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**BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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)

**REPLY BRIEF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)**

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This proceeding addresses a number of critical issues that are essential to the continued implementation of direct access (“DA”) in California, customer protections mandated by California statute, and the equitable allocation of generation costs to customers on whose behalf those costs were incurred. The active parties in this proceeding are diverse, representing the Investor Owned Utilities (“IOUs”) and their customers, ratepayer advocates, Electric Service Providers (“ESPs”), DA customers and Community Choice Aggregators (“CCAs”). On a number of critical issues, the parties have reached general agreement, such as the need to include a Renewables Portfolio Standard (“RPS”) adder in the Market Price Benchmark (“MPB”), the need to revise minimum stay requirements for returning DA customers, and the need to modify the Transitional Bundled Service (“TBS”) rate for customers who return to bundled utility service. However, the challenge in any proceeding is always in the details, and this proceeding is no exception. In opening briefs, parties including PG&E described their positions and proposals on many of the “details.” In this reply brief, PG&E responds to parties’ positions and proposals. Specifically, PG&E addresses proposals regarding the MPB, Power Charge Indifference Amount (“PCIA”) and ongoing Competition Transition Charge (“CTC”), as well as proposals about the TBS rates, DA customer switching rules, and the financial security required by Public Utilities Code section 394.25(e).

In its opening brief, PG&E included a detailed list of recommendations for Phase III. Based on other parties' opening briefs, which provided additional clarification of issues, PG&E has updated and clarified its recommendations. These recommendations are attached as Appendix A to the reply brief.

I. METHODOLOGY FOR DETERMINING THE PCIA AND ONGOING CTC

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

1. Renewable resource added for the MPB

Much of the controversy in this proceeding centers around how to determine the value of an RPS adder to be used in the MPB. However, there is surprising unanimity on one point – almost all of the parties agree that eventually a Renewable Energy Credits (“RECs”) index price should be used to determine the RPS adder.¹ The Joint Parties, Southern California Edison Company (“SCE”), and San Diego Gas & Electric Company (“SDG&E”) do not believe that a RECs Index currently exists, and thus these parties propose interim methodologies for determining an RPS adder until a RECs Index exists. On the other hand, PG&E and the Division of Ratepayer Advocates (“DRA”) have demonstrated that a robust RECs Index does exist and thus there is no need for an interim methodology to be used for an undefined period of time. Below, PG&E supports its proposal to use the SNL RECs Index and explains why the Joint Parties' proposed interim Green Benchmark is flawed. PG&E also explains that if the Commission does not adopt the RECs Index, then it should adopt SCE's and SDG&E's interim proposal to use a Department of Energy (“DOE”) index. Finally, PG&E addresses which RPS-eligible volumes the RPS adder should be applied to when determining the MPB.

¹ SCE Brief at p. 7; DRA Brief at pp. 5-6; SDG&E Brief at p. 5; Joint Parties Brief at p. 14; Exhibit (“Ex.”) 100 at p. 26, lines 24-24 (Joint Parties, Meal).

a. PG&E’s And DRA’s Proposal To Use The SNL RECs Index Should Be Adopted.

PG&E and DRA have proposed using the SNL RECs Index to establish the RPS adder. As PG&E explained in its opening brief, the SNL RECs Index is robust, California-specific, and is fully transparent and available.² DRA did its own independent investigation of the SNL RECs Index and agrees that it is sufficiently robust and transparent to use for the RPS adder.³ The Joint Parties assert that PG&E is proposing a “to-be-developed-and-identified” RECs index.⁴ This is simply wrong – PG&E and DRA have identified a specific index and provided evidence that the index is robust and transparent. Notably, the Joint Parties concede that the market value of a “renewable attribute” (*i.e.*, RECs) should be used for the RPS adder.⁵ This is exactly what PG&E and DRA are proposing. The SNL RECs Index is an index of the market value (bids and offers) for renewable attributes to comply with California’s RPS requirements.

The Joint Parties claim that limits on the use of RECs for RPS compliance will result in REC prices that “understate the value of RPS-compliant renewables in the IOUs portfolio”⁶ and argue that, given the limitations on the use of RECs, PG&E’s proposal “represents a much smaller and skewed segment of the market.”⁷ However, the Joint Parties offer absolutely no evidence to support these assertions. Instead, as PG&E witness John Pappas testified at the hearing, all markets have limits and regulatory requirements, but this does not mean that there can never be a market price.⁸ In fact, in fourteen other states where RECs have been authorized,

² PG&E Brief at pp. 7-8.

³ DRA Brief at p. 6.

⁴ Joint Parties at p. 7, 15-16.

⁵ Ex. 100 at p. 26, lines 24-25 (Joint Parties, Meal).

⁶ Joint Parties Brief at p. 14.

⁷ Joint Parties Brief at p. 9.

⁸ Transcript (“Tr.”) at p. 287, line 25 to p. 289, line 2 (PG&E, Pappas).

robust RECs markets have developed, despite the fact that some of those states have even more restrictions than California.⁹ Moreover, as Mr. Pappas explained, given the volume of renewable energy required for all Load-Serving Entities (“LSEs”) to meet the RPS requirements, there will still be a significant volume of REC transactions, even with the limitations on the amount of RECs that an LSE can use for compliance.¹⁰ The market for RECs is substantially larger and broader than the limited IOU-only cost information proposed by the Joint Parties for their Green Benchmark. The Commission itself stated in adopting the REC rules that it intended to facilitate the development of a robust REC market.¹¹

The Joint Parties also mistakenly claim that the SNL RECs Index does not satisfy the criteria described by the Joint Parties and PG&E to determine whether a RECs Index is appropriate for use in the RPS adder.¹² The Joint Parties assert that a RECs Index must be sufficiently liquid and for a defined product, and then cite to PG&E’s discovery response stating that a RECs Index would need to be for a California RPS-eligible product, and be sufficiently transparent and robust. Notably, all of these criteria are satisfied by the SNL RECs Index. The index is for a defined product that is RPS-eligible in California (*i.e.*, California RECs). The SNL RECs Index is transparent in that the sources of data (*i.e.*, the specific brokers) have been identified and the index is publicly available. Finally, the index is robust and liquid. It includes quotes from a number of California brokers that represent numerous buyers and sellers. Information is reported and updated weekly. All of this evidence, which is in the record in this proceeding, demonstrates that the SNL RECs Index satisfies the Joint Parties’ criteria.

⁹ Tr. at p. 374, line 1 to p. 376, line 27 (PG&E, Pappas).

¹⁰ *Id.*; Tr. at p. 294, line 23 to p. 295, line 13 (PG&E, Pappas).

¹¹ *See e.g.* Decision (“D.”) 10-03-021 at pp. 2-3.

¹² Joint Parties Brief at pp. 16-17.

b. The Joint Parties' Green Benchmark Is Fundamentally Flawed.

As PG&E and SCE explained in their opening briefs, there are a number of fundamental flaws in the Joint Parties' Green Benchmark proposal.¹³ First, and perhaps most fundamental, the Joint Parties' Green Benchmark does not reflect the market value of RPS-eligible power – instead it reflects the IOUs' costs. If the IOUs' cost to purchase RPS-eligible power is used in the MPB, and then the MPB is compared against the IOUs' actual costs to determine the Indifference Amount, there will never be any above-market costs to recover. In effect, the Joint Parties have created a circular process that will result in no or de minimus above-market costs. Second, the Joint Parties' proposal relies on contract prices that may have been negotiated several years ago and do not reflect current market prices for renewable attributes. Third, the Joint Parties' Green Benchmark proposal only relies on a portion of the RPS market in California, and is skewed toward higher prices because of specific requirements that are imposed on the IOUs and not on other LSEs.

In response to these concerns, the Joint Parties assert that their proposal uses a “large, diverse data set of prices”¹⁴ and that IOU cost data will represent a “wide variety of types of renewable resources.”¹⁵ This is simply wrong. The Joint Parties' proposal only looks at RPS price information for the three IOUs, ignoring ESPs, CCAs and Publicly-Owned Utilities (“POUs”) that make up more than 32% of the load in California. Moreover, since the Joint Parties' Green Benchmark only looks at prices for contracts that have started deliveries within a two year window, it may be that in a given year, one or more of the three IOUs does not have any new RPS-eligible contracts that have started deliveries. For example, if SDG&E were the

¹³ SCE Brief at pp. 8-10; PG&E Brief at pp. 8-9.

¹⁴ Joint Parties Brief at p. 8.

¹⁵ *Id.* at p. 10

only utility having a contract that commenced deliveries in 2010 and was forecast to commence deliveries in 2011, which is entirely possible given that the IOUs have entered into contracts many of which will take 4-5 years to commence operations, then the entire Green Benchmark would be based on the prices paid by SDG&E. Finally, there is no guarantee that in a given year a “wide variety” of resources will commence operation. In fact, in a given year, IOU cost information may only reflect wind resources or solar resources, if those are the only resources that commenced operation. The Joint Parties’ proposal is certainly not based on a “large, diverse” data set. Notably, the current MPB, which reflects the value of conventional generation, is not based on IOU-only data.

The Joint Parties also assert that because the IOUs likely will not have excess RPS-eligible power given the increase in the RPS requirement to 33%, it is appropriate to rely on IOU cost and price data.¹⁶ This argument makes little sense. The fact that the IOUs may or may not have excess RPS-compliant power does not justify using IOU contract costs data to determine the RPS adder. As explained above, the IOU cost data is not the same as the market value of renewable attributes, and thus assertions as to whether or not the IOUs have excess RPS-eligible energy are irrelevant. The Joint Parties’ argument that IOU cost data represents the “cost of the next increment of RPS-compliant renewables procurement” is equally unfounded.¹⁷ Contracts entered into four or five years earlier than they commence deliveries clearly do not represent the current market value of renewables, or the cost of the “next increment” that the IOUs could purchase today.¹⁸ Indeed, the undisputed evidence in this proceeding is that RPS prices are

¹⁶ *Id.* at pp. 10-11.

¹⁷ *Id.* at pp. 11-12.

¹⁸ Ex. 301 at 11, lines 2-5 (SCE, Schichtl).

headed downwards and thus the Joint Parties' proposal to use contract prices for agreements entered into 4 or 5 years ago does not reflect current market prices.¹⁹

Apparently recognizing the weakness of their own arguments, the Joint Parties have subtly shifted positions in their opening brief. In testimony submitted in January, the Joint Parties stated that “[w]hen such a market develops, the Green Benchmark should be based on the market value of the renewable attribute from the market.”²⁰ In other words, the Joint Parties acknowledged that the RPS adder should be based on the value of the renewable attribute. Now, faced with arguments that the IOU costs are not the same as the market value of a renewable attribute, the Joint Parties have shifted position. In their opening brief they assert that the “product” to be valued is “RPS-complaint wholesale supply.”²¹ However, the RPS adder is simply intended to be added to the current MPB price to reflect the market value of renewable attributes. It is not intended to create an entirely separate benchmark for RPS-eligible supply.

Finally, in their opening brief, the Joint Parties indicate that they may agree to develop an IOU-specific Green Benchmark.²² Not only does this proposal have all of the flaws of the Joint Parties' Green Benchmark, but it would effectively result in an RPS adder that is even less reflective of market value. Rather than combining all of the IOUs' RPS-eligible costs, this proposal would create a PG&E-specific Green Benchmark based solely on PG&E's RPS-eligible contracts. PG&E's RPS-eligible contracts, which account for less than 30% of the market, certainly do not reflect the “market” value for renewable attributes in California. Moreover, this proposal would almost certainly result in an illusory “determination” that there are no above-

¹⁹ Ex. 301 at p. 14, line 3-11 (SCE, Schichtl).

²⁰ Ex. 100 at p. 26, lines 24-24 (Joint Parties, Meal).

²¹ Joint Parties Brief at p. 9.

²² *Id.* at p. 13.

market costs associated with RPS-eligible contracts and instead would simply shift all of these costs to bundled customers. This proposal, which the Joint Parties did not advance until after the hearing, would clearly violate the bundled customer indifference requirement.

c. SCE's And SDG&E's Proposal Is A Reasonable Alternative To The RECs Index Price.

If the Commission determines, despite the evidence provided by PG&E and DRA, that there is not yet a RECs Index that is sufficiently robust, PG&E supports the SCE/SDG&E proposal to use the DOE data to determine the RPS adder. The Joint Parties' criticize SCE and SDG&E's proposal because they assert it would result in an RPS adder that is substantially below the amount the Joint Parties claim that PG&E is forecasting to pay for RPS-eligible energy.²³ This is, of course, exactly the point. The entire purpose of the total portfolio calculation is to determine the IOUs' above-market costs so that bundled customers remain indifferent. In this context, it is entirely reasonable and to be expected that the RPS adder will result in market prices that are below the actual costs of an IOU's portfolio, reflecting the above-market costs that are in the IOU's portfolio.

d. The RPS Adder Should Only Be Applied To Post-2003 Contracts For The PCIA MPB.

As PG&E explained in its opening brief, RPS-eligible contracts are included in different buckets for purposes of the total portfolio cost calculation. Post-2003 contracts are included in the PCIA, while pre-2003 RPS-eligible contracts (*i.e.*, Qualifying Facility and irrigation district contracts) are included in the Ongoing CTC calculation. It is therefore inappropriate to adjust the MPB used to determine the PCIA by the total percentage of RPS-eligible resources in PG&E's portfolio because many of these resources are not included in the PCIA but are instead included in the Ongoing CTC. In their opening brief, the Joint Parties fail to recognize this

²³ Joint Parties Brief at p. 18.

distinction.²⁴ PG&E also demonstrated in its opening brief that, given the difference in how renewable attributes from pre-2003 contracts are treated, the RPS adder should not be applied to these contracts because they do not have the same market value. Thus, it is not appropriate to use the RPS adder for pre-2003 RPS-eligible contracts.

2. Generation and/or load profile modifications for the MPB

All of the parties in Phase III agree that the generation profile used in the existing MPB methodology needs to be updated. However, there is disagreement as to which profile to use for weighting the MPB. Initially, PG&E and SCE proposed using the IOUs' respective generation output profiles to weight the MPB, and the Joint Parties proposed using the IOUs' respective load profiles. In its opening brief, SCE now proposes using load profiles based on historical data from prior calendar years because this information is publicly available.²⁵ However, the Commission should not adopt a flawed methodology simply because information is publicly available. As both PG&E and SDG&E explained in their opening briefs, the MPB reflects the value of a generation portfolio and thus it is appropriate to weight the MPB with a generation profile, not a load profile.²⁶ Greater availability is not a basis for using the wrong profile to weight the MPB.

The Joint Parties' proposal to use load profiles is equally flawed.²⁷ The Joint Parties assert that the IOU supply portfolio is "constructed to serve the load of bundled service customers" and thus conclude that the load profile should be used.²⁸ This argument misses the point. Whether the IOUs' portfolios are "constructed" to serve load or not, the MPB is intended

²⁴ Joint Parties Brief at pp. 18-20.

²⁵ SCE Brief at p. 13.

²⁶ PG&E Brief at 11; SDG&E Brief at 8.

²⁷ Joint Parties Brief at pp. 21-25.

²⁸ *Id.* at p. 21.

to reflect the market value of a generation portfolio and thus the appropriate weighting is with a generation profile, not a load profile. The only other reason offered by the Joint Parties for using a load profile is transparency.²⁹ However, as explained above, the Commission should not adopt an incorrect weighting factor simply because it is more readily available.

SCE, the Joint Parties, and PG&E all oppose DRA's proposal to produce different MPB weighting factors for each vintage.³⁰ DRA did not address this issue in its opening brief and thus may have decided not to continue to support this proposal.

3. Revised capacity adder for the MPB

Almost all of the parties in Phase III agree that the MPB capacity adder is intended to reflect the market value of Resource Adequacy or "RA."³¹ Initially, in testimony, all of the parties in this proceeding except for PG&E and DRA advocated adopting the CAISO's Capacity Procurement Mechanism ("CPM") price of \$55/kW-year as the capacity adder. However, just before the hearings, the Federal Energy Regulatory Commission ("FERC") issued an order accepting the CPM subject to refund, determining that it may be unjust and unreasonable, and initiating a technical conference process to potentially change the nature of the CPM so that it reflected long-term pricing for new resources.³² As a result of FERC's order, in opening briefs parties have now proposed several new approaches for determining the appropriate MPB capacity adder. Below, PG&E responds to each of these new proposals, and explains why its proposal, to maintain the current capacity adder, should be adopted by the Commission.

²⁹ *Id.* at p. 22.

³⁰ SCE Brief at pp. 13-14; Joint Parties Brief at pp. 24-25; PG&E Brief at p. 11.

³¹ SCE Brief at p. 14; CLECA/CMTA Brief at p. 9; Tr. at p. 27, lines 11-20 (Joint Parties, Fulmer) (capacity adder intended to reflect RA value).

³² *California Independent System Operator*, 134 FERC ¶ 61,211 (2011).

SCE now proposes using the California Energy Commission's ("CEC") determination of the going forward costs of a simple cycle combustion turbine, which is approximately \$50/kW-year as the capacity adder.³³ The CEC estimate was originally used by the CAISO to develop the CPM, except that the CAISO included a 10% adder so that the CPM it proposed was \$55/kW-year. Although SCE's proposal avoids relying on the CPM, which is subject to further change by FERC, it is still fundamentally flawed. First, the capacity adder is intended to reflect the market value of RA, not the operating costs of a generating unit. As SCE concedes, the CEC numbers reflect the costs of operating a specific type of generating unit (*i.e.*, a simple cycle combustion turbine), including costs such as insurance and operations and maintenance.³⁴ The CEC numbers do not reflect the market value of RA. Second, the only actual RA cost data in evidence in this proceeding demonstrates that, even though SCE's \$50/kW-year proposal is lower than the CPM, it is still significantly higher than current RA market values. For example, MEA entered into a contract in 2010 with Shell Energy for a number of energy products, including System and Local RA products.³⁵ The System RA price that MEA agreed to pay in 2010 was \$21/kW-year and the price for Local RA was \$39/kW-year – both well below the CEC numbers.³⁶ More recently, on April 22, 2011, the Commission's Energy Division issued its annual RA report for 2010 in which it explained that the median price for all RA contracts was \$2.25/kW-month or \$27/kW-year.³⁷ This is a little more than half of the \$50/kW-year amount proposed by SCE.

³³ SCE Brief at pp. 18-19.

³⁴ *Id.* at p. 19, n. 73.

³⁵ Ex. 108 at p. 5, Section 5.3.

³⁶ Tr. at p. 31, line 15 to p. 32, line 8 (Joint Parties, Dalessi) (explaining how to calculate annual capacity price).

³⁷ 2010 Resource Adequacy Report at p. 24, available at: <http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/>.

The Joint Parties recommend that the Commission adopt the \$55/kW-year CPM value, but that the capacity adder not be changed based on any further FERC proceedings until parties have an opportunity to file comments on “whether and how a final FERC order should result in change to the updated capacity adder.”³⁸ This proposal suffers from the same flaws as SCE’s proposal because the \$55/kW-year CPM price is based on the same CEC data that SCE proposes to use. In addition, the CPM value advocated by the Joint Parties includes a 10% adder.³⁹ The Joint Parties do not provide any justification for including this 10% adder in the MPB. Notably, SCE does not recommend including the 10% adder and thus its proposal is to use a \$50/kW-year price. Because the Joint Parties’ proposed price does not reflect RA market value, and in fact significantly overstates the market value of RA based on actual, recent data, their capacity adder proposal should be rejected.

SDG&E continues to advocate using the CPM for the MPB capacity adder.⁴⁰ Jan Reid supports using the CAISO’s Interim Capacity Procurement Mechanism (“ICPM”) price which preceded the CPM and is \$41/kW-year.⁴¹ In its opening brief, PG&E explained in detail why the Commission should reject the proposal to use the CPM.⁴² The same arguments apply to the ICPM, which is also based on a generator’s cost not RA market value and is above current RA market prices. Moreover, the ICPM is no longer used by the CAISO and will not be updated to reflect changes in market value. Neither the ICPM nor the CPM should be used for the MPB capacity adder.

³⁸ Joint Parties Brief at p. 27.

³⁹ *Id.* at p. 26.

⁴⁰ SDG&E Brief at pp. 8-9.

⁴¹ Jan Reid Brief at pp. 13-14.

⁴² PG&E Brief at pp. 11-14.

DRA supports PG&E's proposal that the current capacity adder should continue to be used.⁴³ Some of the parties advocating a change in the MPB capacity adder have argued that the current capacity adder is outdated and that a new capacity price needs to be used to determine the MPB. However, no party offered any evidence that the current capacity adder, which was the result of extensive negotiations, does not reflect current RA market values. Until parties can demonstrate that the current capacity adder no longer reflects the RA market value, there is no basis for the Commission to modify it.

Finally, if the Commission believes the current capacity adder needs to be updated with a more recent, transparent number, PG&E proposes using the median value of the "RA/Capacity only" column from Table 13 included in the Commission's annual *Resource Adequacy Report*.⁴⁴ This number should be updated annually by the Commission's staff, is based on current RA market information and values, and is transparent as it is provided in a publicly available report. The Commission's *Resource Adequacy Report* median value of the "RA/Capacity only" is the best indicator of RA market value and best satisfies any concerns about transparency and being up-to-date.

4. CAISO Load-Based Costs

All parties agree that CAISO load-based charges and related congestion charges should be excluded from the total portfolio calculation. The parties have not agreed, however, on exactly which CAISO charge codes are load-based. The Commission should order the parties to conduct a workshop, attended by the CAISO, to determine which CAISO charge codes are load-based and thus should be excluded.

⁴³ DRA Brief at p. 7.

⁴⁴ The median value of the "RA/Capacity only" is appropriate to use because it excludes any tolling contracts which include some energy value.

5. Short-Term Purchases

All parties agree that short-term purchases should not be included in the total portfolio calculation or the MPB.

B. Other Proposals for Changes to MPB, Indifference Calculation, PCIA or Ongoing CTC

1. CLECA/CMTA's Proposal To Pay Departing Customers.

In their testimony, CLECA/CMTA appeared to propose that departing DA customers should be paid to depart when the indifference calculation results in a negative indifference.⁴⁵ CLECA/CMTA did not raise this issue in their opening brief and PG&E assumes that CLECA/CMTA have decided to withdraw this proposal. SCE addressed this proposal in its opening brief and PG&E addressed it in detail in its reply testimony.⁴⁶ Both PG&E and SCE demonstrated that CLECA/CMTA's proposal is contrary to well-established Commission precedent and thus should be rejected.

2. PG&E's Proposal For The Treatment Of Pre-2003 RPS-Eligible Contracts With Regard To The RPS Adder.

The Joint Parties addressed PG&E's proposal for treatment of pre-2003 QF and irrigation district contracts with regard to the RPS adder in two places in their opening brief -- in Sections I.A.1.d and I.B.⁴⁷ The Joint Parties' arguments are the same in both sections. PG&E addressed the Joint Parties' arguments above in Section I.A.1.d, and is including a reference here for completeness.

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⁴⁵ Ex. 800 at pp. 15-16 (CLECA/CMTA, Barkovich).

⁴⁶ SCE Brief at pp. 20-21; Ex. 401 at p. 13, line 6 to p. 14, line 10 (PG&E, Barry).

⁴⁷ Joint Parties' Brief at pp. 18-20 (Section I.A.1.d) and pp. 29-31 (Section II.B).

3. The Joint Parties Have Apparently Withdrawn Their Proposal For A Basis Adjustment.

The Joint Parties' testimony included a proposal for a "basis adjustment" to account for congestion.⁴⁸ PG&E addressed this proposal in its opening brief.⁴⁹ The Joint Parties did not raise this proposal in their opening brief nor did they include this proposal in their summary of recommendations. Thus, it appears that the Joint Parties have decided to withdraw their proposal for a basis adjustment.

C. Other proposals for changes to the indifference calculation

PG&E has proposed a modification to the Indifference Amount calculation to ensure that all customers are treated equally and to ensure compliance with the statutory and Commission requirements that all customers pay Ongoing CTCs.⁵⁰ In particular, PG&E has proposed that when the PCIA is negative, it be set to zero rather than offsetting the Ongoing CTC. Negative PCIA amounts would be carried forward so that departing customers would benefit from these amounts, and bundled customers would remain indifferent. SDG&E supports PG&E's proposal.⁵¹

The Joint Parties are the only parties that opposed PG&E's proposal in opening briefs, advancing several arguments to support their opposition. First, the Joint Parties assert that the Commission has already considered and denied similar requests regarding the PCIA, citing D.07-05-005, the decision that addressed a Petition to Modify ("PTM") of D.06-07-030 and D.08-09-012.⁵² However, the Joint Parties confuse the issue PG&E addressed in its PTM and PG&E's position on the PCIA calculation addressed in D.08-09-012. In both of these instances, the

⁴⁸ Ex. 100 at pp. 33-34 (Joint Parties, Fulmer).

⁴⁹ PG&E Brief at pp. 16-17.

⁵⁰ *Id.* at pp. 17-19.

⁵¹ SDG&E Brief at pp. 9-10.

⁵² Joint Parties Brief at p. 36.

position PG&E was advocating was not whether the PCIA *rate* should be allowed to go negative but rather whether negative indifference amounts should be carried over to offset future charges. Specifically, in D.07-05-005, the Commission simply held that negative indifference amounts could be tracked and used to offset future positive indifference amounts.⁵³ This is exactly what PG&E is proposing to do – setting a negative PCIA in a given year to zero and then tracking the negative amount to offset future positive PCIA amounts in subsequent years. The PTM addressed in D.07-05-005 did not object to the negative PCIA *rate* or in anyway suggest that the Commission should modify ability of the negative PCIA *rate* to offset the CTC.

Second, the Joint Parties rely on D.08-09-012, claiming that PG&E advanced a similar proposal in the proceeding that led to that decision.⁵⁴ In that proceeding, PG&E proposed calculating separate charges for Ongoing CTCs and costs associated with new generation contracts (*i.e.*, contracts entered into after 2003), and that *negative amounts* for each of these separate calculations not be carried forward to offset future positive amounts.⁵⁵ The Commission rejected this proposal and instead adopted a “total portfolio approach” that included both the Ongoing CTC and costs associated with post-2003 generation contracts.⁵⁶ The Commission noted in particular that negative *indifference amounts* should be carried forward for use in subsequent years to maintain customer indifference.⁵⁷ The Commission did not address the issue of the PCIA *rate* being set to a negative amount so that the *Indifference Amount* calculation could become zero, nor did the Commission address concerns that some customers were treated differently than other similarly situated customers because they were not required to pay the

⁵³ D.07-05-005 at pp. 18-19.

⁵⁴ Joint Parties Brief at p. 37.

⁵⁵ D.08-09-012 at pp. 44-45 (describing PG&E’s proposal).

⁵⁶ *Id.* at pp. 47-48.

⁵⁷ *Id.* at p. 48.

Ongoing CTC. Instead, the Commission’s main concern appeared to be looking at a total portfolio of costs and carrying forward negative amounts from that total portfolio. In this proceeding, PG&E is not challenging the total portfolio approach nor is PG&E proposing that negative PCIA amounts not be carried forward. Instead, PG&E’s position is quite the opposite. Here, PG&E is proposing that negative PCIA results be carried forward rather than using the negative results to offset the Ongoing CTC so that all customers pay their “fair share” of the Ongoing CTC, consistent with the guiding principles established in D.08-09-012.⁵⁸

Third, the Joint Parties claim that PG&E fails to recognize the offsetting benefit of a negative PCIA, and thus bundled customers are better off under PG&E’s proposal.⁵⁹ This argument is also mistaken. PG&E is proposing to carry-forward any negative PCIA results to offset future positive PCIA results. Thus, neither bundled customers nor departing customers will benefit – departing customers will have the opportunity to realize the value of the negative PCIA results in future years if there is a future positive PCIA result. However, as PG&E explained in its opening brief, under the current methodology, bundled customers are not indifferent.⁶⁰ Because of the current methodology, bundled customers are required to pay the Ongoing CTCs of non-exempt, departed customers through the negative PCIA being debited to ERRRA. In addition, customers that are otherwise exempt from the PCIA similarly are not indifferent.

Finally, the Joint Parties argue that PG&E is relying on decisions that pre-date D.06-07-030 and thus PG&E’s arguments are “stuck in time.”⁶¹ While D.05-12-045 does precede D.06-

⁵⁸ *Id.* at p. 10.

⁵⁹ Joint Parties Brief at p. 39.

⁶⁰ PG&E Brief at p. 18.

⁶¹ Joint Parties Brief at p. 40.

07-030, the reasoning in D.05-12-045 was never expressly disapproved by the Commission in subsequent decisions. More fundamentally, however, Public Utilities Code section 367 expressly states that the Ongoing CTC shall be recovered from “all customers.” The way the Joint Parties frame this argument, one might think that the two decisions were decades apart. What they neglect to point out is that the two proceedings that culminated in the these two decisions – PG&E’s 2006 Energy Revenue Recovery Account (“ERRA”) Forecast proceeding and DA Suspension Proceeding – were in fact concurrent proceedings and the very same parties were actively participating in both proceedings and dealing with the same issue, namely, whether there should be a negative Ongoing CTC (direct offset), which was being addressed in the ERRA Forecast while the DA Suspension Proceeding was dealing with the indifference calculation which by design, included the ongoing CTC costs in the total portfolio concept. Ultimately, in reaction to D.05-12-045, D.06-07-030 reinvented the DWR Power Charge in order to achieve the same outcome -- a negative Ongoing CTC – thus the PCIA was born and the effect was an indirect offset. Currently, if the Indifference Amount is negative it is set to zero and as a result the PCIA is negative and the Ongoing CTC is not recovered from non-exempt, departing customers. This is inconsistent with Section 367. There is no time limit on this statutory requirement which would render PG&E’s proposal “stuck in time”, nor can the Commission ignore this clear statutory language.

D. Other Proposals for Changes to the PCIA

The Joint Parties addressed PG&E’s proposal regarding the negative PCIA in Section I.D of their opening brief. PG&E addressed this issue above in Section I.C. No other parties raised issues in Section I.D of their opening briefs.

E. Other proposals for changes to ongoing CTC

None of the parties filing opening briefs raised issues regarding Section I.E.

F. Implementation of proposed changes

In its opening brief, SCE urges that the Commission retroactively modify the TBS rate to the extent the Commission retroactively modifies the MPB or Indifference Amount calculation. PG&E supports this proposal.

II. THE TRANSITIONAL BUNDLED SERVICE (TBS) RATE COMPONENTS AND CALCULATION – PROPOSALS AND RECOMMENDATIONS

All of the parties that filed opening briefs agree that the TBS rate should be adjusted to include the RA capacity and RPS adders that are used for the MPB, and all parties except for Jan Reid agree that CAISO load-related costs should be included in the TBS rate. Mr. Reid's opening brief does not explain why CAISO load-related costs should not be included in the TBS. Since CAISO load-related costs would be incurred to serve customers returning from DA service, it is appropriate to include these costs in the TBS rate.

III. DIRECT ACCESS SWITCHING RULES CALCULATION – PROPOSALS AND RECOMMENDATIONS

Phase III of this proceeding involves a number of complicated issues related to the switching rules for existing and future DA customers. PG&E will address these issues below. However, PG&E provides this brief summary for reference regarding its position on the minimum stay, notice period requirements, and applicable rates:

Bundled Customer Departing For DA Service:

- Provide 6 months notice before leaving for DA service

Voluntarily Returning DA Customer Providing 1 to 6 Months Notice:

- Safe Harbor: No safe harbor for voluntarily returning DA customer providing from 1 to 6 months notice.
- Rate(s): If less than 6 months notice, voluntarily returning DA customer will be on the TBS rate for the difference between 6 months and amount of notice provided; if 6 months notice is provided, or at the end of the TBS period, the voluntarily returning DA customer is on the applicable bundled portfolio service rate.

- Minimum Stay on Bundled Service: 18 months, starting on the date the customer starts paying the applicable bundled service rate

Voluntarily Returning DA Customer Providing No Notice (i.e., less than 1 month):

- Safe Harbor: Customer can elect safe harbor when it voluntarily returns. The returning DA customer must submit a DASR within 60 days of its voluntary return.
- Rate(s): TBS rate during safe harbor. If returning DA customer elects safe harbor but does not submit a DASR within 60 days, the customer is on the TBS rate for an additional 6 months after the 60 day safe harbor period ends. At the end of the eight month period (i.e., 60 days for safe harbor + 6 months for TBS rate), the returning DA customer is on the applicable bundled portfolio service rate. If the returning DA customer does not elect the safe harbor, it stays on the TBS rate for 6 months from the date of its return to bundled service.
- Minimum Stay on Bundled Service: 18 months, starting on the date the customer starts paying the applicable bundled service rate

Involuntarily Returning DA Customer⁶²:

- Safe Harbor: Customer can elect safe harbor within 30 days of its involuntary return. The returning DA customer must submit a DASR within the 60 days of its involuntary return.
- Rate(s): TBS rate during safe harbor. If involuntarily returning DA customer elects safe harbor but does not submit a DASR within 60 days, the customer is on the TBS rate for an additional 6 months after the 60 day safe harbor period ends. At the end of the eight month period (i.e., 60 days for safe harbor + 6 months for TBS rate), the returning DA customer is on the applicable bundled portfolio service rate. If involuntarily returning DA customer does not elect safe harbor, it is on the applicable bundled service rate.⁶³
- Re-Entry Fee: Customers would be responsible for the re-entry fee amount calculated at the time they are involuntarily returned, less any amount collected by the IOU from the financial security provided by the ESP and, if the customer pays the TBS rate, the amount of re-entry fee recovered through the TBS rate.
- Minimum Stay on Bundled Service: 18 months, starting on the date the customer starts paying the applicable bundled service rate.

⁶² PG&E assumes that an involuntarily returned DA customer will not provide any notice.

⁶³ This assumes that PG&E's proposal for financial security requirements is adopted by the Commission. If the Commission does not adopt appropriate financial security requirements, the involuntarily returned customer that did not elect the safe harbor would be on the TBS rate for 6 months from the date of its return.

A. Minimum Stay Requirement

All three IOUs support an 18-month minimum stay requirement in order to prevent gaming and to minimize stranded costs associated with long-term commitments made on behalf of returning DA customers. This is fully consistent with existing Commission precedent.⁶⁴ As SCE explained in detail in its opening brief, more than 12 months is required to procure sufficient RA capacity to meet Local and System RA requirements.⁶⁵ In addition, procuring RPS-eligible resources typically involves entering into contracts that are substantially longer than a year in duration.⁶⁶ Limiting the minimum stay requirement will simply allow customers who returned from DA service to depart bundled load service after the IOU has entered into RA, RPS and other procurement commitments on behalf of these customers, stranding long-term supply commitments. This is exactly the type of outcome the Commission wanted to prevent when it created the original three year minimum stay requirement.⁶⁷ Adopting the DA Parties' proposal will result in more stranded supply commitments, especially RPS and RA commitments.

CLECA/CMTA and the DA Parties argue that because the re-opening of DA is currently limited, and over-subscribed, a returning DA customer will in all likelihood remain on bundled service for some time and thus there is no practical need for an 18-month minimum stay period.⁶⁸ However, as CLECA/CMTA candidly admit, market conditions can change and in the future DA may not be over-subscribed.⁶⁹ In that case, or if there is additional legislation further opening

⁶⁴ D.03-05-034 at pp. 37-39.

⁶⁵ SCE Brief at pp. 35-36; *see also* SDG&E Brief at pp. 19-20 (explaining need for procurement planning more than 12 months in advance).

⁶⁶ Ex. 300 at 7, lines 6-14 (SCE, Schichtl) (discussing duration of RPS and RA commitments).

⁶⁷ D.03-05-034 at p. 37.

⁶⁸ CLECA/CMTA Brief at 11; DA Parties Brief at pp. 6-7.

⁶⁹ CLECA/CMTA Brief at 11.

DA, customers may return to DA service within the minimum amount of time specified by a minimum stay requirement. Rather than having to do further revisions to the DA switching rules, or open additional phases of this proceeding if market or legislative conditions change, the Commission should instead adopt an 18-month minimum stay period to minimize gaming and potential stranded costs.

The DA Parties focus on references to “seasonal gaming” and claim that because all four seasons occur during a year, the minimum stay only needs to be 12 months.⁷⁰ However, as explained above, RPS and RA requirements are not “seasonal.” Rather, these requirements require planning and procurement over a time horizon that is longer than a year. These requirements, which were adopted after the original 3 year minimum stay was implemented, support the IOUs’ proposal for an 18-month minimum stay.

B. Notice Period

1. Bundled Customers Departing For DA Service Should Provide Six Months Notice.

The DA Parties propose eliminating the 6-month notice requirement for a customer departing from bundled service to be served by an ESP.⁷¹ Without any evidence, the DA Parties summarily dismiss the reasons provided by PG&E as to why six months notice is needed. However, the DA Parties do not dispute that there is a month and a half needed simply for administratively implementing a switch. In addition, although the DA Parties assert that the volume of switching bundled customers to DA is not “significant,” they do not dispute that PG&E must adjust its RA filings and portfolio to accommodate departing customers. Depending on the amount of load associated with a departing customer(s), PG&E submitted evidence that

⁷⁰ DA Parties Brief at pp. 8-9.

⁷¹ DA Parties Brief at pp. 9-10.

the required RA and portfolio adjustments would take four months, at a minimum.⁷² The DA Parties offer no evidence in response and instead only rhetorically state that PG&E’s time estimates are “exaggerated.”⁷³ There is no reason to modify the current 6-month notice requirement to switch from bundled to DA service, especially when the 6-month period is supported by unrebutted evidence. Notably, CLECA/CMTA support a 6-month notice requirement for customers departing from bundled utility service for DA service.⁷⁴

2. Voluntarily Returning DA Customers Who Provide Notice Of Their Return Should Not Be Able To Elect The Safe Harbor Option.

The safe harbor option is intended to allow DA customers “to return to bundled service on a transitional basis while switching from one ESP to another . . .”⁷⁵ This situation typically occurs when a DA customer’s service abruptly ends and the customer temporarily needs bundled service while it looks for a new ESP. However, in the case where a DA customer is able to give 6 months notice before it returns to bundled service, clearly that customer had sufficient notice that its service from a specific ESP was ending and time to look for a new ESP. In this situation, the returning DA customer should not be eligible for the safe harbor. As the Commission explained, “[t]he safe harbor will provide for a brief bundled service interlude, necessitated by conditions not necessarily under the customer’s control, and will prevent the customer’s loss of the right to resume DA service.”⁷⁶ In order to create a bright line test, only voluntarily returning DA customers that provide less than one month’s notice should be eligible for the 60-day safe harbor.

⁷² Ex. 400 at pp. 3-4 – 3-5 (PG&E, Renson).

⁷³ DA Parties Brief at p. 10.

⁷⁴ CLECA/CMTA Brief at p. 11.

⁷⁵ D.03-05-034 at p. 18.

⁷⁶ *Id.* at pp. 18-19 (emphasis added).

3. Involuntarily Returned DA Customers Should Have A 60-Day Safe Harbor Period.

The DA Parties propose that involuntarily returned customers have an extended 6-month safe harbor period.⁷⁷ This proposal should be rejected. Although involuntarily returned customers may not have been aware that they were going to be returned, they are experienced enough with DA to be able to decide within 30 days whether they are going to pursue another ESP, and thus the elect safe harbor option, or whether they would rather stay on bundled service. Under PG&E's proposal, involuntarily returned customers have 30 days from the date they are returned to consider their options and make this decision. The DA Parties fail to provide any evidence that involuntarily returned customers need more than 30 days to make this kind of determination. SCE and DRA also support rejecting the DA Parties' proposal.⁷⁸

C. Interaction, If Any, With TBS Rate

1. The 60-Day Safe Harbor Period Should Not Be Included In The 6-Month TBS Period.

In its opening brief, PG&E proposed that voluntarily returning customers who did not provide sufficient notice could elect the safe harbor option and would pay the TBS rate during the 60 day safe harbor period. If a returning DA customer that elected the safe harbor option did not submit a DASR within 60 days of its return, PG&E explained that it would remain on the TBS rate "for the remainder of the six month notice period . . ."⁷⁹ After reviewing SCE's, SDG&E's and DRA's opening briefs, PG&E believes that its opening brief was unclear and that its proposal needs to be clarified. The DA Parties assert that the 60-day safe harbor should be included in the 6-month TBS Period.⁸⁰ However, as SCE, SDG&E and DRA correctly note,

⁷⁷ DA Parties Brief at p. 2, Recommendation B.2.

⁷⁸ SCE Brief at p. 47; DRA Brief at pp. 10-12.

⁷⁹ PG&E Brief at p. 26.

⁸⁰ DA Parties Brief at p. 2, Recommendation A.4.

while a returning DA customer is in the safe harbor, the IOU will not enter into longer term commitments on that customer's behalf because it is unclear whether or not that customer will remain on IOU service, or return to DA.⁸¹ Moreover, the IOU will incur costs adjusting its portfolio to serve a returning DA customer if that customer elects to be served by the IOU. However, the IOU cannot know if it will serve the customer until after the safe harbor period ends. Thus, the 6-month period that a customer is on the TBS rate if they provide no notice should start after the 60-day safe harbor period ends if the customer fails to submit a DASR for a new ESP during the safe harbor period.

2. Involuntarily Returning Customers Should Be On The Applicable Bundled Rates Unless They Elect A Safe Harbor Option.

PG&E and SCE have proposed that involuntarily returning DA customers be placed on the applicable bundled rate if the Commission adopts an adequate financial security requirement. The only exception would be for an involuntarily returning DA customer that elects the safe harbor option. In that case, the involuntarily returning DA customer would be on the TBS rate during the safe harbor period, and would remain on TBS for 6 additional months after the safe harbor period ended if the customer did not submit a DASR within 60 days.

Commercial Energy opposes this proposal, arguing instead that involuntarily returned DA customers should be on the TBS rate for the first 6 months.⁸² Commercial Energy maintains that DA customers are fully aware of potential risks when they sign up for DA service and that these risks are more appropriately addressed in the contract between an ESP and DA customer, instead of through financial security requirements. Commercial Energy essentially argues that involuntarily returning DA customers should bear all of the risks associated with an involuntary return by paying the TBS rate, and that the ESP should not bear any of these risks nor should it

⁸¹ SCE Brief at p. 42; SDG&E Brief at p. 12; DRA Brief at p. 10.

⁸² Commercial Energy Brief at p. 9.

be required to post adequate security. There are several key facts that undermine Commercial Energy's reasoning.

First, Commercial Energy is solely focused on large commercial and industrial customers that it claims are "generally sophisticated."⁸³ However, it is undisputed that there are thousands of residential and small commercial customers served by ESPs in California.⁸⁴ None of the parties in this proceeding provided any evidence that these DA customers are aware of potential risks associated with an involuntary return. ESP promotional materials and contracts are not reviewed by the Commission to determine if these risks are ever disclosed. Commercial Energy completely ignores this group of customers.

Second, Commercial Energy assumes that all large commercial and industrial customers are aware of risks associated with DA service and a potential involuntary return, but fails to provide any actual evidence that this is the case. Utility rates and ratemaking are complicated and it is not clear that even a large commercial or industrial customer agreeing to take DA service would be fully aware of the potential risks, and rates, associated with an involuntary return. Commercial Energy argues that there is no evidence in the record that risks are not or cannot be addressed through contracts between ESPs and DA customers.⁸⁵ This argument is backwards. Despite the active participation in this proceeding by a number of ESPs, including Commercial Energy, none of the ESPs provided an example of a single contract in which the risks of an involuntary return were addressed. The ESPs' failure to submit as evidence even a single contract demonstrating that a DA customer was aware of the risk of an involuntary return calls into question Commercial Energy's statements that ESP agreements "adequately address

⁸³ *Id.*

⁸⁴ See e.g., Ex. 301 at p. 27, n. 65 (SCE, Singh).

⁸⁵ Commercial Energy Brief at p. 10.

and manage a customer's risk of an involuntary return to utility service."⁸⁶ Indeed, the only witness offered by the DA Parties, Mark Fulmer, testified that he had no specific knowledge of the terms of contracts entered into between ESPs and their customers.⁸⁷

Third, Commercial Energy asserts that DA customers do not require a "babysitter" and that they instead should be exposed to all of the financial risks associated with an involuntary return.⁸⁸ While Commercial Energy, an ESP, may be satisfied with exposing all of its customers to the financial risks associated with an involuntary return, clearly the California Legislature was not so inclined. Instead, the Legislature adopted Public Utilities Code section 394.25(e) as a "consumer protection" specifically to protect DA and bundled customers with regard to the risks of an involuntary return.

Finally, Commercial Energy asserts that allowing involuntarily returned DA customers to go on the applicable bundled service rate, instead of TBS, treats one group of returning DA customers differently.⁸⁹ However, this is exactly the distinction drawn by the Legislature. Section 394.25(e) is intended to protect involuntarily returned DA customers and provides that re-entry fees are the obligation of the ESP, not the returning DA customers. This statutory distinction is completely reasonable. While a DA customer that voluntarily returns is making its own decision to return to bundled service, and bear the associated risks and costs, an involuntarily returned DA customer did not elect to return to bundled service nor was the customer responsible for its return. In fact, the Legislature explicitly excluded involuntarily returned DA customers where the return was the result of the customer's actions (*i.e.*, customer

⁸⁶ Commercial Energy Brief at p. 10.

⁸⁷ Tr. at p. 428, lines 20-25 (DA Parties, Fulmer).

⁸⁸ Commercial Energy Brief at p. 10. CLECA/CMTA raise similar arguments in their opening brief regarding the financial security calculation. *See* CLECA/CMTA Brief at p. 13.

⁸⁹ Commercial Energy Brief at pp. 11-12.

default or expiration of the customer's contract). It is reasonable, however, that when DA customers are involuntarily returned as a result of the ESP's actions, the ESP should be responsible for their re-entry fees.

3. Commercial Energy's Claims That The IOUs' Portfolios Can Mitigate Costs From Returning DA Customers Are Misplaced.

Commercial Energy asserts that the IOUs' portfolios are sufficiently flexible to adjust to returning DA customers.⁹⁰ To support this claim, Commercial Energy cites load fluctuations that result from temperature changes and the volume of short-term transactions in the IOUs' portfolios. These arguments are misplaced.

First, the temperature data cited by Commercial Energy involved changes in load that were at most 1.5%, and typically much lower.⁹¹ On the other hand, an involuntary return of DA customers cannot be forecasted and, depending on the size of the ESP, may be substantially more than 1.5% of PG&E's load. In 2002, for example, 5,716,696 MWh of load was involuntarily returned to PG&E, which is more than 400% greater than the largest temperature-related change relied on by Commercial Energy.⁹²

Second, Commercial Energy's reliance on short-term transactions in PG&E's portfolio is also misplaced. These transactions are typically for less than 90 days, and are often entered into day-ahead to meet the next day's customer needs.⁹³ In a stressed market where prices are high, an involuntarily return of DA customers will require PG&E to enter into significantly more short-term transactions at high market prices. These short-term market energy costs are one element of the costs that the TBS rate and re-entry fees are meant to cover for returning DA

⁹⁰ *Id.* at pp. 13-14.

⁹¹ *See* Ex. 404, Column F.

⁹² Ex. 410.

⁹³ Tr. at p. 348, lines 12-26 (PG&E, Barry).

customers. In addition to short-term energy transactions, PG&E is also required to enter into longer commitments for RA and RPS-eligible energy in order to satisfy the Commission's RA and RPS requirements. In a stressed market, RA and RPS prices will also likely be very high. These types of RA and RPS transactions are also the kind of transactions that are meant to be covered by TBS rates and re-entry fees. The TBS rate may not be sufficient to recover all of these costs.

IV. ESP FINANCIAL SECURITY REQUIREMENTS CALCULATION

A. Overview of ESP Financial Security Requirements and Definition of Reentry Fees

1. Re-Entry Fees Are Not Limited To Administrative Costs.

Commercial Energy argues that the Commission can simply define the re-entry fee for involuntarily returned DA customers to be the “nominal administrative fees” to return.⁹⁴ Similarly, the DA Parties and CLECA/CMTA argue that the IOUs will be fully compensated if involuntarily returned DA customers go on the TBS rate for 6 months, and thus the financial security only needs to cover administrative costs.⁹⁵ There are several flaws with these arguments.

First, these parties ignore the clear language in Section 394.25(e). The statute provides that “any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation shall be the obligation of the electric service provider or a community choice aggregator . . .”⁹⁶ The DA Parties, Commercial Energy, and CLECA/CMTA ignore the fact that the TBS rate would effectively be a “reentry fee” paid by involuntarily returning DA customers. Moreover, in addition to the TBS rate, the

⁹⁴ Commercial Energy Brief at p. 16.

⁹⁵ DA Parties Brief at p. 14; CLECA/CMTA Brief at pp. 12-13.

⁹⁶ Pub. Util. Code § 394.25(e) (emphasis added).

IOUs can seek residual costs from involuntarily returning DA customers to ensure that costs are not shifted to bundled customers. All of these costs and fees, not just the administrative fees, represent the “reentry fees” for involuntarily returned DA customers.⁹⁷ Under Section 394.25(e), these costs are the “obligation” of the ESPs.

Second, these parties assume that 6 months on the TBS rate will cover the full amount of re-entry fees. As PG&E explained in its reply testimony, re-entry fees may involve more than just 6 months on the TBS rate, especially in a stressed market.⁹⁸

Finally, as explained above in Section III.C.2, it is not appropriate to impose on involuntarily returned DA customers the full cost of all of the re-entry fees, especially given the Legislature’s clear direction in Section 394.25(e).

2. Parties Significantly Overstate The Burden Of The Financial Security Requirement.

Commercial Energy asserts that the financial security requirements could create a “substantial financial hardship” for ESPs that creates a “significant market barrier.”⁹⁹ Similarly, the DA Parties make reference to “onerous financial security costs” that could deter customers from choosing DA service.¹⁰⁰ CLECA/CMTA raise similar arguments.¹⁰¹ Although these parties offer colorful rhetoric, they fail to provide any factual support for their claims. Part of the problem has been that the DA Parties and Commercial Energy focus on the total amount of financial security, not the cost of providing that security. For example, the DA Parties cite testimony from SDG&E witness Spurgeon, who stated that he was not an expert on the financial

⁹⁷ Ex. 401 at p. 10, lines 23-31 (PG&E, Renson); *see also* Ex. 300 at pp. 38-39 (SCE, Singh).

⁹⁸ *Id.*

⁹⁹ Commercial Energy Brief at pp. 10-11, 18.

¹⁰⁰ DA Parties Brief at pp. 14, 17-18.

¹⁰¹ CLECA/CMTA Brief at p. 12.

security methodology, as to the potential amount of the financial security requirement.¹⁰²

However, Mr. Spurgeon’s testimony did not address the cost of obtaining financial security, but rather the total amount of financial security.

Even if the calculated financial security amount for an ESP was \$100 million, it does not mean that the ESP needs to provide \$100 million in cash. SCE and PG&E have proposed financial security requirements that can be satisfied with a number of different types of financial security. For example, an ESP can provide an appropriate parental guarantee, which would not cost the ESP anything to provide other than minimal transaction costs. Moreover, SCE provided evidence that even if a bond amount was \$100 million, an investment grade ESP could obtain a bond to cover the risk for approximately \$1 million.¹⁰³ Given the substantial volume of DA load, even a \$1 million is unlikely to cause financial hardship to an ESP or be a substantial market barrier.

3. The DA Parties And Commercial Energy Mistakenly Claim That The Financial Security Amounts Are Excessive.

Commercial Energy argues that the financial security methodology proposed by PG&E and SCE could result in “extremely high bond requirements” that “vary by *hundreds of millions of dollars* over the course of a year.”¹⁰⁴ The DA Parties and CCSF make similar claims, asserting that the financial security amount far exceeds any incremental costs to serve the involuntarily returned DA customers.¹⁰⁵ These parties base their arguments almost entirely on a chart included in DA Parties’ witness Mark Fulmer’s rebuttal testimony.¹⁰⁶ However, as SCE

¹⁰² DA Parties Brief at p. 18.

¹⁰³ SCE Brief at p. 55.

¹⁰⁴ Commercial Energy Brief at p. 12 (emphasis in original), p. 19.

¹⁰⁵ DA Parties Brief at p. 17; CCSF Brief at pp. 9-10.

¹⁰⁶ DA Parties Brief at p. 17, citing Ex. 201 at pp. 14-15 (DA Parties, Fulmer).

explained in detail in its opening brief, Mr. Fulmer’s analysis contained numerous factual and methodological flaws.¹⁰⁷

Moreover, the DA Parties and Commercial Energy miss the point of the financial security requirement. The financial security requirement is intended to address the involuntary return of DA customers, which is most likely to occur when market prices are high and an ESP does not have sufficient supply, or is not sufficiently hedged, to mitigate a run-up in market prices. In this situation, the IOU will need to procure energy and capacity sufficient to meet the needs of the involuntarily returned DA customers at high market prices, and will also need to meet the regulatory requirements for these customers such as RPS requirements. The financial security calculation proposed by SCE and PG&E takes these factors into account. Commercial Energy asserts that the PG&E/SCE financial security methodology is predicated on a worst case scenario.¹⁰⁸ However, a 95% confidence scenario is not the worst case. A worst case scenario is multiples of this, which is used by parties in the market including exchanges and clearing entities. The stressed factor calculated by the bond model is below the stress factor that exchanges and clearing entities use as providers of last resort (“POLR”). These entities will use confidence intervals or stress scenarios that are much larger than the proposed bond model by PG&E and SCE. Moreover, this is exactly what the financial security calculation should be doing as it is in a high market price scenario that the involuntary return of DA customers is most likely. Notably, SCE’s and PG&E’s proposed financial security methodology uses the exact same confidence interval that the IOUs are required to use for their own procurement purposes.¹⁰⁹

¹⁰⁷ SCE Brief at pp. 63-64.

¹⁰⁸ Commercial Energy Brief at pp. 20-21.

¹⁰⁹ Ex. 400 at p. 43, lines 10-19 (SCE, Singh).

4. Arguments That An Involuntary Mass Return Will Not Occur Are Illusory.

Commercial Energy and the DA Parties argue that there have been almost no involuntary DA returns since the 2000-2001 energy crisis and thus there is little need for sufficient financial security to cover such a return.¹¹⁰ CLECA/CMTA argue that it is “incredibly unlikely” that there will be a mass involuntary return of DA customers.¹¹¹ While this is certainly wishful thinking, the Commission should not ignore its statutory mandate simply based on representations from ESPs that an energy crisis “will never happen again.” As SCE demonstrated in its initial testimony, given the lack of Commission oversight of ESP activities, it is certainly probable that if market prices rapidly increase, one or more ESPs could default.¹¹² Moreover, it should be evident from the recent financial crisis that assuming that entities can never fail or default is a risky bet. As PG&E witness Shahrokh Hessami explained at the hearing, very few people would have thought in 2007-2008 that Bear Stearns or Lehman Brothers would go into bankruptcy among hundreds of financial institutions that have since filed for bankruptcy or were shut down by Federal Agencies. However, less than a year later, both of these entities were bankrupt. In fact, no one predicted between 2000 and 2008 that there could be a scenario where all major financial institutions would be at risk of default and all at the same time. In addition to Bear Stearns and Lehman Brothers, entities in the commodities arena like Merrill Lynch needed to be rescued by Bank Of America while Morgan Stanley and Goldman Sachs had to rely on Federal rescue packages to prevent total collapse.¹¹³

¹¹⁰ Commercial Energy Brief at p. 21; DA Parties Brief at p. 16.

¹¹¹ CLECA/CMTA Brief at p. 12.

¹¹² Ex. 400 at pp. 35-36 (SCE, Singh).

¹¹³ Tr. at p. 617, line 21 to p. 618, line 8 (PG&E, Hessami).

The Commission cannot simply ignore statutory requirements to set an appropriate financial security amount based on claims from ESPs that there is no risk that they will ever default or go bankrupt. History has proven that a market with extensive unsecured leverage will eventually produce default due to lack of appropriate hedging, excessive speculative activities, as well as easy entrant to a market without substantial financial risk to the entities who can shut down overnight and walk away from commitments. An ESP program must be sustainable and applicable to all participants and protect bundled and DA customers from excessive unsecured speculative risk without financial consequences to those causing defaults on obligations.

Finally, outside of this proceeding, certain members of the DA Parties have acknowledged that there continue to be risks associated with ESPs. For example, on its website, Pilot Power, one of the DA Parties, candidly states that:

Direct access energy supply has been a volatile business arena. Many customers have signed direct access supply contracts with retail energy service providers (ESP's) only to find that the ESP has later defaulted on the contract and returned the customer to the utility supplier. In some cases, the ESP's have protected the customers from financial loss incurred by reverting to the utility supply, in some cases they have not.¹¹⁴

This candid admission by one of the DA Parties clearly acknowledges the volatility of the DA market and the risks for customers. This is exactly the kind of risk that the financial security requirements are intended to address.

B. Calculating reentry fees

1. Concerns About Volatility Information Are Overstated.

Commercial Energy claims that the financial security model proposed by PG&E and SCE is “not fully developed” with regard to the volatility component.¹¹⁵ The DA Parties raise similar concerns and assert that the volatility information used in the financial security methodology is

¹¹⁴ See <http://www.pilotpowergroup.com/products/index.htm>

¹¹⁵ Commercial Energy Brief at p. 17.

not publicly available.¹¹⁶ CCSF claims that implied volatility data is not available for PG&E's service area, expresses concern about the use of historic volatility data, and echoes Commercial Energy's concern that the financial security methodology is not fully developed.¹¹⁷ All of these concerns are readily addressed.

First, PG&E acknowledged that implied volatility information is not available for its service territory. Thus, in its testimony and at the hearing, PG&E proposed using historic volatilities.¹¹⁸ As PG&E witness Hessami explained at the hearing, historic volatilities are used generally in the industry and are "highly credible."¹¹⁹ Neither CCSF nor the DA Parties provided any evidence that historic volatilities are not reliable.

Second, PG&E's and SCE's financial security methodology is detailed and fully developed, contrary to Commercial Energy's and CCSF's claim. PG&E provided a detailed presentation from the CCA proceeding explaining the financial security methodology and including detailed examples.¹²⁰ SCE provided lengthy testimony describing how re-entry fees and the financial security amounts are calculated.¹²¹ While PG&E acknowledged a few outstanding issues would need to be resolved, such as the period covered for historic volatilities, PG&E witness Hessami explained that these are the types of issues that can likely be resolved in a workshop.¹²² The Commission certainly has enough information before it to issue a decision on PG&E and SCE's financial security methodology proposal and can order that the parties

¹¹⁶ DA Parties Brief at p. 19.

¹¹⁷ CCSF Brief at pp. 5-6, 8-9.

¹¹⁸ Ex. 400 at p. 4-15, lines 4-8 (PG&E, Hessami); Tr. at pp. 622, line 5 to p. 623, line 11 (PG&E, Hessami).

¹¹⁹ Tr. at p. 628, line 13 to p. 629, line 2 (PG&E, Hessami).

¹²⁰ Ex. 400, Attachment 4-A (PG&E, Hessami).

¹²¹ Ex. 300 at pp. 43-63 (SCE, Singh).

¹²² Tr. at p. 630, line 15 to p. 631, line 3 (PG&E, Hessami).

resolve any outstanding issues. It is typical for the Commission to issue an order addressing general policy issues, and require parties to resolve final issues through workshops, advice letters, or compliance filings.

Third, contrary to the DA Parties' claim, volatility data is readily available. In his testimony, DA Parties' witness Fulmer asserted that he was unable to obtain volatility data from Amerex, the broker identified in PG&E's testimony.¹²³ This assertion turned out to be a significant overstatement. In discovery, PG&E learned that Amerex told Mr. Fulmer that while they could not provide the information to him as a consultant, they could provide the information directly to the DA Parties.¹²⁴ While Amerex does not provide this information for free, parties can receive it for a limited subscription fee. Thus, there is no basis for the DA Parties' claim that the volatility information is unavailable.

Finally, the DA Parties and CCSF are not immune from need for volatility and price curves. These entities cannot conduct business in the energy industry or mitigate risk without having price curves and using volatility to calculate market risk and counterparty exposures. In short, these parties inaccurately portray the financial security methodology proposed by SCE and PG&E as abnormal, when, in fact, the value at risk calculation underlying the methodology is a generally accepted methodology for measuring exposures.

2. CCSF's Concerns About The Financial Security Model Stress Factor Are Misplaced.

CCSF states that it has a general concern about the stress factor used in the financial security model proposed by PG&E and SCE because the stress factor could increase prices representing a stressed market by as much as 57%.¹²⁵ As PG&E explained above, the stress

¹²³ Ex. 201 at p. 16, lines 20-22 (DA parties, Fulmer).

¹²⁴ Ex. 205; Tr. at p. 410, line 4 to p. 411, line 16 (DA Parties, Fulmer).

¹²⁵ CCSF Brief at p. 3.

factor is based in part on volatility information that is available to the parties and generally used in the energy industry. Moreover, CCSF appears to ignore the commercial realities of risk in the energy markets. For example, when an LSE hedges its portfolio over a six month period, the stress factors for hedging can be between 80-90%, which is significantly higher than the stress factor in the financial security methodology.

C. Security Requirements Administration

1. Commercial Energy’s Concerns About A “Retroactive Effect” Are Also Overstated.

Commercial Energy claims that the financial security requirements will have a “retroactive effect” because ESPs and their customers have already entered into contractual relationships and the costs of any financial security requirement may not be able to be passed through to DA customers.¹²⁶ However, Commercial Energy offers no evidence to support these claims. Commercial Energy failed to identify a single, specific instance or contractual provision that would preclude such a pass-through. Moreover, ESPs have been on notice for years about the financial security requirements in Section 394.25(e) and, more specifically, have been on notice for more than a year that the financial security requirements were an issue in Phase III of this proceeding. Finally, changing regulatory requirements is a part of doing business in California. The Commission and the Legislature have periodically imposed requirements on ESPs, such as RA and RPS requirements, that may not have been directly addressed in existing ESP contracts. New regulatory requirements, such as the financial security requirement at issue in Phase III, are certainly not precluded because of an alleged “retroactive effect.”

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¹²⁶ Commercial Energy Brief at p. 18.

2. The Direct Access Parties' Proposal For Establishing Financial Security Based On An Investment Grade Rating Should Be Rejected.

PG&E has proposed a number of different types of acceptable financial security; including a bond, letter of credit, cash collateral and an appropriate parent guarantee. The DA Parties have proposed that “having an investment grade credit rating” is sufficient to satisfy the financial security requirements.¹²⁷ This proposal should be rejected. Even if an ESP has an investment grade rating, it can still get into financial trouble and default, leaving the involuntarily returned DA customers with no financial security. The recent crisis on Wall Street is an example of how firms with investment grade credit ratings, such as Lehman Brothers, quickly unraveled and defaulted on billions of dollars of obligations. Simply having an investment grade financial rating should not be sufficient to satisfy the financial security requirements.

3. The Financial Security Amount Should Be Recalculated Every Six Months.

PG&E and SCE have proposed recalculating an ESP's financial security amount every six months.¹²⁸ The DA Parties assert in a single sentence the financial security amount should be recalculated every year “[c]onsistent with the practices in other states”¹²⁹ Notably, the DA Parties fail to identify the “other states” and do not cite any evidence in the record to support this proposal. Recalculating an ESP's financial security amount every six months is beneficial for the ESPs and DA and bundled customers. If the financial security amount is calculated when markets are high and volatile, the amount of financial security that an ESP needs to provide may be substantial. If this amount is only recalculated once a year, even if market prices drop, the ESP will still be required to maintain a substantially higher financial security amount.

¹²⁷ DA Parties Brief at p. 20.

¹²⁸ See e.g. Ex. 400 at p. 4-14 (PG&E, Hessami).

¹²⁹ DA Parties Brief at p. 20.

Recalculating the financial security amount every six months allows the ESP to capture beneficial changes in the market and potentially reduce the amount of financial security it is required to provide.

The ESPs must have their own estimate of forward prices and volatilities to conduct business. Therefore, during the thirty day-period the IOUs will collect data to calculate the security requirements, ESPs have ample time to estimate their own requirements and provide a dispute to the IOUs or the Commission.

Finally, DA and bundled customers are protected by recalculating the financial security amount every six months if the opposite situation occurs. Specifically, if the financial security amount is calculated when market prices are low, and market prices rise substantially soon after the financial security calculation is completed, the amount of actual re-entry fees may be significantly greater than the financial security amount provided by an ESP. In this case, DA customers will need to make up the difference between the re-entry fee and the financial security amount, and costs may potentially be shifted to bundled customers. By recalculating the financial security requirement every six months, changes in the market are more accurately reflected, protecting DA and bundled customers.

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V. CONCLUSION

For the foregoing reasons, PG&E respectfully requests that the Commission adopt the recommendations attached as Appendix A to this reply brief.

Respectfully submitted,

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APPENDIX A

PG&E'S UPDATED RECOMMENDATIONS

SUMMARY OF RECOMMENDATIONS

Pursuant to Commission Rule of Practice and Procedure (“Rule”) 13.11, PG&E provides the following updated summary of its recommendations in Phase III of this proceeding.

Substantive updates from the recommendations attached to PG&E’s opening brief are identified by underlining. PG&E also deleted or edited language that was unclear.

Subject Area	PG&E’s Recommendations
<p>Modifications to the Market Price Benchmark (“MPB”) – RPS Adder</p>	<ul style="list-style-type: none"> • A Renewable Portfolio Standard (“RPS”) Adder to the MPB should be used to determine the market value of the RPS-eligible energy in each Investor-Owned Utility’s (“IOU”) total portfolio. • The RPS Adder should be calculated based on the Renewable Energy Credits (“RECs”) price in the SNL Publications California REC Index or, if other indices become available, an average of California REC Indices prices. • After the Commission issues a decision in Phase III, the IOUs shall jointly submit a Tier 3 advice letter compliance filing within thirty (30) days of issuance of the decision identifying: (1) the index(ices) that will be included in the RPS Adder; and (2) the methodology for using this index(ices) to determine the RPS Adder. Parties can protest the advice letter filing, but only for the purposes of challenging whether a specific index should be included in determining the RPS Adder. Parties shall not protest whether a REC Index should be used at all as this issue will have been resolved by the Commission decision in Phase III. • For purposes of calculating the MPB for the Indifference Amount, the RPS Adder should be applied based on the percentage of post-2003 RPS-eligible megawatt-hours (“MWh”) in the IOU’s total portfolio. • The RPS Adder shall be calculated annually in each IOU’s respective Energy Resource Recovery Account (“ERRA”) proceeding. • Pursuant to Decision (“D.”) 05-12-025, the Ongoing Competition Transition Charge (“CTC”) is determined using a statutory calculation methodology as defined in Public Utilities Code Section 367(a) and is independent of and not influenced by the total portfolio calculation methodology, which is used to determine the indifference costs.

Subject Area	PG&E’s Recommendations
	<ul style="list-style-type: none"> • The MPB adjustments being considered in this proceeding are specific to the indifference calculation and the determination of the PCIA. Thus, these adjustments should not automatically apply to the MPB used to determine the Ongoing CTC and instead, the MPB adjustments should only apply to the Ongoing CTC calculation if the portfolio of contracts has similar attributes. • In the case of the RPS Adder being considered in this proceeding, the portfolio of contracts included in the Ongoing CTC calculation are not similar because: (1) the contracts were signed prior to 1996; and (2) the contracts do not generate California RECs which can be unbundled and have a value independent of the underlying contractual energy. Thus, imputing a value that is equivalent to an unbundled California REC into the benchmark used to determine the Ongoing CTC portfolio does not fairly represent the value of these contracts in the market. • <u>As an alternative to PG&E’s proposal, the Commission should adopt the RPS Adder proposed by SCE and SDG&E.</u>
Modifications to MPB – Generation profile modification	<ul style="list-style-type: none"> • The MPB should be weighted to reflect an IOU’s generation profile. • A single generation portfolio weighting factor should be developed for all vintages rather than a vintage-specific generation weighting factor.
Modifications to the MPB – Capacity Adder	<ul style="list-style-type: none"> • The capacity adder for the MPB adopted in Decision (“D.”) 06-07-030, as modified by D.07-01-030, should not be modified. • <u>In the alternative, the capacity adder should be based on the median value of the “RA/Capacity only” column from Table 13 included in the Commission’s annual <i>Resource Adequacy Report</i>.</u>
Modifications to the MPB – Congestion Adjustment	<ul style="list-style-type: none"> • The Commission should reject the Joint Parties’ proposal to include a basis adjustment to the MPB to account for congestion.
Modifications to the Total Portfolio Costs – CAISO Load-Based Costs	<ul style="list-style-type: none"> • California Independent System Operator (“CAISO”) costs that vary based on changes in load should be excluded from the determination of an IOU’s total portfolio costs. • After the Commission issues a decision in Phase III, the Energy Division should convene a workshop to review the list of

Subject Area	PG&E’s Recommendations
	<p>CAISO load-related charge codes that are applicable to scheduling coordinators and determine which charge codes represent costs that vary based on the changes to load so that a forecast of these costs can be excluded from the total portfolio. If there are disputes as a result of the workshops, the IOUs shall jointly submit a Tier 3 advice letter compliance filing within thirty (30) days of the workshop identifying their proposed CAISO load-related charge codes. Parties can protest the advice letter filing.</p>
<p>Modifications to the Total Portfolio Costs – Short-Term Purchases</p>	<ul style="list-style-type: none"> • The IOUs should exclude short-term transactions (<i>i.e.</i>, contracts or purchases less than one year in term) from their total portfolio calculation (PG&E has already been doing this).
<p>Modifications to the Indifference Amount Calculation</p>	<ul style="list-style-type: none"> • When the Indifference Amount is less than the Ongoing CTC, the negative PCIA should be set to zero, so that all customers pay their fair share of the Ongoing CTC. • Negative PCIA amounts can be banked forward to offset positive PCIA amounts in subsequent years.
<p>Modifications to the Transitional Bundled Service (“TBS”) Rate</p>	<ul style="list-style-type: none"> • The TBS rate should be adjusted to reflect changes to the MPB and the PCIA, including any changes to the capacity adder and RPS adder. • CAISO load-related costs should not be removed from the TBS rate. • Any changes to the TBS rate should be implemented concurrent with changes to the MPB, PCIA and Indifference Amount.
<p>Switching Rules – Minimum Stay</p>	<ul style="list-style-type: none"> • DA customers returning to bundled service, except in the situation of a 60-day safe harbor return, are required to stay on bundled service for a minimum of eighteen (18) months. • The minimum stay period commences when a returning DA customer begins paying the <u>applicable</u> bundled service rate.
<p>Switching Rules -- Notice Requirements</p>	<ul style="list-style-type: none"> • Voluntarily returning DA customers are required to give six months notice before returning to bundled service. Customers returning after six months notice immediately go on the <u>applicable</u> bundled rate. • If a voluntarily returning DA customer fails to give six months notice before returning to bundled service, the customer pays the

Subject Area	PG&E’s Recommendations
	TBS rate for the difference between six months and the amount of notice that the customer provided.
Switching Rules – Safe Harbor	<ul style="list-style-type: none"> • A DA customer <u>that provides less than one months notice</u> may voluntarily return to bundled service for up to sixty (60) days if the customer is transitioning to a new Electric Service Provider (“ESP”). • A returning <u>DA</u> customer pays the TBS rate during the safe harbor period. • If a DA customer does not find a new ESP within 60 days and does not submit a DA Service Request (“DASR”) to switch to a new ESP, the customer would be considered a returned DA customer and would pay the TBS rate <u>for 6 months after the 60-day safe harbor ended.</u> • Involuntarily returning DA customers have up to 30 days after being returned to bundled service to elect to use the safe harbor option. If an involuntarily returned DA customer elects the safe harbor option, it would be placed on the TBS rate retroactive to the date it returned to bundled service. These customers would need to complete the transition to a new ESP within sixty (60) days of returning to bundled service. <u>If an involuntarily returned DA customer does not find a new ESP within 60 days and does not submit a DASR to switch to a new ESP, the customer would pay the TBS rate for 6 months after the 60-day safe harbor ended.</u>
Switching Rules – Interaction With TBS Rates	<ul style="list-style-type: none"> • Involuntarily returning customers would not be required to pay the TBS rate but would automatically be put on the IOU bundled rate if the Commission adopts a sufficient financial security requirement and allows the IOU to collect re-entry fees from the financial security. • <u>Involuntarily returned DA customers would be responsible for the re-entry fee amount calculated at the time they are involuntarily returned, less any amount collected by the IOU from the financial security provided by the ESP and, if the customer pays the TBS rate, the amount of re-entry fee recovered through the TBS rate.</u>
Financial Security Requirements	<ul style="list-style-type: none"> • The financial security methodology proposed in the settlement submitted in Rulemaking (“R.”) 03-10-003 should be adopted in this proceeding for ESPs with one modification. PG&E

Subject Area	PG&E's Recommendations
	<p>continues to support the six-month recalculation period for the financial security amount, as provided under the settlement.</p> <ul style="list-style-type: none">• The costs to serve involuntarily returned DA customers to avoid cost shifts should be deducted from the financial security posted by an ESP upon the customers' return. If the financial security is not sufficient to cover these costs, the remaining costs should be recovered from involuntarily returned customers.