chapter presents DRA's recommended marginal costs for use in SCE's revenue allocation and rate design for 2012 through 2014. It also discusses marginal cost methodology generally and offers a high-level critique of SCE's proposed marginal cost methodologies. More detailed analyses of each marginal cost component are offered in the following three chapters.

As in the past, SCE presents marginal costs for generation (including separate components for capacity and energy), distribution demand, and customer access. However SCE continues to ignore past Commission marginal cost guidance and sound economic principles. If adopted, SCE's proposed marginal costs would be detrimental to economic efficiency and would fail to promote just and reasonable rates.

As SCE's testimony states, the Commission has long "...relied on marginal cost principles for assigning revenue requirements to customers (by rate group), and as guidance for setting the level of individual rate components."[2] DRA agrees, and further observes that a major reason for the Commission's reliance on marginal costs is that marginal cost-based pricing promotes economic efficiency.[3]

SCE further states that "SCE's marginal costs are intended to represent conditions expected to occur during the period from 2012 to 2014."[4] SCE's marginal cost

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[2] Ex. SCE-02, p. 1.

[3] "We have chosen marginal costs as our foundation for allocation and rate design. We have used marginal costs to promote economic efficiency and to provide the greatest good for the greatest number." (Re PG&E (1981) 7 CPUC 2d 349, 1981 Cal. PUC LEXIS 1279 *285, D.93887); "First, economic efficiency dictates that rates be based on marginal cost, not embedded cost." (Re Rate Design for Unbundled Gas Utility Services (1986) 22 CPUC 2d 444, 456, 1986 Cal. PUC LEXIS 753 *17, D.86-12-009.)

[4] Ex. SCE-02, pp. 6, 16.

showing, however, ignores established Commission policy calling for a longer, six-year period for the analysis of the marginal generation capacity cost ("MGCC").[5]

More importantly, SCE's proposed MGCC utterly fails to represent conditions expected to occur during 2012 through 2014. SCE's proposed MGCC is based on an assumed installation of a new combustion turbine ("CT") in 2012. Yet, as Chapter 2 will show, no new generation capacity is needed for reliability in the 2012-2014 timeframe by any of the major California Investor Owned Utilities ("IOUs"). DRA finds that SCE's assumption of a 2012 CT installation is at least 5 years in advance of actual need, and this causes its proposed MGCC to be overstated by nearly 50%.

Further, both SCE's MGCC and its marginal customer costs ("MCC") misapply the "real economic carrying charge" ("RECC") methodology, causing these costs to be overstated. In brief, SCE's proposed use of the RECC methodology does not accord with economically correct and Commission adopted marginal cost methodology. Moreover, it results in overestimated marginal costs for generation capacity and customer access, to the detriment of economic efficiency and equitable revenue allocation. This issue is discussed further in this chapter (section C.1) as well as in Chapters 2 and 4.

DRA also has concerns about the appropriateness of the 2012-2014 natural gas price assumptions that SCE used in its proposed marginal energy costs. DRA further questions certain adjustments that SCE has made to the regression method which the Commission has used to determine the marginal distribution capacity cost. The natural gas price and regression adjustments are discussed in Chapters 2, and 3, respectively.

The remainder of this chapter will summarize DRA's marginal cost recommendations and discuss methodological issues that are common to multiple marginal cost categories.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends the following marginal costs, methodologies, and studies.

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[5] See Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*79, D. 96-04-050. See also Application of PG&E (1997) 71 CPUC 2d 212, 1997 Cal. PUC LEXIS 138*26, D.97-03-017.

A. Marginal Generation Capacity and Energy Costs

DRA recommends an annual value of $97.88 per kW-year,[6] based on a modification of SCE's proposed RECC methodology to reflect the lack of need for new generating capacity before 2017.

The following are DRA's recommended marginal energy costs and capacity costs by TOU period.

Table 1-1

	Summer			Winter	
	On-peak	Mid-peak	Off-peak	Mid-peak	Off-peak
MEC (¢/kWh)	7.633	6.882	5.783	6.427	5.747
MGCC ($/kW)[7]	68.61	20.07	0.88	7.93	0.39

B. Marginal Distribution Costs

For delivery marginal costs, DRA recommends the following:

The distribution marginal cost of $113.25 per kW-year, 24% above SCE's proposed value of $91.37 per kW-year. DRA also recommends a subtransmission (non-ISO) marginal cost of $41.45 per kW-year, 18% above SCE's proposed value of $35.06 per kW-year.

These recommendations reflect DRA's proposed retention of the Commission's traditional regression-based approach, and changes to SCE's data and methodology as discussed in Chapter 3.

C. Marginal Customer Access Costs

DRA recommends that the Commission adopt marginal customer costs based on the "New Customer Only" ("NCO") methodology which the Commission has adopted in nearly all litigated marginal cost decisions since 1992. The Commission has repeatedly

[6] This value includes a 15% resource adequacy adder.

[7] Includes a 15% resource adequacy adder. DRA accepts the factors proposed by SCE to allocate MGCC to TOU periods.

found that the "Real Economic Carrying Charge ("RECC") Method" as proposed by SCE overcharges customers for the cost of their meter, service extension,[8] and final line transformer. Therefore, DRA strongly recommends that the Commission not adopt SCE's proposed MCCs.

DRA's recommended MCCs are listed below.

Table 1-2

	DRA Annual NCO Customer Cost (2012$)
Domestic	**74.17**
GS-1	**100.44**
TC-1	**104.10**
GS-2	**713.89**
GS-2T	**727.34**
GS-3	**2063.93**
TOU-8	**2613.00**
TOU-8-Sec	**2609.38**
TOU-8-Pri	**1614.36**
TOU-8-Sub	**6745.47**
PA-1	**428.98**
PA-2	**542.31**
TOU-PA-5	**886.11**
AG-TOUs	**784.74**
AG <= 200	**476.27**
AG > 200	**1708.70**
Street Lights	**76.09**

D. Other Recommendations

DRA recommends that the Commission direct SCE to conduct a comprehensive study of its costs to connect new customers to its distribution grid, and that its 2015 GRC Phase 2 MCCs be based on, at a minimum, a statistically valid sample of actual customer connection project costs for connections completed between 2012 and 2014.[9] Such costs should exclude developer contributions under Rules 15 and 16. SCE's current

[8] Also called a "service drop", this is the conductor that carries current from the final line transformer to the customer's meter.

[9] PG&E has based its proposed MCCs on such a study since its 2003 GRC Phase 2.

methodology, which relies on a limited number of "typical" connection scenarios, omits many other connection scenarios, which should be accounted for to accurately represent customer connection costs. SCE's methodology also may improperly include costs that are paid by developers or customers.[10]

Grid connection costs (specifically costs of installing meters, service extensions, and final line transformers) vary by customer class and are a major component of marginal customer access costs. These, in turn, influence the allocation of SCE's distribution revenue requirement among its customer classes. The recommended customer connection costs studies are needed to ensure that those allocations are just and reasonable.

III. DISCUSSION

As described by SCE,[11] a "real economic carrying charge" ("RECC") methodology is used in the calculation of both MGCC and MCCs. SCE describes its RECC methodology thusly:

> When computing marginal costs, SCE converts capital investments into annual costs using a real economic carrying charge (RECC). This approach is sometimes called the economic deferral or rental value method. Under this approach … the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed, and then compared to the present worth of an equivalent asset and its replacements installed one year later. The only difference between these two scenarios is that SCE loses the opportunity to use the asset in the first year of the second scenario. Thus, the difference in present worth between the two scenarios measures the economic (opportunity) cost of using the asset during the first year. The resulting annual charge, when escalated at the rate of inflation over time and then discounted, yields the original cost (in terms of revenue requirement) of the investment …. the RECC results in the same real payment over time. This conclusion is important because in real terms the charge for an asset is the same over time and, assuming electricity customers value the service they receive, the charge should be the same regardless of the age of the equipment. Therefore, the proper charge can be calculated for both existing and new customers by applying the RECC to the current cost of the equipment.

[10] These assertions are explained in Chapter 4.

[11] Ex. SCE-02, p. 12.

In effect, the RECC results in annual payments that rise with inflation and collect the associated revenue requirement for an investment made in year one of SCE's planning horizon over the life of the facility.

DRA finds that RECC is an appropriate starting point for many marginal cost calculations and is appropriate for annualizing the cost of investments for new equipment when such investments occur in the first year of the planning horizon. Use of an RECC also is appropriate for use in conjunction with the Regression Method used for marginal demand-related distribution costs. However, the RECC methodology overstates the marginal cost both for of existing utility plant (e.g., customer hookup facilities) and of future capital investments (e.g., future generation capacity investments). It does so by (1) overstating the opportunity cost associated with existing hookup equipment, and (2) failing to adjust the cost of capacity investments for the time value of money when there is no immediate capacity need.

A fundamental issue in utility marginal cost ratemaking is whether or not marginal costs should reflect the timing of future demand-related investments.[12] From time to time, some parties, most notably SCE, have proposed to base marginal costs on the cost of replacement of existing facilities by new facilities, regardless of the need for or timing of such replacements, or the need for new capacity. The Commission most often, and correctly, has rejected such "replacement cost new" ("RCN") methodologies, because RCN does not accurately capture the change in costs caused by a change in demand.

Over the last 30 years the Commission has generally adhered to the correct incremental definition of marginal cost it adopted in 1981:

> Marginal costs may be defined as the change in total cost which results from a change in output. The result of using marginal cost in rate setting

[12] This issue arises for marginal capacity costs when capacity investments are "lumpy," that is, they tend to be large and occur infrequently, as may be the case for generation capacity. Lumpiness is less a concern for distribution capacity, at least at the utility system level. In the regression method, historical cost data for many small and medium sized demand-related distribution investments are aggregated. For a large utility, the resulting stream of annual costs is generally "smooth" and timing of individual capital investments is not an issue.

is that the rate equals the cost of producing one more unit, or the savings from producing one less unit.[13]

Quoting from a TURN protest in an earlier SCE rate proceeding:

> "The Commission's existing marginal cost methodologies generally set rates based upon the answers it determines to the following questions:
>
> 1. What costs change if the utility adds a customer?
> 2. What costs change if the utility adds a kilowatt of demand (sometimes defined as a kilowatt of demand at a particular location)?"[14]

The answers to these questions depend upon the amount of surplus capacity relative to customer demand. The principle that **marginal costs should signal the amount of surplus capacity and the timing of new additions** was stated by the Commission in 1990 and again in 1992:

> **Prices …should recognize that some customers cause demand for system additions more than others, and some cause demand for additions sooner than others. To recognize these differences between customer groups, [marginal cost] studies should incorporate an adjustment which takes into account the proximity or distance of actual planned additions)….**[15]

> …our goal is to continue to improve our methodology of sending the most accurate marginal cost price signals to PG&E's customers. Because this is our goal, we agree with PG&E's policy principles that marginal cost components should…capture the timing and magnitude of future investments…[16]

The economic intuition behind this principle is that MCs should "be low in times of capacity surplus, rising to full cost when capacity is constrained."[17]

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[13] OII No. 67 (1981) 5 CPUC 2d 620, Appendix B, 1981 Cal. PUC LEXIS 597*3, D. 92749.

[14] Protest of The Utility Reform Network, February 11, 2000, in A.00-01-009.

[15] OII into Rate Design for Unbundled Gas Utility Services (1990) 37 CPUC 2d 66, 1990 Cal. PUC LEXIS 766*10, D.90-07-055, emphasis added.

[16] Application of PG&E (1992) 47 CPUC 2d 143, 1992 Cal. PUC LEXIS 971*13, D.92-12-057, mimeo, pp. 235-236.

[17] OII Implementing A Rate Design, (1992) 47 CPUC 2d 438, 1992 Cal.PUC LEXIS 970*43, D.92-12-058, mimeo, p. 33, quoted from CACD Workshop Report.

This principle implies that marginal costs should vary over time depending on the amount of surplus capacity. Immediately before a major investment, which is intended to resolve an anticipated capacity shortage, marginal capacity costs should be high. After the investment, when excess capacity exists, marginal capacity costs should be reduced to a low level.

Historically, the Commission has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity.

In one of the more recently litigated SCE decisions dealing with generation marginal cost issues, D.96-04-050, the Commission reaffirmed its previous guidance that marginal costs should be reduced at times of near-term capacity surplus. To understand this guidance, one must understand that, during the 1990s, the Commission used an "Energy Reliability Index" ("ERI") to adjust the marginal generation capacity costs to reflect near-term surplus capacity. In its Test Year 1995 GRC, SCE proposed an ERI of 1.0, reflecting **no adjustment** for near-term surplus capacity.[18] In resolving that Application, the Commission stated:

> The CT cost is … adjusted by an Energy Reliability Index (ERI). The ERI reflects the actual situation faced by Edison in maintaining reliable generation service. When a utility needs capacity to increase reliability of service, its ERI is 1.0 and marginal costs include all the costs of a CT. As capacity is added and reserve margin increases, the value of incremental capacity declines and the ERI drops below 1.0.[19] (D.96-04-050, p. 52)

> …several parties take issue with Edison's use of a 1.0 ERI. Edison argues that an ERI of 1.0 is appropriate because its system is designed to meet customers' needs for reliable firm capacity "for an indefinite period." Accordingly, Edison believes that marginal generation costs should reflect the long-run need for capacity by including the full cost of a CT...[20]

---

[18] This proposal, which was rejected in D.96-04-050, is identical to SCE's current proposal in A.11-06-007.

[19] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*76, D.96-04-050, mimeo, p. 52.

[20] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*78, D.96-04-050, mimeo, p. 54.

> DRA, CFBF, and CLECA recommend the use of a six-year average ERI of 0.85. They argue that a six-year average appropriately balances both long-run and short-run considerations, including the near-term market conditions...[21]
>
> As discussed above, we believe that marginal costs for use in revenue allocation and rate design should appropriately reflect expected year-to-year price variations during the forecast period. A six-year average ERI is consistent with this approach…[22]
>
> …we continue to find its arguments for an ERA of 1.0 to be unpersuasive. **Moreover, Edison 's preference to ignore short-term capacity conditions in the valuation of marginal generation costs is inconsistent with how we evaluate the capacity value of new resource additions, such as DSM** …. We adopt an ERA of 0.85…[23]

Although the ERI methodology of the 1990s is obsolete, the economic principles embodied in D.96-04-050 remain valid and are equally relevant today. Furthermore, they are consistent with mainstream economic thought. Most economists agree that the marginal cost concept most relevant for ratemaking takes into account the near-term existence or lack of surplus capacity.[24] **In other words, marginal cost should consider not simply the cost of the next unit of supply, but should reflect the cost of serving the next unit of customer demand.**

There is much support in the economics literature for basing marginal cost estimates on demand, considered in conjunction with supply, rather than on supply costs alone. SCE's RECC methodology is based solely on supply (i.e., capacity) costs without regard for demand. This cannot be correct in a period with excess capacity: As stated by Alfred Kahn **"…the intensity and elasticity of demand help determine the level of marginal costs."**[25]

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[21] Id.

[22] Id.

[23] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*79, D.96-04-050, mimeo, p. 55, emphasis added. See also Finding of Fact 25 in this Decision.

[24] See, for example, Kahn, Alfred (1970). "The Economics of Regulation," The MIT Press. http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948. Retrieved 2010-11-30, pp. 70-71.

[25] Kahn, p. 89.

In a similar vein, Nobel Laureate (in economics) Sir Ronald Coase stated:[26]

> In calculating the costs of an additional supply of a public utility service, it is of course necessary to start with the industry as it is, with whatever assets it possesses and the circumstances in which it finds itself. **Costs are rooted in the actual situation.**[27]

This is a clear statement that marginal cost methodology should be based on real utility investment plans (which consider the timing of need), rather than on the undiscounted cost of capacity when such capacity may not be required for several years into the future. Chapter 2 discusses how this principle applies in the context of marginal generation capacity cost.

As discussed in Chapter 2, generation reserve margins are now well above target levels and are forecast to remain so throughout 2012 to 2014. This implies that SCE is now at a time of near-term excess generating capacity.

RECC Methodology Overstates Marginal Costs At Times of Excess Capacity. As noted above, SCE's RECC approach does not adjust for the timing of future capacity investments. If capacity is not needed until say, five years into the future, it does not discount such costs back to the present, as suggested by Kahn.[28] SCE's RECC approach fails to account correctly for the time value of money when no current capacity investments are needed. Estimating marginal costs based on discounting future investment costs leads to the following comparisons shown in Table 1-3:

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[26] R. H. Coase, "The Theory of Public Utility Pricing and Its Application," Bell Journal of Economics and Management Science, Volume 1, No. 1 (Spring 1970), p. 123.

[27] R. H. Coase, "The Theory of Public Utility Pricing and Its Application," Bell Journal of Economics and Management Science, Volume 1, No. 1 (Spring 1970), p. 123, emphasis added.

[28] Kahn, p. 104, footnote 47. Kahn's suggestion is discussed extensively in Chapter 2.

Table 1-3:
Adjustment of Future Costs for the Time Value of Money[29]

Year of Investment	Year	Adjustment Factor for Time Value of Money		Percent Overstatement of Costs By RECC Method
		RECC Method	Correct Adjustment	
1	2012	1.0	1.0	0%
2	2013	1.0	0.926	8.0%
3	2014	1.0	0.857	16.7%
4	2015	1.0	0.794	26.0%
5	2016	1.0	0.735	36.1%
6	2017	1.0	0.680	47.0%
7	2018	1.0	0.630	58.8%
8	2019	1.0	0.583	71.5%
9	2020	1.0	0.540	85.3%
10	2021	1.0	0.500	100.1%

The overstatement of costs, indicated in Table 1-3 potentially applies to SCE's use of the RECC methodology in both marginal generation capacity costs ("MGCCs") and marginal customer costs ("MCCs").

For MGCCs, SCE's RECC methodology would be correct in concept if SCE were required to invest in new generation capacity in 2012 to maintain accepted service reliability standards. However, as indicated in Chapter 2, SCE will not require additional generation capacity until at least 2017, the sixth year of the six-year planning horizon that the Commission has established for purposes of estimating MGCC. According to Table 1-3, SCE's RECC methodology would overstate the correct 2012 marginal cost by 47%. Therefore, the Commission should not adopt SCE's RECC-based MGCC; it is too high because it does not properly reflect the time value of money. Chapter 2 presents DRA's detailed justification for its recommendations concerning SCE's MGCC.

In a similar vein, Chapter 4 discusses how the Commission has consistently found that applying the RECC methodology applied to customer hookup equipment overstates

[29] Data in this table are based on SCE's assumptions of a 10.0% discount rate and an inflation rate of

(continued on next page)

SCE's marginal customer access costs. This application of the RECC is often called the "rental method." These access costs include the capital costs of customer access equipment such as final line transformers ("FLTs").[30] SCE's FLTs are assigned a 30-year service life, and SCE's field-installed FLTs have vintages ranging from new to 30 years old, or older. For FLTs newly installed in 2012, the RECC methodology would yield the correct marginal cost. It would exactly recover the capital-related costs of the newly installed FLT over its service life spanning 2012 through 2041.

However, this approach would overstate the cost of an existing FLT which could be due, for example, for replacement in year 6 (2017 in this case). A correct 2012 marginal cost analysis would adjust the 2012 cost by a factor of 0.68 to account for the time value of money and inflation over the period 2012 to 2017.[31] SCE's RECC methodology fails to make this adjustment. Instead, SCE's RECC methodology treats all FLTs (and other customer hookup equipment) as if it were being replaced in 2012. For an item not due for replacement until 2017, SCE's methodology overstates costs by 47% (per Table 1-3).

As explained in Chapter 4, the economic value (or opportunity cost) of an existing utility distribution system (including customer hookup facilities) is considerably less than the "replacement cost new" ("RCN") value embodied in SCE's use of RECC methodology in marginal customer costs. RECC methodology ignores both sunk costs and economic depreciation associated with existing facilities. Use of the RECC methodology, as proposed by SCE, would greatly overcharge customers for their hookup facilities. This assertion is consistent with numerous previous Commission findings in a series of decisions rejecting the rental methodology.[32]

(continued from previous page)
1.84% which it uses to estimate its generation RECC.

[30] Customer access (or hookup) equipment consists of meters, service extensions, and FLTs. The latter comprise about 60% of SCE's hookup equipment by dollar weight. DRA discusses customer access marginal costs in Chapter 4.

[31] Per Table 1-3, which is based on SCE's assumed 10% discount rate and 1.84% inflation rate.

[32] See, for example, In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*79, D.96-04-050, Findings of Fact 37 and 38. Other decisions are cited in Chapter 4.

IV. CONCLUSION

The Commission has a long history of either rejecting the RECC methodology outright (as in the case of marginal customer hookup costs) or adjusting it downward to reflect near-term capacity surplus (in the case of marginal generation capacity costs). SCE, in offering the identical RECC methodology that the Commission has repeatedly rejected, is swimming against the mainstream of economic thought as well as Commission precedent.

By failing to reflect near-term lack of need for new investments, SCE's proposals overstate both types of marginal costs, to the detriment of economic efficiency. The Commission should reject SCE's unadjusted RECC proposals for both marginal generation capacity and customer hookup costs.

CHAPTER 2.

MARGINAL COSTS OF ELECTRIC GENERATION

(Witness Robert Levin)

I. INTRODUCTION

SCE presents separate marginal cost components for generation capacity and energy, as has been the practice during most of the Commission's thirty-year history of basing electric rates on marginal costs. For the marginal generation capacity cost, DRA recommends an annual value of $97.88 per kW-year,[33] including a 15% resource adequacy adder, based on a modification of SCE's proposed RECC methodology to reflect lack of need for new generating capacity before 2017. For marginal energy costs, DRA recommends that SCE's proposed values be increased by 24% to reflect a more realistic forecast of natural gas prices.

As described by SCE:

> The Commission has a long-standing policy of developing marginal generation costs using the deferral value of a combustion turbine ("CT") proxy for estimating the avoided cost of capacity, and a system marginal energy cost for estimating the avoided cost of energy. Capacity and energy costs were combined into a single market price when the market structure adopted in California anticipated that generators would recover their fixed investment costs from market prices during periods of scarcity when the market prices rose above the variable operating costs of generators participating in the market. However, the Commission's implementation of resource adequacy requirements has returned the utilities and the market to a structure that requires the clear separation of capacity and energy costs as the basis for generation marginal costs. The separation of energy and capacity costs makes it possible to evaluate the relative reliability contribution of different resources, and is more flexible across a range of capacity factors and TOU periods.[34]

DRA agrees, in general, with this SCE testimony and, in particular, with SCE's proposal to separate the energy and capacity marginal cost components. While SCE is

[33] SCE's proposed MGCC ($125.10 per kW-year) excludes the 15% resource adequacy adder. On a comparable basis (excluding the adder), DRA proposes $85.11 per kWh.

[34] Ex. SCE-02, pp. 15-16.

correct in stating that the Commission has used the deferral value of a combustion turbine ("CT") proxy for estimating the avoided cost of capacity,[35] SCE neglects to state the key fact that **the Commission has a long history of adjusting the CT deferral value downward, reflecting a reduced marginal generation capacity cost ("MGCC") when surplus capacity exists.**

As discussed in Chapter 1, for nearly a decade the Commission used an "Energy Reliability Index" ("ERI") to adjust the annualized CT cost downward when it found the existence of near-term surplus capacity. The ERI methodology fell out of use with electric industry restructuring of the late 1990s, and is now considered obsolete. As mentioned in the SCE testimony quoted above, after a hiatus, the Commission reinstated separate marginal cost components for capacity and energy. Since 2001, the capacity costs always have resulted from a settlement. While some parties proposed to use the full annualized cost of capacity, other parties proposed lower values, and the settled values have generally been somewhat below the full annualized capacity cost.

There are at least two factors that could, and should, reduce that MGCC below the real economic carrying cost of a CT. First, one could deduct the "energy rent" of a new CT, defined by SCE as "the operating profits that a proxy CT is able to earn when market prices are above the CT's variable operating costs, which principally consist of fuel, emission costs, and variable O&M."[36] SCE proposes to deduct its estimate of energy rent, resulting in about an 8% reduction to its "full CT proxy cost."[37]

The second factor that could, and should, further reduce the MGCC is the existence of a near-term surplus capacity. As discussed below, according to the Commission's Long-Term Planning Proceeding ("LTPP"), no new generation capacity is

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[35] Equivalently, the CT cost, annualized in real dollars.

[36] Ex. SCE-02, p. 17.

[37] Ex. SCE-2, Table I-5, p. 19. SCE's proposed energy rent adjustment is smaller than that proposed by SCE in its previous GRC and smaller than energy rents proposed by other utilities. It is also smaller than the energy rent values that DRA has recommended in the past. DRA accepts SCE's energy rent analysis as reasonable, nonetheless, due to the current unusually low natural gas prices and the unexpected lack of volatility in CAISO day-ahead hourly wholesale market prices since CAISO's Market Redesign and Technology Upgrade (MRTU) became effective in April, 2009.

needed in California through at least 2017. As discussed in Chapter 1, both Commission precedent and mainstream economic theory dictate that the marginal capacity cost used to set retail prices should be reduced, relative to its long-run value, when near-term surplus capacity exists.

DRA finds that SCE's proposed MGCC values are overestimated because SCE does not adjust MGCC downward to reflect near-term surplus capacity. To correct this defect, DRA proposes an adjustment to SCE's MGCC value, which is based on annualized CT cost, reduced by energy rent. As described by SCE, its RECC methodology is equivalent to a deferral approach in which "the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed [based on 2012 installation], and then compared to the present worth of an equivalent asset and its replacements installed one year later [in 2013].[38] DRA proposes to modify SCE's RECC approach by computing the deferral value of a 2017 CT installation deferred to 2018. This adjustment, reflecting the time value of money, reduces the MGCC by about 30%. The detailed justification for DRA's approach is presented below.

With respect to marginal energy costs ("MEC"), SCE presents averaged MEC for the 2012-2014 period by its five time-of-use periods. SCE's proposed MECs are based on a commercial production simulation model which produces forecasts of hourly market clearing prices. SCE described its computations thusly: "[t]he [hourly] prices are then sorted and averaged by time-of-use periods corresponding to the pricing periods in SCE's TOU-8 rate schedule."[39]

MECs generally have two independent attributes, their average level, and their "shape," which accounts for the relationship (ratio) between MECs in peak-demand periods to the MECs in off-peak periods. DRA compared SCE's proposed MECs with publically available energy cost data, primarily for shape. In general, SCE's proposed MECs are "flatter" than the data for recent years available from public sources. That is,

[38] Ex. SCE-02, p. 12

[39] Ex. SCE-02, p. 21.

SCE's MEC results show less variation between the on-peak and off-peak periods, as compared to recent public data. SCE explains its forecast reduction in the "spread" between peak and off-peak MECs as resulting from the combined effects of the Renewable Portfolio Standard ("RPS") and Greenhouse Gas ("GHG") carbon emissions pricing initiatives.[40] As discussed below, DRA finds SCE's reasoning credible and accepts the **shape** of the MECs as proposed by SCE.

DRA does not, however, accept the **level** of SCE's proposed MECs. A key input in determining the average level of MECs is the price of natural gas. Natural gas-fueled generation is expected to be "on the margin" during most hours of the period 2012-2014.[41] SCE states that its MECs are based on a three-year average gas price of $5.36 per million Btu. This price is well below historical levels and is also beneath the levels in a number of forecasts. DRA proposes to increase the level of SCE's MECs by about 24% to render them consistent with a current California Energy Commission natural gas forecast for 2012-2014.

DRA's specific marginal generation cost recommendations are presented below, along with a discussion detailing DRA's findings.

II. SUMMARY OF RECOMMENDATIONS

For the marginal generation capacity cost, DRA recommends an annual value of $97.88 per kW-year,[42] including a 15% resource adequacy adder, based on a modification of SCE's proposed RECC methodology to reflect lack of need for new generating capacity before 2017.

The following are DRA's recommended marginal energy costs and capacity costs by TOU period.

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[40] Ex. SCE-02, pp. 22-26.

[41] That is, in most hours a small increase or decrease in SCE's electricity demand would cause one or more gas-fired generating plants to increase or decrease its output.

[42] SCE's proposed MGCC ($125.10 per kW-year) excludes the 15% resource adequacy adder. On a comparable basis (excluding the adder), DRA proposes $85.11 per kWh. DRA accepts the factors proposed by SCE to allocate MGCC to TOU periods.

Table 2-1

	Summer			Winter	
	On-peak	Mid-peak	Off-peak	Mid-peak	Off-peak
MEC (¢/kWh)	7.633	6.882	5.783	6.427	5.747
MGCC ($/kW)[43]	68.61	20.07	0.88	7.93	0.39

III. DISCUSSION

A. Marginal Generation Capacity Costs

DRA accepts SCE's proposed conceptual framework for calculating MGCC, starting with the real annualized cost of a CT and deducting energy rent, with two exceptions. First, **the Commission historically has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity.** Yet SCE proposes no such adjustment. Second, the MGCC should be adjusted upward by 15% to reflect resource adequacy requirements.

1. Marginal Generation Capacity Costs Should Signal the Amount of Surplus Capacity and Timing of New Additions

As discussed in Chapter 1, the principle that **marginal costs should signal the amount of surplus capacity and the timing of new additions** was stated repeatedly by the Commission during the 1990s in the era when marginal costs were litigated rather than adopted through settlements. The Commission has applied this principle in both electric and natural gas contexts.[44] DRA is unaware of any litigated Commission decision that adopted a marginal cost based on the full annualized cost of new capacity when near-term surplus capacity was shown to be present.

[43] Includes a 15% resource adequacy adder.

[44] In D.92-12-058, the Commission rejected a proposal to base the marginal cost of gas transmission on the annualized cost of a new pipeline. The rejected proposal was equivalent to the unadjusted RECC methodology SCE proposes here.

The capacity costs reflected in the MGCC accordingly must be reduced when there is near-term surplus capacity. SCE's failure to adjust its MGCC accordingly runs counter a long series of Commission decisions epitomized by D.96-04-050, one of the more recently litigated SCE decisions dealing with generation marginal cost issues, which is quoted extensively in Chapter 1.

In D.96-04-050, the Commission reaffirmed its previous guidance that marginal costs should be reduced at times of near-term capacity surplus. SCE's failure to reduce its MGCC to reflect near-term surplus capacity also is at variance with mainstream economic thought that marginal costs must take into account demand conditions and should not be based solely on the cost of the next unit of supply (or capacity).[45]

In the next section, DRA will establish the existence of near-term surplus generation capacity and explain in detail how it proposes to adjust SCE's MGCC proposal to reflect that surplus capacity.

2. California Will Have Surplus Generation Capacity At Least Through 2016.

The Commission utilizes a Long-Term Procurement Planning ("LTPP") process to assess generation capacity needs, typically over a ten-year horizon. The current LTPP proceeding (R.10-05-006) was initiated in May, 2010. LTPP is now organized in 3 "tracks", of which Track 1 is relevant here:

> (1) **Track I** will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through-cooling ("OTC").

SCE's testimony in A.11-06-007 provides no information about whether SCE needs new generation capacity for reliability purposes in 2012, or indeed in any year of the Commission's traditional six-year time horizon (2012 through 2017, in this case).

[45] See, Chapter 1, p. 10.

However, SCE's Opening Brief in R.10-05-006 does shed light on SCE's perception of its own capacity needs:

> "There is no conclusive evidence in this proceeding that SCE needs to procure additional generation for any purpose at this time."[46]

Coupling this SCE statement with the generally recognized 5 to 7-year lead time needed to plan and construct new generation capacity, one can logically infer that SCE sees no need for new generation capacity in the period of 2012 through 2016. This conclusion is confirmed more generally by most participants in the current LTPP proceeding (Track 1). In a motion to approve a settlement agreement signed by 23 parties, including SCE, the parties state: "[t]he Commission does not need to authorize procurement authority relating to LCR [Local Capacity Requirements] for SCE's and PG&E's service areas at this time."[47]

Further confirmation can be found in a recent independent (non-Commission sponsored) report by the North American Electric Reliability Corporation ("NERC").[48] NERC examined the resource balance for each of the major sub-regions within the Western Electricity Coordinating Council ("WECC") region. NERC's analysis shows that generation reserve margins will be well above the Commission's 15% to 17% targets through 2021. The following figure summarizes NERC's findings for Southern California.

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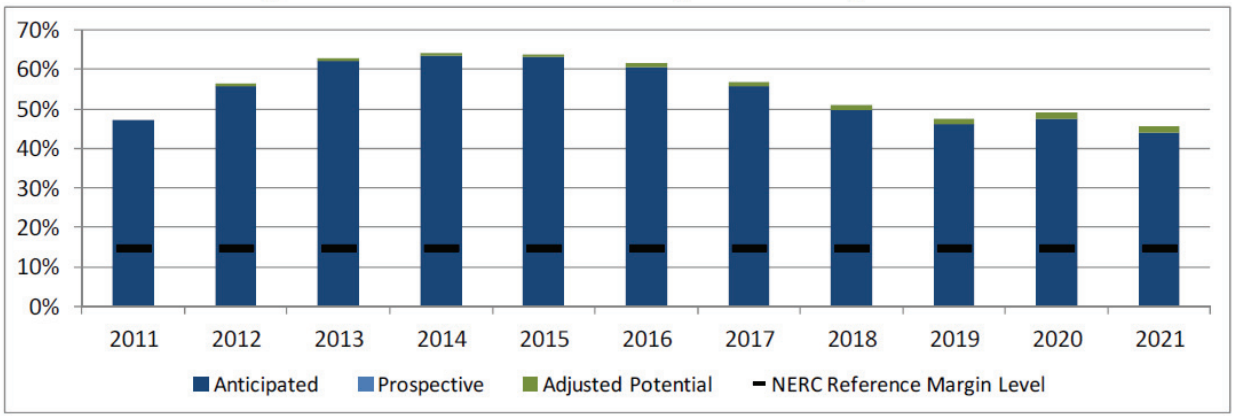
[46] SCE Opening Brief in R.10-05-006, September 16, 2011, p. 6.

[47] Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum, filed August 3, 2011 in R.10-05-006.

[48] North American Electric Reliability Corporation (NERC) 2011 Long-Term Reliability Assessment, November 2011, p. 463, Fig. 130

Figure 130: Annual On-Peak Planning Reserve Margins – CALS



3. SCE's MGCC Should Be Estimated Based on The Value of Deferral of Capacity from 2017 to 2018.

As discussed above, 2017 is the soonest that new generation capacity could be needed for reliability purposes in California. Further, 2017 is the last year of the six-year period which begins 2012. The Commission has traditionally adopted a six-year period for estimating MGCC because it balances short-run and long-run capacity needs. For these reasons, DRA bases its MGCC estimate on a scenario that capacity will not be needed during the years 2012 through 2016, but **could** be needed in 2017.[49]

Accordingly, DRA proposes to modify SCE's proposed RECC methodology by escalating the CT cost to 2017 and then computing the present value in 2012 of the annualized cost of a CT installed in 2017. Incorporating the energy rent adjustment proposed by SCE, the effect of the assumed five-year delayed CT installation from 2012 to 2017 reduces the 2012 MGCC from $125.10 per kW-yr to $85.11 per kW-yr.[50]

DRA's proposed methodology is consistent with marginal cost theory, as articulated by Alfred Kahn. Kahn, in describing a situation in which lumpy investments in capacity occur in anticipation that they will be needed to satisfy future peak demands, states the following:

[49] DRA emphasizes that it is not forecasting the need for new generating capacity in 2017. It simply accepts that there *could* be a need in 2017, and proposes therefore to base SCE's MGCC on the value of deferring CT capacity from 2017 to 2018.

[50] These values exclude the 15% resource adequacy adder discussed below.

> Typically, public utility companies must build in advance of demand in order to be in a position to meet unexpected peak requirements and simply because the investment process is a lumpy one: additions to capacity are most economically made in large units. Therefore at any given time, there is almost certain to be excess capacity, which will remain idle if customers are charged long-run marginal costs.[51]

Kahn then asks, rhetorically: "What, in these circumstances, is the proper measure of marginal costs?" He answers his own question thusly:

> …there is a strong economic case for letting price rise and fall as demand shifts…in the presence of excess capacity, no matter how temporary, no business should be turned away that covers the SRMC [short run marginal cost] of supplying it.[52]

Kahn describes in a footnote how capacity costs could be assigned to current peak period usage even though such usage is not causing an immediate need for new capacity:

> It might appear that no customer whose continued patronage would eventually require additions to capacity should ever be charged a price that completely excludes those capital costs; the economic ideal, it might appear, would be to include them, but **discounted back to the present value**, to reflect the fact that continued service of the customer in question would require their incurrence only sometime in the future.[53]

In the current context, therefore, DRA believes that it is entirely consistent with economic theory, when near-term surplus capacity exists, to charge current on-peak electricity users a substantial fraction, but not 100%, of the full long-run cost of capacity. DRA proposes to use the traditional RECC approach applied to a CT

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[51] Kahn, Alfred, The Economics of Regulation (1970), p. 104. (see http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948.)

[52] Id at p. 104.

[53] Kahn, Alfred, The Economics of Regulation (1970), p. 104, footnote 47, emphasis added. (see http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948.) The reader may note the phrase "it might appear." This caveat refers to the subsequent statement (in the same footnote): *"Such a prescription ignores the fact that buyers whose continued patronage could require the incurrence of additional capacity costs are not in fact responsible for them if they drop out of the market when the time comes for the supplying company to make the decision whether to make the additional investment."* DRA believes that Kahn's caveat does not apply, in the main, to electricity, because most electrical equipment has an expected lifetime of five years or more, and so, any change in current electricity consumption due to acquisition of new or replacement electrical equipment or appliances is likely to be of long duration and is likely, therefore, to affect future capacity needs.

proxy installed in 2017, but **discounted back to the present value** as described by Kahn.[54] For the 10% discount rate and 1.84% inflation rate proposed by SCE, discounting back to the present value results in about a 32% reduction, from $125.10 per kW-yr to $85.11 per kW-yr.

4. SCE's MGCC Should be Adjusted Upward by 15% to Reflect Resource Adequacy Constraints.

DRA notes that the MGCC value proposed by SCE excludes a resource adequacy adder.[55] Such an adder should be included to reflect the fact that each additional kW of customer demand causes the need for 1.15 kW of additional generation capacity. This is a result of a requirement, instituted in the Commission's Resource Adequacy proceeding, that utilities maintain a planning reserve margin of at least 15%.[56]

This proposed adjustment is not new: a 1.15 "Capacity Response Ratio" ("CRR") factor was also adopted in D.96-04-050 and used to adjust the MGCC upward.[57] Finally, SCE acknowledged its inadvertent omission of the 1.15 factor in an informal communication to DRA.[58]

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[54] Id. The necessary adjustment is given by the formula: Y = X (1+i)^n/(1+r)^n where Y is the adjusted capacity value, X is the unadjusted capacity value proposed by SCE, i is the inflation rate, r is the discount rate, n is the number of years elapsed (5, in this case) between the test year and the year of capacity need), and "^" denotes exponentiation.

[55] SCE's MGCC calculation is shown in Ex. SCE-02, Tables I-4, I-5 and I-6, pp. 17-20.

[56] As described on the Commission's website: "The CPUC adopted a Resource Adequacy (RA) policy framework (PU Code section 380) in 2004 to in order to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs)."

"Each LSE is required to file with the Commission demonstrating that they have procured sufficient capacity resources including reserves needed to serve its aggregate system load on a monthly basis. Each LSE's system requirement is 100% of its total forecast load plus a 15% reserve, for a total of 115%."

[57] See In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*76 and *78, D.96-04-050, p. 52 and p. 54. While the 15% adjustment could be made in the revenue allocation stage instead of including the 15% factor explicitly in the marginal cost, DRA believes its inclusion in the marginal costs is needed to ensure the correct evaluation of the cost impact of a 1 kW change in customer demand.

[58] In an e-mail sent on December 1, 2011 from Mr. Russell Garwacki, SCE stated: "In determining Marginal Cost Revenue Responsibility for generation, SCE omitted making an adjustment to the generation capacity marginal cost revenue requirement to reflect a 15% planning reserve margin (PRM) under resource adequacy (RA). The (PRM) should be included as SCE will need to procure PRM

(continued on next page)

5. Summary and Comparison of SCE's and DRA's Proposed MGCC Values

In summary, DRA's proposed MGCC differs from SCE's in two respects:

1. DRA reduces the MGCC value proposed by SCE by about 32% to adjust for the time value of money, reflecting a 2017 to 2018 deferral rather than a 2012 to 2013 deferral; and
2. DRA increases the MGCC by 15% to account for resource adequacy constraints.

The following table compares SCE's and DRA's MGCC values, with, and without the 15% resource adequacy adder.

Table 2-2:
Comparison of SCE and DRA Proposed MGCC Values

	Without 15% adder	With 15% Adder
SCE Proposed MGCC	$125.10	$143.88[59]
DRA Proposed MGCC	$85.11	$97.88

6. The Outlook For Continuing High Generation Reserve Margins Could Support a Lower MGCC Value

Southern California's generation reserve margins are forecast to remain above 40% through 2021, according to Figure130 from NERC's 2011 Long-Term Reliability Assessment, shown above. Thus, while DRA supports the Commission's use of a six-year planning horizon for determination of the MGCC, DRA notes that use of a longer planning horizon (e.g., 10 years), combined with NERC's long-term generation capacity outlook, would result in a reduced MGCC value.

Using the same methodology proposed above, with a ten-year planning horizon, would result in an MGCC value of $71.91,[60] very nearly half of SCE's proposed value of $143.88.

(continued from previous page)
capacity for each additional MW of load growth. This results in a 15% increase in the cost for capacity. The PRM is already included in the determination of the cost for capacity for dynamic pricing and demand response programs."

[59] SCE's proposed value of $125.10 per kWh x 1.15.

[60] See Chapter 1, Table 1-3, line 10. The factor 0.500 applied to SCE's proposed MGCC value would yield DRA's 10-year sensitivity case value of $71.91. These values include the 15% resource adequacy adder discussed above.

7. DRA's Proposed MGCC Value Is "Just Right" and Should be Adopted.

DRA notes that DRA's recommended MGCC value of $97.88 is very close to the value proposed by SCE in its 2009 GRC Phase 2,[61] and close to the generation capacity value embedded in SCE's current rates. Thus, adopting DRA's recommendation would further the Commission's goal of rate stability.

In contrast, SCE's proposed value of $143.88 is nearly 50% higher than the value it recommended for 2009. While the cost of a new CT may have increased, the **need** for new capacity has greatly decreased. If the Commission were to adopt SCE's proposal, it would not foster rate stability but would, instead, move rates in a direction which is simply not warranted either by market conditions or by the current short-, intermediate-, or long-term outlook for availability of generation capacity.[62]

B. Marginal Energy Costs

As discussed above, MECs generally have two independent attributes, their average level, and their "shape." The former is determined predominantly by fuel costs. The latter captures the variation in costs caused by changes in demand, by time-of-use period. Typically MEC is lowest in off-peak periods and highest at times of peak demand, as less efficient generating units must be placed into operation in periods of higher demand.

1. The "shape" of SCE's Marginal Energy Costs

SCE's proposed summer season on-peak MEC is 32% above its off-peak MEC; the part-peak MEC is 19% above the off-peak MEC. These proposed MECs are somewhat "flatter" than those seen historically.

SCE states that it bases its MEC forecast on a commercial production simulation model. This model simulates electricity production in the Western Electricity

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[61] SCE proposed an MGCC value of $90.90 per kW-year in its 2009 GRC (A.08-03-002). This value does not appear to include a 15% resource adequacy adder.

[62] See, for example, testimony of Andrew Bell in Phase 2 of PG&E's 2011 General Rate Case, A.10-03-014, filed March 22, 2010, Exhibit PG&E-1, Chapter 9, pp. 9-2 to 9-3, discussing the lack of price volatility in day-ahead hourly CAISO prices. This lack of volatility has continued during the summers of 2009, 2010, and 2011, and indicates lack of a near-term capacity need.

Coordinating Council ("WECC") transmission areas. For each transmission area, the model uses as inputs the hourly loads of each load-serving entity, the available thermal, hydro, and renewable resources, and their operating characteristics, including fuel costs. As SCE states, "The outputs of the simulations are typically the operating costs of generating units, energy not served, and a forecast of [hourly] market clearing prices for each region."[63]

SCE explains that it customizes various model inputs to reflect "updated or more accurate information." Among these, SCE utilized "natural gas fuel prices from February 2011," "renewable targets" consistent with the statutory requirement of 33% renewables per California's Renewable Portfolio Standard (RPS), and carbon emissions priced at "the 2008 Synapse mid-case."[64]

SCE describes the impact of the RPS on its MEC thusly:

> …the increase in renewable energy due to the RPS has altered the net load shape served by dispatchable generation. The large amount of solar power projected to come online over this GRC cycle will reduce the daytime net load by a larger proportion than net load during the night-time hours. …Because of the change to the net load shape, which will impact prices, we can expect the on-peak price to decline more than the off-peak price as demand moves down the marginal supply curve.[65]

DRA finds this SCE testimony both plausible and consistent with economic theory, and agrees with SCE that increased utilization of solar energy could be expected to reduce the spread between on-peak and off-peak marginal energy costs.

SCE also discusses the effect of carbon emissions pricing on MECs. While inclusion of a carbon emissions adder would increase the cost of both natural gas-fired and coal-fired generation,[66] SCE states that:

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[63] Ex. SCE-02, p. 20.

[64] Ex. SCE-02, p. 21. Per Ex. SCE-02, p.16: "The Synapse mid-case starts with a carbon value of $15 per ton (2007$) in 2013 increasing to $53.40 per ton (2007$) in 2030."

[65] Id., p. 23

[66] While coal is not used directly as a fuel source by California utilities, it is used elsewhere in the WECC transmission area.

> Because coal has significantly higher carbon emissions, compared to natural gas, the application of a carbon cost causes the cost of coal to increase more than natural gas. Thus when coal is on the margin, the cost increase will be higher than if it was natural gas.[67]

SCE states that the difference in carbon intensity between coal and natural gas causes the MEC to increase more in the off-peak periods than in the peak periods, thus further narrowing the spread between on-peak and off-peak MECs.[68]

Implicit in SCE's analysis is that, excluding carbon pricing, coal-fired generation has a lower operating cost than natural gas-fired generation. Therefore, most of the hours when coal is on the margin tend to be off-peak hours.[69] With the addition of carbon pricing, the MECs for those hours when coal is on the margin are substantially increased, and, in some cases, natural gas generation may be dispatched ahead of coal.

For carbon pricing as well as increased solar generation, DRA finds SCE's testimony concerning the reduction in the MEC peak to off-peak differentials plausible and consistent with economic theory. Therefore DRA accepts SCE's MEC recommendations insofar as the **shape** of its MECs.

2. The "level" of SCE's Marginal Energy Costs

SCE states that its MECs are based on a three-year average gas price of $5.36 per million Btu.[70] This price is well below historical levels and is also below the levels in a number of forecasts. DRA does not accept SCE's natural gas price assumptions.

In a very recent report, the California Energy Commission ("CEC") states:

> Natural gas is a heavily traded commodities market characterized by inherent volatility. Over just the last decade, natural gas prices spiked several times.[71]

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[67] Id, p. 25.

[68] Id, p. 25, see Table I-10.

[69] During peak periods, coal is likely to be fully utilized and natural gas generation will be needed to meet demand.

[70] Id, p. 21.

[71] CEC Draft Staff Report: 2011 Natural Gas Market Assessment: Outlook, September, 2011, CEC-200-2011-012-SD, p. 4.

Figure ES-3 of the 2011 CEC Natural Gas Market Assessment report shows historical gas prices from 2005 through 2011 and CEC's reference case price forecast, together with three additional "change case" forecasts.[72] According to this Figure, Henry Hub daily spot market natural gas prices were above $6 per MMBtu prior to 2009, and then collapsed to below $4 in 2009 through 2011. However, in all four CEC forecasts, prices are expected to return to the $6 level or above, by 2013. According to the CEC:

> The Reference Case results suggest that the combination of recession-driven weak demand and abundant domestic supply has driven current wholesale market prices significantly below the … highs of a few years ago. These conditions are projected to be temporary as:
>
> 1. Future demand increases with economic recovery and diminishing opportunities on the production side
> 2. Prices rise as production marches up the marginal cost supply curve….
> 3. Even with returning demand, prices could plateau at about $6.00/MMbtu (2010$).[73]

The CEC expects the current low natural gas prices to be temporary:

> The spot purchase price of natural gas at the Louisiana trading hub called Henry Hub is a nationally important market price benchmark. Currently, natural gas prices at Henry Hub are in the low $4/MMBTU range (in 2010$). Current spot prices of natural gas reflect a large supply from shale natural gas and a slow economy. Much of the natural gas production is occurring on leased land where many gas developers must drill for gas soon or lose their lease. Since demand is low due to the recession, the resulting temporary oversupply situation pushes current market prices down.[74]

The CEC forecasts end-use natural gas prices for each of the major California natural gas utilities. For electric generation located in the Southern California Gas

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[72] Id, p. 8.

[73] Id, p. 6.

[74] Id, p. 42.

service area, the CEC forecasts an average price of $6.24 per million Btu for the period 2012 through 2014, which is 24% higher than the input price ($5.36) used by SCE.[75]

DRA finds that the CEC natural gas price forecast of $6.24 better represents the most likely level of natural gas prices in 2012 through 2014 than the value of $5.36 assumed in SCE's MECs. Further, DRA assumes, as a first approximation, that natural gas will be on the margin during most hours of that period. For these reasons, DRA retains the shape of SCE's proposed MECs, but increases the level by 24% to reflect the higher CEC natural gas price forecast.

IV. CONCLUSION

The Commission should adopt SCE's marginal generation capacity costs with the adjustment proposed by DRA to reflect that fact that no additional generation capacity will be needed by California utilities for reliability before 2017. The Commission should increase SCE's proposed marginal energy costs for all time periods by 24%, as proposed by DRA, to reflect the higher natural gas prices forecast by the California Energy Commission for 2012 through 2014.

[75] The annual price forecasts are $6.30, $6.99, and $5.94 per MMBtu, respectively, for the years 2012 through 2014. These forecasts are from the CEC's worksheet on the IEPR website at: http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27 workshop/xls results/. This website is referenced on p.85 of the above-cited CEC report.

CHAPTER 3.

DISTRIBUTION DEMAND MARGINAL COST

(Witness Louis Irwin)

I. INTRODUCTION

This chapter addresses SCE's delivery marginal costs ("DMC"). These costs are comprised of distribution and subtransmission (non-ISO) costs. DRA is concerned about two sizable revisions that SCE has applied to its DMC:

1. The addition of five extra yeas of historical data for its forecast, and
2. The substitution of planned capacity in lieu of actual capacity.

SCE applied these data transformations to both distribution and subtransmission (non-ISO) MC. DRA recommends the Commission reject both of these proposed changes.

II. DRA RECOMMENDATIONS:

For delivery marginal costs, DRA recommends the following:

1. That the Commission use ten years of historical data instead of the proposed fifteen for SCE's forecasted MDC; and
2. That the Commission use actual capacity data instead of planned capacity data for the forecasted MDC.

The combined effect of DRA's recommendations is to raise the distribution marginal cost 24%, from $91.37 to $113.25 per kW-year. It raises the subtransmission (non-ISO) marginal costs 18% from $35.06 per kW-year to $41.45.

The amount of historical data DRA recommends be used for the DMC has been previously approved by the Commission. It has not been left to chance as it is far from inconsequential. The DMC traditionally has been estimated using ten years of historical data and five years of forecast data. Adding an additional five years to the analysis de-emphasizes the short-run elements of this estimate. Moreover, the use of planned data is one additional large step removed from the immediacy of actual short-run data. DRA's recommendations are discussed further in turn below.

III. DISCUSSION

A. Historical Data

SCE uses the regression method to calculate its delivery related marginal costs, but has added for this GRC, an additional five years of historical data:

> "In past GRC's, SCE has applied the NERA regression methodology to ten years of historical data and five years of forecasted data to determine delivery-related marginal costs. For this GRC, SCE proposes to use fifteen years of historical data and five years of forecasted data."[76]

SCE's justification for its proposed change is that "[g]enerally, more data points improve regression accuracy."[77] This generalization is not a compelling reason to break precedent. More data can be better from a statistical sense, but it also results in a divergence from what the DMC is intended to represent. Marginal costs are used in rate design to give the ratepayer a forward-looking price signal. When input costs become over ten years old, it runs contrary to the very purpose of using marginal costs in ratemaking. The Commission and the National Economic Research Associates ("NERA") already addressed the issue of how much data is optimal, and ten years of historical data was the result.[78]

SCE presented no compelling argument indicating how present-day data needs have changed. Using more data (going back further in time) directly dilutes the effect of the more recent data. One could argue that recent economic volatility requires the use of more data in order to represent a longer-term trend. However, DRA believes that the recent economic downturn, and its effects on DMC, should be represented in the marginal costs that are used for rate design. Successful businesses, whether regulated or not, need to be sensitive to current economic conditions rather than setting them aside. The DMC is meant to capture current conditions, which can only be accurately reflected by more current data. In this case, the older data used in the analysis is not discounted,

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[76] Ex. SCE-02, p. 28, lines 13-15.

[77] Ibid. lines 15-16.

[78] Ibid. lines 13-14.

so the use of more data is not necessarily an improvement. Moreover, SCE did not include an analysis of how previous GRC DMC results were harmed by using only ten years of historical data.

The effect of using ten instead of fifteen years of data would increase the distribution marginal costs from $91.37 per kW-year to $96.54 per kW-year, or 5.7%.[79] The subtransmission (non-ISO) marginal costs would increase from $35.06 per kW-year to $37.74 per kW-year, a 7.6% increase.[80]

B. Planned Versus Actual Capacity

SCE's DMC proposal deviates from past precedent by using planned rather than actual capacity figures. On this topic it states,

> In addition, the value used to determine the distribution demand growth has been changed to reflect the systems' "planned capacity" versus "actual capacity." This will mitigate "cost-to-growth" distortions that are caused by intermittent negative load growth caused by the recent recession, the 2002 conservation efforts, or cool temperature years.[81]

Using ten years of historical data provides more than adequate smoothing of the data. Lumpiness in cost data, especially capital investment in utility capacity is certainly nothing new. Furthermore, consumers are constantly reacting to variable economic and weather conditions. Therefore, the ten year history that was used in the NERA regression approach is its recommended method to address the variability inherent in both cost and consumption data. SCE goes on to claim that the change to planned capacity has resulted in decreasing the distribution marginal costs by over 15% by creating a larger base of capacity over which to spread the distribution costs.[82]

DRA believes that the divorce from the real data is not justifiable or preferable. As far as DRA can determine, the 15% reduction in distribution costs is just an indication

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[79] This was calculated by SCE in response to DRA data request DRA-004, question #1.

[80] Per phone call with Joe Cox, SCE, December 12, 2011.

[81] Ex. SCE-02, p. 29, lines 8-11. In discovery process it was revealed that this change was also applied to the subtransmission. Phone conversation with Joe Cox, SCE, December 7, 2011.

[82] Ibid. lines 11-13.

of how far "planned" data deviates from the real data. The planned data incorporates no checks and balances to assure the Commission that it matches reality. Furthermore, the more turbulent or "surprising" the real data is, the farther that the planned data will likely deviate from that reality. There is no intrinsic reason or mathematical necessity for SCE's planned capacity data to lead to a 15% deflation of the distribution MC. It is merely a manifestation of SCE's particular plans – and had SCE's planned capacity been "rosier" (further divorced from actual capacity) then this cost gap would have been larger than 15%. The same principles apply to the subtransmission (non-ISO) MC.

SCE's use of planned data allowed it to decrease the distribution MC from $106.38 to $91.37 and the subtransmission (non-ISO) MC from $40.25 to $35.06. Reversing this effect creates an increase of 16% and 15%, respectively. Combining DRA's proposed method of using 10 years of historical data and using actual capacity data would increase the distribution MC from $91.37 to $113.25 (24%) and the subtransmission (non-ISO) MC from $35.06 to $41.45 (18%).[83]

Perhaps, SCE is also attempting to suppress the increase from the 2009 GRC values, as the change is aggressive. For distribution MC, the SCE proposal of $91.37 kW-year is 32.4% higher than it proposed for the previous GRC ($69 per kW-year). SCE's subtransmission (non-ISO) cost ($35.06) is 21% higher than the value proposed for the previous GRC ($29 per kW-year).[84] The DRA proposals are even higher, 64% and 43%, respectively. Sizable cost increases are also found in other areas of the testimony. The size of the DMC cost increase alone is not sufficient reason to distort its value.

C. Regression Technique

As part of the 2009 GRC settlement, SCE worked with agricultural interveners to address a problem of serial correlation of the data used for its regression analysis. The result of that investigation is that SCE now proposes using a Maximum Likelihood

[83] SCE DR 4 question #2, Subtransmission MCs as per phone conversation with Joe Cox, SCE, December 12, 2011.

[84] Ex. SCE–02, p. 28, Table 1-9.

Estimate ("MLE") method instead of Ordinary Least Squares ("OLS").[85] These methods yield identical results except in the case where the errors are not normally distributed (as in serial correlation).[86] The use of cumulative load and investment data in the NERA methodology has the potential to create serial correlation. Moreover, application MLE in fact did change the results, thereby demonstrating its relevance. Thus, DRA will not challenge this methodological change.

IV. CONCLUSION

SCE deviates from the NERA approved regression method in three ways. In regard to regression methods (the change from OLS to MLE), DRA makes no challenge. In regard to two substantive data revisions (adding five historical data years and using planned instead of actual capacity data) DRA urges the Commission to reject SCE's proposal. In both cases, SCE is straying from more recent and actual data that is more informative and predictive of the underlying economic environment that the delivery marginal costs are intended to represent.

[85] Ex. SCE- 02, p. 29, lines 19-25.

[86] Ordinary Least Squares, Wikipedia, November 30, 2011, p. 1.

CHAPTER 4.

CUSTOMER ACCESS MARGINAL COST

(Witness Robert Levin)

I. INTRODUCTION

Marginal customer costs are those distribution costs that vary with the number of customers in a given customer class, and do not vary by the customers' usage or peak demand. Alternatively, they can be characterized by determining what costs change if the utility adds a customer.[87]

A classic example of a marginal customer cost would be the cost of providing, maintaining, and reading customers' meters. Such costs vary with the number of customers, but do not generally vary with demand within a given customer class.[88]

Marginal customer costs consist of the capital costs of customer connection (or "hookup") equipment, together with operations and maintenance "O&M" costs. The latter include costs of customer services such as billing, customer inquiry, and meter reading. About 78% of SCE's reported customer marginal costs consist of capital costs.[89] Most of DRA's testimony focuses on these capital costs, which pose a considerable challenge for the marginal cost methodology and can have a disproportionate affect on revenue allocation and rates.

SCE has proposed a methodology to compute customer marginal costs that the Commission has rejected in five decisions dating back to 1992. DRA believes that SCE's proposed marginal cost methodology overestimates the capital cost component of marginal customer costs. This belief accords with previous Commission findings.

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[87] Unlike other marginal costs, customer costs are not symmetric: the costs that a utility avoids on losing a customer are typically less than the costs it incurs by adding a customer.

[88] Here it is assumed that a customer class is reasonably homogeneous and all members have similar meters that are rated for the range of demands that is typical for the class.

[89] Per SCE's electronic workpapers, residential TSM costs per customer with loaders comprise $116.04 out of a total customer cost of $148.79 in 2009 dollars. Non-residential MCCs are more heavily weighted toward capital costs.

Therefore, DRA proposes that the Commission adopt marginal customer costs based on the methodology it has generally adopted for this purpose since 1992.

Beyond the marginal cost methodology, DRA takes issue with SCE's assessments of the costs of customer hookups themselves, which, for residential customers, are based on the costs of connecting a "typical" housing tract. DRA believes that SCE's methodology is inadequate to capture the range of costs imposed by various sizes and configurations of new housing, and also fails to take into account contributions of housing developers when costs exceed allowances granted under tariff Rules 15 and 16.[90]

As described by SCE:

> Customer marginal costs include: (1) the investment-related costs associated with connecting a customer to the T&D system and related ongoing O&M; and (2) the expenses associated with customer-related services such as meter reading, billing, and other customer service functions.
>
> For calculating investment-related costs, the methodology includes the cost of equipment, which is directly associated with providing service access to a typical customer, i.e., the customer's service drop and meter. Service drops and meters are dedicated to individual customers. For larger customers, final line transformers ["FLTs"] are generally dedicated to an individual customer. For residential and groups of small business customers, the transformers are generally shared….[91]

DRA concurs with SCE's conceptual description of marginal customer costs, but takes issue with:

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[90] Rules 15 and 16 apportion the responsibility for customer connection costs (including but not limited to the final line transformer, service drop, and meter) between the customer or developer, and the utility. Since D.97-12-098, the customer or developer is responsible for all costs exceeding an "allowance" which is based on the projected distribution revenue provided by the newly connected load.

[91] Ex SCE-02, p. 30. The practice of designating the final line transformer as the boundary between demand-related distribution and customer-related distribution dates back to the 1980s, and has generally been accepted by most parties to Commission marginal cost proceedings. This approach has sometimes been called the TSM method (Transformer, Service drop, Meter). Not all transformers are considered customer-related. Substation transformers and line transformers upstream of the FLT are considered demand-related distribution and are accounted for in the MDC. While it is usual for a cluster of smaller customers to share a final line transformer, the FLT costs are considered customer-related and are shared among the customers in a typical cluster. If, for example, typically 10 customers share a single FLT, one tenth of the cost is assigned to each customer. The service drop is also sometimes called a "service extension." It carries electric current from the final line transformer to the customer's meter.

1. SCE's determination of the customer access facilities required by a typical customer in a given customer class, and
2. The rental cost methodology that SCE uses to compute marginal customer costs.

With regard to the former, SCE's testimony states that customer hook- up facilities and associated costs are determined via a typical customer cost study.[92]

As discussed below, SCE's "typical customer cost" studies are not based on samples of cost data from actual customer connection "jobs" but are, instead, based on "costing out" a limited number of hypothetical customer connections. For single-family residential construction, SCE assigns costs based on hypothetical subdivisions containing exactly 22 residences.[93] DRA believes that such narrowly defined cost analyses are inadequate to capture the full range of residential connection costs. Single-family residential connections can range from a single residence connected to an existing transformer to a subdivision containing hundreds of new homes. Additionally, the density of residential developments (number of homes per acre) can have a major impact on the connection cost per home. Finally, under tariff Rules 15 and 16, developers may be responsible for some portion of connection costs.

DRA believes that SCE's "typical customer cost" methodology is inadequate to reflect the variation in customer connection costs among its residential customers, and also fails to account for developer contributions to residential connection costs. Given these limitations of SCE's hypothetical cost analyses, DRA proposes modest downward revisions to the connection costs for all customer classes to reflect customer or developer contributions under tariff Rules 15 and 16, and to the residential class only, to reflect lower cost "infill" connections to an existing distribution transformer.

More fundamentally, DRA objects to SCE's continued use of the "rental method"[94] for computing the capital investment components of its marginal customer

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[92] Ex SCE-02, p. 30. According to SCE: "Typical is the most frequent type of customer hook-up." Ex SCE-02, p. 30, footnote 30.

[93] SCE data response dated August 4, 2011, to DRA data request 002, Q.3.

[94] Also termed "RECC methodology"; RECC stands for "real economic carrying charge." See section C below for explanation.

cost. Since 1992, the Commission has repeatedly rejected utility attempts to use the rental method, because it overcharges customers for their access equipment. DRA proposes, instead, to use a modified version of the "new customer only" ("NCO") method that the Commission has adopted in nearly all proceedings since 1992 in which marginal costs were litigated. DRA finds that the NCO method captures customer-related marginal costs more accurately than the rental method.

The next sections present and discuss DRA's marginal customer cost recommendations.

II. SUMMARY OF RECOMMENDATIONS

A. Marginal Customer Cost recommendations for this proceeding

DRA recommends that the Commission adopt marginal customer costs ("MCCs") based on the NCO methodology which the Commission has adopted in nearly all litigated marginal cost decisions since 1992. DRA's recommended MCCs are listed below in Table 4-1.

In more detail, DRA proposes:

1. To adjust the capital cost component of SCE's marginal customer cost downward by 10% to reflect customer or developer contributions (under Rules 15 and 16) to the costs of new customer connections to SCE's electric distribution grid.
2. To adjust the capital cost component of SCE's residential marginal customer cost downward by an additional 5% to reflect lower cost connections not captured by SCE's methodology such as infill connections (discussed below).
3. To compute SCE's marginal customer costs based on the "new customer only" ("NCO") method adopted in SCE's most recently litigated marginal cost decision (D.96-04-050). In applying the NCO methodology, DRA proposes a uniform customer growth rate of 0.96% for all customer classes, and a transformer, service, and meter ("TSM") facility replacement rate of 2.22% for all customer classes.

Table 4-1

	DRA Annual NCO Customer Cost (2012$)	SCE Annual Rental Method Customer Cost (2012$)	Ratio DRA NCO/SCE Rental Method MCC
Domestic	**74.17**	**160.17**	**46%**
GS-1	**100.44**	**234.69**	**43%**
TC-1	**104.10**	**243.56**	**43%**
GS-2	**713.89**	**1886.50**	**38%**
GS-2T	**727.34**	**1927.22**	**38%**
GS-3	**2063.93**	**4090.01**	**50%**
TOU-8	**2613.00**	**5832.85**	**45%**
TOU-8-Sec	**2609.38**	**5700.85**	**46%**
TOU-8-Pri	**1614.36**	**2882.76**	**56%**
TOU-8-Sub	**6745.47**	**19674.77**	**34%**
PA-1	**428.98**	**1108.35**	**39%**
PA-2	**542.31**	**1447.08**	**37%**
TOU-PA-5	**886.11**	**2150.42**	**41%**
AG-TOUs	**784.74**	**1951.35**	**40%**
AG <= 200	**476.27**	**1245.64**	**38%**
AG > 200	**1708.70**	**3678.07**	**46%**
Street Lights	**76.09**	**163.02**	**47%**

B. Recommended cost studies for SCE's next Marginal Cost proceeding

DRA also recommends that the Commission direct SCE to conduct a comprehensive study of its costs to connect new customers to its distribution grid, and that its 2015 GRC Phase 2 MCCs be based on, at a minimum, a statistically valid sample of actual customer connection project costs for connections completed between 2012 and 2014.[95] Such costs should exclude developer contributions under tariff Rules 15 and 16.

In greater detail, DRA proposes that the Commission direct SCE, in its next (e.g., 2015) GRC Phase 2 proceeding, to either:

[95] PG&E has based its proposed MCCs on such a study since its 2003 GRC Phase 2.

1. Provide a statistically valid sample of detailed cost data from new customer connection work orders completed within 24 months of its next GRC Phase 2 application; or
2. Provide an extract from its "Enterprise Resource Plan" system containing detailed cost data for all customer connection work orders completed in a 24-month period within the 36 months prior to its next GRC Phase 2 application.[96]

III. DISCUSSION

A. Methodological issues: Rental versus NCO

1. Background

In standard marginal cost theory, the costs of serving an additional unit of demand are generally the same as the costs avoided by a unit decrease in demand. As normally defined in economic textbooks, marginal costs are symmetric. This symmetry, however, does not hold for customer connection capital costs because such equipment is often dedicated to individual customers rather than shared.

For over 20 years, the Commission has defined customer connection costs to consist of meters, service drops, and final line transformers ("FLTs"), the latter serving as the boundary between customer facilities and demand-related distribution. When a customer at a previously unserved location is newly connected to the distribution grid, establishing that connection usually requires all three of the above elements, sometimes termed "TSM" equipment. Installation of TSM equipment requires significant labor as well as material costs. These costs are capitalized and included in utility rate base.

If, however, a previously occupied customer premise is abandoned, (or a customer chooses to go "off-the-grid" and surrender his connection equipment), only a fraction of the original TSM cost can be recovered by salvage and/or reuse of the meter and FLT. Similarly, if a portion of a utility system is sold (e.g., to a municipal utility district), the selling utility will likely receive only a fraction of the current replacement cost of the facilities.

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[96] SCE stated, in response to a DRA data request (#006, Q.1c, sent August 25, 2011): "SCE records all costs associated with connecting new customers to its distribution grid for the purpose of recovery in capital work orders in our Enterprise Resource Plan (ERP) system."

Thus, the costs of adding a customer and the costs avoided by losing a customer are not symmetric. This lack of symmetry has vexed practitioners of marginal cost based ratemaking since its introduction in the early 1980s. The Commission has adopted a number of approaches over the years, including:

1. Treating TSM costs as entirely sunk (thereby excluding marginal customer-related capital costs altogether from the marginal costs used for ratesetting);
2. Treating TSM costs as if they were always fully recoverable at their replacement cost new ("RCN") value, regardless of the age or depreciation of the facilities. This is the so-called "rental method" or RECC method proposed here by SCE.
3. Including as marginal only TSM costs for new customers (at previously unserved sites) or for customers whose TSM equipment is being replaced in the test year. This is the so called "new customer only" or NCO method.

Approach (1) was abandoned early on in the history of CPUC ratemaking because the Commission found that the revenue allocation resulting from this methodology did not capture the role of the customer hookup in cost causation and resulted in skewing costs to large customers.

Approach (2), popular in the later 1980s, took the opposite tack to Approach (1). Where Approach (1) treated all TSM costs as sunk and none as marginal, Approach (2) treated **none** of the TSM costs as sunk and **all** as marginal, and in addition, valued all TSM facilities at RCN, regardless of vintage.

Beginning with its decision in PG&E's Test Year 1993 GRC,[97] the Commission has consistently rejected the rental method (Approach (2)) because it found that the rental method overcharges customers for the cost of their TSM equipment. Thus, the revenue allocation resulting from the RECC methodology applied to TSM overstates the role of the customer connection in cost causation and results in skewing costs to small customers.

Since deciding PG&E's TY 1993 GRC, the Commission has nearly always adopted Approach 3 (NCO) when marginal costs were litigated. In doing so, the Commission has judged that NCO best reflects cost causation for TSM facilities

[97] Application of PG&E (1992) 47 CPUC 2d 143, 1992 Cal. PUC LEXIS 971, D.92-12-057.

2. Discussion and critique of SCE's MCC methodology

As described by SCE,[98] a "real economic carrying charge" ("RECC") methodology is used in the calculation of both MGCC and MCCs. SCE describes its RECC methodology thusly:

> When computing marginal costs, SCE converts capital investments into annual costs using a real economic carrying charge ("RECC"). This approach is sometimes called the economic deferral or rental value method. Under this approach … the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed, and then compared to the present worth of an equivalent asset and its replacements installed one year later. The only difference between these two scenarios is that SCE loses the opportunity to use the asset in the first year of the second scenario. Thus, the difference in present worth between the two scenarios measures the economic (opportunity) cost of using the asset during the first year. The resulting annual charge, when escalated at the rate of inflation over time and then discounted, yields the original cost (in terms of revenue requirement) of the investment…. the RECC results in the same real payment over time.[99]

In effect, the RECC results in annual payments that rise with inflation and collect the associated revenue requirement for an investment made in year 1 of SCE's planning horizon over the life of the facility. SCE describes its basis for applying the rental method (RECC methodology) to MCC thusly:

> …assuming electricity customers value the service they receive, the charge [based on marginal cost] [for hookup equipment] should be the same regardless of the age of the equipment. Therefore, the proper charge can be calculated for both existing and new customers by applying the RECC to the current cost of the equipment.[100]

This makes sense only if one assumes that the economic value (or opportunity cost) of old equipment is the same as that of new equipment. There are very few markets to which such logic might apply. One might consider housing, for example, in which an older house might sell or rent for the same price as a newer one, if they are

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[98] Ex SCE-02, p. 12.

[99] Ex SCE-02, p. 12.

[100] Id.

similar in other attributes. **SCE's concept of "age-indifference" most certainly does not apply, however, to most utility distribution plant, including customer hookup plant, for the following reasons:**

1. There is no active rental or resale market for electric utility customer hookup equipment.
2. Once installed, a large part of the costs of customer hookup equipment is sunk. Labor costs of the installation are typically capitalized and cannot be recovered if equipment is salvaged. While meters and FLTs have some salvage value, service drops (comprising nearly 40%[101] of the dollar value of hookup equipment), have little or no salvage value. Typically, the overall salvage value of hookup equipment is less than half of its replacement cost.
3. Utilities, when selling their distribution systems, do not price them at the cost of new facilities (replacement cost new or RCN). Much as they might like to price at RCN, no buyer would pay that amount. Instead, utilities typically ask a lower price based on replacement cost new less depreciation ("RCNLD"). The RCNLD price is the "gold standard" price to which utilities aspire if they wish to (or are required to) sell part of their distribution system. The actual sale price for utility distribution plant is often less than RCNLD.[102]

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[101] Per SCE's electronic workpapers, for the residential class, the average service extension cost is $272.93, just under 40% of the total TSM cost of $700.66.

[102] See, for example, the following excerpt from D.03-04-032, authorizing a sale of certain PG&E distribution facilities to the Turlock Irrigation District (TID):

"LID [Laguna Irrigation District] argues that PG&E and TID considered only one method of determining the value of the assets, replacement cost less depreciation new (RCNLD), and that other valuation methods might have yielded a ***lower*** and more reasonable sales price. LID therefore asks the Commission to include a condition that provides that the use of RCNLD to value the assets sold to TID shall not be precedent in other cases involving transfers of utility assets. Laguna has been recently involved in litigation with PG&E to condemn certain electric distribution facilities. (Laguna Irrigation District v. Pacific Gas and Electric Company, Kings County Superior Court No. 99 C 052.) Laguna is therefore concerned that the valuation method here may be precedent in its pending litigation. We agree with PG&E that the courts will assess whether evidence regarding the valuation of utility assets in Commission proceedings should be considered in the condemnation proceedings, as well as the weight to be given Commission decisions pursuant to California law. LID does not oppose the sales price and has presented no evidence to show that the use of the RCNLD method of valuation has created an unfair or unrealistic price for the assets being sold to TID, or that another method of valuation would have resulted in a different price. Previous Commission decisions have found that a sales price for utility assets based on RCNLD, when negotiated between the parties in arms-length transactions, is fair and reasonable. We therefore approve the sales price here based on RCNLD. However, we recognize that RCNLD is only one method of valuation, and we may consider different valuation methodologies in other cases." (D.03-04-032, mimeo, pp. 42-43, emphasis added).

For all of these reasons, the economic value of an existing utility distribution system (including customer hookup facilities) is less than the RCN value embodied in SCE's use of RECC methodology. Effectively, SCE's rental proposal values customer access facilities at RCN, a value far higher than the RCNLD price at which they could actually be sold. The rental method would charge customers the full price of new facilities for the use of existing facilities on which they have already paid years of depreciation expense. RECC methodology ignores both sunk costs and economic depreciation associated with existing facilities.

3. The Commission has a long history of rejecting the rental method

Since 1992, the Commission has consistently found that the rental method (i.e, RECC methodology applied to customer hookup equipment) overstates costs. For example, in 1996, the Commission made the following Findings of Fact:[103]

> 37. The rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market.
>
> 38. Under the rental method, and the associated RECC assumptions, Edison's marginal customer costs exceed the cost of hooking up new customers, installing replacements and covering the variable expenses for all customers….

The overstatement of marginal customer hookup costs inherent in SCE's RECC methodology stems from (1) its failure to adjust for the time value of money as it relates to the future replacement of hookup equipment; and (2) the assumption of an inappropriately high economic value (opportunity cost) of existing hookup equipment.

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[103] Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal.PUC LEXIS 270, D.96-04-050, FOF 37 and 38.. These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCalGas. While these decisions are old, they are among the most recent Commission decisions to address marginal cost issues. The Commission has generally adopted "black box" settlements of marginal cost issues since 2000.

4. The Commission has found the NCO method to be appropriate for computing MCCs

Each of the decisions, cited in the previous section as rejecting the rental method, adopted the NCO in its place. However NCO (new customer only) is a misnomer.[104] In all but D.92-12-057, costs of replacing existing TSM facilities are included along with the cost of installing TSM facilities at premises not previously connected to the distribution grid.

In summary, NCO includes the two streams of customer connection capital costs faced annually by utilities: the costs of connecting new customers, and the costs of replacing failed or obsolete TSM equipment serving existing customers.

B. Data issues: Gaps in SCE's customer cost data

Customer connection costs (specifically costs of installing meters, service extensions, and final line transformers) vary widely by customer class and within customer classes. These TSM costs are the major component of marginal customer access costs, which, in turn, influence the allocation of SCE's distribution revenue requirement among its customer classes. SCE's current methodology for estimating TSM costs relies on a limited number of "typical" connection scenarios. As explained below, SCE's cost studies omit many other connection scenarios which should be accounted for, to have an accurate representation of customer connection costs, and may improperly include costs that are paid by developers or customers.

1. SCE's methodology for estimating TSM costs

As described above, SCE proposes to base its MCCs on "typical customer cost" studies:

> Customer hook-up facilities and associated costs are determined via a typical customer cost study. This study identifies the current typical equipment necessary to connect a particular customer type and is used to estimate the costs of final line transformers, service drops, and meters.[105]

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[104] PG&E generally terms its version of NCO "one-time hookup cost" methodology. This terminology did not appear to "stick."

[105] Ex. SCE-02, p. 30.

Thus, SCE's typical customer cost "studies" are not based on samples of cost data from actual customer connection "jobs" but are, instead, based on "costing out" a limited number of hypothetical customer connection scenarios. For the residential class, SCE estimates costs for just the following four distinct customer configurations:[106]

1. Single family overhead (OH) subdivisions
2. Single family underground (UG) subdivisions
3. Multifamily dwellings
4. Domestic master-metered dwelling complexes.

Per SCE's electronic workpapers, single family residences account for about 73% of SCE's residential customer population. For single-family residential construction (both OH and UG), SCE assigns costs based on hypothetical subdivisions containing exactly 22 residences.[107] SCE stated in response to DRA discovery, that it did **not** validate its typical customer cost studies against actual customer connection cost data.[108]

In discovery, DRA requested SCE to draw a representative sample of customer connection cost data for the purpose of allowing DRA to validate SCE's typical customer cost studies.[109] SCE was unable, however, to comply within the timeframe required by DRA to complete this testimony.[110]

2. Critique of SCE's methodology for estimating TSM costs

DRA believes that SCE's narrowly defined cost analyses are inadequate to capture the full range of residential connection costs. Single-family residential connections can

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[106] A fifth configuration, "TOUs" is listed in SCE's electronic workpapers but appears to be a weighted average of the single family OH and UG costs.

[107] SCE response to DRA data request #006, Q2c, sent August 25, 2011.

[108] SCE response to DRA data request #006, Q1a, sent August 25, 2011.

[109] DRA's data request (#008, Q.7, sent September 16, 2011) for a sample of data from actual customer connections was suggested by a similar data request from TURN to PG&E in PG&E's 1996 GRC Phase 2 proceeding. At that time PG&E conducted typical connection analyses similar to those presented here by SCE. PG&E has since revised its methodology to include a large body of data from actual customer connection "jobs." PG&E's data allows for the separate identification and exclusion of customer or developer contributions under Rules 15 and 16.

[110] As of December 8, 2011, SCE had not yet responded to DRA's data request #008, Q.7.

range from a single new "infill" residence connected to an existing transformer to a subdivision containing hundreds of new homes. Additionally, the density of residential developments (number of homes per acre) can have a major impact on the connection cost per home. SCE's testimony and workpapers provide no indication that it has accounted for this variability in its residential TSM costs per customer.

On a per item basis, the FLT is by far the most expensive of the TSM equipment. On average, according to SCE's data, the cost of the FLT accounts for over 40% of residential customer connection costs.[111] Because less dense residential developments require more transformers per customer (or fewer customers can be served per transformer), and require longer, more costly service extensions, the variation in TSM costs per customer can be quite significant.

In addition, not all new residential customer connections require a new transformer. Occasionally, a newly constructed residence can connect to an existing transformer, resulting in a much reduced connection cost.[112] SCE's workpapers state an average residential TSM cost of $700.66 per customer. However, an "infill" connection to an existing transformer could cost as little as $408.86.[113] Such low-cost residential customer connections are not accounted for in SCE's data or methodology.

In addition, SCE has apparently not accounted for the contributions of residential and non-residential developers to customer connection costs, as required by Rules 15 and 16. Since D.97-12-098,[114] developers have been required to bear all connection costs

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[111] Per SCE's electronic workpapers, for the residential class, the average per customer FLT cost is $290.75, slightly over 40% of the total TSM cost of $700.66. The FLT is a larger share of the total TSM cost for nonresidential classes.

[112] In response to DRA data request #006, Q.5, SCE acknowledged that it does occasionally connect a new customer to an existing FLT.

[113] Per SCE's electronic workpapers, $136.83 for the meter, plus $272.03 for the service drop (based on the value for an underground residential subdivision).

[114] The Commission's policy regarding revenue-justified allowances (D.97-12-098) requires that allowances differ according to the amount of revenue provided by new loads. An exception is made for residential connections, for which a fixed allowance is granted per dwelling unit. In response to DRA data request #006, Q.6a, SCE acknowledged that some portion of the TSM costs incurred for new customer connections has been borne by applicants for new service (developers or customers) since March, 2008.

exceeding an allowance that is determined by formula that is based on the projected distribution revenue expected from the customer.

In summary, SCE's MCCs are based on TSM cost data that has major gaps; it simply fails to account for the variability in the cost of customer connections or the cost responsibility of developers under Rules 15 and 16.

3. DRA's proposed adjustments to SCE's TSM costs

a) Adjustments to reflect low cost residential customer connections

As stated above, in some cases, residential customers can connect to SCE's distribution grid for as little as $408, about 40% less than SCE's stated average TSM cost of $700. In discovery, DRA asked SCE what percentage of its recent residential customer connections consisted of such "infill" connections. SCE replied that it did not collect such data.[115]

Because SCE's stated $700 "average" residential TSM cost is not a true average cost over a fully representative range of connection scenarios, it does not account for lower cost connections. To correct for the omission of low cost scenarios from SCE's data, DRA proposes a 5% downward adjustment in the TSM cost for the residential class only.[116]

b) Adjustments to reflect customer/developer contributions under Rules 15 and 16

Under Rules 15 and 16, customers and/or developers may be required to contribute toward the costs of new customer connections, including TSM costs. SCE's data supporting its MCCs do not account for customer/developer contributions. DRA

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[115] SCE's response to DRA data request #002, Q.5, sent August 4, 2011.

[116] It might seem that high-cost connections are also not captured by SCE's data and methodology. However ratepayer cost responsibility for high-cost residential customer connections is capped at the fixed Rule15/16 allowance of $2,322. Further, a portion of the allowance applies to distribution line extension costs upstream of the FLT. Such upstream costs are considered demand-related and are excluded from the MCC. Limitations in SCE's cost data prevent parties from assessing the frequency and impact of higher-cost connections. As discussed elsewhere in this testimony, DRA recommends SCE conduct a comprehensive study of its customer connection costs to ensure that the variability of its customer connection costs is accounted for in its MCCs.

asked SCE in discovery to estimate what portion of TSM costs are covered by customer or developer contributions; again, SCE responded that it does not track such data.[117]

DRA proposes a downward adjustment of 10% in the TSM costs of all customer classes to reflect customer/developer contributions under Rules 15 and 16. DRA believes this adjustment is conservative; an earlier (2003) PG&E analysis indicated that customers and/or developers bore an average of 22% of PG&E's cost to connect new customers.[118]

4. Need for new comprehensive studies of SCE's customer connection costs and apportionment of those costs under Rules 15 and 16.

As discussed above, SCE's TSM cost data contains major gaps which SCE was unable to fill in response to DRA discovery requests. These data deficiencies are especially pertinent for the residential class but may also affect non-residential customer classes.

For its next marginal cost/rate design proceeding, DRA recommends that SCE be directed to conduct a comprehensive study of the cost of recent customer connections. This should be accomplished either by using a statistically valid sampling procedure or by tracking all of its new customer connection costs over a minimum 24 month period.

In conducting this study, it is vital that SCE separately identify the contributions of customers and or developers pursuant to Rules 15 and 16.

Accurate MCCs are a key input to electric rates. The recommended customer connection cost studies are needed to ensure that those rates are just and reasonable.

C. Implementing the NCO method

In addition to the TSM cost estimates discussed in the previous section, the NCO method requires two additional parameters: customer growth rates, and TSM equipment replacement rates.

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[117] SCE's response to DRA data request #002, Q.11f, sent August 4, 2011.

[118] Note that, just because the average hookup cost representing a hypothetical "typical" customer may be below the line extension allowance allowed under rules 15 and 16, this does not mean that there are not individual cases where the cost exceeds the allowance, resulting in the developer paying a portion of the

(continued on next page)

1. Customer growth rates

While SCE's primary MCC proposal is based on the rental method (which does not consider customer growth), SCE also provides an NCO proposal. The customer growth rates for the various classes range from 0% to 0.85%, with two (seemingly anomalous) exceptions: 5.14% for large agricultural customers, and 13.23% for "Ag-TOUs."[119]

SCE explains its assumption of 0% growth for certain customer classes as follows:

> Several customer groups are forecasted to decline in number over 2010-2012 due to actual decline or rate group switching. The decline creates difficulty because there is negative customer growth. The NCO methodology has problems when there is negative customer growth because it can create negative marginal costs. SCE will cap the negative growth at zero and use the annual replacement rate based on the 2012 customer forecast.[120]

DRA proposes an approach that it considers more appropriate: Compute the average growth rate (rate of new customer additions) of SCE's residential customer population over the last five years and project that growth rate forward over the 2012-2014 test period. This approach smoothes out the erratic variation in growth that sometimes occurs with smaller customer groups, and eliminates obvious anomalies such as the large values shown above for large Ag. and Ag-TOU. It is also reasonable because (1) the customer growth rates for nonresidential classes have a relatively minor impact on the overall revenue allocation, (2) nonresidential customer growth rates can be roughly expected to track residential growth over extended periods of time (at least, for commercial customers), and (3) while it is reasonable to charge existing customers rates that are based inter-class variations in hookup costs, it makes little sense to penalize a customer unlucky enough to be in a class that is quickly growing.

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hookup cost.

[119] SCE electronic workpapers, worksheet "NCO Method 5% Replacement" rows 61 and 69, less 5%.

[120] Ex. SCE-02, Appendix E, p. E-2.

Based on SCE's response to a DRA data request, DRA calculated an average customer growth rate of 0.96% over the last five years.[121] DRA proposes to use this growth rate in its NCO calculation for all customer classes.

2. TSM equipment replacement rates

SCE uses a 5% TSM replacement rate in its NCO calculation. Its testimony states:

> An annual replacement rate was assumed based on the 20-year depreciation life for electronic meters which is the large portion of the customer cost.[122]

SCE's statement is inconsistent with actual data. For residential customers, FLTs and service extensions make up over 80% of the capital costs of TSM equipment.[123] Both of these items have a 30-year service life. Based on SCE's reasoning, the TSM replacement rate could more reasonably have been set at 3.33% (i.e., in the long run, and with a stable population, one thirtieth of all equipment could be expected to be replaced each year).

However, TURN has consistently shown that actual replacements are invariably less than the theoretical long-run replacement rate, primarily because customer growth reduces the average age of the TSM stock. DRA proposes to use two-thirds of the long-run replacement rate based on a 30-year life, i.e. 2.22%, as the TSM equipment replacement rate for all customer classes.

3. NCO Multiplier for customer connection capital costs.

The NCO method computes an expected annual TSM investment by multiplying the fully loaded cost of the TSM equipment, including the present value of associated

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[121] SCE provided the annual number of new residential customer connections for 2006 through 2010 in response to DRA's data request #002, Q.11e. The average for the 5 year period was 40,098. Dividing by the 2009 residential customer count of 4,157,672 from SCE's electronic workpapers yields an average growth rate of 0.96% per year.

[122] Id, p. E-1. This is essentially repeated in SCE's response to DRA data request #008, Q.6.

[123] Per SCE's electronic workpapers, the cost of a residential meter is $136.98, less than 20% of the total residential TSM cost of $700.66. The FLT and service drop make up the remaining 80% plus of the TSM cost. For the non-residential classes, the FLT and service drop comprise an even larger share of the total cost.

revenue requirements (return, depreciation, taxes), by the sum of the customer growth rates and TSM equipment replacement rates. DRA's recommended multiplier for all customer classes is 3.18% (0.96% + 2.22%). This contrast with SCE's recommended NCO multipliers which are mostly between 5% and 5.85%.

As a final step in calculating the capital component of the NCO values, the expected annual TSM investment for each customer class is divided by the number of customers in that class, to arrive at the average TSM investment per customer.

4. Non-capital MCC cost components.

The NCO method also includes customer-related operations and maintenance costs and customer services costs such as meter reading, billing, customer inquiry, etc. The treatment of these costs is identical for the NCO and rental methods. These non-capital cost components of the MCC were studied extensively during the Commission's revenue cycle services proceedings of the late 1990s. DRA does not take issue with SCE's analyses of its non-capital related MCC components.

IV. CONCLUSION

Accurate MCCs are a key input to electric rates, because they have a major impact on the allocation of utilities' distribution revenue requirements among the various customer classes. The Commission should reject SCE's rental approach, as it did in five major marginal cost and rate design decisions in the 1990s, because the rental method overestimates the marginal cost of providing customer access to the distribution grid. The Commission should instead adopt DRA's proposed MCCs, which are based on the NCO method it has adopted since 1992.

In addition, the Commission should require SCE, in preparation for its next triennial marginal cost and rate design proceeding, to perform a comprehensive analysis of its actual costs of connecting new customers. The recommended customer connection cost studies are needed to ensure that those rates are just and reasonable.

CHAPTER 5.

REVENUE ALLOCATION

(Witness Lee-Whei Tan)

I. INTRODUCTION

This chapter addresses the proposals of the Division of Ratepayer Advocates ("DRA") for allocating generation, distribution, and a variety of miscellaneous revenue responsibilities among customer groups. Below, DRA provides its analysis of Southern California Edison's ("SCE's") proposals and explanations of DRA's recommendations.

II. SUMMARY OF RECOMMENDATIONS

Revenue allocation and rate design typically involve balancing a number of competing goals. These goals[124] are based on the principles that rates should be:

1. Fair and equitable,
2. Stable and predictable,
3. Economically efficient,
4. Understandable by the public,
5. Conducive to stable revenue collection by the utility,
6. Reflective of the external and social costs of energy production and consumption, and
7. Similar to what a fully competitive unregulated market would charge.

In this General Rate Case ("GRC") Phase II proceeding, DRA recommends using a marginal cost-based revenue allocation methodology to accomplish economic efficiency while applying a cap on the rate changes so that rate stability also can be achieved. DRA's proposal caps the rates so that no class will face a rate increase of more than 5% above the system average rate percent change ("SAPC"). SCE's

[124] Bonbright, *et al*., Principles of Public Utilities Rates (Arlington, Va: Public Utilities Reports, Inc., 1988), pp. 383-384. Principles similar to the last two are discussed in "Charging for Distribution Utility Services: Issues in Rate Design", National Association of Utility Regulatory Commissioners, Regulatory Assistance Project, December 2000.

proposal, on the other hand, does not cap the rates, and based on SCE's cost allocation proposals, one customer class, TOU-8-Sub, would see an 8.9%[125] rate increase.

Though DRA is given legislative responsibility to mainly represent residential and small business customers for revenue allocation and rate design issues,[126] DRA believes it is a good public policy to mitigate significant rate increase for any customer class. This is important, especially during these difficult economic times when most customers are facing significant financial challenges. DRA's proposal is also consistent with considerable Commission precedent to limit or cap revenue allocation increases at a small percentage above average system increases.

DRA proposes using a total revenue allocator[127] instead of the distribution allocator[128] used by SCE for demand response programs ("DRP") and advanced meter (smart meter) infrastructure ("AMI") costs to better reflect their cost impact on the system. DRA disagrees with SCE in applying SAPC to allocate the program costs for California Solar Initiative ("CSI")[129] and the public purpose programs ("PPP"). Instead, DRA recommends that the Commission use an equal cents per kilowatt- hour ("kWh") allocator consistent with the Commission's established policy. In addition to the aforementioned allocation approach and the cap proposal, DRA also has proposed

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[125] SCE's original filing reflected a 9.3% increase for TOU-8-Sub class and it is revised to 8.9% in its October 2011 update. SCE later made a correction to its marginal generation capacity cost, which would result in a 7.9% rate increase for TOU-8-Sub. This is in addition to any general rate case rate increase that comes through Phase I of this GRC.

[126] Public Utilities Code Section 309.5. (a) There is within the commission a Division of Ratepayer Advocates to represent and advocate on behalf of the interests of public utility customers and subscribers within the jurisdiction of the commission. The goal of the division shall be to obtain the lowest possible rate for service consistent with reliable and safe service levels. For revenue allocation and rate design matters, the division shall primarily consider the interests of residential and small commercial customers.

[127] Generation allocator is to allocate cost based on the proportion of each class' marginal generation revenue (which include marginal energy cost revenue and generation capacity cost revenues) relative to the total system generation revenues.

[128] The Distribution allocator is to allocate cost based on the proportion of each class' marginal distribution revenue (which include marginal customer cost revenue and distribution demand cost revenues) relative to the total system distribution revenues.

[129] CARE, FERA and streetlighting customers are exempted from CSI allocation. Ex. SCE-3, p. 14.

significant adjustments to SCE's marginal cost estimates, all of which contribute to the final allocation and to how it deviates from that of SCE.

In summary, DRA recommends the Commission adopt:

1. DRA's marginal costs to allocate revenue responsibilities;
2. Use of a total revenue allocator for demand response programs and AMI costs; An equal cents per kWh allocation of CSI and other public purpose programs; and
3. A capped allocation so that no class would face a rate increase more than 5% above the system average rate percent change.

The following is DRA's proposed class average rates in contrast to those of SCE's:

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Table 5-1 SCE and DRA's Proposed Bundled Rates

	Present Rate	DRA (5% Cap)		SCE[130]	
	June 2011 (¢/kWh)	Proposed (¢/kWh)	% Change	Proposed (¢/kWh)	% Change
Total Domestic	15.6	15.5	-0.9%	16.0	2.7%
GS-1	17.0	15.0	-11.8%	15.6	-8.1%
TC-1	15.3	13.7	-10.2%	16.0	4.9%
GS-2	15.2	14.8	-2.5%	14.7	-2.9%
TOU-GS-3	13.2	13.8	5.0%	13.5	2.5%
Total LSMP	15.0	14.6	-2.9%	14.6	-2.8%
TOU-8-Sec	12.4	13.0	5.0%	12.0	-3.2%
TOU-8-Pri	11.2	11.7	5.0%	10.9	-2.1%
TOU-8-Sub	7.1	7.4	5.0%	7.6	7.9%
Total Large Power	10.8	11.3	5.0%	10.6	-1.1%
TOU-PA-2	13.0	12.5	-3.8%	12.6	-2.8%
TOU-PA-3	10.2	10.7	5.0%	10.5	3.4%
Total Ag. & Pumping	11.9	11.8	-0.8%	11.8	-0.6%
Total Street Lighting	18.0	18.4	2.2%	18.1	0.7%
STANDBY/SEC	11.5	12.1	5.0%	11.5	-0.3%
STANDBY/PRI	11.3	11.9	5.0%	11.4	0.7%
STANDBY/SUB	8.1	8.5	5.0%	8.0	-1.1%
Total Standby	9.2	9.7	5.0%	9.2	-0.5%
Total System	14.2	14.1	-0.6%	14.1	-0.1%

[130] DRA has updated SCE's rates to reflect its correction on marginal generation cost.

III. DISCUSSION

A. Marginal Cost Revenue Allocation

Revenue allocation is a process of assigning to each customer class a portion of the utility's revenue requirement. The Commission has applied marginal cost-based revenue allocation since late 1970s. The process starts with calculating marginal costs for each utility function (generation and distribution).[131] Then cost responsibility is assigned to classes based on the proportion of each class' marginal cost revenue relative to the total system marginal cost revenues.

In D.97-08-056, the Commission adopted separate revenue requirements for each individual function. Those revenues are then allocated on an unbundled basis using the separate marginal cost revenues for each function. This method determines each customer class' revenue responsibility based on the marginal cost revenue assigned to the class. The latter then is scaled up to match the revenue requirement for each of the functions. The result is called an equal percent marginal cost ("EPMC") allocation.[132]

The marginal cost revenue is basically the product of the functional marginal cost and the marginal demand measures ("MDM"). Marginal costs include marginal energy, generation capacity, distribution demand, and customer access costs. MDMs include measurement of each class' energy consumption, demand during the system peak, the non-coincident peak, and the number of customers.

In this proceeding, SCE proposes to continue using the same functional marginal cost allocation, where the generation and distribution functions are allocated separately using the EPMC method,[133] and DRA concurs.

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[131] Since the electric industry restructuring of the late 1990s, most transmission is regulated by Federal Energy Regulatory Commission (FERC). The lower-voltage portions of SCE's transmission system remained under CPUC jurisdiction and are treated as distribution for revenue allocation purposes.

[132] Transmission revenue is set separately by FERC.

[133] SCE proposes to allocate its CPUC-jurisdictional revenue requirements for distribution and generation services based on its marginal costs. (Ex. SCE-3, p. 4.) The transmission revenue is allocated based on the average of the 12 monthly system coincident peak ("12-CP") shown in SCE's cost allocation model.

B. Marginal Generation Cost Revenue

There are two generation-related cost elements. The marginal generation energy cost refers to the incremental cost of adding one additional unit (i.e. kWh) of energy consumption on the electrical system. The marginal generation capacity cost measures the incremental cost that an incremental kilowatt of demand imposes on the system. These marginal costs are discussed in Chapter 2 of DRA's testimony. Other than the fact that DRA has different marginal energy and generation capacity costs, DRA agrees with how SCE calculates marginal cost revenues. Mathematically, the marginal generation cost revenues can be expressed below:

> **Σ Marginal energy cost revenue $_i$** = Σ Marginal energy cost by time of use ("TOU") period * energy consumption in each TOU period by customer class i

> **Σ Marginal generation capacity cost revenue $_i$** = Σ Marginal generation capacity cost * class i's MW demand during the system's top 100 hours demand

Though DRA applies the same approach as SCE in calculating the marginal generation cost revenues, DRA would impose a rate cap on class average rates, a proposal which will be elaborated upon later in this chapter.

C. Marginal Distribution Cost Revenue

Distribution marginal costs are associated with providing customer access to, and accommodating customer demand, on the distribution system. DRA presents marginal distribution demand and customer cost proposals that differ from those of SCE, as explained in Chapters 3 and 4. DRA uses the new customer hookup ("NCO") method, while SCE uses the "rental" method. In the NCO method, the marginal demand measure is the number of new customers, whereas in the rental method, it is the total number of customers. Again, the marginal distribution costs are expressed as follows:

> **Σ Marginal distribution demand cost revenue $_i$** = Σ Distribution demand marginal cost * Class i's non-coincident peak[134] demand * effective demand factor[135] ("EDF")

[134] Non-coincident peak is the maximum demand of a customer class regardless of when the system peak occurs.

Σ Marginal customer cost revenue $_i$ = Σ Number of customers for customer class i * TSM[136] costs[137]

Because of the marginal cost differences, DRA's marginal cost revenues are different from SCE's.

D. Demand Response Programs and AMI-related Costs Should be Allocated Based on a System Revenue Allocator

Demand response programs ("DRPs") are typically designed to reduce the need for additional generation capacity and/or reduce energy purchases and consumption. Thus it makes sense to allocate the costs of these programs using a generation allocator or, alternatively, by the total revenues as some DRPs may be able to reduce or defer distribution and transmission investments as well. SCE states, on its website, that it offers a variety of Demand Response Programs to help qualifying customers **reduce their energy usage during peak times** while reducing their electricity costs.[138]

However, SCE has used a distribution allocator instead of a generation or a total revenue allocator to assign DRP costs. This is shown in SCE's cost allocation model. DRA notes that SCE's distribution revenues include several demand response program costs: $51 million adopted by the DRP Decision ("D") 09-08-027, and $19 million and $1 million categorized as DR capacity contracts and DR purchase agreement administration, respectively.[139]

(continued from previous page)

[135] SCE describes its effective demand factor ("EDF") as the ratio of a customer's contribution to the peak load on a transmission or distribution circuit to the customer's annual noncoincident peak demand. EDFs vary by type of customer and by the voltage level of the circuit. (A.11-06-007, Ex. SCE-02, p. 8.)

[136] TSM refers to transformer, service drop, and meter, which are the facilities that provide customer access to the system and grouped as customer costs.

[137] Even though DRA's NCO uses one time total hook-up costs for new customers, the numbers are converted to per customer as comparable to the rental in the model.

[138] http://www.sce.com/b-rs/demand-response-programs/demand-response-programs.htm, emphasis added.

[139] SCE Nov. 3, 2011 e-mail response to DRA's inquiry regarding SCE revenue requirement components. They are also shown in SCE's cost allocation spreadsheet.

D.09-08-027 shows that SCE's DRP includes emergency programs (interruptibles, summer discount plan, curtailments, rotating outages) and price responsive programs (capacity bidding, critical peak pricing ("CPP"), demand bidding, and energy option bidding), as well as DR aggregator, DR enabled, and smart meter enabled programs.[140] These programs are clearly designed to reduce either energy consumption or capacity needs, and hence their costs should be allocated based on total revenues as they are used to reduce energy cost and/or capacity costs associated with generation, transmission, or distribution.[141] More importantly, SCE's testimony in this proceeding actually reflects such costs being allocated based on generation revenue. For example, SCE explains that the authorized cost-based credits associated with AC Cycling and interruptible programs are allocated based on the marginal cost of generation.[142] The aforementioned SCE DRPs are similar to the AC Cycling and interruptible programs in that they are intended to reduce system energy and capacity needs.

SCE's also includes $206 million for SCE SmartConnect program (which is SCE's AMI program), and they are aggregated with the distribution revenues and allocated using distribution allocator.[143] DRA disagrees with this approach and recommends separately allocating AMI using a total revenue allocator. AMI is being deployed with the expectation that it will bring system operational benefits as well as enhancing demand response programs and enabling time-varying rates. Therefore, AMI expenses should also be allocated based on a total system revenue allocator. The Commission noted how installing time-of-use meters and introducing dynamic rates can help reduce system energy and demand costs:

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[140] D.09-08-027, pp. 213-214.

[141] In D.09-08-027, SCE appeared to recognize some of these costs should be allocated with generation allocation. (see discussion at p. 216) However, the cost allocation model in this proceeding (A.11-06-007) does not appear to remove these dollars from distribution allocation.

[142] Ex. SCE-3, p. 17.

[143] SCE's Nov. 3, 2011 e-mail response to DRA's inquiry about SCE's revenue requirement components. However, SCE's cost allocation model (revenue requirement worksheet) showed a different value. DRA used the number reflected in the model.

> Requiring time-of-use meters would encourage customers to shift their energy use away from periods of peak demand. Such a shift away from periods of peak demand can be expected both to help avoid blackouts and to reduce system energy costs by reducing demand during periods where power is most expensive.[144]

Similarly, in a previous AMI proceeding, PG&E characterized time-varying pricing demand response benefits as being associated with generation capacity and energy costs:

> Demand response impacts refer to the change in customer-specific peak demand and energy use, by rate period, **resulting from time-varying tariffs.** In this chapter, the term "financial benefits" means the monetary value of reductions in both capacity and energy that flow from changes in peak demand and energy use induced by new tariffs….
>
> This chapter discusses the financial benefits associated with **avoided generation capacity and changes in the total cost of energy needed to meet demand**.[145]

IV. CALIFORNIA SOLAR INITIATIVE AND OTHER PUBLIC PURPOSE PROGRAM COSTS SHOULD BE ALLOCATED BASED ON EQUAL CENTS PER KWH

SCE explains that it first allocates the authorized California Solar Initiative ("CSI") revenue requirement to rate groups based on each rate group's proportion of the SAPC, excluding CARE and FERA customers and streetlight facilities.[146] SCE allocates other PPPs based on SAPC. DRA disagrees with these proposals. The Commission has consistently allocated the costs of programs that provide environmental benefits to all customers on an equal cent per kWh or therm basis. The CSI is exactly such a program in that it is intended to provide environmental benefits that benefit all ratepayers, as pointed out by the Commission:

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[144] D.01-05-064, mimeo, pp. 32-33.

[145] PG&E, A.05-06-028, Ex.PGE-4, Ch. 5, pp. 5-1, 5-2, emphasis added.

[146] Ex. SCE-3, p. 14.

> The development of solar energy projects is consistent with state policies generally that support environmentally sound energy resources and an energy infrastructure that is diverse and disbursed."[147]

Therefore, DRA recommends that the Commission allocate the costs of CSI by equal cents per kWh as it has for other programs that have environmental benefits. Examples of programs that provide environmental benefits, whose costs the Commission has allocated by equal cent per kWh or therm, include the Natural Gas Vehicle Program ("NGV") and gas Self Generation Incentive Program ("SGIP"). The Commission has stated:

> The Legislature has declared that the pursuit of cleaner air and relief from global warming is in the public interest. There is nothing in the hearing record which suggests that these benefits, as well as the strategic advantage of lowering our dependence upon foreign oil, will not be realized by the successful implementation of this program. To the extent that they are, they will be enjoyed by all Californians in their capacity as ratepayers.[148]

> The fixed infrastructure costs associated with the NGV program result in air quality benefits enjoyed by all Californians in their capacity as ratepayers and, as such, should be recovered on **an equal cents per therm basis** over all volumes sold by PG&E to all customer classes consistent with the intent of Public Utilities Code 740.3(c).[149]

The Commission further stated in a PG&E 2007 Biennial Cost Allocation Proceeding ("BCAP"):

> Consistent with our view that all customers should pay for programs that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers and adopt PG&E's proposal to allocate the costs on an equal cents per therm basis.[150]

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[147] D.06-01-024, mimeo, p. 12.

[148] D.91-07-018, 40 CPUC 2d, pp. 738-739.

[149] 40 CPUC 2d at 744, Finding of Fact #13, emphasis added.

[150] D.05-06-029, mimeo, p. 18.

Similarly, the Commission has generally adopted the approach of allocating equal cents per kWh for PPPs. For instance, CARE is one of the major PPPs and the costs are to be allocated based on equal cents per kWh. P.U. Code Section 327(a) (7) states:

> For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an **equal cents per kilowatthour or equal cents per therm basis** to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008. (Emphasis added.)

The legislature also provides guidance about how public programs are to be allocated and charged. P.U. Code Sections 381(a) & (b) describe how energy efficiency ("EE") and research and development ("RD&D"), and the development of renewable programs are to be collected on the basis of usage (which is equivalent to being allocated by cents per kWh) but charged through distribution rates:

> **381**. (a) To ensure that the funding for the programs described in subdivision (b) and Section 382 are not commingled with other revenues, the commission shall require each electrical corporation to identify a separate rate component to collect the revenues used to fund these programs. The rate component shall be a nonbypassable element of the local distribution service and **collected on the basis of usage.**
>
> (b) The commission shall allocate funds collected pursuant to subdivision (a), and any interest earned on collected funds, to programs that enhance system reliability and provide in-state benefits as follows:
>
> (1) Cost-effective energy efficiency and conservation activities.
>
> (2) Public interest research and development not adequately provided by competitive and regulated markets.
>
> (3) In-state operation and development of existing and new and emerging eligible renewable energy resources, as defined in Section 399.12.

DRA recommends that the Commission continue this policy of allocating the costs of the CSI and PPP programs in a similar manner to how CARE, EE, and RD&D costs are allocated. They should be allocated to all customer classes on an equal cents per

kWh basis. These programs benefit ratepayers broadly and thus non-exempt ratepayers should pay for these programs equally.

V. A REVENUE ALLOCATION CAP OF NO MORE THAN AVERAGE SYSTEM CHANGE PLUS 5 PERCENT IS JUSTIFIED IN THIS PROCEEDING

SCE's cost allocation does not reflect its requested revenue increase in Phase I. Therefore, the allocation results are more for illustrative purposes. DRA follows this approach. In the table below, DRA presents illustrative allocations with a 5% cap, with a 10% cap, and with a full movement to EPMC (no cap) to provide a range of comparisons.

Table 5-2 DRA's Illustrative Proposed Bundled Rates and Changes from Present Rate by Class Based on Caps and No Cap

		DRA (5% Cap)		DRA (10% Cap)		DRA (no Cap)	
	June 2011 (¢/kWh)	Proposed (¢/kWh)	% Change	Proposed (¢/kWh)	% Change	Proposed (¢/kWh)	% Change
Total Domestic	15.6	15.5	-0.9%	15.4	-1.7%	15.3	-2.0%
GS-1	17.0	15.0	-11.8%	14.9	-12.6%	14.8	-12.8%
TC-1	15.3	13.7	-10.2%	13.6	-10.9%	13.6	-11.1%
GS-2	15.2	14.8	-2.5%	14.7	-3.3%	14.6	-3.6%
TOU-GS-3	13.2	13.8	5.0%	14.3	8.7%	14.3	8.3%
Total LSMP	15.0	14.6	-2.9%	14.6	-2.7%	14.6	-3.0%
TOU-8-Sec	12.4	13.0	5.0%	12.9	4.0%	12.9	3.7%
TOU-8-Pri	11.2	11.7	5.0%	12.0	7.1%	11.9	6.7%
TOU-8-Sub	7.1	7.4	5.0%	7.8	10.0%	8.5	20.5%
Total Large Power	10.8	11.3	5.0%	11.4	5.9%	11.5	7.3%
TOU-PA-2	13.0	12.5	-3.8%	12.4	-4.7%	12.3	-5.0%
TOU-PA-3	10.2	10.7	5.0%	11.2	10.0%	11.5	13.0%
Ag.&Pumping	11.9	11.8	-0.8%	11.9	0.4%	12.0	1.2%
Street Lighting	18.0	18.4	2.2%	18.3	1.8%	18.3	1.6%
STANDBY/SEC	11.5	12.1	5.0%	12.6	9.3%	12.6	8.9%
STANDBY/PRI	11.3	11.9	5.0%	12.5	10.0%	12.6	11.0%
STANDBY/SUB	8.1	8.5	5.0%	8.9	10.0%	8.9	10.2%
Total Standby	9.2	9.7	5.0%	10.1	9.9%	10.2	10.3%
Total System	14.2	14.1	-0.6%	14.1	-0.6%	14.1	-0.6%

A comparison of currently effective and DRA's proposed average rates for bundled service, by rate group, for a full EPMC (no caps) allocation, indicates rate impacts ranging from -13% to +21%. The variation around the system average change for individual rate groups is largely caused by:

1. The movement towards a full cost-based allocation of revenue requirements,
2. Marginal cost changes,
3. SCE's changes for agriculture customer and pumping rate groups, and
4. SCE's segregation of standby from non-standby large power (TOU-8) customers.

As mentioned earlier, the results presented here should be considered illustrative pending the Commission's decision for SCE's Phase 1 revenue requirement requests. DRA recommends modifying the allocation of final revenue requirements to limit the increase to rate groups to no more than 5% in excess of the final system average rate increase.

This approach can be used to limit individual rate group increase to acceptable levels, while maintaining some movement of groups towards fully cost-based rates. Both SCE and DRA have frequently supported capping approach in the past.[151]

DRA makes this recommendation because: (1) The economic conditions have been difficult for all customer classes in recent years and will likely continue for the near future, (2) Additional rate increases will likely be implemented in subsequent years, and (3) It conforms with the Commission's policy to cap revenue allocations to moderate rate increases.

A. All Customer Classes Face Difficult Economic Challenges Today, Which Will Likely Continue in the Next Few Years

DRA recommends imposing a rate cap so that no customer class will see rate increases more than 5% above system average increase. The economic conditions

[151] In its last GRC, SCE states "In SCE's opinion, capping is a reasonable option when wide variation around the system average rate, as indicated in this illustrative case, makes a full cost-based allocation and rate design difficult to achieve in a single proceeding." (A.08-03-002, Ex. SCE-03, p. 22.)

currently are difficult, and will likely continue to be challenging for all customer classes in the next few years. Based on Bureau of Labor Statistics (BLS) data, the unemployment rate in California has been persistent at about 12% for almost three years now, and it is predicted to remain high for the next few years.[152] It is a difficult environment for the residential customers as well as for small and large businesses. Large rate increases for any customer classes would exacerbate their financial conditions.

B. SCE Customers Will Likely Receive Additional Rate Increases in the Coming Months

DRA recommends limiting the increase to any class in this proceeding to a **maximum** increase of 5% above average system change. This recommendation takes into account the fact that SCE is warning the Commission and parties that rates will likely increase due to costs associated with the need for compliance with the renewable portfolio resource requirements, the Assembly Bill 32 cap and trade program, and SCE's plans to continue to upgrade its infrastructure. In addition, SCE requested $866 million revenue requirements increases for its GRC Phase I proceeding, which could translate to system average increases of 7.5% in 2012.[153] Given the likelihood of these substantial known increases, it is important to cap or limit the increase that will result from updating marginal costs and re-allocating SCE's revenue requirement.

C. Past Precedents for Capping the Revenue Allocation

The Commission has consistently adopted caps on the revenue allocation to moderate the movement towards full marginal cost rates. This policy continues to be reasonable at the present time. In SCE's 1995 GRC Phase II Decision (D.96-04-050), the Commission provided an extensive discussion of the policy of capping, including a number of proceedings where capping was adopted:

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[152] BLS showed 11.7% in July 2009 and stay at or above 12% until April 2011. BLS reported 11.7% for Nov. 2011. http://data.bls.gov/timeseries/LASST06000003.

The Federal Reserve Board predicted unemployment rate remains relatively high in the next two to three years. "http://www.federalreserve.gov/monetarypolicy/fomcminutes20111102ep.htm".

[153] A.10-11-015, Application Amendment filed on Nov. 24, 2010, p. 2.

> In the past, we have capped full movement to 100% EPMC in order to mitigate harsh bill impacts. In Edison's last GRC, we determined that average rate increases of approximately 20% to the agricultural and pumping class should be mitigated by imposing a cap of SAPC plus 3.5%. In Edison's test year 1988 GRC, we capped full EPMC revenue allocation by SAPC plus 5% to mitigate increases to the domestic class of a similar magnitude. (D.87-12-066 26 CPUC 2d 392, 528-529; D.92-06-020, 44 CPUC 2d 471, 496-497.)

Caps have continued to be used by the Commission to moderate revenue allocation increases to specific classes. In the last few years, the Commission has adopted caps in most rate cases. In San Diego Gas and Electric's ("SDG&E") 2000 Rate Design Window ("RDW") proceeding, the revenue allocation was capped at SAPC plus or minus 3%.[154] In Pacific Corp's 2003 GRC, the Commission granted an overall system average increase of 4.7% plus a cap of 2.5%.[155]

The decisions discussed above show the preference of the Commission to limit extraordinary bill increases by adopting caps on the revenue allocation, and DRA's cap proposal is consistent with this Commission policy.

VI. CONCLUSION

DRA recommends that revenue allocation adjustments in this proceeding be limited to a maximum of average system change plus 5%. DRA's recommendation is close to the level of caps adopted by the Commission in past decisions. DRA further recommends that DR programs and AMI costs be allocated based on total revenue allocator, and programs that produce public benefits and/or environmental benefits such as the CSI and PPPs be allocated equal cents per kWh.

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[154] D.00-12-058, mimeo, Appendix C, p. 2.

[155] D.03-11-019, mimeo, p. 5.

CHAPTER 6.

RESIDENTIAL RATE DESIGN

(Witness Dexter Khoury)

I. INTRODUCTION AND SUMMARY

This chapter presents DRA's rate design recommendations for residential customers in this proceeding. DRA's rate design recommendations are based on DRA's revenue allocation proposals, which are explained in Chapter 5.

DRA recommends:

1. SCE's proposal to reduce the number of residential rate tiers from 5 to 4 tiers by combining tiers 4 and 5 should be adopted.
2. SCE's proposal to decrease baseline allowances from 55% to 50% of average consumption should be rejected.
3. SCE's proposal to calculate separate baseline allowances for single family and multifamily residences should be rejected.
4. DRA recommends minimal changes to SCE's Schedule TOU-D-T.

Table 6-1 shows SCE's current rates, SCE's proposed rates, and DRA's proposed rates for bundled residential customers. As can be seen in this table, DRA's proposals continue to make progress in reducing upper tier rates.

Table 6.1

	SCE Current Rate (¢/kWh)	SCE Proposed Rate[156] (¢/kWh)	DRA Proposed Rate[157] (¢/kWh)
Non-CARE Rates			
Tier 1	12.5	12.4	12.577
Tier 2	14.8	14.8	15.511
Tier 3	22.9	23.0	23.031
Tier 4	26.4	27.0	27.031
Tier 5	29.9	27.0	27.031
CARE Rates			
Tier 1	8.533	8.532	8.534
Tier 2	10.668	10.668	10.669
Tier 3	17.503	17.497[158]	17.561

II. SCE'S PROPOSALS

A. SCE's Residential Rate Design Proposals

SCE proposes several changes to residential rate design that it states will help reduce upper tier residential rates. Unfortunately, many of these changes also impact other residential customers. In fact, if all of these proposals are adopted simultaneously, substantial numbers of SCE's residential customers will experience unacceptable bill impacts.

SCE proposes three significant residential rate design changes:

1. Reduce the number of non-CARE residential rate tiers from 5 to 4 tiers by combining tiers 4 and 5. "SCE proposes to reduce the number of rate tiers

[156] SCE's proposed rates are not directly comparable to DRA's proposed rates as SCE's rates include changes to baseline allowances, and do not include proposed increases to Tier 1 and Tier 2 rates as proposed in Advice Letter 2654-E.

[157] Assumes a revenue allocation reduction of 0.9% to the residential class and SCE's proposed increases to Tier 1 and Tier 2 rates as proposed in SCE Advice Letter 2654-E.

[158] SCE's proposed rates are based on lower baseline allowances, and are thus not directly comparable to DRA's proposed rates.

from five to four and to set the Tier 3 to Tier 4 rate differential at $0.04/kWh."[159]

2. Decrease the baseline allowance from 55% to 50% of average consumption in each climate zone; "SCE proposes to again modify baseline allowances, setting baseline allowances for basic customers at 50% of average usage. Baseline allowances for all-electric customers would be set at 50% of average usage during the summer months, and 60% during the winter heating season."[160]

3. Establish separate baseline allowances for single-family and multi-family dwellings. "SCE proposes to establish separate baseline allowances for single and multi-family households, and to base the allowances on the average usage for each dwelling type, setting the baseline allowance percentage at 50% of average usage (60% for all-electric customers during the winter heating season)."[161]

III. DISCUSSION AND DRA'S PROPOSALS

A. Background

Senate Bill ("SB") 695 was enacted on October 11, 2009, and was a reform of rate protections for residential customers that were contained in Assembly Bill ("AB") 1X from 2001. AB 1X froze residential rates for usage up to 130% of the baseline level (i.e., Tier 1 and Tier 2 residential rates). SB 695 reformed this residential rate protection by allowing gradual increases to non-CARE residential Tier 1 and Tier 2 rates from 3% to 5% per year depending on inflation.

P.U. Code Section 739.9(a) states:

> The commission may, subject to the limitation in subdivision (b), increase the rates charged residential customers for electricity usage up to 130% of the baseline quantities, as defined in Section 739, by the annual percentage change in the Consumer Price Index from the prior year plus 1%, but not less than 3% and not more than 5% per year. For purposes of this subdivision, the annual percentage change in the Consumer Price Index shall be calculated using the same formula that was used to determine the annual Social Security Cost of Living Adjustment on January 1, 2008. This subdivision shall become inoperative on January 1, 2019, unless a later enacted statute deletes or extends that date.

[159] Ex. SCE-04, p. 24, lines 13-14.

[160] Ex. SCE-04, p. 18, lines 15-18.

[161] Ex. SCE-04, p. 20, lines 13-16.

P.U. Code Section 739.9(b) states:

> The rates charged residential customers for electricity usage up to the baseline quantities, including any customer charge revenues, shall not exceed 90% of the system average rate prior to January 1, 2019, and may not exceed 92.5% after that date. For purposes of this subdivision, the system average rate shall be determined by dividing the electrical corporation's total revenue requirements for bundled service customers by the adopted forecast of total bundled service sales.

DRA was an active participant in the crafting of SB 695, and it continues to believe that this reform can help take pressure off of upper tier residential rates, as the extra revenue received from Tier 1 and Tier 2 rate increases is used to lower upper tier (i.e., Tier 3, 4, and 5) rates. Since SB 695 was passed, SCE increased its Tier 1 and Tier 2 rates by 3% in January 2010, and its Tier 1 rates by 0.97% and its Tier 2 rates by 3% in June 2011. SCE further is proposing Tier 1 increases of 0.8% and Tier 2 increases of 5% in January 1, 2012.[162] The revenue from Tier 1 and Tier 2 rate increases is used to reduce upper tier residential rates.

DRA's proposals in this proceeding would also result in maintaining Tier 3 rates at near current levels and in reducing tier 5 rates. DRA urges caution in adopting all of SCE's proposed changes, as in many instances, residential rate design is a zero-sum game. This means that, to benefit one group of customers, another group will be harmed. SCE's proposals in this application benefit customers with high usage, but if all of SCE's proposals are adopted simultaneously, low usage, low income, and multi-family dwelling customers would experience bill increases. The baseline proposals in particular would especially harm both Non-CARE and CARE multi-family dwelling customers.

[162] The recent Proposed Decision granting SCE's Petition to Modify Decision (D.) 09-12-048 would allow SCE to further increase its Tier 1 rate a further 4.2% if SCE's system average rate increases by a sufficient amount as a result of its GRC Phase I and ERRA decisions, and if such an increase would also satisfy the conditions of the secondary rate cap contained in P.U. Section 739.9(b).

B. DRA's Approach to Reduce or Limit Increases to Upper Tier Residential Rates

1. Discussion of DRA's package of proposals

DRA understands SCE's motivation to take steps to reduce pressure on upper tier residential rates, and DRA has cooperated with SCE in the past to further this goal. In fact, DRA has been an active participant in the residential rate design changes enacted the past few years, such as the crafting of SB 695, which reformed AB 1X rate protections by allowing Tier 1 and Tier 2 rate increases of 3% to 5% per year. Nonetheless, DRA does not agree with all of SCE's residential rate design proposals in this proceeding. DRA prefers a different approach to reducing upper tier rates – that not only includes rate design, but also includes controlling revenue requirements increases and reducing the revenue allocation to the residential class. DRA has sponsored its proposals to reduce revenue requirements in Phase 1 of this proceeding. It presents its revenue allocation proposal in Chapter 5 of this Phase 2 testimony. DRA's approach is designed to reduce upper tier residential rates in a way that will have less impact on low usage customers, and multi-family dwelling customers.

DRA's recommends several actions that can help reduce upper tier residential rates and limit future increases:

1. DRA's revenue allocation recommendations in this proceeding result in a lower revenue allocation to the residential class. DRA's revenue allocation recommendation would result in a 0.9% decrease to the residential class.
2. DRA recommends limiting revenue requirements increases,[163] especially following the recent recession and the continuing stagnant economy.
3. The annual residential Tier 1 and 2 rate increases of 3% to 5% allowed by SB 695 will help take pressure off of upper tier rates.
4. Combining residential Tier 5 and Tier 4 rates will lower the Tier 5 rate.

[163] DRA reminds parties that any reduction in revenue requirements allocated to the residential class will also take pressure off of residential Tier 3, 4, and 5 rates. For example, if SCE were to receive a lower increase than it requests in its GRC Phase I application, residential customers would be allocated fewer revenue requirements and there would be less of an increase in upper tier residential rates.

DRA's revenue allocation recommendation would result in a 0.9% decrease to the residential class. DRA's GRC Phase I revenue requirements recommendations would help even more to take pressure off of residential upper tier rates. DRA has repeatedly recommended restraint to the Commission and the Investor Owned Utilities ("IOU") about revenue requirements increases which result in higher residential upper tier rates. This is especially important now as California is in what appears to be a lengthy period of economic stagnation. Currently, 11.7% of Californians are unemployed.[164] People are experiencing difficulty paying their bills, and increasing rates will make it that much harder for struggling Californians.

While the Phase 1 revenue requirements are technically outside the record of Phase 2, they do impact rates. Moreover, there is no reason to look at revenue requirements and rates separately, as revenue requirements increases to the residential class can only be collected in upper tier residential rates. DRA notes that GRC Phase I increases would quickly reverse any progress on lowering upper tier rates achieved by rate design changes. SCE's own testimony shows that its GRC Phase I proposals would result in a 4.3 cent per kWh increase for residential Tier 3, 4, and 5 rates.[165] DRA repeats its recommendation that SCE more carefully evaluate its plans and requests for revenue requirements increases, and then prioritize which are absolutely essential, and proceed with only the most essential projects.

2. Bill Impacts

DRA notes that there are several potential changes that may impact rates for low usage, low income, and multi-family dwelling customers. The proposed reduction and changes to baseline allowances, and the proposed 0.8% Tier 1 and 5% Tier 2 increases for January 2012, would all contribute to increasing bills for low usage and multi-family dwelling residential customers. DRA is also concerned about upper tier residential

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[164] See Table A of the Bureau of Labor Statistics November 22, 2011 News Release, Regional and State Employment and Unemployment—October 2011.

[165] See Ex. SCE-04, p. 26, Table II-11. Compare Columns 2 and 3 to arrive at the 4.3 cent per kWh increase.

rates, but urges caution in enacting the proposed baseline changes that would result in substantial bill increases for these other customers.

If all of SCE's residential rate design proposals and its revenue allocation proposals were adopted simultaneously, too many of SCE residential customers would experience bill increases.[166] Approximately 69% of Non-CARE residential multi-family dwelling customers would receive bill increases of 5% or greater per year, 49% would receive bill increases of 10% or greater, and 34% of customers would receive bill increases of 15% or greater.[167] 4.9% of Non-CARE residential customers would receive bill increases of 20% or more (144,291 customers), and some customers would even receive bill increases greater than 45% per year.[168] Low income customers on CARE schedules would receive even greater bill increases. Of CARE multi-family customers, approximately 76% would receive bill increases of 5% or more per year; 57% of CARE multi-family customers would receive bill impacts of 10% or more; and 38% would receive bill impacts of 15% or more.[169] Looking at all CARE customers (single and multi-family), 31.5% would receive bill increases of 5% or greater, 25.3% would receive increases of 10% or greater, 16.6% would receive increases of 15% or greater, and 8.2% would receive bill increases of 20% or greater per year (96,380 customers). Some customers would even receive bill increases of greater than 45% per year.[170] This level of bill increases would be especially burdensome to low income customers, and could quite possibly lead to an increased number of disconnections for these customers. To prevent this from happening, DRA recommends slower and more cautious changes to residential rate design.

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[166] The bill impact analysis from DRA Data request DRA-007 does not show the impact of SCE's proposed residential Tier 1 and Tier 2 increases for January 1, 2012 that were later proposed in Advice Letter 2654-E (November 16, 2011).

[167] This information is contained in SCE's response to DRA Data Request DRA-007, question #4.

[168] See Ex. SCE-04, Appendix C, p. C-2, Figure C-1.

[169] This information is contained in SCE's response to DRA Data Request DRA-007, question #6.

[170] See EX. SCE-04, Appendix C, p. C-3, Figure C-2.

3. Summary

DRA's proposed revenue allocation recommendations and DRA's proposed residential rate design recommendations would result in a Schedule D Tier 3 rate of 23 cents per kWh and a Tier 4 rate of 27 cents per kWh. Tier 1 and Tier 2 rate increases on January 1, 2012 help reduce pressure on upper tier residential rates, and restraint on further revenue requirements increases would help even more. This package of proposals would help reduce upper tier residential rates (or limit further increases) and would result in fewer bill impacts for lower usage and middle usage customers. DRA recommends that the Commission reject SCE's proposals which would dramatically impact bills for low usage customers.

DRA's proposed rates will continue to make progress in reducing upper tier residential rates. As shown in Table 6-2, SCE's upper tier residential rates would be lower than its current rates and also lower than those of PG&E and SDG&E.

Table 6-2

	PG&E's Current Rates (¢/kWh)	SDG&E's Current Rates (Summer) (¢/kWh)	SCE's Current Rates (¢/kWh)	DRA's Proposed Rates for SCE (¢/kWh)
Tier 1	12.2	13.8	12.5	12.57
Tier 2	13.9	15.9	14.8	15.51
Tier 3	29.3	29.3	22.9	23.03
Tier 4	33.3	31.3	26.4	27.03
Tier 5	33.3	31.3	29.9	27.03

C. Proposal to reduce the number of Non-Care residential rate tiers from 5 to 4 tiers by combining Tiers 4 and 5

SCE proposes to reduce the number of non-CARE residential rate Tiers from 5 to 4 and to set the Tier 3 to Tier 4 rate differential at 4 cents per kWh.

DRA supports SCE's proposal to reduce the number of non-CARE residential rate tiers as a way to help reduce the highest tier rate. Other things being equal, the resulting Tier 4 rate will be slightly higher than the previous Tier 4 rate, and lower than the

previous Tier 5 rate. And a four -tier rate structure would still provide incentives to conserve energy. PG&E and SDG&E already have a four- tier increasing block rate structure for Non-CARE customers.

D. Baseline Proposal to reduce the baseline allowances from 55% to 50% of average consumption

SCE proposes to reduce its baseline allowances from 55% to 50% of average consumption per climate zone as another way to decrease the upper tier residential rates. The Commission previously set baseline allowances at the upper end of the prescribed range at 60% of average consumption in the Baseline OIR. Several years later, in SCE's last GRC Phase II proceeding, SCE's residential baseline allowances were reduced from 60% to 55% of average consumption, as part of a residential rate design settlement in SCE's last GRC Phase II. Since then, SDG&E and PG&E have used SCE's change as grounds to decrease their own respective baseline allowances to 55% of average consumption. Thus, currently SCE, PG&E, and SDG&E all set their baseline allowances based on 55% of average residential consumption.

DRA recommends that the Commission exercise caution in reducing SCE's baseline allowances for several reasons:

1. The proposal will result in bill increases for low usage and low income customers;
2. Before the energy crisis, baseline allowances were typically set in the middle of the 50% to 60% of average consumption range; and
3. Granting this request for SCE will likely result in pressure from SDG&E and PG&E to make a similar change.

DRA opposes SCE's proposal to decrease the baseline allowances from 55% to 50% of average consumption per climate zone because it would increase bills for customers who are predominantly consuming in the Tier 1, Tier 2, and Tier 3 ranges. A customer who is currently consuming the maximum amount of the Tier 1 baseline allowance would pay higher Tier 2 rates for the difference between the old and new baseline allowances. A customer consuming the maximum Tier 2 allowance would see an even greater bill increase, as part of the usage would be billed at 23 cents per kWh rather than at the Tier 2 rate of 14.7 cents per kWh. The same would apply for a

customer at the top of the Tier 3 range. DRA's summary of the bill impacts that would result from SCE's proposals is discussed in section B.2. above.

Before the energy crisis, baseline allowances for SCE were typically set in the middle of the 50% to 60% of average consumption range.[171] Responding to the energy crisis, the Commission raised the baseline allowance to the upper end of the allowable range.[172] Baseline allowances were maintained at the top of this range until SCE's last GRC Phase II, where baseline allowances were again set back to 55% of average consumption as part of a settlement on residential rate design that was adopted by the Commission. At this time, DRA believes it is preferable to maintain baseline allowances at 55% of average consumption. This also helps maintain compliance with P.U. Code Section 739(a)(1), which states: "[t]he Commission shall review and revise baseline quantities as average consumption patterns change in order to maintain these ratios."

As a practical matter, baseline allowances are updated every three years, or sometimes longer. If average residential consumption were to increase during this time interval, baseline allowances set initially at 50% of average consumption would become out of compliance if average consumption increased while baseline allowances remained the same. Baseline allowances set at 55% of average consumption would likely remain in compliance.

The proposal to reduce the baseline allowance also impacts PG&E and SDG&E. Before changes such as this are considered, they should be made in a proceeding that includes all three of these IOUs. SCE's proposal to set the baseline allowance at 55% of average consumption was adopted in a settlement. Both SDG&E and PG&E asked for the same treatment in their respective rate cases. A large part of their reasoning relied

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[171] See D.02-04-026, p. 10, footnote #5. "In Exhibit 2 at p. 7, SCE states that basic customers' baseline is set at the midpoint of average use in both summer and winter months, while for all-electric customers, baseline allowances are currently set at the maximum percentage allowed under law."

[172] See D.02-04-026, mimeo, p. 2. "Specifically, we require the utilities to update the data used for calculating baseline allowances to reflect current usage of both gas and electricity, **to increase baseline allowance to the maximum percentage levels allowed by state law** for those customers not already receiving those maximum allowances…"(emphasis added)

on the precedent of SCE's change in setting the baseline allowance. The same result will likely occur if the Commission now approves SCE's proposal to set baseline allowances based on 50% of average residential consumption in a given climate zone.

E. SCE's Proposal to Establish Separate Baseline Allowances for Single-Family and Multi-Family Dwellings

SCE is proposing a second change to how it calculates baseline allowances. In addition to proposing to reduce the baseline allowance to 50% of average consumption, SCE also is proposing to establish separate baseline allowances for single-family and multi-family dwellings. DRA opposes this proposal for several reasons:

1. It would create unacceptable bill increases—especially for multi- family dwelling CARE customers;
2. It conflicts with Public Utilities Code 739(a)(1);
3. It goes against Commission guidance from the Baseline OIR; and
4. It would impact CARE customers especially hard as low income customers are more likely to occupy multiple family dwellings.

SCE's proposals result in dramatic bill impacts especially for multi-family dwelling customers. Virtually all Non-CARE and CARE multi-family dwelling customers would experience bill increases if SCE's proposals are adopted. Of SCE's CARE multi-family customers, approximately 76% would receive bill increases of 5% or more per year; 57% of CARE multi-family customers would receive bill impacts of 10% or more; and 38% would receive bill impacts of 15% or more. These levels of bill impacts are unacceptable – especially following a recession and during a long drawn out stagnant economy that hits poor people especially hard.

SCE's proposal also violates Public Utilities Code Section 739 (a)(1). This section of the P.U. Code describes the baseline program and gives direction on how to calculate baseline allowances:

> "Baseline quantity" means a quantity of electricity or gas allocated by the commission for residential customers **based on from 50 to 60 percent of average residential consumption of these commodities**, except that, for gas residential customers and for all-electric residential customers, the baseline quantity shall be established at from 60 to 70 percent of average residential consumption during the winter heating

> season. In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service. The commission shall review and revise baseline quantities as average consumption patterns change in order to maintain these ratios.[173]

When SCE calculates separate single family and multi family dwelling baseline allowances, the single-family allowance becomes larger and the multi-family allowance becomes smaller. The result is that the single-family allowance becomes larger than a baseline allowance based on the average consumption of all customers in a given climate zone, and the multi-family allowance becomes smaller than a baseline allowance based on the average consumption all customers in a given climate zone. PU Code Section 739(a)(1) states that the baseline allowance should be based on average consumption, and thus, multi-family dwelling customers are also entitled to a baseline allowance based on average residential consumption. SCE's proposal would result in multi-family dwelling customers not receiving this full baseline allowance, and thus this proposal violates PU Code Section 739(a)(1).

In the Baseline OIR, the Commission summarizes several criteria in addition to the rate design principles articulated in PU Code 739(c), for evaluating each Baseline Phase 2 proposal.[174] One of these key criteria is that "The burdens on non-participants should be reasonable." SCE's proposal would lower multi-family baseline allowances by 18.4% to 34% in SCE's nine climate zones.[175] Such dramatic changes to baseline allowance help create the large bill increases for multi-family customers that are discussed above. These burdens on non-participants (i.e. those not receiving the larger single-family baseline allowance) are severe and, thus, are not reasonable.

Low income customers are also more likely to live in multi-family dwellings and hence, this proposal especially impacts low income customers. From information

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[173] Emphasis added.

[174] See OIR to Determine Baseline Allowances/ Final Opinion on Phase 2 Issues (2004), D.04-02-057, mimeo, p. 34.

[175] See Ex. SCE-04, Appendix F, and compare the proposed baseline allowances set at 50% of average residential consumption on p. F-3 with the proposed multifamily baseline allowances on p. F-5.

provided by SCE, it appears that 45.64% of SCE's CARE customers live in multi-family dwellings.[176] DRA recommends rejecting this proposal that would result in bill increases for nearly half of SCE's low income residential customers.

F. Schedule TOU-D-T

SCE proposes to modify its residential Time of Use ("TOU") schedule by changing the TOU periods for Schedule TOU-D-T to make residential TOU periods better reflect system peak usage and to improve the price signals to customers in different rate groups.[177] SCE also notes that Schedule TOU-D-1 and Schedule TOU-D-2 will be eliminated as agreed to in a settlement of SCE's marginal cost, revenue allocation and rate design approved by the Commission in 2009.[178] SCE proposes to transfer Schedule TOU-D-1 and TOU-D-2 customers to Schedule TOU-D-T after implementation of rates in this proceeding.

DRA has concerns with SCE's proposals and recommends minimal changes to Schedule TOU-D-T at this time. DRA also recommends that customers on Schedules TOU-D-1 and TOU-D-2 be contacted by SCE to determine whether they prefer to take service on Schedule D or Schedule TOU-D-T.

DRA is concerned about SCE's proposed rates for Schedule TOU-D-T as there are fairly large changes to the rates that are not discussed or explained in SCE's testimony. It is possible that these changes are caused in part by changes to marginal costs, and changes of this magnitude merit discussion. SCE's proposed rates for Schedule TOU-D-T would increase the summer Level 1 on peak rate by 63.3% from 18.9 cents per kWh to 30.9 cents per kWh.[179] SCE also proposes to decrease its summer Level II on- peak rates by 14.1% from 50.4 cents per kWh to 43.3 cents per kWh.

These are large changes to summer on- peak rates and DRA believes that these changes will make this rate schedule far less attractive to potential new customers. SCE

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[176] This is calculated from information contained in SCE's response to DRA Data Request DRA-007, questions #2 and #6.

[177] See Ex.SCE-04, p. 74.

[178] Application of SCE to Establish Marginal Costs (2009), D.09-08-028.

itself notes that "Most customers will realize lower average rates on Schedule TOU-D-T only if they take measurable actions to reduce on-peak usage, such as installing a photovoltaic ("PV") system or participating in demand response programs."[180] Schedule TOU-D-T will be the only residential TOU rate offered by SCE (except for EV TOU schedules for customers who have an EV), and DRA would prefer residential TOU options that have broad appeal to residential customers. In fact, DRA believes that residential TOU rates will be far more wide-spread in the future, and that it makes sense to start moving in this direction. SCE's proposed changes will move in the opposite direction and will likely result in less interest in TOU rates until new and better TOU rate options are created.

DRA recommends making minimal changes to Schedule TOU-D-T, and suggests that SCE propose additional residential TOU rate schedules in its next GRC Phase II filing. DRA also recommends that SCE attempt to notify all current TOU-D-1 and TOU-D-2 customers to determine if they prefer service on Schedule D or Schedule TOU-D-T. Schedule TOU-D-T is very different from the earlier TOU rates and there is no reason to assume that these customers would prefer Schedule TOU-D-T, as taking service on this schedule could easily result in bill increases to these customers.

IV. CONCLUSION

DRA recommends that the Commission adopt DRA's revenue allocation and rate design proposals that will help take pressure off of upper tier residential rates. DRA recommends a revenue allocation decrease of 0.9% to the residential class, restraint in approving revenue requirements increases, maintaining current baseline allowances, implementing the annual SB 695 increases to residential Tier 1 and Tier 2 rates, and combining residential Tier 4 and Tier 5 rates. DRA's proposals in this proceeding would result in a residential non-CARE Tier 4/5 rate of 27 cents per kWh. DRA's

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(continued from previous page)

[179] See Ex. SCE-04, Appendix B, p. 2.

[180] See Ex. SCE-04, p. 74.

proposals should be adopted as they help lower upper tier rates in a way that harms other residential customers less.

DRA also recommends minimal changes to rates for Schedule TOU-D-T, and that customers on the closed schedules TOU-D-1 and TOU-D-2 be allowed to choose between taking service on Schedule D and Schedule TOU-D-T. DRA further recommends that SCE propose more residential TOU options in future rate cases.

CHAPTER 7.

SMALL COMMERCIAL RATE DESIGN

(Witness CHERIE CHAN)

I. INTRODUCTION

This chapter presents the Division of Ratepayer Advocates' ("DRA's") recommendations on the rate design for Southern California Edison's ("SCE's") nearly half a million small commercial customers.

In its application, SCE proposes to:

1. Transition customers to mandatory fully cost-based Time-of-Use ("TOU") rates by October, 2012.
2. Continue to offer Critical Peak Pricing ("CPP") as an **optional** rate for small commercial customers. SCE does **not** support a subsequent transition to default CPP rates
3. Update the current seasonally-differentiated flat small commercial General Service ("GS-1") rate according to new marginal cost data.

DRA's recommendations to SCE's small commercial rate design proposals are summarized in the next section.

II. SUMMARY OF RECOMMENDATIONS

DRA agrees with many of SCE's proposals in this application. For example, DRA concurs with SCE that the implementation of default or mandatory time-varying rates for small commercial customers[181] should be delayed by at least one year, and that time-of-use and critical peak pricing rates should not be introduced concurrently to small customers. DRA proposes the following modifications, intended for application to small commercial customers only:

1. Since SCE's Smart Meter rollout to customers will be completed the summer of 2012 at the earliest, the soonest any default time variant pricing

[181] The Commission has defined "Small" in this context to be customers with actual or expected maximum demands of 20 kilowatts (kW), see D.08-07-045. DRA commends SCE for continuing to restrict eligibility for service by the GS-1 rate to prevent larger, savvier commercial customers from benefitting from protections reserved for smaller commercial customers.

("TVP")[182] rates should be implemented for small commercial customers ought to be the Fall/Winter season of 2013, beginning October 1st.

2. Critical Peak Pricing or Real-time pricing should remain voluntary (opt-in) for these customers, as SCE also recommends. However, if the Commission chooses to implement default CPP, it should not do so until customers have had two full summers of experience under TOU rates.
3. To mitigate bill impacts, the on-to-off-peak rate differentials for small commercial TOU customers should be initially limited to a "TOU-lite" rate, which would have lower on-to-off-peak price differentials than SCE's proposed rates.
4. The current summer-to-winter energy charge differentials for small commercial customers on Schedule GS-1 should be maintained, as these customers will be subject to many other changes over the next few years.

III. TIME-OF-USE RATES AND CRITICAL PEAK PRICING

In its application, SCE proposes its preferred scenario with mandatory cost-based TOU rates and optional CPP rates beginning October 1, 2012.[183] DRA agrees with SCE in taking the common-sense approach of proposing to introduce TOU rates first, with CPP rates to be considered later, but DRA disagrees with SCE on the timing and type of TOU pricing.

DRA proposes that small business customers be granted more time to gain familiarity with Smart Meter data before implementing mandatory cost-based TOU rates. Below is a table summarizing DRA's rollout schedule compared to SCE's proposed schedule. The table also shows the current TVP schedules for Pacific Gas and Electric ("PG&E") and San Diego Gas and Electric ("SDG&E").

[182] DRA defines TVP rates as including both 1) Time of Use rates as well as 2) Dynamic Pricing rate schedules such as CPP, in which prices are responsive to system conditions.

[183] SCE-05, on page 9, Figure III-1, shows its preferred schedule for introducing time-varying pricing. It recommends that critical peak pricing remain voluntary rather than being introduced as the default tariff, as discussed in A.10-09-002.

Table 7-1			
	Effective Date	**TOU**	**CPP**
DRA Recommendation	October 2012	Optional	Optional
	October 2013	Default TOU–Lite[184]	Optional
	October 2014	Mandatory TOU-Lite	Optional
	2015/Future GRC	Mandatory TOU[185]	Optional
SCE Preference[186]	October 2012	Mandatory	Optional
SDG&E[187]	March 2013 March 2014	Optional Default	Optional Optional
PG&E[188]	November 2012	Default TOU-Lite	Optional
	March 2013	Mandatory TOU-Lite	Optional
	November 2014	Mandatory TOU-Lite	Default[189]

DRA also encourages the Commission to start with mild "TOU-lite" rates as customers are introduced to time-variant pricing. Below is a table which compares SCE's proposed rates and DRA's proposed rates. DRA's proposed rates for SCE are roughly modeled after PG&E's adopted rate structures, shown in the middle column.

[184] Customers who opt out of TOU would be placed on non-TOU seasonally-differentiated rates.

[185] The Commission should consider transitioning small business customers to a fully cost-based TOU rate design at some point, though not necessarily by 2015, and possibly with options that can be tailored to the needs of individual small businesses.

[186] Which is later than SCE's compliance filing in A.10.09.002 or D.09-08-028.

[187] "SDG&E's Motion for adoption of Joint Party Settlement and Memorandum of Understanding" in A.10-07-009, filed June 20, 2011. Exhibit 1, Joint Party Settlement Agreement, page 2. In its pending GRC2 application A.11-10-002, SDG&E correctly proposes a time-variant pricing rollout schedule consistent with the settlement agreement. DRA will file testimony in this case in 2012.

[188] Pacific Gas and Electric Company ("PG&E") D.11-11-008.

[189] Per D.11-11-008. Customers who opt out of CPP would be placed on mandatory TOU-lite rates.

Table 7-2									
	SCE Proposal[190]			PG&E Settlement[191]			DRA Proposal for SCE[192]		
¢/kWh	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
Summer	29.874	16.000	10.414	22.231	19.644	18.101	20.334	16.290	13.601
Winter	-	11.424	10.144	-	15.284	14.179	-	12.967	11.766
Customer Charge (¢/day)		69.0		29.569			69.0		

A. DRA Supports SCE's Preference for TOU First, and also Agrees that TOU is a Better End-State than CPP

DRA strongly concurs with SCE's statement that it "… shares the concerns expressed by PG&E and others that the simultaneous introduction of mandatory time-of-use and default CPP rates could be overwhelming for customers." SCE adds that "The first transition from flat rates to time-variant rates should be to TOU rates, not to default CPP rates."[193] DRA agrees with SCE that "it is preferable to retain CPP as an optional rate."[194]

Much has changed since SCE initially filed this application on June 6, 2011. The SDG&E Rate Design Window case was settled the following month, with parties agreeing to begin with both optional TOU and CPP rates for small commercial customers instead of mandatory TOU and default CPP rates. In October, PG&E's and DRA's requests to delay the implementation of time-variant rates for small business customers were granted.[195] Moreover, the TOU prices that the Commission previously adopted for

[190] SCE-04, B-4.

[191] PG&E Tariff Sheet, Electric Schedule A-1, Small General Service. PG&E's Settled Rate from D.10-02-032, with decision on PFM D.11-11-008.

[192] DRA Workpapers, Sheet Optional Rates, tab Default TGS1-A.

[193] SCE-05, p. 7, lines 20—22.

[194] SCE-04, p. 4, lines 6—7.

[195] Both PG&E and DRA filed petitions for modification of D.10-02-032 requesting a delay, among other items. D.11-11-008 granted PG&E's petition, and partially granted DRA's petition (filed jointly with the California Small Business Association).

PG&E embody a lower level of price differentiation between the on and-off peak periods ("TOU-lite") than do SCE's proposed rates.

1. TOU is Easier to Understand than CPP

Most customers have had some exposure to TOU rates in other areas of their lives. For example, most customers, large and small, have paid on-peak and off-peak rates through telephone bills for years. Motorists driving portions of toll roads 73, 133, 241, 261 within or near SCE's service territory pay different rates during on-peak, off-peak, and weekend periods.[196] In the San Francisco Bay Area, drivers on the Bay Bridge also pay time-varying rates each rush-hour period, during other weekday hours, and on weekends.[197] Introducing a larger subset of customers to these predictable time-of-use rates without including unpredictable event-based surcharges will provide small businesses a less confusing introduction to electric time-varying rates. In contrast to TOU, dynamic pricing (such as CPP) of a delivered commodity will be a completely new concept for many small commercial customers. For these reasons, DRA joins SCE in advocating for TOU pricing as more appropriate than CPP for small commercial customers.

2. Dynamic Pricing Produces Limited Gains

In the most recently-available comprehensive *2010 California Statewide Non-Residential Critical Peak Pricing Evaluation*, the report authors noted that that SCE "customers that experienced CPP for the first time due to the default, on average, provided very small load reductions."[198] The report consultants also noted that "larger SCE participants are more price-responsive than smaller ones."[199]

Neither DRA nor the consultants are criticizing SCE's CPP implementation as detailed in the report; rather, DRA notes the reality of limited demand response amongst

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[196] https://www.thetollroads.com/assets/objects/other/TR_RateCard.pdf.

[197] http://goldengatebridge.org/tolls_traffic/toll_rates_carpools.php.

[198] 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation, April 1, 2011. George, et. Al., Freeman, Sullivan & Co, page 38, SCE Ex Post Load Impact Report.

[199] Id., p. 41.

small customers as well as those who are new to time variant pricing. In addition, as described elsewhere in DRA's testimony in this proceeding,[200] there will be a surplus of generation, well beyond the Commission's current targets, for the foreseeable future. This surplus capacity on the wholesale market has decreased price fluctuations in the wholesale market that would justify more aggressive time-variant rate differentiations.

Given the somewhat disappointing benefits of dynamic pricing shown above, DRA questions whether the expense, disruption to customers, and bill unpredictability is worth the potentially meager gains.

3. TOU May Produce More Greenhouse Gas Reductions Than Does CPP

The Commission's Energy Action Plan II states that the impacts of climate change should drive Commission energy policy:

> Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California. …. Increasing energy efficiency, demand response, and renewable resources to the maximum extent possible in California and the western region will … reduce our contribution to climate change.

New research shows that TOU may produce greenhouse gas reductions comparable to or better than CPP.[201] While CPP events can be called a set number of times per year with as little as one day of notice, predictable year-round TOU price differentials are more likely to lead to permanent customer behavioral changes and capital investments that can reduce greenhouse gas emissions derived from on-peak generation even more.[202]

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[200] Levin, Robert. DRA's testimony in this proceeding, submitted concurrently with this testimony. Chapter 2, Marginal Cost of Electric Generation, pp. 2-8.

[201] Electric Rate Design and Greenhouse-Gas Emissions Reduction. Proceedings of the IEEE Power and Energy Society, 2009, Calgary Abs. Blumsack.

[202] CPP rates are typically effective on average 12 days per year, whereas summer peak TOU rates are typically effective up to 120 days per year.

4. A Recent Commission Decision Reaffirms SCE's and DRA's Preferences for TOU Rates Before CPP

The Commission recently ruled in response to two petitions to modify from PG&E and DRA with the California Small Business Association/Roundtable in the 2009 PG&E Rate Design Window. Both petitions argued that small commercial customers need to have experience on TOU rates prior to being assigned to a CPP rate.[203] Based on this new information, the Commission thus stated that it was:

> …persuaded that these customers should first be exposed to TOU rates alone, in order to simplify customer education about the new rates. In keeping with our intention to provide more time for this to take place, we believe that customers should have two full years (and two summers) of TOU experience before being defaulted to a PDP rate design.

While DRA continues to assert that TOU rates are an appropriate end-point for small commercial customers, DRA agrees with the caution the Commission demonstrates by requiring two years of experience on TOU rates first before the introduction of CPP rates is contemplated.

B. Large Customers Had the Benefit of Years of Experience with TOU Rates, yet CPP Rates Remain Unpopular

SCE's larger commercial customers have the resources and knowledge to understand, elect and respond to Critical Peak Pricing better than can small businesses. As SCE states: "SCE's C&I [Commercial and Industrial] customers with demands equal to or greater than 200 kW were introduced to time-varying rates through TOU first, not to default CPP rates, in the case of larger customers, for decades, prior to being subject to default CPP rates.[204]

Larger businesses generally have more employees, and are more likely to have dedicated energy managers or consultants who understand electricity rate options monitoring their usage. Furthermore, larger businesses currently subject to CPP receive face-to-face interaction and billing analysis through assigned SCE account representatives. Once businesses are aware of a CPP event, it is more likely that

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[203] D.11-11-008, Order 1.b.3.

[204] SCE-05, p. 7, line 22 to p. 8, line 2.

somebody is available to change the energy usage on-premise. It also is more probable that automating technologies have been installed.

Despite all of these advantages, CPP remains unpopular with large commercial customers. The retention rate for CPP customers overall, since October 2009, was merely 41%, with only 33% of non-legacy customers remaining on CPP.[205] "Legacy customers" are those who had previously volunteered to opt into CPP before it became the default tariff.

As noted above, SCE's C&I customers with demands greater than or equal to 200 kW experienced a much more gradual transition to CPP than is being proposed for small businesses. It makes little sense to impose a more rapid schedule for introducing CPP to small businesses than was followed for large customers.

The dismal retention rates for non-legacy CPP customers are an indication of a "best case scenario" for small commercial customers, and the actual results will likely be even less favorable. DRA does not see the purpose of defaulting SCE's smallest commercial customers to rates that these consumers clearly are not ready for, and generally do not want.[206]

1. Small Business Face Greater Obstacles to Success with Time-Variant Pricing As Compared To Larger Businesses

DRA cautions that small businesses will likely have even more difficulty adapting to dynamic pricing than large ones, and will be less equipped to deal with the bill volatility associated with dynamic rates. The CPUC stated in Rulemaking 10-05-005:

> Small businesses are much like residential customers; they do not have the resources available to larger corporations nor the flexibility in accessing funds that bigger businesses have. This is a crucial time for policy makers to ensure that our small businesses stay afloat.[207]

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[205] SCE Response to CLECA Data Request 3.7.

[206] 7123 of SCE's 475,781 customers, or less than 1.5% of all GS-1 customers, have enrolled in the TOU option. Data from DRA Data Request 12, Question 1. For calculations, see 7_DRA_SCE Workpapers; tab CustomerCount from DR DRA 12-1.

[207] Commissioner John A. Bohn, CPUC Press Release. San Francisco, Oct. 28, 2010. CPUC Revises Small Business Billing and Deposit Rules.

As noted by the commission, small businesses are likely to fare worse, not better, under CPP rates, and should also be gradually transitioned to more predictable rates such as TOU pricing. Small customers have less staff, fewer direct contacts from utilities and less access to capital, and deserve more, not fewer protections than larger customers as they are introduced to TVP.

2. Small Commercial Customers Are Less Able to Curtail

Recent data from the 2010 CPP season showed that SCE's smallest commercial customers, those with average demand below 50kW, had an average load impact of less than 0.4% in response to the introduction of the CPP rate. Small business were the only commercial group with less than a 1% load impact, while the largest customers with over 500 kW had a 5.6% load impact.[208] As explained in the report: "On aggregate, the load impacts are concentrated among larger customers because they not only have more load, **but are also more price responsive**."[209]

DRA expresses concern that imposing punitive time variant pricing prematurely on small business not only can create a hardship on vulnerable small businesses, but also will fail to produce the desired load shift.

For the reasons stated above, DRA strongly recommends that TOU rates continue as a voluntary rate, with default rates being the next step. Customers should be allowed to opt back to the protections afforded by flatter seasonally-differentiated rates until they are able to adjust their energy consumption, prepare for higher bills, or save money for new technologies to lessen the impacts of time-differentiated rates. Now is not the time to impose another potential hardship on California's small businesses, especially the 99% of customers who are less knowledgeable, or did not choose time-variant rates.

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[208] 2010 California Statewide Non-Residential Critical Peak Pricing Evaluation, April 1, 2011. George, et. al., Freeman, Sullivan & Co. Table 5-3, p. 41.

[209] Id., p. 41, emphasis added.

C. DRA Recommends Changes to SCE's Proposed Schedule for Transitioning to Time-Variant Pricing

DRA agrees with SCE that delaying TOU and CPP from the dates ordered in D.09-08-028 is a prudent step, especially in light of the limited acceptance CPP has gained from larger commercial customers. Furthermore, DRA recommends that the Commission follow its recommendations in its 2009 PG&E Rate Design Window case[210] and require that customers have access to one full year of data before being transitioned to time-variant pricing to ensure better customer awareness and acceptance of the new rate.

1. Customers Need at Least One Year of Interval Data Before being Defaulted to TOU Rates

It is crucial that customers have at least one year of Smart Meter data, including data for the same month the previous year, before being defaulted to new rate structures dependent on such data. As discussed by the Commission in regard to CPP, "[t]he default process shall not begin until…affected customers have access to 12 months of recorded interval data at least 45 days prior to their default date."[211] The same policy should apply to TOU rates.

At last count, SCE had replaced 3,438,217[212] of approximately 5 million meters with Smart Meters. Thus, only a subset of these 60% of customers will have had one year and 45 days of interval data by SCE's proposed transition date to TOU rates. Given a current daily installation rate of approximately 7,000 meters per day, the earliest SCE would complete its smart mater installation would be the summer of 2012.[213] Therefore, for purposes of practicality, DRA does not support SCE's proposal to require mandatory TOU rates by 2012. Rather, DRA recommends that TOU rates remain purely optional

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[210] D.10-02-032 in A.09-02-022.

[211] D.11-11-008, Order 1.d.9.

[212] Edison SmartConnect Quarterly Program Update, page 7 of the handout from the quarterly Technology Advisory Panel Meeting November 2, 2011. Statistics are as of October 27, 2011.

[213] DRA Workpapers Ch. 07. Tab: SCE Meter Install Estimate.

to GS-1 customers in October of 2012, and that default TOU (lite) rates be implemented, at the earliest, in October 2013.

2. TOU Rates Should Begin in the Fall or Winter to Avoid Rate Shock

Whether the adopted TOU differentials are as high as those recommended by SCE or more moderate, DRA recommends that any transition to TOU rates be introduced in the fall or winter season, when the TOU differentials are substantially lower. This will help reduce rate shock and potential customer backlash to the rate change.

Historically, SCE also has held—and continues to hold—the position that the introduction of new rates or substantial rate changes is more appropriate in the fall and winter season, rather than during the summer season. As stated by SCE:

> The rate case plan, D.93-07-030, calls for an October 1 implementation date (every three years) in part to soften bill impacts which are generally more significant in the summer by implementing rate design and cost structure changes on the first day of the winter season, which is October 1.[214]

DRA encourages the Commission to reaffirm its earlier decision consistent with SCE and DRA's preference in which the Commission "agree[d] with SCE that a single annual date for default is simpler, and that a date after the summer period has ended is most appropriate."[215] Avoiding rate shocks, which would likely occur if time-varying pricing is introduced just prior to the summer rate season, remains a high priority for DRA's constituent customers.

3. Outreach and Education Should Be Required Similar to that Ordered for PG&E in D.11-11-008

In the past, DRA has recommended objective measures of customer awareness and penetration prior to the introduction of time variant pricing, with customers being defaulted to TVP only in the absence of a certain number of complaints. To that end, DRA recommended for PG&E that:

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[214] SCE-05, p. 17, lines 13-16.

[215] D.11-11-008, p. 28.

> Instead of an arbitrary date, we propose a schedule for defaulting customers to Time of Use rates, based on objective measures of customer understanding (as measured by customer awareness), customer acceptance of time-varying rates (as measured by penetration) and [the utility's] ability to serve its customers on time-varying rates with no significant problem (as measured by customer complaints).[216]

While the Commission did not adopt DRA's recommended customer awareness and understanding thresholds, D.11-11-008 adopted an outreach and education program in Ordering Paragraphs 12 through 16. Such an outreach and education program also would be appropriate for SCE in the absence of more specific customer awareness and acceptance thresholds. Moreover, DRA would be open to a slightly less intensive outreach effort than the TOU and CPP outreach described in D.11-11-008 because TOU-only rates are easier to understand and do not require event-based notification. This is not to say that extensive customer education and outreach will not still be required, as time-variant energy pricing will be new to the overwhelming majority of small commercial customers.

4. Communications and Outreach Will be Easier if All Customers are Transitioned at the Same Time

DRA agrees with SCE that a set of single transition dates for time-varying rates will result in a streamlined and more efficient outreach and education effort. SCE states:

> "… while SCE also believes that there are benefits to having a specified date for customer transitions to mandatory TOU (or default CPP/TOU), as opposed to rolling in customers as each becomes eligible, SCE would prefer a single transition date to default or mandatory rate structures occurring after the summer period has ended."[217]

With a single transition date, SCE can mass-market the same message to its entire small commercial customer class or to specific small business publications, include bill inserts, and partner with trade and business organizations. This is easier if there is a clear, predictable and expected rollout schedule and message that can be clearly and

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[216] DRA et. al., as cited on pp. 12-13 in D.11-11-008.

[217] Response of Southern California Edison to Petition of Pacific Gas and Electric Company to Modify D.10-02-032, dated February 14, 2011.

easily communicated. For these reasons, DRA agrees with SCE's preferred strategy to transition customers to time-variant pricing on a single date, rather than to transition customers in groups according to a somewhat arbitrary meter installation schedule.

D. If Default or Mandatory TOU Rates are Imposed, DRA Proposes a "TOU-Lite" Rate with Smaller Time-Differentiations to Start

DRA agrees with SCE for taking the common-sense approach of proposing to introduce TOU rates first, with CPP rates to be considered later. However, DRA encourages the Commission to begin with mild or "TOU-lite" rates when customers are introduced to time-variant pricing, as discussed below.

1. 64% of TOU Customers Are Projected to Be "Net-Losers"

SCE's TOU rate proposals will result in bill increases to 64% of customers[218], with average annual increases of 8% for this cohort. Over 20% of customers would receive annual bill increases of over 10%.[219] To mitigate these extreme bill increases, DRA strongly recommends adoption of a TOU-lite option similar to what was implemented by PG&E.[220]

The TOU differentiations DRA proposes in this chapter have been generally scaled down to the adopted levels for PG&E, while maintaining DRA's proposed revenue requirements in SCE's models discussed elsewhere in DRA's testimony.

2. In the Absence of a TOU-Lite Rate, DRA Recommends Seasonal Bill Protection

If TOU-lite rates are not adopted, and the Commission defaults or mandates that most small businesses in SCE's service territory be subject to highly-differentiated TOU rates, DRA recommends that seasonal bill protection be provided for a minimum of one year to help mitigate hardships for customers. In lieu of bill protection, and if feasible

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[218] SCE-05, B-1.

[219] SCE-05, B-2.

[220] DRA is not opposed to the introduction of a second, voluntary or experimental TOU rate with higher price-differentials, if it can be implemented with minimal cost or confusion to ratepayers.

for SCE, DRA would also support a "Snap Credit" as adopted by SDG&E, whereby those customers who experience an unusually high summer bill have the option of spreading the high bill over the next 3-6 months.[221]

Bill protection has been proposed by SCE for its **optional** CPP rate, which DRA supports, but not for TOU. Bill protection for TOU will help mitigate risk for small commercial customers, and would allow them to be "made whole" at the end of the summer, winter or snap credit season as they continue to familiarize themselves with time-variant pricing.

3. A TOU-Lite Rate Will Reduce Price and Bill Fluctuations

Another benefit of starting with TOU-lite rates, rather than fully cost-based TOU rate periods, is to avoid confusing small customers. The TOU rate element, in a rate schedule that combines CPP and TOU, inherently is less time-differentiated than is that in a fully cost-based TOU rate. This is because, in the combination TOU/CPP rate design, the marginal generation capacity costs assigned to the summer season are recovered in both the CPP surcharge and in the summer on-peak rate. In contrast, these costs would be recovered entirely through the summer on-peak rate in a fully cost-based TOU rate.

Starting with a fully cost-based TOU rate, and then ramping down the magnitude of the TOU rate differentiation when the combination rate is introduced, might be confusing to customers. It also might harm customers who made investments assuming a higher TOU differential, but subsequently will face a different price structure, possibly rendering their investments less cost effective.

SCE's proposed combination CPP/TOU rate design is shown in Table A-1 of Exhibit SCE-5. As shown, without the CPP overlay, the TOU summer on-peak to off-peak price differential is nearly 3-to-1. When CPP is overlaid, that differential effectively drops to about 1.6-to-1 because generation capacity costs are collected in both the CPP surcharge and in summer on-peak rates. DRA believes it is preferable to send

[221] San Diego Gas & Electric Company's Motion for Adoption of Joint Party Settlement and Memorandum Of Understanding in A.10-07-009, Filed June 20, 2011. Settlement Agreement, p. 4.

customers a consistent message, and thus it would be better to transition small customers to a TOU rate that is less time-differentiated than are the rates that SCE proposes.

IV. LEGACY GS-1 SEASONALLY-ADJUSTED RATE

In its application in this proceeding, SCE proposes an 8% average rate decrease to SCE"s customers served by the General Service Non-Demand rate ("GS-1") available to commercial customers with demand less than 20 kW.[222] This rate decrease is a result of SCE's proposed revenue allocation. Under SCE's proposal, the annual average rates for legacy seasonally-differentiated small commercial bundled customers will decrease from 17.1 cents to 15.8 cents/kWh.[223] While this, and SCE's recommendations overall represent some good news to small commercial customers struggling to survive or recover from the Great Recession, DRA has concerns about the proposed increase in the seasonal differential between its proposed summer and winter rates.

Below is a summary of SCE's current seasonally-differentiated GS-1 rates, SCE's proposed rates, and the GS-1 rates proposed by DRA.

[222] SCE Schedule GS-1 General Service Non-Demand Tariff Sheet, filed May 2, 2011 and available at: http://www.sce.com/NR/sc3/tm2/pdf/ce74-12.pdf.

[223] Updated Testimony of Southern California Edison, filed October 7, 2011, Exhibit SCE-04, p. C-4.

Table 7-3				
	Current	**Proposed**[224]	**% Change**	**DRA Recommendation**
Summer Energy Charge (¢/kWh)	17.413	17.493	0.5%	16.015
Winter Energy Charge (¢/kWh)	12.749	10.754	-15.6	12.080
Customer Charge (¢/day)	0.733	0.69	-5.90%	0.69

A. SCE's Proposed Changes to the Seasonal Differential Ratio will be Confusing and Burdensome

In its application, SCE Proposes to increase the summer energy charge by 0.5% from 17.413¢/kWh to 17.493 ¢/kWh, and to reduce the winter energy charge from 12.749 ¢/kWh to10.754 ¢/kWh. On balance, this will change the summer-to-winter energy charge ratio from 1.366% to 1.627%.[225]

Though what SCE proposes may be a cost-based change, DRA fears how customers will react to this change followed by the introduction of a completely different kind of time-varying pricing. For this reason, DRA recommends that the seasonal rate differential remain essentially the same until time-variant rates are implemented, especially if the Commission decides to impose both the increased seasonal differential and time-varying rates upon small commercial customers within a short timeframe such as one year or less.

B. Customers Need Time to Adjust to New Rate Structures

In proposing the introduction of time-based rates, SCE reasonably notes that "[t]he transition of small and medium size C&I …customers to time variant rates should be coordinated and implemented with other rate changes adopted in this proceeding."[226]

[224] SCE-04, page B-4.

[225] DRA Workpapers Chapter 7 Tab GS-1 Rate Ratios.

[226] SCE-05, p. 20, line 7.

DRA also agrees with the assessment that "SCE expects it will take some time for customers to begin to understand the new rates and that extensive communications will be required to facilitate this understanding."[227] If sufficient time to inform customers of significant changes to their rates is lacking, DRA encourages the Commission to delay or consolidate changes to customer rates, by eliminating the change to the seasonal differential.

According to the scoping memo in this case, a final decision is expected in November, 2012 with new rates to be implemented in January 2013,[228] leaving just one month for customer outreach and communication. Customers could experience a 15% rate decrease on their January bills, but then subsequently would see bills jump dramatically to over 60% above their winter bills when they receive their first summer season bill. Under SCE's preferred plan, they would be subject to another change in October when customers are moved to mandatory TOU rates. It would be much better to delay default TOU rates until October 2013 at the earliest, to allow time for the dissemination of new rate information, and to allow time for customers to prepare for time-varying rates.

V. CONCLUSION

DRA has been encouraged by many of SCE's small commercial rate design proposals, most notably, that small business customers should be protected from unpredictable CPP rates in favor of TOU rates. DRA believes that the Commission's goals will be best served if the 99% of small business currently served on flat, seasonally differentially rates are gradually introduced to and transitioned to time-varying rates through TOU-lite rates that are first introduced as a voluntary and then a default rate.

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[227] SCE-05, p. 20, lines 2—3.

[228] "Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling" in this proceeding, p. 6, December 2, 2011.

APPENDIX

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ROBERT LEVIN

Q.1. Please state your name and business address.

A.1. My name is Robert Levin. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the State of California at the California Public Utilities Commission (CPUC) as a Senior Regulatory Analyst in the Division of Ratepayer Advocates (DRA).

Q.3. Please state your educational background and experience.

A.3. I have a Ph.D. in Operations Research and an M.A. in Mathematics from the University of California, Berkeley, and a B.A. in Mathematics from U.C.L.A.

I was employed by PG&E for 24 years in various professional capacities in the areas of resource economics, capacity planning, marginal cost studies, and project cost-effectiveness evaluation.

I joined the Commission staff early in 2008. Since then, I have worked primarily on gas AMI and electric rate design proceedings. I sponsored policy and economic analysis testimony in the SoCalGas AMI proceeding (A.08-09-023) and in PG&E's GRC Phase 2 (A.10-03-014).

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapters 1, 2, and 4 of DRA's prepared testimony.

Q.5. Does this complete your testimony?

A.5. Yes.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
LOUIS IRWIN

Q.1 Please state your name and business address.

A.1 My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Division of Ratepayers Advocates.

Q.3 Please describe your educational and professional experience.

A.3 I have a Master of Arts in Economics from the University of Colorado at Boulder and a Master of Public Administration from the JFK School of Government. Both degrees included coursework in finance and economics that I find relevant to this case. The range of policy areas that I studied included natural resource, environmental, urban and health. Since joining DRA in 1999, I have worked on a large variety of energy related proceedings including marginal generation and customer costs, smart metering, curtailment policy, distributed generation, congestion pricing and undergrounding issues (regarding distribution wires) prior to working on this case. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates, a specialist in these areas.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am sponsoring testimony for Chapter 3, Distribution Demand Marginal Costs.

Q.5 Does this complete your testimony?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
LEE-WHEI TAN

Q.1. Please state your name and business address.

A.1. My name is Lee-Whei Tan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst V in the Electric Pricing and Consumer Program Branch of the Division of Ratepayer Advocates ("DRA").

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Science Degree in Chemistry from National Tsing Hua University in 1979 (Taiwan) and a Master of Arts Degree in Economics in 1986 from San Francisco State University.

In July 1986, I joined the Fuels Branch of the Division of Ratepayer Advocates where I sponsored testimony relating to utilities fuel management practices. I transferred to the Special Economics Branch in July 1987 and was involved in the benchmarking of computer programs (ELFIN, PCAM, PROMOD). In April 1988, I joined the Economics and Energy Rate Design Branch where I was assigned marginal costs and rate design for gas and electric cases. In 2001, I was assigned to the Telecommunications Branch of ORA, where I was assigned to work on telephone utility cases, such as New Regulatory Framework proceedings, mergers, and Public Utilities Code §851 proceedings.

I joined the Electric Pricing and Consumer Program Branch in July, 2009, and have been assigned to work on the revenue allocation and project coordination for San Diego Gas and Electric ("SDG&E") Critical Peak Pricing Application and Pacific Gas and Electric Company's ("PG&E") 2011 GRC Phase 2 Filing.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 5 on "Revenue Allocation" of DRA's prepared testimony in SCE's 2011 GRC Phase 2 Filing.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
DEXTER KHOURY

Q.1 Please state your name and business address.

A.1 My name is Dexter Khoury. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Electricity Pricing and Customer Programs Branch of the Division of Ratepayer Advocates (DRA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I graduated from the University of California at Santa Barbara with a Bachelor of Arts in Economics in 1977. I received a Master of Arts degree in Economics from San Francisco State University in 1987.

I joined the staff of the California Public Utilities Commission in 1986 and have worked in the Special Economics Branch, The Telecommunications-Operations and Cost Branch, The Energy Rate Design and Economics Branch, the Monopoly Regulation Branch, the Electricity Resources and Pricing Branch, and The Electricity Pricing and Customer Programs Branch of DRA. I have worked on numerous electric and gas rate design and cost allocation proceedings.

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 6, Residential Rate Design.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
CHERIE CHAN

Q.1. Please state your name and business address.

A.1. My name is Cherie Chan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By whom are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Division of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities as a Project Manager and Product Engineer. I joined the Commission in 2005 and have sponsored Marginal Cost and AMI Technology testimony, departing in 2007 to manage marketing and product management of smart grid programs at eMeter and Oracle. I returned to The Commission in 2009, and have sponsored DRA's Small Commercial Rate Design Window recommendations in SDG&E's most recent Rate Design Proceeding.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapter 7, Small Commercial Rate Design of DRA's prepared testimony.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **"TESTIMONY ON SOUTHERN CALIFORNIA EDISON'S 2012 GENERAL RATE CASE PHASE 2"** to the official service list in **A.11-06-007** by using the following service:

[**X**] **E-Mail Service:** sending the entire document as an attachment to all known parties of record who provided electronic mail addresses.

[ ] **U.S. Mail Service:** mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses.

Executed on **December 20, 2011** at San Francisco, California.

/s/ ROSCELLA V. GONZALEZ
Roscella V. Gonzalez

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