BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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Rulemaking Regarding Whether, or Subject to What conditions, the Suspension of Direct Access May Be Lifted Consistent with Assembly Bill 1X and Decision 01-09-060.	Rulemaking 07-05-025 (Filed May 24, 2007)

OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission (Commission), Southern California Edison Company (SCE) respectfully files its opening brief on the issues in this Direct Access (DA) Rulemaking Phase III proceeding. This opening brief follows the submission of direct and rebuttal testimony and evidentiary hearings, in which the following parties participated: California Large Energy Consumers Association (CLECA) and California Manufacturers and Technology Association (CMTA), Division of Ratepayer Advocates (DRA), Direct Access (DA) Parties,[1] the Joint Parties,[2] L. Jan Reid (Reid), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and SCE.

1 The DA Parties are Alliance for Retail Energy Markets, the Direct Access Customer Coalition, BlueStar Energy, and Pilot Power.

2 The Joint Parties are City and County of San Francisco, Alliance for Retail Energy Markets, the Direct Access Customer Coalition, BlueStar Energy, Marin Energy Authority, the Energy Users Forum, San Joaquin Valley Power Authority, and the California Municipal Utilities Association.

II. DISCUSSION

Based on SCE's analysis of the evidence in this case, set forth in Sections III through VI below, SCE recommends the following actions in resolution of the issues in this case:

1. Modify the existing indifference calculation approved in Decision (D.)06-07-030[3] to:
   - Reflect in the Market Price Benchmark (MPB) the value of the Renewable Portfolio Standards (RPS) eligible resources in the investor-owned utilities' (IOUs') portfolios through the use of a transparent, publicly available Renewable Energy Credit (REC) index when it becomes available in California, and in the interim, use an administratively set proxy for the "premium" value of renewable resources based on all available data points. These premium values should be used to establish a "green benchmark" for determining the above-market cost of the RPS-eligible resources for each vintage of total portfolio costs.
   - Reflect in the MPB the value of shaping resources to the load by using the historical load profiles of the IOUs' bundled service customers to weight the MPB;
   - Determine the market value of Resource Adequacy (RA) capacity in the IOUs' total portfolios using the going-forward costs of a simple cycle combustion turbine (CT) as reported in the California Energy Commission's (CEC's) bi-annual generation cost study;
   - Exclude load-based charges of the California Independent System Operator (CAISO) from the IOUs' total portfolio costs;
   - Exclude forecasted costs associated with the IOUs' energy purchases at the CAISO to fill anticipate "short" positions to serve bundled service customers from the IOU's total portfolio costs; and exclude the energy associated with such purchases from the total energy supplied by the portfolio;

[3] As modified by D.07-05-005 and D.07-01-030.

2. Modify the IOUs' Transitional Bundled Service (TBS) rate to:
   - Reflect the value of RA and RPS, calculated in a manner consistently with the calculations used for the indifference amount;
   - Include CAISO load-based charges;
3. Decrease the minimum stay requirement on Bundled Portfolio Service (BPS) to eighteen (18) months; otherwise maintain the existing switching rules for DA customers opting to depart from or return to the IOU's procurement service;
4. Adopt SCE's proposed methods for calculating ESP bonds and reentry fees pursuant to Public Utilities (P.U.) Code Section 394.25(e), which protects DA customers and bundled service customers from the costs of reentry of DA customers that are involuntarily returned *en masse* by their ESP to the IOU's procurement service;
5. Adopt SCE's proposal for administering ESP bonds and reentry fees.

SCE's recommendations are discussed in detail below.

III.

THE METHOD FOR DETERMINING DEPARTING LOAD POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA) AND ONGOING COMPETITIVE TRANSITION CHARGE (CTC) FOR ALL CUSTOMERS SUBJECT TO SUCH CHARGES

The issue in this case is whether the method for calculating the Power Charge Indifference Adjustment (PCIA) and the Ongoing Competitive Transition Charge (CTC) remains appropriate for preserving bundled service customer indifference to departing load. The principle of indifference has been articulated in a number of Commission decisions, including the recent D.08-09-012:

> "In addressing issues related to [non-bypassable charges], the Commission has generally applied the bundled customer indifference principle, whereby bundled customers should be no worse off, nor

> should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation). The Commission has also supported the principle that stranded costs should be recovered from those customers who benefited from the stranded asset, as well as those customers on whose behalf the IOU incurred these costs. . . . The notion that each customer pay its fair share of the costs the IOU incurred on behalf of this customer or the load associated with this customer is part of these guiding principles. Therefore, the rule is that when costs are incurred on its behalf, that customer must pay its fair share of the costs."[4]

The Commission has determined that bundled service customer indifference is required by the mandates of Assembly Bill (AB) 117 to "prevent any shifting of recoverable costs among customers" and require *each* retail end-use customer "to bear a fair share of the Department of Water Resources electricity purchase costs, as well as electricity purchase contract obligations that are recoverable from electrical corporation customers in commission-approved rates."[5]

Consistent with the indifference principle, the Commission in D.06-07-030 (as modified by D.07-05-005 and D.07-01-030) adopted the current method of calculating PCIA and CTC which is explained in SCE's testimony as follows:

> "Pursuant to D.06-07-030, SCE develops an 'indifference amount' annually in the Energy Resource Recovery Account (ERRA) forecast proceeding. Each year represents a different 'vintage' portfolio of generation resources and is assigned a separate indifference amount. . . . . The 'total portfolio' cost for each vintage year is calculated on an annual basis and compared to the market value of energy and capacity produced by the portfolio.
>
> Pursuant to D.06-07-030, the Energy Division produces a market price benchmark (MPB) for each forecast year, which includes:
>
> - Value of energy (average price for a 12-month forward strip over 31 days in October);
> - Value of RA/generation capacity (per MWh adder);

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4 D.08-09-012, pp. 10-11, *citing* Public Utilities (P.U.) Code Section 366.2(d); D.02-11-022, p. 158, Conclusion of Law (COL) 21; D.03-04-030, p. 39; D.03-07-028, p. 13; D.04-12-046, p. 24; D.04-12-048, p. 57; D.05-09-022, pp. 15-16.

5 *See* Section 366.2(d).

- Line losses (per MWh adjustment).

> Each vintaged portfolio is valued at the MPB to produce a market value for that portfolio. The market value of the portfolio is subtracted from the portfolio cost for each year to determine the indifference amount, positive or negative. A positive indifference amount indicates that the portfolio cost is above-market for that year, and that contributions from departing customers of that vintage toward these costs are necessary to maintain bundled service customer indifference. A negative value for the indifference amount essentially means that bundled service customers benefit from the departure of customers, because energy and capacity produced by the portfolio is more valuable in the market than if sold to departing customers. Pursuant to D.07-05-005, negative indifference amounts are carried forward to offset positive indifference obligations in future years. . . .Statutory [CTC] revenue is subtracted from the indifference amount to produce the [PCIA]."[6]

No party recommends a *de novo* review of the indifference calculation adopted in D.06-07-030 (as modified). Rather, parties recommend various modifications to the existing method, each of which must be assessed for consistency with the indifference principle.

A. Recommended Changes to Market Price Benchmark (MPB), Indifference Calculation and PCIA

1. Proposals to Reflect in the MPB the Value of Renewable Resources

The current method for calculating the indifference amount benchmarks the costs of renewable resources against the price the IOUs can expect to obtain for selling the energy produced by those resources into the market to adjust for departing load. Any above-market costs are shared among all customers to preserve bundled service customers indifference.[7]

The Joint Parties and CLECA/CMTA testified that requiring DA customers to pay their share of the above-market costs, relative to the MPB, of the renewable resources procured to serve their load while they were on bundled service is unfair. According to the Joint Parties and

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6 *See* Exhibit 300, pp. 18-19 (lines 20-23).
7 *See* Exhibit 300, pp. 24-25 (lines 23-8).

CLECA/CMTA, DA customers must pay twice for RPS resources but only get RPS credit for renewable resources procured by their DA supplier.[8] In addition, the Joint Parties and CLECA/CMTA claim that bundled service customers "benefit" when customers depart for DA because the IOUs have less renewable resources to procure to meet their Renewables Portfolios Standard (RPS) goals as their RPS percentages increase.[9]

Any evidence that bundled service customers benefit under the RPS program when customers depart to DA service is anecdotal and unquantified, and overlooks lost opportunities for procuring less expensive resources to meet RPS goals.[10] Additionally, requiring DA customers to pay for the above-market costs of renewable power stranded by their departure is no different than requiring DA customers to pay for the above-market costs of conventional "brown" power stranded by their departure.

Accordingly, any inequity to DA customers under the current method is questionable. Nevertheless, the general consensus among the parties is that the MPB should be adjusted to reflect the "premium" value of renewable resources included in the IOU portfolio.

All parties agree that the most appropriate way to reflect the value of renewable resources in the MPB is to use prices from an open, transparent and liquid market for renewable attributes.[11] However, there are differences of opinion as to when such a market will be available.

PG&E testified that a transparent renewable energy credit (REC) market will be available by third quarter 2011, which is expected to include "the development of published, transparent REC indices."[12] PG&E explained that the REC index is the best alternative because "it provides

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[8] *See* Exhibit 100, p. 10 (lines 17-18).
[9] *See* Exhibit 100, p. 9 (lines 18-22); Exhibit 800, pp. 9-10 (A.13).
[10] *See* Exhibit 300, p. 25 (lines 15-20).
[11] *See* Exhibit 100, p. 22 (lines 26-32).
[12] Exhibit 401, p. 1-13 (lines 13-15).

an objective measure of the market value for renewables."[13] Pending development of a REC index, PG&E recommended using a negotiated, administratively set value as a proxy.[14]

In their testimony, SCE and SDG&E agreed that a REC index would be appropriate, but recommended setting an interim proxy based on the Department of Energy's (DOE's) survey of reported contract premiums for renewable energy in the Western U.S.[15] Alternatively, SCE supported an administratively set value as the interim proxy, based on a variety of available data points contained in the record, which provide a range of values for determining a proxy renewable adder.[16]

DRA's testimony also supported the use of publicly available, transparent REC market values to determine the market value of RPS resources when this information becomes available, and an interim proxy price either agreed to by all parties or administratively set by the Commission.[17]

The Joint Parties and CLECA/CMTA oppose the use of the REC index, preferring instead the use of confidential IOU cost data. The Joint Parties testified that they are "skeptical" that the market for tradable RECs (or TRECs) would be appropriate for use in calculating MPB because the Commission placed restrictions on the use of TRECs.[18]

However, as DRA observed:

> "The Joint Parties did not provide any information on how the Commission imposed restrictions will affect market value for TRECs. . . . The Commission's restrictions on the use of TRECs are intended to protect ratepayers from excessive payments for TRECs in the early stages of the TREC market and to promote the development of new RPS-eligible generation. However, the Commission also noted that in the early years of a California TREC market, prior to load serving entities (LSEs) attaining the goal of 20% . . . demand for TRECs is likely to exceed supply. Therefore, in DRA's view, the Commission-

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13 Exhibit 401, p. 1-13 (lines 26-29).
14 *See id.* (lines 22-24).
15 *See* Exhibit 504, CF-2-3 (lines 25-6); Exhibit 300,
16 *See* Exhibit 301, p.11-12 (lines 13-6).
17 *See* Exhibit 600, p. 4 (lines 16-17); also Exhibit 601, p.7 (lines 8-12).
18 *See* Exhibit 100, p. 23 (lines 4-9).

> imposed restrictions should have little to no impact on TREC prices given the expected supply shortage."[19]

At hearings under examination by DRA, the Joint Parties tried to further explain their opposition:

> "[I]t would be irresponsible to rely on a market that doesn't exist yet for future ratemaking which is what we'd be doing here."[20]

Yet, no party proposed the use of RECs prior to the development of a REC index. All parties supporting the use of the REC market agreed that an interim proxy would be necessary, pending development of a REC index.

The Joint Parties' concern regarding "uncertainty"[21] with the decision is also misplaced because – as DRA pointed out at hearings[22] – any objections to the decision do not stay its effectiveness, and the Commission is moving forward with its implementation.

CLECA/CMTA oppose the use of the REC because " it is much too soon to be able to determine if the price of unbundled RECs in the market will track what utilities are paying for the renewable attribute in their renewable generation purchases."[23] CLECA/CMTA's testimony suggests that the IOUs' costs – rather than a California market index price for renewable attributes – are more reflective of the market value of renewable attributes. Given that the REC market will not to be limited to the IOUs, the REC index does not need to "track" the IOUs' costs to be a reasonable, transparent, and publicly available price for renewable attributes.

Accordingly, Joint Parties and CLECA/CMTA offer no compelling objections to the use of the REC index when it becomes available. And, their proposals to use confidential IOU cost data to establish a proxy for the "market value" of renewable resources run counter to the goals of transparency, verifiability, and bundled service customer indifference.

Joint Parties propose "that the Green Benchmark in *year n* equal the average of the IOUs'

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19 Exhibit 601, pp. 5-6 (lines 18-15).
20 Tr. 1, p. 62 (lines 13-22).
21 *See* Exhibit 100, p. 23 (lines 8-11).
22 *See* Tr. 1, p. 62 (lines 8-19).
23 Exhibit 801, p. 3.

RPS-compliant generation costs in year *n* for generators that began delivering in year *n-1* and are projected to begin delivery in year *n*."[24] In other words, the Joint Parties suggest that the cost of resources that have recently come on line are reflective of the "market price." This suggestion fails to account for several key facts:

- Renewable resources just beginning delivery in a particular year have usually been contracted for years ago at prices that were reasonable at that time;[25] however, those prices (i.e., the current cost of those resources to bundled service customers) may bear little relationship to *current prices* for renewable resources. SCE testified that renewable contracts' prices are trending downward over time, based on contract data.[26] The Joint Parties concede that innovation in renewable technologies will place downward pressure on the price of renewable resources, and this impact may not be reflected in the cost of IOU contracts entered into years ago.[27] Consequently, when a renewable resource begins delivery and the contracted price for that resource bears little – if any – relationship to the current prices of renewable resources.

  The Joint Parties' proposal is antithesis to the whole concept of Cost Responsibility Surcharge (CRS) for departing customers. The purpose of the CRS is to ensure that all customers share in the above-market costs of the IOU's portfolio in a given year. Other than for the meaningless proposal to average the renewable contract costs across the IOUs (discussed below), this proposal in effect results in no "above-market" costs for the IOUs' renewable contracts signed many years ago for delivery in the current (or a year prior to the current) year no mater how low is the current price for renewable energy.

- While the IOUs' account for a large portion of demand for renewable resources in California, they are by no means the entire market. Publicly-owned utilities (POUs), ESPs and Community Choice Aggregators (CCAs), who are all subject to the statutory 20% RPS requirement, make up about forty-two percent (42%) of the California

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24 Exhibit 100, p, 24 (lines 13-15).
25 *See* Exhibit 101, p. 11 (lines 2-4).
26 *See* Exhibit 301, p. 14 (lines 5-6).
27 *See* Tr. 1, pp. 43-45 (lines 20-10).

market.[28] By targeting only the renewable resources procured by the IOUs, a significant portion of the California market is omitted from the Joint Parties' and CLECA/CMTA's proposed renewable market benchmark, without justification. The Joint Parties simply stated that they "do not see [the POU prices] as relevant to the utility prices."[29]

- Using IOU-only cost data to derive a "market" value of renewable resources skews the "green benchmark" high, because the IOUs' portfolios have significantly larger percentages of new, higher-cost renewable resources than those of ESPs and CCAs.[30]

- Some IOUs' average RPS costs are higher than others.[31] Consequently, under the Joint Parties' and CLECA/CMTA's proposal, the lower-cost IOU's ratepayers will be disadvantaged by a benchmark that is higher than their actual average cost, and the higher cost IOU's ratepayers will be advantaged by a benchmark that is lower than their actual average costs, simply as a result of averaging the three IOUs' costs to establish the benchmark. This would not hold each IOU's bundled service customers indifferent to departing load.

A more reasonable cost-based proxy would use the current price of renewable resources, and set a "green benchmark" based on all RPS-compliant LSE data or, if using only IOU data, would set an IOU-specific benchmark based on the average price each IOU currently pays for renewable power. However, such an approach may raise issues of data availability (as to the former option)[32] and data confidentiality (as to the latter option).

Therefore, the Commission should reject an approach based on the cost of IOU's renewable contracts in the current year and administratively set a proxy renewable premium

[28] *See* Tr. 1, pp. 25-26 (lines 11-28).
[29] *See* Tr. 1, p. 25 (lines 19-25).
[30] *See* Exhibit 101, pp. 12-13 (lines 19-6).
[31] *See* Tr. 1, p. 45 (lines 21-27).
[32] *See* Exhibit 108, containing data request responses of several ESPs and CCA parties, indicating their willingness (or lack thereof) to provide their RPS costs to the Energy Division for purposes of establishing a green benchmark for the indifference calculation.

price – to be used in the interim pending the development of the REC index – based on the all available data points on the value of renewable attributes, including:

- The DOE survey of reported contract premiums for renewable energy in the Western U.S. of approximately $20/MWh.[33] The DOE data was recently recommended for use as the "green premium" for net surplus compensation pursuant to Assembly Bill 920 in the proposed decisions recently issued in Application (A.)10-03-001 et al.[34]

- The IOU data on the cost of renewable generation resources in their total portfolios as of 2009, which – for SCE – showed a renewable premium relative to the 2011 forward strip price-based MPB of $20 to $40 per MWh, depending on whether the premium reflects energy costs only, or energy and capacity costs.[35]

- The MEA renewable cost data in its power purchase agreement, showing two renewable energy premiums of $10.50/MWh and $39/MWh.[36]

- The Commission's Market Price Referent (MPR). The Joint Parties testified that "a recent report prepared by [DRA] reports that *on a weighted-average basis,* 59% of all three IOUs' renewable contracts are priced above a weighted-average applicable MPR of $104/MWh."[37] This testimony is incorrect. DRA's report does *not* benchmark an average price per MWh across the IOUs' contracts to the MPR. Rather, the report finds that 59% of all IOU renewable contracts are priced above the MPR.[38] The report contains no analysis of the weighted average price per MWh of

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[33] *See* Exhibit 301, p. 11 (lines 15-16). SCE testified to the merits of this data in Exhibit 300, p. 26 (lines 18-23): "This data reflects premiums paid by energy consumers in the market and self-reported by utilities and other energy service providers. SCE prefers the DOE report premium for several reasons. First, it is publicly available data. Also, customers voluntarily elect service on the rate offerings incorporated in the report and as such, the premiums reflect what customers are willing to pay for renewable energy over and above what they would otherwise pay for non-renewable energy."

[34] *See* Proposed Alternate Proposed Decision of President Peevey, dated 4/5/2011, at pp. 38-39 and Table 3, adopting an $18/MWh green energy premium.

[35] *See id*., pp. 11-12 (lines 17-2)

[36] *See* Exhibit 107, p. 5, Section 5.2.

[37] *See* Exhibit 101, p. 4 (lines 1-4).

[38] *See* DRA, February 2011 Green *Rush: the Investor-Owned Utilities' Compliance with the Renewable Portfolios Standard*, p. 8, Figure 2, available at www.dra.ca.gov/DRA/energy/Procurement/Renewables/greenrush.htm.

the IOUs' contracts compared to the MPR, which is the relevant comparison. This report also shows that a majority of SCE's contracts are priced below the MPR.[39]

Furthermore, in establishing the proxy renewable premium, the Commission must ensure that the value of capacity is not double counted in the MPB. SCE proposed the following method, which ensures no double-counting of capacity, is reasonable for use in calculating the "green benchmark" for renewable resources, and should be adopted:

> "For each vintage of the total portfolio, SCE determines the percentage of total energy provided by RPS-eligible resources. The MPB for that vintage is then produced by calculating a weighted average of:
>
> 1. The portion of energy in the portfolio produced by non-RPS eligible resources valued at the TOU-weighted forward market energy price, and;
>
> 2. The portion of energy produced by RPS eligible resources valued at the TOU-weighted forward market energy price plus the . . . [CPUC established] renewable premium (which is an energy only value and does not account for the value of capacity).
>
> Multiplying the renewable weighted MPB for each vintage by the total energy associated with the generation resources for that vintage produces the market energy value of the vintaged portfolio. This amount is added to the market value of the portfolio's generation capacity to produce the total market value of the generation portfolio."[40]

2. Proposals to Reflect in the MPB the Value of Shaping Resources to the Load

Under the current method for calculating the indifference amount, the total portfolio reflects the profile of the underlying generation resources or contracts; however, the MPB calculation essentially reflects a flat profile.[41] Parties generally agree that some weighting of the MPB benchmark is appropriate. Two proposals were advanced in direct testimony. The IOUs

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39 *See id.*
40 Exhibit 300, p. 27 (lines 5-15).
41 *See* Exhibit 300, p. 6 (lines 15-17).

proposed the use of the generation output profile, because it is consistent with the profile that underlies the total portfolio cost component of the indifference amount.[42] On the other hand, the Joint Parties proposed the use of the bundled load profile, because "the IOU supply portfolio is constructed to serve the load of the bundled service customers as that load varies from hour-to-hour."[43]

DRA objected to both proposals because they would require the use of confidential IOU data, which is inconsistent with the Commission's objective of transparency for the MPB.[44] In response to DRA's legitimate concern, in its rebuttal testimony, SCE proposed to use *historical* bundled load profiles from prior calendar years to weigh the MPB, because the historical data is not confidential.[45] SCE explained that the bundled load profile is not expected to differ substantially from the generation output profile, and would therefore "serve as a reasonable and transparent alternative."[46] The Joint Parties in their testimony also acknowledged that historical bundled load profiles were "an acceptable alternative" and could be used to derive a profile adjustment for the MPB.[47] They concurred that "there appears to be little difference in the adjustment factor whether one uses the generation profile or the bundled load profile."[48]

Because SCE already makes historical bundled load profiles by rate group publicly available,[49] as do the other IOUs, no additional calculations should be required for purposes of the MPB.[50]

Given the importance of transparency, the Commission should approve the use of the IOUs' historical bundled load profile data for weighting the MPB. However, the Commission should reject DRA's proposal to produce a different weighting factor for each vintage. The

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42 *See id.*, pp. 6-7 (lines 22-2).
43 *See* Exhibit 100, p. 28 (lines 18-21).
44 *See* Exhibit 601, pp. 13-14 (lines 12-5).
45 Exhibit 301, p. 7 (lines 7-11).
46 *See id.*
47 *See* Exhibit 100, p. 30 (lines 15-19); *also* Exhibit 101, p. 15 (lines 8-16).
48 *See* Exhibit 101, p. 16 (lines 4-5).
49 *See* http://www.sce.com/AboutSCE/Regulatory/loadprofiles.
50 This addresses Joint Parties' testimony, Exhibit 100, p. 30 (lines 17-19), stating that the use of historical load profile data involved "an additional set of calculations" and therefore they preferred use of the confidential data.

IOUs and the Joint Parties have demonstrated that weighting each vintage would impose additional burdens on the IOUs in calculating the indifference amounts and departing load charges, without a noticeable corresponding benefit. At hearings under examination by DRA, SCE explained,

> "[O]ur proposal is to use the single weighting factors, so it would not differ by vintage. We've proposed a single weighting factor because, again, this gets to administrative simplicity versus complexity for very little gain . . . there is very little difference over time [in the load profiles] . . . so you are not really gaining anything significantly by calculating a different percentage between on- and off-peak year to year."[51]

SCE explained that under DRA's proposal, SCE would have to run 10 calculations rather than just 1 to weigh the MPB; and this difference would grow larger as the number of vintages increases.[52] The Joint Parties also testified that they "do not expect significant variation in the load shapes adjustment from year to year"[53] and do not believe that "doing the extra analysis to try and come up with different profiles for different vintages is going to change the numbers sufficient to warrant the effort."[54]

3. Proposals to Revise the Value for Capacity in the MPB

There is no dispute among the parties that the value of RA capacity must be appropriately reflected in the MPB; however, there is disagreement on how to do so.

The current capacity values used in the MPB are based on the annualized cost of a combined cycle combustion turbine (CT); however, there is no means of updating the capacity values over time.[55] To include a method of regularly updating the MPB's RA capacity value based on publicly available data, SCE proposed to use the CAISO's Interim Capacity Procurement Mechanism (ICPM) or its successor, the Capacity Procurement Mechanism

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[51] Tr. 1, p. 127 (lines 7-17).
[52] *See* Tr. 1, p. 129 (lines 8-21).
[53] Exhibit 101, p. 15 (lines 12-14).
[54] Tr. 1, pp. 65-66 (lines 7-2).
[55] *See* Exhibit 300, p. 23 (lines 11-15).

(CPM),[56] which is the CAISO's backstop mechanism for RA capacity and is the amount the CAISO pays for capacity on an annualized basis.[57] SDG&E, CLECA/CMTA, Reid, and the Joint Parties also proposed the use of ICPM and its successor, CPM, as the value for the MPB's RA capacity adder.[58]

The ICPM and the CPM are both based on the going-forward fixed costs of a simple cycle CT, established in the CEC's bi-annual report *Comparative Costs of California Central Station Electricity Generation*.[59] This was a key factor in certain parties' support for the ICMP and CPM in establishing the RA adder.

In particular, SCE explained:

> "[T]he capacity adjustment reflected in the MPB [should] be updated on an annual basis and set at the then-effective CPM payment, so long as the CPM payment continues to reflect the "going-forward" fixed costs of a simple cycle combustion turbine, as defined by the [CEC]. SCE would not support a generation capacity adder based on the cost of new generation capacity."[60]

The Joint Parties testified that the ICPM or CPM is a reasonable measure of RA value because it reflects "*short-term capacity prices*" as well as being publicly available.[61]

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[56] At the time of SCE's direct testimony, the CAISO had proposed to replace ICPM with CPM.

[57] Exhibit 300, p. 23 (lines 18-19).

[58] *See* Exhibit 501, p. CF-5 (lines 11-20); Exhibit 800, p. 10 (A.14); Exhibit 700, pp. 12-13 (lines 14-26); Exhibit 100, pp. 20-31 (lines 28-13). p. 13 (lines 7-26).

[59] *See* CAISO's December 1, 2010 CPM proposal, pp. 7-8, 23, explaining "[u[nder the existing Tariff, the compensation for ICPM capacity is based on going-forward fixed costs. Specifically, the ISO used the going-forward fixed costs of a 50 MW simple-cycle gas-fired unit built by a merchant generator, plus a 10% adder. The going-forward costs of such a unit are determined based on a comprehensive study conducted by the California Energy Commission (CEC). . . . The ISO's backstop capacity mechanism can only procure existing generation for a term of one-year or less (depending on the specific deficiency that is being addressed) and is not intended to incent the development of new generation. . . . The ISO proposes to maintain the going-forward fixed costs compensation methodology; although, as discussed below, it is updating the minimum price based on the most recent CEC study (provided with this filing as Attachment H). The ISO believes that, for the limited circumstances of CPM designations, the proposed minimum capacity payment amount will meet or exceed the going-forward costs for the vast majority of eligible resources, and where it is not sufficiently compensatory the resource owner can file a resource-specific cost justification with FERC."

[60] Exhibit 300, pp. 23-24 (lines 20-2) and fn. 27, explaining that the going-forward cost components include insurance, ad valorum taxes and fixed Operations and Maintenance (O&M) costs.

[61] *See* Exhibit 100, p. 31 (lines 9-13).

DRA and PG&E oppose the use of the ICPM and CPM. They argue that the ICPM and CPM prices are too high to be reflective of short-term capacity prices. PG&E testified that "in general, the short-term RA value is less than the $41/kW-year ICPM backstop price of capacity." However, the sources relied on by PG&E in its testimony show that RA prices have been at or below $45/kW-year.[62] While the ICPM price of $41/kW-year was on the high side of the range, it was certainly within the range of prices cited by PG&E's sources as reflective of RA capacity prices.

Moreover, while the CPM price is higher – at $55/kW-year – it is still based on the CEC's determination of the going-forward fixed costs of a simple cycle CT.[63] PG&E's testimony never addressed *the method* for setting the CPM. PG&E's testimony appears primarily concerned that the CPM is on the high end of the potential range of RA prices.

DRA's testimony reveals the same concern; that CPM is on the high end of the potential range of RA prices: "given Energy Division's conclusion that sufficient RA capacity was available [in] 2009-10 . . . at or below the $40/kW-year "waiver trigger" price . . . the waiver-trigger price and the CAISO ICPM backstop price, taken together, establish the maximum price an LSE would want to pay for RA procurement."[64]

Demonstrating – as PG&E and DRA do – that the CPM is on the high side of a potential range of RA prices does not establish that CPM is not reflective of short-term capacity prices.

However, to the extent CPM is modified to reflect the cost of new generation capacity or the cost of new entry (CONE) – it would no longer be reflective of short-term capacity prices and would not be appropriate for use in the MPB. The possibility of a CPM price reflecting CONE appeared to be remote at the time of SCE's direct and rebuttal testimony, given the CAISO's proposed CPM tariff, which continued to base the CPM on the going-forward costs of

[62] Exhibit 401, p. 19 (lines 9-10; 20-22), citing FERC and CPUC sources.
[63] *See* fn. 59, *supra*; *also*, CAISO's December 1, 2010 CPM proposal, pp. 23-24, explaining why CAISO found CONE inappropriate for CPM pricing.
[64] *See* Exhibit 600, pp. 5-6 (lines 19-3)

a simple CT, and rejected compensation based on CONE.[65] However, FERC's recent order on CPM has increased the odds of a CPM price more reflective of longer-term capacity prices.

On March 17, 2011, FERC issued its order conditionally accepting CPM subject to modification, based on further examination of whether a capacity backstop mechanism based on the going forward costs of CT sufficiently "compensates non-resource adequacy resources for short-term transitory events but also whether it provides a just and reasonable long-term backstop to the CPUC's ongoing resource adequacy program."[66] FERC explained its primary concern with CAISO's CPM proposal:

> "CAISO, in this filing, has not explained how the use of going-forward costs for CPM compensation will provide incentives or revenue sufficiency for resources to perform long-term maintenance or make improvements that may be necessary to satisfy new environmental requirements or address reliability needs associated with renewable resource integration. On the other hand, we also are not persuaded that parties have provided sufficient evidence that pricing backstop capacity compensation on the basis of CONE will yield a just and reasonable capacity rate for non-resource adequacy resources. Furthermore, and significantly, we find the continuation of a fixed going-forward cost price has not been shown to be just and reasonable because of the likelihood that market conditions, which can affect the price of capacity, will fluctuate over time."[67]

FERC has ordered a technical conference to obtain additional information on the potential long-term changes that may be important to the pricing of a CPM of indefinite duration, and compensation methodologies that would provide, at a minimum, a meaningful opportunity for CPM resources to recover additional fixed costs.[68]

The outcome of FERC's effort and the CAISO's CPM is uncertain; which is problematic for this proceeding, because the Commission seeks to resolve longer-term DA rules and requirements for the newly reopened DA market. At evidentiary hearings, SCE explained its

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[65] *See* fn. 60, *supra*.
[66] FERC Order, parag. 56.; *see also* Tr. 1, p. 126 (lines 2-20), taking judicial notice of the 134 FERC 61, 211.
[67] *Id.*, parag. 57-58.
[68] FERC Order, parag. 58-59.

reservations with CPM given the uncertainty, and suggested an alternative means of establishing RA value for the MPB:

> Q: Now, do you have concerns about [CPM] given the fact that the FERC has issued this new order. . . ?
>
> A: Yes. . . reading the recent order from FERC, clearly they were looking at the calculation of that number on the basis of the going-forward cost of capacity or cost of new entry of capacity. . . .
>
> Q: So is it fair to say you don't really know what is going to happen with the CPM price at this point?
>
> A: I think that is fair say . . . in our proposal, again, when we pointed to the ICPM and identified it as the number that was developed by the CEC as the going-forward cost of capacity; that is what we supported. I think if the ISO departs from that for their capacity procurement mechanism we could just as easily say we continue to support the CEC's number which is the going-forward calculation. . . .
>
> Q: And for clarification, do you mean the CEC's current study . . . that reported in the $41 per kilowatt year or the updated one that resulted in the $55 per kilowatt year?
>
> A: It is the methodology that matters here. So the $55 was the same methodology updated from the $41 . . . It was the going-forward cost of capacity.[69]

Accordingly, the record reflects more concern with the CPM than acceptance of it, given the recent FERC order. Rather than adopting the CPM price for use in setting the RA adder, the Commission should approve a method of setting the RA adder based on the CEC's determination of the going-forward cost of a simple cycle CT, which is evaluated bi-annually as part of the CEC's generation cost study, most recently for 2007-2009.[70] Doing so reasonably addresses parties' proposals for an RA value based on the CEC's bi-annual determination of the going-forward costs of a simple cycle CT.

SCE's testimony described the specific method for calculating the MPB for RA capacity:

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[69] Tr. 1, pp. 124-126 (lines 8-1).

[70] *See* January 2010 Final Staff Report, *Comparative Costs of California Central Station Electricity Generation*, available at www.energy.ca.gov.

> "[M]odify the calculation to incorporate a capacity value based on the amount of capacity actually included in each vintaged portfolio. The market value of capacity in each vintaged portfolio would be determined as follows:
>
> 1. Summing the net qualifying capacity (NQC) of all RA resources on a monthly basis. NQCs are set by the CAISO, and reflect the varying amount of capacity provided by different generation resources. NQC is significantly lower than nameplate capacity for intermittent resources.
>
> 2. Converting the effective annual CPM payment to a monthly value and shaping it to reflect the higher value of capacity in peak months. SCE proposes to use the monthly shaping factors used in the development of the RA transfer credit adopted in D.10-03-022.
>
> 3. Multiplying the monthly shaped CPM payment by the monthly NQC of the RA portfolio and summing over 12 months provides the market value of the portfolio's RA capacity. This amount is added to the market value of the energy supplied by the portfolio, discussed below, to produce the total market value of the generation portfolio."[71]

The Joint Parties' testimony supports SCE's proposed calculation using NQCs,[72] and it should be adopted with the modification that "CPM payment" should be replaced with "going-forward cost of a simple cycle CT," as determined by the CEC in its bi-annual generation cost study.[73]

4. Proposals to Account for Load-Based CAISO Costs

No party disputes that the IOUs avoid load-based CAISO charges when load departs for DA service;[74] therefore, load-based CAISO charges should be excluded from the IOUs' total

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71 Exhibit 300, p. 24 (lines 9-21).

72 *See* Exhibit 100, pp. 30-31 (lines 28-9).

73 *See* January 2010 Final Staff Report, *Comparative Costs of California Central Station Electricity Generation,* Table B-4, p. B-5, showing the Insurance, Ad Valorum and Fixed O&M components of the going-forward costs of the 50 MW simple cycle gas unit based on a merchant facility, totaling $50.17/kW-year (nominal). Note that the CAISO's ICPM and CPM prices included a 10% adder "to account for any measurement error in the CEC's study used to set the components of the going forward fixed costs or other difficult to quantify costs." *See* CAISO's December 1, 2010 CPM proposal, pp. 22, 26.

74 *See e.g.,* Exhibit 301, p. 14 (lines 20-21); *see* Exhibit 501, CF-6, lines 3-5; Exhibit 100, pp. 31-33; Exhibit 800, p. 12, A.17.

portfolio costs in calculating the indifference amount. PG&E recommended simply excluding all CAISO-related charges from the IOUs' total portfolio costs; however, SCE testified that "the load-related subset is fairly easy to identify (see the Joint Parties' list); thus, only load-related CAISO costs should be removed from the total portfolio costs in the interest of bundled service customer indifference."[75] The Joint Parties included a list of CAISO load-related charges in their testimony,[76] which SCE finds reasonable for use in identifying CAISO load-related charges for exclusion from the IOUs' total portfolio costs.[77]

SCE also concurs with the Joint Parties' proposal to exclude CAISO congestion costs from the IOUs' total portfolio costs,[78] because these costs are also avoided when load departs for DA service.[79]

5. Proposals to Account for Short Term Purchases

There is no dispute among the parties that forecasted costs associated with the IOUs' energy purchases at CAISO to fill anticipated "short" positions to serve their bundled service customers should be excluded from the IOUs' total portfolio costs.[80] The energy associated with such purchases should similarly be removed from the total energy supplied by the portfolio.

B. Other Proposals for Achieving Bundled Customer Indifference

CLECA/CMTA propose that bundled service ratepayers should pay DA-eligible customers departing for DA service when the indifference calculation results in a negative indifference.[81] CLECA/CMTA acknowledge that the negative indifference offsets future positive indifference; but complain that "if a DA or CCA customer returns to bundled service, it

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[75] *See* Exhibit 301, p. 15 (lines 4-9).
[76] *See* Exhibit A to Exhibit 100.
[77] *See* Exhibit 301, p. 15 (lines 1-3); also Tr. 1, pp. 84-85 (lines 16-5).
[78] *See* Exhibit 100, p. 32 (lines 17-20).
[79] *See* Exhibit 301, lines 10-13); *also* Tr. 1, p. 85 (lines 6-26). SCE's witness corrected his direct testimony under direct examination at hearings to state that "SCE agrees, and clarifies that SCE's forecast of total portfolio costs *does* include a forecast of potential congestion costs." *See* Tr. 1, p. 72 (lines 14-23).
[80] *See e.g.,* Exhibit 301, pp. 14-15 (lines 20-3), Exhibit 501, CF-6 (lines 6-8); Exhibit 400, p. 1-14 (lines 16-30).
[81] *See* Exhibit 800, pp. 15-16 (A.21).

would never get the value of this negative indifference," which CLECA/CMTA find inequitable.[82]

CLECA/CMTA's proposal should be rejected, because they bring forth no new evidence to support a change in the Commission's policy on this issue. CLECA/CMTA simply reargue for adoption of a policy previously rejected by the Commission in D.06-07-030, wherein the Commission explained:

> In D.05-12-045, we restricted the use of negative ongoing CTC only to offset positive above-market costs, but not to offset other components of ongoing CTC (*e.g.,* QF restructuring costs) or other CRS components. ***This is because negative ongoing CTC provides no cash, and thus, cannot be used to offset costs that involve actual cash expenditures*** (e.g., QF restructuring costs). . . .[83] We conclude that parties' proposed treatment of negative indifference charges is reasonable and hereby adopt it. Once the existing CRS undercollection is eliminated, the indifference charge for non-exempt DA customers shall *not be* permitted to decrease below zero, and no negative balance should be carried forward***. In no event shall such a negative indifference charge result in any net payment to customers who have left utility service.*** However, any accumulated negative indifference amount shall continue to be tracked and applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS. This approach is consistent with D.05-12-045, which permits a negative ongoing CTC to offset a subsequent positive ongoing CTC.[84]

In D.07-05-055, the Commission reiterated that:

> "D.06-07-030, however, did not intend for negative indifference amounts to be "carried forward" in a manner that would produce a credit on customers' bill for such negative amounts. It was in this context of avoiding a credit balance on customers' bills that OP 8 stated that 'no negative balance shall be carried forward'."[85]

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[82] *Id.*
[83] D.06-07-030, p. 42.
[84] *Id.*, p. 17.
[85] *See* D.07-05-055, pp. 19-20.

The Commission found that allowing for negative indifference amounts to be netted against future positive amounts preserves the goal of bundled customer indifference,[86] which is the objective of the indifference rate. There is no inequity in this result, because it maintains customer choice to elect DA service while preserving bundled customer indifference.

C. Implementation of Proposed Changes

The issue of implementing the proposed changes to the indifference amount has already been addressed by Administrative Law Judge (ALJ) Pulsifer in his April 14, 2011 Ruling. Therein, ALJ Pulsifer ruled that the IOUs' 2011 PCIA rates would be subject to true-up once the Commission issues a final decision in this proceeding modifying the indifference amount calculation.[87] The effective date of the true-up for SCE and SDG&E would be the date their 2011 ERRA rates become effective, and for PG&E the effective date of the Ruling.

The Ruling explains the reason for granting retroactive relief:

> "The Joint Parties raise a valid concern that a decision in Phase III of this proceeding could have a material impact on the methodology used to calculate the 2011 PCIA rate. Depending on the provisions adopted in Phase III, the PCIA rates applicable for 2011 could be materially impacted, particularly depending on the length of time between the 2011 ERRA rate decision and the effective date of the Phase III decision. Thus, this ruling grants relief to mitigate the effects of potentially incorrect price signals applicable from the date of this ruling until a decision in Phase III of this proceeding. To accomplish this purpose, requested adjustments to PCIA rates will be granted, but limited only to the difference between the existing and revised PCIA."[88]

The Ruling was amended on April 22, 2011 to reconcile a discrepancy in its ordering paragraphs by deleting ordering paragraph 2.[89] The Ruling is required, by its own terms, to be

[86] *See* D.07-05-055, pp. 19-20.
[87] *See generally* April 14, 2011 Administrative Law Judge's Ruling Regarding Motion of Joint Parties.
[88] April 14, 2011 Ruling, p. 4.
[89] *See generally* April 22, 2011 Administrative Law Judge's Ruling Amending Prior Ruling.

affirmed by the Commission through the issuance of a proposed decision put to a Commission vote.[90]

If the Commission affirms the Ruling through a decision, the Commission should also require a retroactive true-up of the IOUs' Transitional Bundled Service (TBS) rates as of the effective dates of the 2011 PCIA true-up. The final decision in this proceeding is expected to modify the TBS rate consistent with the modifications to the indifference rate calculation. There is no dispute among the parties that TBS must be modified to be fully compensatory for procurement related costs, consistent with the changes to the indifference amount calculation. As SCE explained in its testimony:

> "TBS is the rate paid by returning DA customers, under certain circumstances, for generation service provide[d] by SCE and is essentially the market rate for energy, plus certain other ISO costs. TBS customers are required to continue to pay the applicable indifference rate, and the combination of the two – the market rate and the above-market cost of the relevant portfolio, represents a proxy generation rate for bundled utility service until the customer is reintegrated into the bundled portfolio. The combination of the two rates should reflect all procurement costs associated with serving the customer to avoid shifting costs to other bundled service customers. Therefore, any applicable costs not reflected in the indifference rate should be included in the TBS calculation. For example, if CAISO costs associated with serving load are reflected in the TBS it is consistent that such costs not also be recovered in the indifference rate. Removing load-related CAISO costs from the total portfolio, as proposed previously, ensures that they do not appear in the indifference amount."[91]

No party disputes the need to include in the TBS rate those costs that are not reflected in the indifference rate. CLECA/CMTA testified:

> "Just as the MPB includes a capacity adder, various parties have proposed that the TBS have a capacity adder. This makes sense. In addition, if the indifference calculation includes a renewable component, as I recommend, then the TBS should include an adder to

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[90] *See generally* April 14, 2011 Ruling, Ordering Paragraph 5.
[91] Exhibit 300, pp. 31-32 (lines 15-2)

> reflect the renewable part of the utility's portfolio, compared to the renewable adder. . . ."[92]

> The DA Parties testified:

> Q: Should the MPB and the TBS rate take into account the same factors?

> A: Yes. As described in the Joint Parties' testimony submitted in this proceeding, the MPB reflects an estimate of the current market prices, which would be the same as the current market cost to service a departed load customer who returns unexpectedly to utility service: market-based commodity power, renewable attributes sufficient to cover the RPS requirement of that customer, the capacity to meet the [RA] obligations to serve that customer, and all necessary variable [CAISO] costs associated with the customer's load."[93]

Other parties provided similar testimony on the consistency in calculating the indifference rate and TBS.[94]

By retroactively modifying the indifference rate consistent with the Phase III decision (as per the Ruling) but only prospectively modifying the TBS rate, the Commission would alter the alignment between the indifference rate and TBS rate, which would result in DA customers shifting costs to bundled service customers during the period of time the indifference rate and the TBS rate remain out of alignment.

If the Commission sees fit to retroactively modify the indifference rate calculation in the interest of bundled service customer indifference, it should also retroactively modify the TBS rate calculation. Otherwise, bundled service customer indifference will not be achieved under the Ruling.

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92 Exhibit 800, p. 17, A.23.
93 Exhibit 200, pp. 5-6 (lines 21-7).
94 *See e.g.,* Exhibit 400, pp. 2-3 (lines 6-9).

IV.

THE TRANSITIONAL BUNDLED SERVICE RATE COMPONENTS AND CALCULATION – PROPOSALS AND RECOMMENDATIONS

TBS is currently available to DA customers that wish to serve out their six-month advance notice period to return to bundled portfolio service (BPS) on the IOU's procurement service rather than on DA service, or need a 60-day "safe harbor" period while they switch ESPs.[95] TBS continues to be an important component of the DA switching rules, and parties in this proceeding support maintaining it.

The Commission in D.03-05-034 found that by charging DA customers for the incremental costs of short-term power during the six-month advance notice period or the safe harbor period, no costs will be shifted to bundled service customers.[96] While this was reasonable in 2003, with the addition of RA and RPS requirements to the IOUs' procurement obligations, as well as recognition of CAISO's load-related costs, recovery of incremental power costs alone is insufficient to avoid cost shifting from DA customers on TBS to bundled service customers. TBS rate must be modified to include RA, RPS and CAISO's load-related costs to mitigate cost shifting to bundled service customers as a result of migrating load. No party opposes modifying the TBS rate to include RA, RPS and CAISO's load-related costs.

While parties disagree on how to calculate RA and RPS values for inclusion in the MPB, and how to identify CAISO's load-related costs, the record reflects strong consensus that whatever methods is adopted for calculating RA and RPS values for inclusion in the MPB, and for identifying the IOUs' Total Portfolio costs related to the CAISO's load-related costs, should also be used to adjust the TBS rate to include these costs.

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[95] TBS was incorporated into the DA switching rules for these purposes pursuant to D.03-05-034. *See* Section III.V *infra*.

[96] *See* D.03-05-034, FOF 10, 15;

A. Resource Adequacy Costs

The IOUs, DA Parties, Joint Parties, DRA, CLECA/CMTA all propose that the Commission adopt an RA adder for TBS calculated in the same manner as the RA adder for the MPB.[97] For the reasons discussed in Section III.A.3 above, the RA adder should be based on the CEC's determination of the going-forward cost of a simple cycle CT, evaluated bi-annually as part of the CEC's generation cost study,[98] and should be calculated as follows:

> "The market value of portfolio RA capacity, of the current year vintage, divided by the market value of energy (based on the forward strip prior to adjustment for renewable energy) produces a scalar that is then applied to the TBS energy rate. The scaled rate reflects market RA capacity costs."[99]

B. RPS Compliance Costs

The IOUs, DA Parties, Joint Parties, DRA, CLECA/CMTA all propose that the Commission adopt an RPS adder for TBS calculated in the same manner as the renewables "premium" calculated for the green benchmark in the MPB.[100] For the reasons discussed in Section III.A.1 above, the RPS adder should be based on the REC index when available, and in the interim on a Commission-determined price, and calculated as follows:

> "SCE proposes that the market energy rate from which TBS is constructed be scaled proportional to the renewable premium reflected in the revised MPB calculation. For example, if the weighted average forward market price, after adjusting for renewable premiums, is \$50/MWh, and the forward market price is \$40/MWh then SCE would propose to scale TBS energy price inputs up 25% (scalar = \$50/\$40 or 1.25)."[101]

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[97] *See e.g.,* Exhibit 400, pp. 2-3 (lines 6-9).

[98] *See* January 2010 Final Staff Report, *Comparative Costs of California Central Station Electricity Generation*, (available at www.energy.ca.gov.

[99] *See* Exhibit 300, p. 32 (lines 17-20).

[100] *See e.g.,* Exhibit 700, p. 14 (lines 1-10); Exhibit 300, pp. 28-29 (lines 11-18); Exhibit 100, pp. 31-33 (lines 26-17).

[101] *See* Exhibit 300, pp. 32-33 (lines 24-3).

C. CAISO Load-Related Costs

The IOUs, DA Parties, Joint Parties and CLECA/CMTA all agree that, to the extent the Commission removes CAISO's load-related costs from the IOUs' Total Portfolio costs (see Section III.A.3, 4 above), which are avoided and therefore not shifted to bundled service customers when load departs for DA service,[102] the Commission should include CAISO's load-related costs in the TBS rate, because they are incurred by the IOUs to serve DA customers on TBS, and absent recovery through TBS rate, would be shifted to bundled service customers. As previously discussed, the Joint Parties entered into evidence a list of load-related CAISO's charge-types,[103] which no party challenged. Accordingly, the record supports adopting the Joint Parties' list of load-related CAISO charge-types for use in including CAISO's load-related costs in the TBS rate.

V.

DIRECT ACCESS SWITCHING RULES PROPOSALS AND RECOMMENDATIONS.

The issue in this case is whether the existing DA switching rules, which were adopted during the DA suspension in 2003, remain appropriate for the newly reopened DA market.

There are four main components of the currently effective DA switching rules:

- 6-month advance notice to transfer to DA service;
- 6-month advance notice to return to bundled portfolio service (BPS);
- 3-year minimum BPS stay period; and
- TBS option, which allows a DA customer to receive temporary procurement service from the IOU while switching to a new ESP, or returning to IOU procurement service in advance of the requisite 6-month advance notice.[104]

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[102] *See* Exhibit 300, pp. 28-29 (lines 22-2).
[103] *See* Exhibit A of Exhibit 100.
[104] *See* SCE Rule 22.1.

These switching rules were first established in D.03-05-034*, Opinion Adopting Rules for Switching Exemption*, wherein the Commission articulated the reasons why restrictions on customers' ability to switch between bundled and DA service are necessary and appropriate. Specifically:

1. *Switching restrictions are appropriate to prevent arbitrage and cost shifting to bundled service customers.* The Commission reiterated that bundled service customers should not experience cost shifting as a result of DA customers' departure for DA service,[105] consistent with AB 1X and AB 117 relating to DA cost responsibility.[106]

2. *Rules for switching should guard against placing any burden on bundled service customers and also promote customer choice and economic efficiency.* The Commission recognized the competing interests that must be balanced through the switching rules.[107]

3. *DA customers should not have indiscriminate ability to come and go from bundled service without regard for the cost-shifting that may occur, but should also not be unduly constrained from selecting the most economically efficient service option, consistent with avoidance of cost shifting.*[108] The Commission articulated the balance to be achieved by the switching rules.

4. *Restrictions on DA customers' switching options should correspond to the level of commitment that the DA customer elects to make upon return to bundled service.* The Commission observed that a customer returning to bundled service on a temporary basis should not be obligated to remain for an extended period; however, a transient customer is not entitled to benefit from the price stability offered by bundled service.[109]

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105 *See* D.03-05-034, p. 36 and Conclusion of Law (COL) 5, 8.
106 *See id.,* COL 6.
107 *See* D.03-05-034, p. 34.
108 *See* D.03-05-034, p. 34.
109 *See id*., pp. 36-37.

5. *Customers electing to return to bundled service to obtain price stability should be obligated to remain on bundled service for an appropriate minimum commitment to avoid gaming, cream skimming or cost shifting to other bundled service ratepayers.* The Commission found merit in setting rules that preclude DA customers from being able to game the spot price and the BPS price or from "skimming the cream" off of the bundled portfolio.[110]

6. *It is reasonable to require customers benefiting from the price stability of the IOU's portfolio to give up the ability to go back immediately to cheaper DA supplies as soon as the electric prices fall.* The Commission stated that if a DA customer does not want a long-term commitment, then bundled service is not an appropriate option, and the customer remains free to choose competitive options outside the bundled utility service.[111]

7. *The minimum commitment period should bear some relationship to the duration of contractual supply commitments underlying the bundled portfolio.* The Commission observed that the potential exists for cost shifting to occur if DA customers are permitted to abandon bundled service at will without any responsibility for the ongoing costs the utility may incur under multi-year contracts that were undertaken to serve the DA customer returning as part of bundled load: "If the DA customers were permitted to depart bundled service without restriction, they could leave long-term supply commitments stranded, and thereby shifted to the remaining bundled customers. When market prices are high, DA customers would have an incentive to return to bundled service and potentially cause higher costs to be incurred as new long-term contracts are signed. Conversely, when market prices decline, DA customers would have the incentive to switch back to DA. Yet, when prices are low, it is harder for the utility to broker the stranded capacity to recover a reasonable portion of the contract costs."[112]

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[110] *See id*., p. 25 (noting SCE's argument on gaming), and pp. 36-40.
[111] *See id*., p. 37.
[112] *See* D.03-05-034, p. 37.

8. *The rules need to recognize the effect of ongoing provisions for prospective procurement obligations*. The Commission found the IOUs' practice of procuring a mix of diverse resources with varying terms that take into account customer growth and seasonal demand fluctuations, as well as the turnover in portfolio supplies over time, with new contracts replacing old ones, relevant in adopting an appropriate set of switching rules.[113]

These reasons for restricting customers' ability to switch between bundled and DA service remain entirely valid in the context of the DA market today. No party in this proceeding has argued otherwise. The fundamental drivers for the switching rules continue to be grounded in the basic principles of indifference for bundled service customers while providing sufficient choice and economic efficiency for DA customers.

Accordingly, D.03-05-034 provides the appropriate framework for evaluating parties' proposals on the DA switching rules in this proceeding. The Commission should focus on whether the underlying facts are so different today as to warrant modifications to the switching rules. As discussed below, the facts in this case do not support significant modifications to the switching rules.

A. <u>Minimum Stay Requirement</u>

The minimum BPS stay requirement was adopted in D.03-05-034 to preserve bundled service customer indifference to departing DA load. The Commission observed that the potential existed for cost shifting to occur if DA customers were permitted to abandon bundled service at will without any responsibility for the ongoing costs the utility may incur under multi-year contracts that were undertaken to serve the DA customer when that customer was served as part of bundled load:

> "If the DA customers were permitted to depart bundled service without restriction, they could leave long-term supply commitments stranded,

[113] *See id.,* pp. 38-39.

> and thereby shifted to the remaining bundled customers. When market prices are high, DA customers would have an incentive to return to bundled service and potentially cause higher costs to be incurred as new long-term contracts are signed. Conversely, when market prices decline, DA customers would have the incentive to switch back to DA. Yet, when prices are low, it is harder for the utility to broker the stranded capacity to recover a reasonable portion of the contract costs."[114]

The Commission found it reasonable to require customers benefiting from the price stability of the IOUs' portfolios to give up the ability to go back immediately to cheaper DA supplies as soon as the electric prices fall.[115] The Commission adopted a three-year minimum BPS commitment.

The minimum BPS stay requirement continues to be an important component of the DA switching rules, and no party has argued that it should be eliminated. However, parties disagree on the ***duration of time necessary for the minimum commitment period*** to reasonably protect bundled service customers from cost shifting as a result of departing load. DRA supports maintaining the three-year commitment period adopted by the Commission in D.03-05-034.[116] The IOUs propose to reduce the minimum stay period to eighteen (18) months.[117] The DA parties propose a twelve (12) month minimum stay period.[118]

In evaluating these different proposals, the Commission should consider the basis for the current three-year period. The Commission in D.03-05-034 found that to adequately mitigate the potential for stranded costs when DA customers switch between bundled and DA service, the minimum stay requirement must (i) recognize the effect of ongoing provisions for prospective procurement obligations; and (ii) bear some relationship to the average duration of contractual

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[114] *See* D.03-05-034, p. 37.
[115] *See id*., p. 37.
[116] *See* Exhibit 600, p. 11 (lines 2-4).
[117] *See* Exhibit 400, p. 3-6 (lines 21-27); Exhibit 500, p. JS-5 (lines 26-30).
[118] *See* Exhibit 200, p. 12 (lines 1-4).

supply commitments underlying the bundled portfolio.[119] In assessing these issues, the Commission in D.03-05-034 considered:

- The overall impact of the migration of large versus smaller customers. Large load has a greater impact on utility procurement and justifies a longer BPS commitment,[120] whereas smaller customers have comparatively smaller impact on utility procurement and justify a shorter BPS commitment.

- The mix of short-term, intermediate, and long term contracts in the IOUs' portfolios, which take into account customer growth and seasonal demand fluctuations and turnover as old contracts expire and new ones are signed.

In establishing a three-year minimum BPS term, the Commission in D.03-05-034 adopted an appropriate balance to mitigate the overall impact of DA load migration on utility procurement.[121]

The same balance must be struck in this case. Proposals from DA parties to substantially reduce the minimum stay requirement must be balanced against the need to reasonably protect bundled service customers from cost shifting as a result of DA load migration.

1. <u>There is Support in the Record for Maintaining the Current Three-Year Minimum Stay Requirement</u>

DRA testified that the current switching restrictions "are appropriate and do not need to be modified at this time."[122] DRA's testimony did not specifically address the need for maintaining the three year minimum stay period. However, the record demonstrates that:

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[119] *See* D.03-05-034, p. 37, stating that "[a]s a general principle, the minimum commitment period should bear some relationship to the duration of contractual supply commitments underlying the bundled portfolio."

[120] *See* D.03-05-034, p. 35, explaining "[b]ecause large industrial customers represent a disproportionately large share of load, the large DA customers that return to bundled service will have a disproportionately larger impact on utility procurement plans. In order to obtain the lowest commodity price, the utility may find a greater need to enter into long term contracts to meet the needs of returning large industrial customers as opposed to smaller customers."

[121] *See* D.03-05-034, pp. 34-36; 39 (discussing the reasonable balance in the commitment period).

[122] Exhibit 600, p. 11.

- DA customers today are predominately large customers, who represent a disproportionately large share of load.[123] As the Commission found in D.03-05-04, large DA customers that return to bundled service have a disproportionately larger impact on utility procurement plans, and to obtain the lowest commodity price the utility may have a greater need to enter into long term contracts to meet the needs of returning large industrial customers as opposed to smaller customers.[124]

- While there has been no fundamental change in the *relative mix* of resources in the IOUs' portfolios – as IOUs' procurement portfolios continue to be comprised of a mix of short-term, intermediate, and long-term contracts in the IOUs' portfolios,[125] which take into account customer growth and seasonal demand fluctuations, and turnover as old contracts expire and new ones are signed – there has been an *increase in the average duration* of contractual obligations in the IOUs' portfolios because of the IOUs' RPS obligations, which commenced after 2003, and tend to involve longer-term contracts (*i.e.,* 20-year contracts).[126] The average duration of the IOUs' contractual obligations have increased since 2003.[127]

- RA obligations, which also commenced after 2003, also involve longer-term procurement obligations, which tend to increase the average duration of contractual obligations in the IOUs' bundled portfolios.[128]

These facts weigh in favor of maintaining the current three-year minimum BPS stay, based on the criteria the Commission previously found dispositive on the matter.

The DA Parties have argued that the cap on the DA market needs to be considered in determining the appropriate minimum stay requirement. As discussed below, the cap may mitigate the risks to IOUs' bundled service customers to some extent, but it does not do so

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[123] *See* Tr.1, p. 90 (lines 6-19).
[124] *See* D.03-05-034, p. 35.
[125] *See* Exhibit 300, p. 7 (lines 1-5).
[126] *See* Exhibit 300, p. 7, lines 6-11.
[127] *See e.g.,* Exhibit 300, p. 7 (lines 7-11).
[128] Exhibit 300, p. 7, lines 11-14.

sufficiently to allow for only a one-year minimum stay period. The IOUs' proposal for an 18-month minimum stay requirement strikes a reasonable balance.

2. The DA Parties' Proposal Does Not Sufficiently Mitigate the Risks Associated with the Minimum Stay Requirement

The DA Parties testified that the cap on the DA market mitigates most of the risks associated with minimum stay requirement, and that a one-year minimum stay period is sufficient. They contend that "with the amount of DA load and demand for DA exceeding the capped amount, there is little opportunity for customers to 'game' rates by strategically jumping between DA and bundled service."[129] The DA Parties' theory is that DA customers will be less likely to try to game rates when demand for DA is high, because they may not be able to switch back to DA service even if they are eligible to do so, given the cap.

However, demand for DA service has fluctuated over the years, and the DA market can experience large swings depending on market conditions.[130] When demand for DA service drops off, the cap on the DA load will not mitigate the risk of gaming. The DA Parties' conclusions depend on continued high demand for DA service, which itself indicates lower price power available in the competitive market. But these market conditions are not the circumstances with which the IOUs are concerned. As prices rise in the market and DA service becomes potentially less competitive with IOU service, opportunities for gaming increase at the same time customer interest in DA service would be expected to diminish. It is these changes over time in the competitive market prices which the minimum stay requirement is intended to address.

Moreover, gaming is not the only concern the Commission seeks to address by the minimum stay requirement. As explained above, the Commission also seeks to mitigate the risk of stranded costs from the utilities' prospective procurement obligations by considering the mix of resources and the average duration of contractual obligations. On this issue, the DA Parties

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[129] Exhibit 200, p. 12 (lines 16-18).
[130] *See* Exhibit 300, p. 10, lines 5-10.

testified that "DA load that departs DA service to return to the utility will likely be quickly replaced by new DA load [thus] [u]tility resources are simply not stranded."[131] Again, the DA Parties' argument is entirely premised on the continued high demand for DA service, which ignores the fact that demand for DA service will vary with market conditions.

As SCE testified, "[n]othing prohibits the entire 11,710 GWh of maximum DA load from returning to SCE's procurement service in stressed market conditions."[132] If even *half* of that load returned to SCE's procurement service in a stressed market, without a long-term commitment to bundled service, the risk of stranded costs when that load departs for DA service would be substantial. It is also possible that a significant reduction in the minimum stay provision would, in the face of the potential for a mass return, result in a change in the mix of short, medium and long-term contracting by the IOUs over time. This could have the affect of increasing the average cost of procurement, which would impact all customers.

Thus, the cap on the DA market provides some mitigation and may support lowering the minimum stay requirement from its current three years; however, the one-year period proposed by the DA Parties is too short to mitigate stranded costs.

To present a straightforward example, consider the IOUs' forward RA procurement obligations. As SCE testified, the current RA program requires the IOUs to procure ninety percent (90%) of their System RA and one-hundred percent (100%) of their Local RA requirement up to 18-months in advance due to the timing of the Year-Ahead System and Local RA showings.[133] Specifically, in May of each year, the RA requirements for the following year are established, and the IOUs have until the end of October to meet their 90% System and 100% Local RA requirements for the following year.[134] So if, in January of 2012, a DA customer provides SCE with six months advance notice of its return to BPS, that customer's load is factored into the May 2012 RA requirements, and by October of 2012, SCE has procured 90%

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131 *See* Exhibit 200, p. 13 (lines 5-6).
132 Exhibit 300, p. 10, lines 7-8.
133 Exhibit 300, p. 7, lines 11-14.
134 *See* D.05-10-042 and D.06-06-064.

System RA and 100% Local RA for that load for all of 2013. If, when the customer returns to BPS in July 2012, it has only a 12-month minimum stay requirement, the customer becomes eligible to depart to DA in July 2013. Assuming the customer can and does depart at that time, that customer will strand RA costs that SCE was obligated to incur on its behalf to meet RA obligations through the remainder of 2013. Because the RA market is very illiquid, the IOU is not likely to recover its costs in the market once the load departs.

This same outcome holds true for DA customers providing notices of intent to return to BPS in February, March, April and May, because their load is added to the RA requirements established each May for the subsequent year. If the Commission moves the RA window to July of each year, as it has recently indicated it may do,[135] then notices in June and July will also factor into the year-ahead requirements.

Under the current RA requirements, even with the six-month advance notice requirement the risk of stranded costs with a one-year minimum stay requirement is high. For this reason, the DA Parties' proposal for a one-year minimum stay requirement should be rejected.

The IOUs' 18-month minimum stay requirement strikes a better balance because it mitigates the risk of stranded RA costs, among other potential stranded costs, while acknowledging that the capped DA market may support lowering the minimum stay requirement from its current length of three years.

3. The IOUs' 18-Month Proposal Strikes the Appropriate Balance in this Case

All three IOUs testified that an 18-month minimum stay requirement – accompanied by the six-month advance notice requirements – is the shortest period that is sufficient to adequately plan to serve bundled customers and mitigate the risk of gaming and stranded costs.[136] The example set forth in Section V.A.2 above demonstrates this to be true.

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[135] *See* January 25, 2011 Energy Division 2011 RA Phase II Proposals, Proposal 5 on Slides 11, 12 in R.09-10-032, available at www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_history.htm.

[136] *See* Exhibit 300, pp. 15-16; Exhibit 400, p. 3-6; Exhibit 500, pg. JS-5.

The evidence in this case supports adoption of the IOUs' proposal. The IOUs' proposal is the only one that appropriately balances the competing interests in this case, because it provides adequate protections against gaming *and* stranded costs while acknowledging that a reduced minimum stay requirement may be warranted in a capped DA market.

However, as SCE testified, the 18-month requirement necessitates maintaining the six-month advance notice requirements for DA customers migrating between BPS and DA service. The 18-month minimum stay period alone is insufficient to mitigate the risk of stranded costs.[137] Moreover, if DA is ever fully reopened through subsequent legislation, the Commission must consider any necessary modifications to the DA switching rules, as it is doing in this proceeding in the context of the partial reopening of DA under SB 695.[138]

B. Notice Period to go to DA Service or Return to Bundled Service.

The current six-month advance notice requirements for customers returning to BPS or departing to DA service were adopted in D.03-05-034 to preserve bundled service customer indifference to migrating load. The Commission in D.03-05-034 found that a six-month advance notice to return to bundled service was a necessary "added precaution" to give the IOUs sufficient time to adjust their procurement to accommodate the additional load. The Commission noted that the six-month advance notice, together with the minimum BPS commitment period, would "guard against arbitrage or other gaming practices that could be detrimental to bundled customers."[139]

These requirements continue to be appropriate for the reasons discussed below.

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137 *See* Section V.A.2 *infra*.
138 *See* Exhibit 300, p. 16 (3-5).
139 *See* D.03-05-034, p. 40.

1. <u>No Party Disputes the Need for the Six Month Advance Notice to Return to Bundled Service</u>

The IOUs, the DA Parties, CLECA/CMTA and DRA all support the continuation of the six month advance notice for DA customers to return to bundled service.[140] No party opposes the requirement. DA customers may serve out the six-month advance notice period while on DA service, in which case they will return directly onto BPS, or they may elect to take the IOU's TBS during the advance notice period.[141] Therefore, customers have reasonable flexibility under the rule, and it should be maintained.

2. <u>The DA Parties' Proposal to Eliminate the Six-Month Advance Notice to Depart IOU Procurement Service Should be Rejected</u>

Currently, DA customers must provide the IOU a six-month advance notice of intent to depart the IOU's procurement service for DA. The Commission in D.03-05-034 found that "[a] six-month advance notice by DA customers to the utility prior to any shifting into ***or out of*** the bundled portfolio rate provides a reasonable opportunity for the utility to adjust its portfolio and also guards against arbitraging or similar activities by customers."[142]

The DA Parties propose to eliminate the requirement that a DA customer provide the IOU six months advance notice to switch to DA service, but provide no reasonable justification for doing so.[143] The DA Parties simply believe that advance notice to the IOUs is not needed, as they presume that any space that opens up under the DA cap will be immediately taken up by another DA eligible customer.[144] Their presumption is flawed because it ignores the fact that demand for DA service will vary with market conditions, in which case the cap will not mitigate

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[140] *See e.g.,* Exhibit 200, p. 10 (10-15); Exhibit 300, p. 12 (lines 15-22); Exhibit 800, pp. 18-19 (A.25, A.26).
[141] Exhibit 300, pp. 13-14, (22-2).
[142] D.03-05-034, FOF 14 (emphasis added).
[143] *See* Exhibit 200, p. 14 (15-17).
[144] *See id.*

the risks of cost shifting, arbitrage, or similar activities by customers. As SCE explained in its testimony,

> "The six-month notice is needed to 'allow the IOU to reasonably mitigate the risk of (i) having to 'dump' energy and RA capacity in a depressed market due to departing load resulting in stranded costs to be recovered from all customers; and (ii) sudden swings in bundled service customers' load that make it difficult for the IOU to reasonably procure for its bundled service customers' . . . the DA cap does not obviate the need for the six-month advance notice . . . . The potential for swings [in demand for DA service] remains, even in a capped DA market. . . . Only reasonable switching rules can mitigate the impacts of swings in bundled service load from customers migrating to and from DA as the market changes."[145]

Also flawed is the DA Parties' presumption that the minimum stay requirement provides the needed "notice" to the IOU of a DA customer's intent to depart for DA service.[146] SCE explained in its rebuttal testimony:

> "[T]he minimum stay requirement is not a notice of intent to depart bundled service. The IOUs have no way of knowing whether a DA-eligible customer intends to depart Bundled Portfolio Service (BPS) upon the conclusion of a minimum stay requirement. Therefore, the minimum stay provides no notice of intent to depart an IOU's procurement service for DA, much less a binding notice that allows the IOU to adjust its procurement for departing DA load."[147]

The six-month advance notice requirement remains reasonable, and should not be an obstacle to DA given the consensus reached during the Process Improvement workshops (Working Group 3) for an annual DA enrollment window, which SCE describes in detail in its opening testimony.[148] Representatives from customer groups have indicated that the six-month advance notice requirement to switch to DA does not pose a problem for DA customers.[149]

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[145] Exhibit 301, p. 3 (12-22), citing to SCE's opening testimony, Exhibit 300, pp. 8-12.

[146] *See* Exhibit 200, p. 12, stating "[i]f SCE has the flexibility to deal with the migration of load onto direct access resulting from the reopening of direct access in 2010, one can safely infer that the portfolio can address the migration of customers given a year's notice," referring to their recommended one-year minimum stay requirement.

[147] *See* Exhibit 301, p. 4 (lines 16-21).

[148] *See* Exhibit 301, pp. 10-12 (lines 13-11).

[149] *See* Exhibit 300, p. 11 (lines 13-16); customer representatives noted concerns with the three-year duration of the minimum stay requirement.

The six-month advance notice requirement should be maintained.

C. Interaction, if any, with TBS Rate

TBS is relevant to the DA switching rules in two ways (i) as an option for DA customers that wish to serve out their six-month advance notice to return to BPS period on the IOU's procurement service rather than on DA service; and (ii) for DA customers electing a 60-day "safe harbor" period while they switch ESPs. The record in this case supports maintaining these options as long as the TBS rate is modified to include RA and RPS costs, as discussed below.

1. TBS Must be Modified to Include RA, RPS and CAISO Load-Related Costs

The Commission in D.03-05-034 found that by charging DA customers for the incremental costs of short-term power during the six-month advance notice period or the safe harbor period, no costs will be shifted to bundled service customers.[150] With the addition of RA and RPS requirements to the IOUs' procurement obligations as well as CAISO's costs since 2003, recovery of incremental power costs alone is not sufficient to avoid cost shifting to bundled service customers. The TBS rate must be modified to include RA and RPS cost components, as well as CAISO's load-related costs, as discussed in detail in Section IV above.

2. TBS Should Continue to be Available for DA Customers During their Advance Notice to Return to BPS Period

TBS should continue to be available to DA customers that wish to return to IOU procurement service to serve out their six-month advance notice period to return to BPS. The IOUs, the DA Parties, DRA all support maintaining this option with modifications to the TBS rate to incorporate RA and RPS costs.[151] No party opposes it, and it should be maintained,

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[150] *See* D.03-05-034, FOF 10, 15.
[151] *See e.g.,* Exhibit 300, pp. 32-33 (lines 8-3); Exhibit 200, pp. 7-8 (lines 4-12).

provided that the TBS rate is modified to incorporate RA and RPS cost components to avoid cost shifting to bundled service customers.

3. **The Safe Harbor on TBS for Voluntarily Returning Customers Should be Preserved without Modification**

In D.03-05-034, the Commission found that DA customers should be permitted to return to bundled service for a temporary period of not more than 60 days while switching ESPs.[152] The Commission limited the "safe harbor" to 60 days to address concerns regarding the possible need for limits on the amount of load that can elect the safe harbor during a particular year. The Commission found that "imposing this 60-day time limit should have some effect on limiting the amount of DA load in the safe harbor at any given time."[153] Customers failing to switch to DA from the safe harbor remain on TBS during the requisite six-month advance notice period and are subject to the minimum stay requirement.[154] Thus, under the current DA switching rules, a customer that elects the safe harbor but fails to timely switch to DA will be on TBS for the safe harbor period *plus* an additional six months before returning to BPS.

The DA Parties propose to modify the safe harbor rule, such that any DA customer that elects the safe harbor but fails to timely switch to DA would serve out a *total* of six months on TBS before going to BPS. Thus, for those customers, the IOU would not receive a six month advance notice; rather, the notice period would effectively be shortened to four months.[155] The DA Parties offer no justification for shortening the advance notice period for safe harbor customers, nor do they justify why customers electing safe harbor should have a shorter notice period than those who do not elect the safe harbor.[156]

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[152] *See* D.03-05-034, p. 19 and COL 10.
[153] *Id.,* pp. 21-22.
[154] *See* D.03-05-034, OP 9; 10 and Rule 22.1, Section A.
[155] *See* Exhibit 300, pp. 2-3 (lines 19-5)
[156] *See* Tr. 3, p. 461-62 (lines 1-17); the only reason offered was to keep the overall TBS rate to a total of six months.

The DA Parties proposal should be rejected. The record does not support different treatment of DA customers under the switching rules simply on the basis that some customers elect TBS for a 60-day safe harbor. Being on safe harbor provides no notice to the IOU of a customer's intent to return to BPS, because customers electing the safe harbor *intend to return to DA service,* not BPS and can do so at any time during the 60-day window. All customers returning to BPS – including those that fail to timely switch to DA out of the safe harbor – should be required to provide the same advance notice.   The DA Parties have provided no evidence that the IOUs can adjust their portfolios for returning DA load in as little as four months. The IOUs have testified that six months advance notice is still required to adjust their portfolios to accommodate DA load returning to BPS.

The current safe harbor rules are reasonable, and should be maintained without modification for voluntarily returning DA customers.

4. Switching Rules for Involuntarily Returned DA Customers

The DA switching rules currently draw no distinction between DA customers that voluntarily return to the IOU's procurement service and those that are involuntarily returned as a result of service termination by their ESP. The statutory requirements for a bond (or financial security) for involuntarily returned customers under P.U. Code Section 394.25(e) drives the need to distinguish between voluntarily and involuntarily returned DA customers for purposes of the switching rules.

Unfortunately, Section 394.25(e) does not expressly define what an "involuntary return" is; it only partially defines the term by carving out from its protections certain cases of involuntary returns.[157]

[157] *See* Section 394.25(e), excepting from the bond requirement those customers involuntarily returned to the IOU's procurement service because they defaulted on their payments or other contractual obligations or because their DA contract has expired.

SCE has proposed a straightforward definition of the term: an involuntary return is any return to the IOU's procurement service that is initiated *not* at the election of the customer, but rather at the election of the ESP.[158] In other words, the ESP – not the customer – has elected to return the customer to IOU procurement service. This is consistent with the definition of a *voluntary* return to IOU procurement service, which has always been understood to occur at the election of the DA customer.

SCE's definition is broad enough to be consistent with Section 394.25(e), because the statute carves out most instances of involuntary returns from its protections.[159] Thus, only those involuntary returns that come within the statute's protections need to be distinguished for purposes of the DA switching rules and the bond requirement. As SCE discusses in Section VI below, only *mass* involuntary returns should be protected under Section 394.25(e). All other involuntary returns should be treated under the DA switching rules just like voluntary returns.

The DA Parties propose a more specific definition of an involuntary return, which they admit deviates from what is contemplated in Section 394.25(e).[160] In particular, the DA Parties would define as "voluntary" those returns that are deemed involuntary under Section 394.25(e) but are carved out from the protections of the statute.[161] Their definitions also overlook a mass involuntary return caused by an ESP that chooses to close its operations.[162]

SCE questions the prudence of a proposal that deviates from statute, but also *the need* for it, because – with the inclusion of involuntary returns caused by ESPs that choose to close operations – the outcome of the DA Parties' proposal is the same as the outcome under SCE's proposal – that is, *only mass involuntary returns* are distinguished under the switching rules, and

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[158] *See* SCE's January 24, 2011 Opening Brief, pp. 4-5.

[159] In other words, the definition of an involuntary return is necessarily broad because the statute excepts from its protections most instances of involuntary returns. *See* fn. 157, *supra*.

[160] *See* Exhibit 200, p. 9, fn. 9, stating "the working definitions of 'voluntary return' and 'involuntary return' presented in Attachment A and utilized in [the DA Parties'] testimony differ slightly from the usage of the terms in the [P.U.] Code section 394.25(e)."

[161] *See* Exhibit 200, p. 10 (lines 3-5), discussing DA customers that have defaulted under their DA contracts.

[162] *See* id., pp. 9-10 (lines 19-2), defining involuntary returns as those that *require* the ESP to close its operations *for cause* as a result of an ESP failure to meet its obligations. The definition would appear to omit ESPs that simply elect, for whatever reason, to close their operations.

obtain the protections of the bond. All other returns – whether voluntary or involuntary – are treated the same under the rules. The DA Parties acknowledged this under cross-examination at hearings.[163]

Therefore, the record supports distinguishing only mass involuntary returns under the switching rules. All other involuntary returns should be treated consistent with voluntary returns under the DA switching rules.

a) TBS for Mass Involuntarily Returned DA Customers

SCE testified that mass involuntarily returned DA customers should be protected by a bond (or financial security) that covers the incremental and administrative costs to the IOU to serve those customers for a one year period; therefore, DA customers returned *en masse* to the IOU's procurement service need not – and should not – be subject to a potentially high TBS upon their return to DA service.[164] Only if the Commission declines to impose a bond requirement on ESPs designed to reasonably cover the IOU's incremental procurement and administrative costs to serve the involuntarily returned DA load, should DA customers returned *en masse* to the IOU's procurement service be exposed to the spot market prices on TBS, for a one-year period.[165]

PG&E also proposed the protections of an ESP bond for mass involuntarily returned DA customers covering the incremental and administrative costs to the IOU to serve those customers for a one year period;[166] however PG&E's testimony left open the possibility that those customers can be placed on TBS rather than directly onto BPS.[167] Under such a

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163 *See* Tr.2, pp.441-442 (lines 10-26).
164 *See* Exhibit 300, p. 13 (lines 6-11), citing Section V.E.
165 *See id.*
166 *See* Exhibit 400, p. 4-14 (lines 10-32).
167 In rebuttal, PG&E agreed with SCE that if the Commission adopted adequate bond protections, involuntarily returned DA customers could be placed directly onto bundled service rates. *See* Exhibit 401, pp. 11-12 (lines 18-4)

scenario, the monies collected from the ESP's bond would presumably be credited to the DA customers to offset the costs they incur on the TBS rate.

Other parties, including SDG&E and the DA Parties, proposed that mass involuntarily returned DA customers be placed on TBS, but for different reasons and for different durations of time (see discussion in Section VI below).

SCE's proposal to place involuntarily returned DA customers directly onto BPS was primarily for equity reasons, as explained in its testimony:

> "In SCE's view, requiring ESPs to be liable for the incremental procurement (as well as administrative) costs that result from an involuntary return of its customers is entirely consistent with Section 394.25(e), which mandates that the ESP be liable for reentry costs that would otherwise have to be borne by the involuntarily returned DA customers to prevent cost-shifting to bundled service customers.
>
> Requiring the ESP to be liable for costs caused by its failure ***is also consistent with fundamental notions of fairness***. It would be unfair to require involuntarily returned ESP customers to pay spot market prices on TBS for a one-year period because the ESP failed to provide the requisite advanced notice of an involuntary return (for a voluntary service termination), or because the ESP failed in some other manner that caused the Commission to order ESP service termination (an involuntary service termination)."[168]

However, nothing in Section 394.25(e) *requires* mass involuntarily returned DA customers to be placed directly onto BPS. SCE acknowledges that the Commission can implement the bond protections of Section 394.25(e) and also require these customers to be placed on TBS to doubly ensure that bundled service customers do not experience cost shifting as a result of DA customers' mass involuntary returns to IOU procurement service. Doing so would place additional administrative burdens on the IOU to credit the DA customers for the monies collected from their ESPs for the reentry fees, but it would likely be comparable to the process of charging the DA customers who are placed directly on BPS for

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[168] Exhibit 300, pp. 64-65 (lines 12-2)

any residual reentry fees not collected from the ESP, which may be necessary under SCE's proposal.[169]

If the Commission adopts SCE's proposed methods for calculating ESP bonds and reentry fees, the record supports a finding that bundled service customers will be adequately protected from cost shifting, and mass involuntarily returned DA customers can be placed directly on BPS. If, however, the Commission rejects or modifies SCE's proposed methods for calculating ESP bonds and reentry fees, there is no dispute that the Commission must place mass involuntarily returned DA customers on TBS, with continued payment of the applicable CRS as currently required of customers served on TBS, to avoid cost shifting to bundled service customers. Their stay on TBS needs to correspond with the period of time required to adequately protect bundled service customers from incremental costs in a mass involuntary return, which is a contested matter in this proceeding, and SCE discusses it in Section VI below as part of the bond issues.[170]

b) <u>Safe Harbor in a Mass Involuntary Return</u>

Little consensus exists among the parties' proposals for a safe harbor for DA customers returned *en masse* to the IOU's procurement service. SCE testified that a safe harbor in the context of mass involuntary returns is not feasible because the IOU needs certainty as to the load it will be obligated to serve so that it can continue to reasonably procure for its bundled service customers, begin to hedge for the returned customers,[171] and also calculate the reentry fees due from the ESP and/or the returning customers (for residual reentry fees) as a result of the involuntary return.[172]

SCE recommended that ESPs should provide their customers with as much advance notice of an involuntary return as possible to allow customers to switch ESPs prior

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169 *See* Exhibit 300, Section V.G, p. 66.
170 *See* Section VI.B *infra* for a discussion of the duration of the bond/reentry fee coverage.
171 Exhibit 301, pp. 28-29 (lines 16-3).
172 *See* Exhibit 300, pp. 65-66 (lines 20-26).

to being involuntarily returned to the IOU's procurement service.[173] Otherwise, SCE proposed that DA customers included in an ESP's mass involuntarily return to IOU procurement service should be placed on bundled service, which would not provide for a safe harbor; however, they should be permitted to provide the IOU with a six-month advance notice to depart to DA.[174]

PG&E, on the other hand, testified that involuntarily returned DA customers could elect a safe harbor:

> "An involuntary returning customer should have 60 days to select a new ESP and submit their DA Service Request (DASR) if they wish to remain on DA service and retain their vintage. Once a customer elects to pursue the path of the safe harbor provision, it would remain on TBS until it receives service from its new ESP. If such a customer fails to get service from its new ESP within that six-month period, then that customer would automatically return to PG&E's bundled service and would be required to remain on bundled service for the minimum stay period."[175]

PG&E's testimony does not address how or when an involuntarily returned customer would elect the safe harbor option and go on TBS. If the mass involuntary return occurs with little or no notice, presumably the customer cannot make this election prior to returning to IOU procurement service, in which case the customer would have to elect a safe harbor while on BPS or TBS (depending on which rate the Commission determines involuntarily returned customers should take).

Because the IOUs require six months advance notice to place customers on BPS, safe harbor customers that fail to timely switch to DA would need to serve another six months advance notice period on TBS after the safe harbor period ends, which also does not appear to be factored into PG&E's proposal.

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173 *See* Exhibit 301, p. 29 (lines 4-11),
174 *See id*.
175 Exhibit 401, p. 12 (lines 9-16).

PG&E's proposal also requires the IOUs to hold safe harbor customers' space under the DA cap for up to six months, which is a long time considering the limited space for DA-eligible customers under the cap, and the uncertainty as to whether safe harbor customers will actually decide to take DA service and depart the IOU's procurement service. Nothing under the proposal would prevent a safe harbor customer from keeping the "option" to return to DA open for the entire six months and ultimately staying with the IOU, which may harm other DA-eligible customers' chances of switching to DA.[176]

Moreover, PG&E's testimony does not reconcile the safe harbor option with the calculation of the ESP's reentry fees under its bond proposal. Specifically, how would the uncertainty surrounding the safe harbor customers factor into PG&E's demand for reentry fees from the ESP? As SCE testified, the demand for reentry fees needs to be made within 90 days of the involuntary return to ensure that the financial instrument (surety bond or letter of credit, *etc.*) securing the reentry fees is actually available to PG&E.[177] A safe harbor option may require some true-up of the reentry fees after they have been collected from the ESP.

Similar issues arise in the context of the DA Parties' safe harbor proposal,[178] as it assumes that the ESP has no obligation to pay the IOU for procurement-related reentry fees caused by its mass involuntary return of DA customers, which SCE and PG&E dispute. Therefore, the DA Parties' proposal does not address the safe harbor in the context of the reentry fee calculations.[179] The DA Parties proposal – like PG&E's – overlooks the need for advance notice to return to BPS from the safe harbor. The safe harbor provides the IOU with

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[176] PG&E would presumably require a six month advance notice to return safe harbor customers that fail to timely switch to DA to bundled service, which also does not appear to be factored into its proposal.

[177] *See* SCE's testimony at Exhibit 300, p. 66 (lines 8-14), explaining "commercial financial instruments (like letters of credit or surety bonds) available to meet the bond obligation often contain a ninety (90) day notice of termination provision in the event of a default. An ESP's involuntary return of DA customers to IOU procurement service is likely to be considered an event of default, which would trigger the creditor's right to termination the credit line within 90 days."

[178] *See* Exhibit 200, p. 11, lines

[179] The safe harbor proposals of SDG&E and CLECA/CMTA also do not address the safe harbor in the context of the reentry fee calculations.

no notice of a DA customer's intent to return to BPS, because safe harbor customers intend *to return to DA service*, not BPS.

The DA Parties' proposal also requires the IOUs to hold safe harbor customers' space under the DA cap for up to 6 months, which raises the same fairness concerns for other DA-eligible customers seeking to switch to DA as PG&E's proposal does. On this issue, SDG&E testified:

> [U]nder the existing DA rules, the amount of load that can transfer from bundled service to DA is capped. By essentially extending the safe harbor for an additional four months, the utility would necessarily be required to track and hold the customer's load until it made a decision to either commit to bundled service or return to DA. Holding load that might otherwise be available for DA for up to six months is simply unfair to other customers . . . ."[180]

These issues with the safe harbor for involuntarily returned customers are what prompted SCE to propose that involuntarily returned customers that wish to return to DA should be placed on BPS, should not be subject to the minimum stay requirement, but should be required to give a six-month advance notice to the IOU to return to DA. In this way, they would be on the same footing as other customers on bundled service that are eligible to depart for DA service under any available space.

SCE finds the record is insufficient to support a safe harbor option in the context of involuntary returns, in particular with respect to the bond and reentry fee calculations. If the Commission approves ESP bonds and reentry fees that include procurement costs – as SCE argues it should under P.U. Code Section 394.25(e) – then the record provides no reasonable means of incorporating a safe harbor option. To the extent the Commission wishes to allow a safe harbor for involuntarily returned customers, it should require the parties to work together to determine whether such an option is feasible and can be factored

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[180] *See* Exhibit 503, p. JS-5 (lines 16-22).

into the ESP bond and reentry fee calculations, and if so, to make a subsequent proposal for the Commission's consideration.

VI.

ESP FINANCIAL SECURITY REQUIREMENTS CALCULATION – PROPOSALS AND RECOMMENDATIONS

The issue in this case is how to implement the consumer protections of AB 117, which requires:

> "If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electric corporation shall be the obligation of the electric service provider or a community choice aggregator, except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers."[181]

Pursuant to the ALJ's November 22, 2010 Ruling Adopting Amended Scoping Memo an Schedule and January 7, 2011 Ruling Amending Procedural Schedule, the parties to this proceeding were directed to file opening and reply briefs on the legal issues in dispute regarding Section 394.25(e),[182] which are (i) whether the consumer protections of Section 394.25(e) extend to ESP and CCA customers as well as bundled service customers of the IOUs; and (ii) whether the legal obligations arising under Section 394.25(e) apply differently to ESPs and CCAs. Parties filed their opening and reply briefs on January 24, 2011 and February 11, 2011, respectively.

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[181] Section 394.25(e).

[182] The Ruling directed the parties to file their opening and reply briefs in the CCA Rulemaking, Phase III Bond Issues, concurrently with their filings in this DA Rulemaking.

SCE's positions on the legal issues (joined by PG&E) are fully explained in its opening and reply briefs; therefore, SCE will not repeat those arguments here.[183] For the reasons explained in SCE's opening and reply briefs, the Commission should find that Section 394.25(e) protects *both* bundled service customers *and* ESP customers[184] from costs associated with mass involuntary returns to IOU procurement service, because:

- Under the statute bundled service customers are protected from costs arising out of an involuntary return through any reentry fees imposed on involuntarily returned customers to avoid shifting costs onto bundled service customers.

- In turn, the reentry fees imposed on involuntarily returned DA customers are the obligation of the ESP under the statute, and the ESP must post a bond or insurance "sufficient to cover those reentry fees."[185]

The Commission should also find that reentry fees include incremental procurement costs because incremental procurement costs – as well as incremental administrative costs – must be imposed on involuntarily returned DA customers to avoid shifting them to the IOU's other customers (those customers on bundled service at the time of the involuntary return). Moreover, the protections of Section 394.25(e) should apply in the context of *mass* involuntary returns, only. The legal arguments in support of these findings are presented in SCE's opening and reply briefs, and the supporting facts are discussed below.

In addition to the legal and factual issues regarding Section 394.25(e), the Commission must assess the policy implications of the bond/reentry fee requirement. In particular:

- <u>Whether DA customers can sufficiently protect themselves from the risks associated with mass involuntary returns without ESP bonds or reentry fees</u>. The DA Parties

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183 SCE and PG&E filed joint opening and reply briefs. *See* January 24, 2011 Joint Opening Brief of Southern California Edison Company and Pacific Gas and Electric Company; and Joint Reply Brief of Pacific Gas and Electric Company and Southern California Edison Company, February 11, 2011.

184 ESP customers are also referred to herein as DA customers.

185 Section 394.25(e). Because the CCA bond issues are outside the scope of this proceeding, SCE focuses its discussion exclusively on ESP bond issues. SCE's opening and reply briefs on the legal issues address the similarities and differences between the ESP and CCA obligations under the statute.

testified that DA customers are large and sophisticated, and can adequately address the risks of involuntary returns.[186] What they conveniently overlook is that the majority of DA customers are residential and small C&I customers.[187] The DA Parties provide no evidence that residential and small C&I customers understand the risks of an involuntary return, or their rights under Section 394.25(e). The DA Parties alluded to the potential for contractual rights and remedies as part of the customers' DA contracts.[188] However, they produced no evidence that customers have actually sought to protect themselves from the risks of involuntary returns in their DA contracts. Because the DA Parties claim their contracts are confidential, there is no way to verify the existence of any contractual rights and remedies for involuntary returns.

In any event, the opportunity to bargain for rights and remedies in a DA contract is only as good as the DA customer's comprehension of the risks. As SCE explained in its testimony, most DA customers cannot be expected to appreciate the risks associated with certain procurement practices[189] or the volality of spot market prices. Most DA customers probably do not know that spot market prices got as high as $150/MWh in the commodity price run-up in 2008.[190] If a mass involuntary return occurred during that timeframe, and the DA customers were required to absorb the incremental procurement costs without the coverage from an ESP bond, those customers – most of whom are residential and small commercial – would have been paying as much as $1.50/kWh for their electricity.

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[186] *See e.g.,* Tr. 1, pp. 171-172.
[187] *See* Exhibit 301, p. 27, fn. 65; *also* Tr. 1, p. 90 (lines 6-14).
[188] *See* fn. 186, *supra*.
[189] *See* Exhibit 300, pp. 35-36 (lines 2-3) and p. 37 (lines 5-15).
[190] *See* DOE's website for SP-15 prices for 2008, available at http://www.eia.doe.gov/electricity/wholesale/wholesale.html.

Moreover, in an involuntary return, DA customers have no control over the timing and conditions of the involuntary return and condition of a mass involuntary return:

> "Involuntary returns are materially different than voluntary returns from a DA customer's perspective . . . . With a voluntary return to IOU procurement service – which is initiated at the request of the customer – the DA customer has the ability to control the *timing* of the return, which enables the customer to account for electricity market conditions and other relevant factors; and the *conditions* of the return. For example, the customer can choose to provide sufficient advance notice to the IOU of the return, so the customer can return directly onto BPS and thereby mitigate the risk of paying high spot market prices on TBS.
>
> With mass involuntary returns – when the exceptions to statute's protections should not apply – DA customers have no control over the timing or conditions of their return to IOU procurement service. [T]he timing is dictated by the ESP in a voluntary service termination; or by the exigent circumstances that cause the Commission to order an involuntary service termination. . . .[and] the customer has no reasonable means of providing the IOU with advance notice of their involuntary return."[191]

Without the protections of Section 394.25(e), DA customers would be exposed to significant risks associated with the timing and conditions of their involuntary return (e.g., being ineligible for BPS, having to serve out a sufficient notice period on TBS and being subject to the volatility of the spot market during that notice period.)[192]

- <u>Whether DA customers would have a reasonable opportunity to pursue claims related to involuntary returns in court.</u> The DA Parties testified that DA customers do not need the consumer protections of Section 394.25(e) because they can – and should – sue their ESP for any damages arising out of an ESP's involuntary return of its DA customers to the IOU's procurement service.[193] The Commission should be wary of this argument. This "alternative" to the bond is illusory, because an ESP that is closing its operations or being forced to cease its operations will, in all likelihood, have little or no assets to satisfy claims of

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[191] *See* Exhibit 300, pp. 36-37 (lines 12-12).
[192] *See* Exhibit 300, pp. 36-37 (lines 12-12).
[193] *See* Tr. 3, p. 502 (lines 6-12).

DA customers who actually inititate actions in court. It is also unreasonable, because it would require each and every DA customer to file court actions to recover damages arising from a mass involuntary return. If this "remedy" were acceptable from a public policy perspective, the legislature would not have provided the Commission with authority to enforce minimum consumer protections for DA customers under Article 12 of the P.U. Code, including Section 394.25(e).

- Whether the Commission can adequately protect DA customers from the risks of a mass involuntary return in the absence of a bond requirement. SCE testified – and the DA Parties did not dispute – that the Commission has limited jurisdiction over ESPs pursuant to its own decisions.[194] Accordingly, the Commission has limited ability to protect DA customers from the risks of a mass involuntary return, particularly because the Commission does not review ESP procurement contracts for reasonableness, or oversee their hedging practices, or require ESPs to enter into long-term contracts, *etc.*[195] Accordingly, to reasonably protect the DA customers from the risks associated with mass involuntary returns, the Commission needs to exercise the consumer protections authority provided in Section 394.25(e).

- Whether the Commission can prevent cost shifting in the absence of a bond requirement. AB 117 requires the Commission to prevent "any shifting of recoverable costs between customers."[196] In absence of an ESP bond covering the exposure to incremental procurement costs in a mass involuntary return, the Commission's ability to prevent cost shifting is questionable. There is no dispute that to prevent cost shifting in absence of an ESP bond, involuntarily returned DA customers must be placed on TBS for a period of time sufficient to reasonably recover incremental procurement costs, which is 12 months as the IOUs testified.[197] Residential and small commercial customers may not be able to afford to pay the

194 *See* Exhibit 300, p. 38 (lines 8-11).
195 *See* Exhibit 300, pp. 35-36 (lines 2-10), discussing the risk of a mass involuntary return.
196 *See* P.U. Code Section 366.2(d).
197 *See* Exhibit 300, pp. 43-45 (lines 24-10).

spot market prices on TBS, particularly during a stressed market, which is the risk scenario for mass involuntary returns. If the Commission has to grant these customers relief from spot market prices, some or all of incremental costs arising out of the mass involuntary return will, inevitably, be shifted to bundled service customers, contrary to the requirements of AB 117 generally, and Section 394.25(e) specifically. Bundled service customers would not be indifferent to DA migrating load, as a result.[198]

Whether the bond can reach unreasonable amounts and how the *price* of the bond is relevant to that determination. The risks associated with incremental procurement costs correspond to market risks, and market risks are not capped. Accordingly, the bond amounts under SCE's and PG&E's proposed method are not capped, and will increase as market prices rise, and decrease as market prices decline, when the bond amount is updated every six months. The DA Parties focus on the potential bond amounts under the method, but never address their *actual costs* to obtain the bond. They never address or rebut SCE's testimony that an ESP with investment grade credit can expect to obtain a bond for about 1% of the face value of the bond.[199] In other words, if the bond amount did reach $100 million, which the DA Parties decry in their testimony,[200] an investment grade ESP can expect to obtain a bond to cover that risk for about $1 million.

Moreover, the DA Parties produce no evidence that disproves the validity of the exposure calculation in the proposed bond method. They attempt to discredit the method by comparing illustrative bond amounts with illustrative reentry fee amounts; however, their analysis is flawed for a variety of reasons, which are discussed in Section VI.B below. The DA Parties' one legitimate complaint with the method is the lack of availability of the implied volatiliaty

[198] Even DA Parties concede that '[t]he policy rationale for placing Financial Security Requirements on ESPs working in California is still to maintain bundled customer indifference. That is, bundled customers rates should not rise due to circumstances where DA customers are involuntarily returned to utility service." Exhibit 200, pp. 14-15 (lines 22-2).

[199] *See* Exhibit 300, p. 63 (lines 1-12).

[200] *See* 201, pp. 13-14 (lines 17-1).

data; and both SCE and PG&E have adequately addressed the concern by proposing the use of historical volatility.[201]

- Whether the DA Parties' desire to keep their costs down is a sufficient reason to allocate the risks of an involuntary return to the IOUs' customers, including bundled service customers and DA customers upon their involuntary return to IOU procurement service. The DA Parties' proposal seeks to allocate all of the risks of mass involuntary returns to the IOUs and their customers – both involuntarily returned DA customers through a six-month stay on the IOU's TBS rate, and bundled service customers for any remaining incremental procurement costs caused by an ESP's mass involuntary return. The DA Parties propose to cover through a bond the incremental administrative costs, only. The DA Parties testified that their proposal seeks to minimize costs to the DA customers.[202] The only way their proposal on involuntary returns actually minimizes costs for DA customers is in the context of *the ESP's* service – it shifts all the risk to the IOUs and their customers to recover the incremental procurement costs caused by ESPs that fail.

  The Commission needs to carefully weigh the equities of the DA Parties' proposal in the context of retail competition. Appropriate risk allocation is fundamental to a level playing field. It is also critical to bundled service customer indifference. The legislature in Section 394.25(e) allocated the risks associated with involuntary returns – which are caused by ESPs – to the ESPs. The DA Parties seek to shift it back to the IOUs, so they can "minimize costs" and be "competitive." Good public policy does not support subsidies for ESPs, and neither does state law under AB 117.[203]

- Whether complexity of the bond and reentry fee calculations is sufficient reason to nullify the consumer protections of Section 394.25(e). The Commission should also carefully consider

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201 *See* Exhibit 301, p. 17 (lines 9-12).
202 *See* Exhibit 200, p. 3 (lines 12-15) and Tr. 2, p. 440 (lines 6-23).
203 *See* Sections 366.2(d) and 366.2(c)(17).

the concerns of DA Parties and others that the bond and reentry fee methods proposed by SCE and PG&E are "too complex."[204] Complaints over the complexity of these calculations from parties that propose numerous, complex modifications to the PCIA calculation in the name of indifference are self-serving and should be given little weight. The issue *is* complex; however, it is not a sufficient reason to shift risks – and ultimately costs – arising from ESP failures to the IOUs and their customers.

A. Defining Reentry Fees

SCE testified that reentry fees under Section 394.25(e) should be defined as any incremental costs incurred by the IOU to serve DA customers who are returned *en masse* to the IOU's procurement service.[205] Only incremental costs – those costs above what the IOU is recovering in bundled service rates[206] – would be shifted onto the IOUs' other customers (customers on bundled service at the time of the involuntary return) unless recovered from the involuntarily returned DA customers. Accordingly, incremental costs arising from a mass involuntary return are the "reentry fees" because those incremental costs must be imposed on the involuntarily returned DA customers to avoid shifting those costs to the IOU's other customers. In other words, the incremental costs are any costs that "would not have occurred *but for* the involuntary return of DA customers to utility procurement service."[207] Incremental costs arising from a mass involuntary return of DA customers reflect *the cost of reentry*.

The DA Parties' definition of reentry fees materially differs from SCE's definition in one key regard: what is *incremental*. The DA Parties regard incremental costs as those arising from the involuntary return *that are not recovered from the DA customers on the TBS rate*.[208] Yet,

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[204] *See e.g.,* Exhibit 500, pp. 7-8 (lines 22-2).
[205] *See* Exhibit 300, pp. 38-39 (lines 25-3).
[206] *See* Exhibit 300, p. 39 (lines 1-3), explaining that "[b]y incremental costs, SCE means all costs above those recovered in bundled service rates at the time of the involuntary return."
[207] *See* Exhibit 300, p. 41 (lines 16-22).
[208] *See* Exhibit 200, Attachment A, p. 2, defining reentry fees as the difference between the IOU's marginal portfolio costs to serve the involuntarily returned DA customers and the amounts collected from those customers on "bundled service," by which the DA Parties mean TBS.

incremental costs that could be recovered from DA customers through the TBS rate are the costs of reentry for those customers involuntarily returned to the IOU's procurement service.

The DA Parties' position appears to boil down to a timing issue: because the Commission previously deemed it necessary to recover incremental procurement costs from DA customers returning to IOU's procurement service to avoid shifting to bundled service customers -- and implemented TBS to do so -- the only costs the Commission must now "deem necessary" to recover from involuntarily returned DA customers to avoid cost-shifting to bundled service customers are incremental administrative costs. Incremental administrative costs – at a proxy of \$1.54 per customer[209] – are what the legislature intended to protect consumers from in Section 394.25(e), accordingly to the DA Parties. Of course, the DA Parties carefully caveat their position by testifying to the need to modify TBS to allow the IOU to recover RA costs, RPS costs, and CAISO load-related costs to avoid shifting costs to bundled service customers. One wonders why the DA Parties did not simply tack onto their list of TBS modifications a proxy for IOU incremental administrative costs, and attempt to dispose of the bond requirement for their involuntary returns entirely.

The DA Parties have suggested the DA customers have no "right" to go directly onto BPS; therefore they have no "right" to be protected from the incremental procurement costs on TBS. To the contrary, Section 394.25(e) gives DA customers the right of to be protected from the costs of reentry in an involuntary return, including the incremental procurement costs, as SCE has argued in its opening and reply briefs. The DA Parties' definition of "incremental costs" in the context of the consumer protections of Section 394.25(e) should be rejected.

As for other definitional issues, SCE argued in its legal briefs that the protections of Section 394.25(e) should apply in the context of a *mass* involuntary return, which would arise when an ESP elects to cease its operations or is required to do so for cause. SCE explained:

> "There are exceptions to the ESP or CCA customer indemnity in the statute. Specifically, if an ESP or CCA customer defaults on

[209] *See* Exhibit 300, p. 45 (lines 12-13, 23-24).

> its payments or other contractual obligations or its contract has expired, and as a result, the customer is involuntarily returned to IOU procurement service, the customer is not entitled to be indemnified by its ESP or CCA for the reentry fees the customer incurs upon its return to IOU procurement service. These exceptions are best understood as arising outside of a *mass involuntary return* of customers to IOU procurement service, which would occur if an ESP or CCA chooses to terminate service to all its customers and return them all to IOU procurement service (*i.e.*, a voluntary service termination by the ESP or CCA), or an ESP or CCA is ordered (for cause) to terminate service to all its customers and return them all to IOU procurement service (*i.e.*, an involuntary service termination).
>
> Thus, *in a mass involuntary return*, exceptions to the ESP and CCA customer indemnity in Section 394.25(e) should not apply."[210]

At hearings, the DA Parties asked a number of questions regarding how an IOU would determine whether a "mass" involuntary return has occurred.[211] SCE acknowledges there may be instances where the circumstances of a return are questionable. However, the issue should turn on whether the ESP has ceased it operations in California or has been forced to do so for cause. Thus, where an ESP serves two customers, decides to cease operations or must do so for cause, and returns both customers back to the IOU's procurement service, those two customers should be entitled to have their reentry fees paid by the ESP. In a similar vein, if the ESP returns half its customers to the IOU's procurement service, and waits for some time before involuntarily returning the other half, this would appear to be a phased approach to involuntarily returning all of the ESP's customers to the IOU's procurement service, which, in SCE's view, should be considered a mass involuntary return.

B. Calculating Reentry Fees

SCE testified that calculating reentry fees involves two distinct steps:

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[210] Joint Opening Brief of SCE and PG&E, filed January 24, 2011, p. 5.
[211] *See e.g.,* Tr. 1, pp. 192-197 (lines 14-11); Tr. 2, pp. 212-225 (lines 13-3).

1. Forecasting reentry fees (incremental costs) for purposes of securing a bond sufficient to cover those fees in the event of an involuntary return, as Section 394.25(e) requires; and
2. Determining actual reentry fees (incremental costs) once an involuntary return of DA customers has occurred.[212]

As for forecasting the reentry fees, SCE explained:

> "Forecasting the incremental costs (or reentry fees) for the bond is a distinct undertaking from determining the actual reentry fees in an involuntary return, because the forecast of incremental costs must account for a number of uncertainties, including when the involuntary return may occur and what the market conditions may be at that time. As such, to be sufficient to cover actual reentry fees – the amount of which is uncertain at the time of the forecast – the forecast should reasonably seek to establish a bond amount sufficient to protect bundled service customers and indemnify involuntarily returned DA customers 95 percent of the time on a forecast basis (*i.e.,* with a 95 percent confidence level). The 95 percent confidence interval represents a one-in-twenty (1-in-20) event and was adopted by the Commission in D.07-12-052 as the confidence interval to be used by IOUs to manage rate level risk for bundled service customers. This same confidence level should apply to forecasting the possible reentry fees that could occur. The bond should provide the same level of protection that the bundled service customers currently have."[213]

SCE proposed to forecast incremental costs over a 12-month period. SCE testified that the IOUs can incur incremental costs in a mass involuntary return well beyond a year because the IOUs make longer-term commitments on behalf of bundled service customers, such as gas and power hedges of five-years duration:

> "For example, if SCE hedges its power costs by signing five-year contracts at a fixed-price of $60/MWh and DA customers involuntarily return *en masse* one year into the contracts when the forward price for power is $80/MWh, the expected cost impact of the involuntary return on bundled service customers could be four years. This is because the forward price for power of $80/MWh is

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[212] *See* Exhibit 300, p. 43 (lines 1-6).
[213] *See* id. (lines 7-19).

> the current price for hedging power for the involuntarily returning DA load and is also the "expected" spot price for purchasing power on the spot market for this load. Adding this $80/MWh power into the bundled portfolio with hedges at $60/MWh will raise the bundled portfolio's average price, thus impacting bundled service customers. The duration of the impact to bundled service customers depends on the duration of the high market prices. This is true whether or not SCE is long or short when the returning customers enter the portfolio."[214]

SCE explained that while a one-year period will likely not achieve full indifference of bundled service customers to mass involuntary returns, it should provide for reasonable indifference.[215]

The DA Parties state that six months is sufficient for the IOUs to recover incremental costs in a mass involuntary return; however, they provide no evidence demonstrating that the IOUs' exposure in a mass involuntary return is limited to six months. Instead, they reason that "since after six months an involuntarily returned customer remaining on bundled service [*sic*] is equivalent to a customer who has given six months notice, there is no reason to extend forward looking financial security timeframe beyond six months."[216] The flaw in their logic is assuming that a mass involuntary return of customers with *no notice* to the IOU has the equivalent impact on the IOU's procurement as an individual customer who gives six-month advance notice to the IOU before voluntarily returning to the IOU's procurement service. Also, the six-month advance notice horizon was designed for voluntary returns, which are expected to be intermittent and involve one to a few customer at a time, not a mass of customers returning all at once to the IOU's procurement service.[217] Moreover, in the CCA context, the Commission has already recognized that the IOU requires a one-year advance notice to adjust its procurement practices to

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[214] *See* Exhibit 300, p. 44 (lines 6-17).
[215] *See* id., pp. 43-44 (lines 26-2).
[216] Exhibit 200, p. 16 (lines 15-18).
[217] While it is possible that a mass involuntary return would just involve a few customers, ESPs tend to serve more than just a few customers.

serve CCA customers involuntarily returned en masse as a result of the CCA electing to cease operations.[218]

In its testimony, SCE proposed a detailed method for forecasting each incremental cost component – Energy, RA, RPS, and Administrative – for purposes of the ESP bond,[219] which is consistent with the method proposed in the Bond/Reentry Fee Settlement in the CCA Bond proceeding.[220] SCE also proposed detailed methods for determining actual incremental costs (or reentry fees) in an involuntary return,[221] consistent with the method proposed in the Bond/Reentry Fee Settlement in the CCA Bond proceeding.

The DA Parties' rebuttal testimony addressed only the method for calculating the ESP bond. They testified that the bond calculation "consistently" overstates the cost of reentry exposure; the implied volatility data is not reliable or consistently available; and the 95% percentile confidence interval does not account for the "probability of the ESP actually defaulting."[222] These issues are discussed below.

1. The DA Parties' Comparative Analysis of the Bonds and Reentry Fees is Flawed

According to the DA Parties' testimony, if the Commission agrees that ESP bonds must include procurement cost exposure, the method proposed by SCE and PG&E for calculating that exposure results in "grossly excessive" amounts.[223] The DA Parties point to historical prices during the commodity price run-up in 2008, which would have resulted in a bond amount in SCE's service area of $55/MWh, or about $112 million for an ESP with $2 million in annual sales.[224] Evaluating the bond amount in isolation of the market prices at the time and the actual

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[218] *See* SCE's Rule 23.S.1.
[219] *See* Exhibit 300 and Appendix B thereto.
[220] *See* CCA Bond/Re-Entry Fee Settlement, June 2009, R.03-10-003. SCE testified that "[a]s SCE discussed in its Opening Brief, because the bond (or insurance) obligations of the CCAs and ESPs under Section 394.25(e) are the same. . . [therefore] the methods for calculating the bond amount for CCAs and ESPs should be the same." Exhibit 300, p. 34 (lines 23-27).
[221] *See* Exhibit 300 and Appendix C thereto.
[222] *See generally* Exhibit 201, pp. 16-19.
[223] *See* Exhibit 201, p. 12 (lines 20-24).
[224] *See* Exhibit 201, pp. 13-14 (lines 17-1).

cost to an ESP to meet the security requirement demonstrates little about the bond amount's reasonableness. At the time the bond amount would have hit $55/MWh (July 2008),[225] market prices were as high as $150/MWh.[226] Consequently, SCE's procurement exposure to an ESP's mass involuntary return of its DA customers would have been significant. If the ESP does not cover that risk – which arising directly out of the ESP's "right" to return its customers onto the IOU's procurement service at any time with no notice – the risk is shifted to the IOU and its customers.

Moreover, the price of a $112 million bond would be expected to cost about 1% of the face value of the bond – or $1.1 million – for an ESP with investment grade credit,[227] which places the bond amount into the appropriate perspective. Of course, an ESP without investment grade credit may be expected to pay a higher percentage on the face value of the bond; however, it is because it is perceived by the market to be a riskier business.

In an effort to support their claim that the bond amounts under SCE's proposed method are "grossly excessive," the DA Parties attempted in their testimony to compare the illustrative historical bond amounts to "actual" reentry fees. However, the Commission should give no weight to this analysis, shown in Table 1 of their rebuttal testimony, for the following reasons:

- The DA Parties omitted including of any RPS costs in their "actual" exposure calculation. The DA Parties testified that "there were no RPS requirements" during the 2005 – 2010 period, which is incorrect.
- RA costs are not appropriately reflected in the DA Parties "actual" exposure calculation. While the DA Parties' witness testified at hearings that RA was included, he could not state with certainty what RA value was used for the calculation or whether it reflected SCE's RA obligation of 115% of the load,[228] as required by the Commission.[229]

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225 *See* Exhibit 201, p. 15, Table 1, showing the price per MWh "Difference" in July 2008 at $55.83.
226 *See* fn. 190 *infra*.
227 Exhibit 300, p. 63 (lines 1-7).
228 *See* Tr. 3, pp. 491-492 (lines 24-14).
229 *See* D.05-10-042, summary page 2 and COL 13.

- The data relied on by the DA Parties for SCE's historical TBS rates does not produce a reasonable TBS proxy. The DA Parties used a "weighted average of the peak and off-peak daily SP-15 values for Platt's Megawatt Daily" to estimate SCE's TBS rate.[230] However, TBS rate is not based on a day-ahead price, but rather a 10-minute spot market price, which the DA Parties' witness acknowledged at hearings.[231] Despite knowing that SCE makes historical TBS rate information available, the DA Parties used day-ahead prices to avoid assumptions about the load shapes.[232] The DA Parties provided no evidence that the day-ahead price is a reasonable a proxy for a 10-minute spot price. They also annualized their proxy TBS rate,[233] which is not appropriate when comparing against non-annualized bond amounts.

- The DA Parties' "actual" exposure calculations do not reflect reentry fees – or the costs of reentry – because they result from a comparison between the proxy TBS rate (which is flawed) and SCE's annualized generation rate, which – as SCE explains in Section VI.A above – overlooks any and all incremental procurement costs incurred by SCE and recovered through the TBS rate.

- The comparison fails to account for the fact that bond calculation must cover the potential exposure to market prices every day during the bond coverage period, because the ESP can involuntarily return DA customers to the IOU's procurement service on any day during that period. The DA Parties calculated 11 "actual" exposure data points in Table 1 to show, for example, that the bond in January 2005 would have been \$17.12/MWh and the "annualized" exposure in January 2005 would have been \$5.96/MWh. Once again, the \$5.96 does not include RPS costs, RA costs, spot prices, which the DA Parties do not dispute are costs the IOU would be exposed to in a mass involuntary return of DA customers. However, even

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230 *See* Exhibit 201, p. 14 (lines 12-13).
231 *See* Tr. 3, pp. 492-493 (lines 23-2).
232 *See* Tr. 3, p. 493 (lines 1-13).
233 Exhibit 201, p. 14 (lines 18-20).

taking the data points at face value, the comparison is flawed because it does not account for "actual" exposure on each day of the coverage period. In other words, the comparison does not reflect that market prices can change significantly from day to day depending on the volatility in the market, and would have moved the $5.96/MWh exposure up or down each day of January 2005 – and each day of each month thereafter. Accordingly, the comparison fails to support the DA Parties' conclusion that the bond amounts exceeded the actual exposures by $25/MWh or more over the historical period.[234]

2. SCE and PG&E Have Adequately Addressed the DA Parties' Concerns Regarding the Implied Volatility Data

The DA Parties testified that implied volatility data from certain brokers, like AmerEx, declined to provide quotes to consultants. As such, the DA Parties concluded that this data is not publicly available.[235] Their conclusion is incorrect. The data may not be directly available to a consultant if that consultant is viewed as a competitor by a broker like AmerEx. However, just as the IOUs do with their consultants, an ESP can access a broker's data under a subscription and share the data with a consultant pursuant to appropriate confidentiality and non-disclosure obligations. Simply because a broker declines to provide its data directly to a competitor who is consulting for an ESP does not mean that the ESP, itself, cannot access such data from the broker.

The DA Parties also testified that implied volatility data is not readily available for North Path (NP) 15 for PG&E's service area.[236] In response, PG&E proposed to use historical volatility if implied volatility data is not available. PG&E's proposal reasonably addresses the DA Parties' concerns, because it would use actual volatility in the markets as a proxy for future volatility, which is not "weak" data in any way.[237]

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[234] Exhibit 201, p. 14 (lines 18-21).
[235] *See* Exhibit 201, pp. 16-17 (lines 20-2).
[236] *See* Exhibit 201, p. 17 (lines 4-8).
[237] *See* Exhibit 201, pp. 17-18 (lines 22-3).

3. <u>The Bond Model Reasonably Approximates the Probability of an ESP Defaulting</u>

The DA Parties testified that SCE's bond method is flawed because "even if the market events that result in wholesale costs that are above the 95th percentile, . . . simply because wholesale prices are exceptionally high does not in itself mean that *[sic]*an ESP will default. The probability of the ESP actually defaulting is not accounted for . . . ."[238]

The probability of an ESP actually defaulting is reasonably accounted for in the bond calculation's assumption that stressed market prices correlate with an increased risk of default. The bond model cannot reasonably account for each ESP's unique circumstances, because those circumstances are not known to the IOU or the Commission. However, the underwriter of an ESP's financial security instrument – whether a bank or a surety company – can and will assess each ESP's individual circumstance in *pricing* the bond. As SCE explained in its testimony:

> "Certain factors regarding an ESP's portfolio may mitigate the risk of an involuntary return; for example, reliance on longer-term procurement strategies that can hedge against market volatility.
>
> SCE sees significant value in having third parties manage the impacts of risk mitigating factors on the bond. Mitigating factors should appropriately be taken into account by the surety company in *pricing* the bond or insurance. So, for example, if an ESP has investment grade credit, then it can expect to obtain a bond for about one percent (1%) of the face value of the bond. On the other hand, if an ESP does not have investment grade credit, but offers collateral or provides guarantees and/or joint and several liability agreements, the surety company will price this protection into the bond.
>
> Accordingly, in SCE's view, there is no reason to consider the risk mitigating factors in determining the bond amount. Rather, these factors should be considered by third-party surety companies or other commercial creditors in pricing the bond. In this way, neither the IOUs nor the Energy Division would need to incorporate the impact of risk mitigating factors on the bond."[239]

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[238] Exhibit 201, p. 18 (lines 19-22).
[239] Exhibit 300, pp. 62-63 (lines 24-12).

C. Security Requirements Administration

In its testimony, SCE proposed a detailed means of administering the ESP bonds and reentry fees -- comparable to the process used for submitting the indifference calculation for the Commission's and parties' review -- using advice filings for establishing the bond amounts, which can then be verified by the Commission and interested parties. The process relies on existing tariff rules for challenging those filings and addressing failures to comply with the bond requirements. It also relies on market mechanisms for satisfying the bond requirement and managing the impacts of risk mitigating factors on the bond.[240] No other party provided any testimony on the actual administration of the ESP bonds or reentry fees. SCE's proposal is reasonable, consistent with the Bond/Reentry Fee Settlement in the CCA Bond proceeding, and should be adopted for administering the bonds and reentry fees.

VII.

CONCLUSION

SCE appreciates the opportunity to submit this opening brief.

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[240] *See generally* Exhibit 300, Section V.D, pp. 57-63.

Respectfully submitted,

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May 6, 2011

CERTIFICATE OF SERVICE

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

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