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 OF THE ALLIANCE FOR RETAIL ENERGY MARKETS, COMMERCE ENERGY, COMMERCIAL ENERGY, DIRECT ACCESS CUSTOMER COALITION, RETAIL ENERGY SUPPLY ASSOCIATION, AND SCHOOL PROJECT FOR UTILITY RATE REDUCTION TO THE JOINT PROPOSAL FILED BY SOUTHERN CALIFORNIA EDISON COMPANY, PACIFIC GAS AND ELECTRIC COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY

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AND ON BEHALF OF THE JOINT PARTIES

April 6, 2012

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RECOMMENDATIONS OF THE JOINT PARTIES

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3. Such affiliation shall be demonstrated by means of a customer self-certification process, as discussed herein.

4. The financial security requirement calculation methodology should be modified as discussed in Section IV below.

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Pursuant to the *Administrative Law Judge's Ruling and Amended Scoping Memo,* issued in this docket on February 8, 2012, the Alliance for Retail Energy Markets ("AReM"),[1] Commerce Energy, Commercial Energy, Direct Access Customer Coalition ("DACC"),[2] Retail Energy Supply Association ("RESA"),[3] and School Project for Utility Rate Reduction ("SPURR")[4] (hereafter collectively referred to as the "Joint Parties") submit this reply to the

[1] AReM is a California mutual benefit corporation formed by electric service providers that are active in California's direct access market. The positions taken in this filing represent the views of AReM but not necessarily individual members or the affiliates of its members with respect to the issues addressed herein.

[2] DACC is a regulatory alliance of educational, commercial, industrial and governmental end-use customers that utilize direct access for all or a portion of their electricity load requirements.

[3] RESA's members include: Champion Energy Services, LLC; ConEdison *Solutions*; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Energetix, Inc.; Energy Plus Holdings LLC; Exelon Energy Company; GDF SUEZ Energy Resources NA, Inc.; Green Mountain Energy Company; Hess Corporation; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; PPL EnergyPlus, LLC; Reliant and TriEagle Energy, L.P.. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

[4] SPURR is a joint powers authority, a membership organization that aggregates utilities services purchasing power and expertise for over 200 California public K-12 school districts, county offices of education, and community college districts.

March 16, 2012, Joint Proposal filed by Southern California Edison Company ("SCE"), Pacific Gas and Electric Company ("PG&E") and San Diego Gas & Electric Company ("SDG&E") (collectively, "the Utilities") relating to the determination of the Electric Service Provider ("ESP") financial security requirements ("FSR") and related re-entry fee provisions to cover incremental procurement costs for involuntarily returned small commercial and residential Direct Access ("DA") customers pursuant to the requirements of Public Utilities Code Section 394.25 (e)[5] and the directives of Ordering Paragraph 42 and Conclusion of Law 15 of Decision 11-12-018 (the "Decision").[6]

I. Introduction

The issues in this proceeding are quite well known, as they were very thoroughly discussed in the last phase of this proceeding that led to the recent Decision issued on December 7, 2011. As noted by the Utilities, "In Decision (D.) 11-12-018, the Commission addressed the obligations of ESPs under P.U. Code Section 394.25(e)."[7] That statute relates to the unlikely possibility that customers of an ESP or CCA might be involuntarily returned to service provided by an electrical corporation, and directs the Commission to determine any reentry fee that it deems is necessary to avoid imposing costs on other customers of the electric corporation. That fee, also referred to as the FSR, is to be the obligation of the ESP or CCA. In the Direct Access context, the recent Decision very clearly spelled out the following directive with regard to the FSR:

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[5] All future references herein to code sections are to the California Public Utilities (P.U.) Code unless otherwise stated.

[6] The Amended Scoping Memo provided that the Utilities proposal on this topic would be due on February 24, 2012. Subsequently, in an email ruling dated February 14, 2012, Administrative Law Judge ("ALJ") Pulsifer approved an extension of time to file this proposal to March 16, 2012, with reply comments due on April 6, 2012.

[7] Joint Proposal at p. 2.

> We define the applicable re-entry fee and ESP financial security requirements for en masse involuntarily returned DA customers as generally being limited to the administrative costs of switching customers to bundled service. In order to prevent cost shifting to bundled customers, we require that involuntarily returned large commercial and industrial DA customers bear the risks of increased procurement costs through payment of the Temporary Bundled Service tariff. However, we also determine that the re-entry fee and ESP financial security requirements for involuntarily returned small commercial and residential DA customers should include a provision to cover their incremental procurement costs. For this purpose, we intend to limit this latter requirement to exclude small commercial DA customers that are affiliated with a large DA customer. We defer to the next phase of this proceeding the specific process by which to define small commercial customers for purposes of calculating the ESP financial security requirement.[8]

It is the latter section of this excerpt that is under consideration here, the deferred consideration of the ESP financial security requirement for those ESPs that serve so-called "small customers." There are essentially three issues that must be determined here.

First, the term small customer is generally understood to encompass both residential and small commercial customers. As the financial security requirement for these ESPs is to include the incremental procurement costs associated with an involuntary return, it is highly important that the Commission be very precise about how to define a small customer. Second, since the Commission created an important distinction for small customers "affiliated with a large DA customer," the issue of affiliation must also be determined. Third, the actual bonding methodology must be determined.

This could have all been quite routine. Unfortunately the Utilities' Joint Proposal overreaches, perhaps in an effort to "claw back" on issues where PG&E and SCE did not prevail in the earlier Decision. Having failed in their collective efforts to impose incremental procurement costs on <u>all</u> involuntarily returned customers, the Joint Proposal now proposes an

[8] Decision, at pp. 3-4.

unreasonably high load threshold to define small customers that is inconsistent with existing statute, Commission precedent, the Utilities' own tariffs and current Commission procedures with regard to ESP reporting. Each of these clearly establish that threshold at 20 kilowatts ("kW"), rather than the 200 kW threshold contained in the Utilities' Joint Proposal.

As a result, the Joint Proposal would significantly increase the number of Direct Access customers for whom a much higher bonding requirement would be required. On the question of affiliation, the Utilities' Joint Proposal to use federal tax ID's to determine affiliation may seem administratively easy for the Utilities, but the facts described herein show that not to be the case, as it simply does not reflect commercial realities of how customers manage their businesses. As a result, the Joint Proposal thus would also increase the number of Direct Access customers that would be saddled with higher costs. Finally, the Joint Proposal's methodology for calculating the required financial security also offers certain problematical aspects, as discussed below.

In short, the Utilities' Joint Proposal is intrinsically anticompetitive, as illuminated further in these comments.

II. Small customers should be defined as those having demand of less than 20 kilowatts.

The essence of the Utilities' thinking is encompassed in the following excerpt from their Joint Proposal:

> The IOUs submit that C&I customers with demands of 200 kilowatts (kW) or greater should be presumed to have this level of sophistication as well as the know-how and negotiating leverage with the ESPs to mitigate the risks of a breach by the ESP. Commercial customers with demands under 200 kW vary in size and character, but include a vast array of small businesses that cannot be presumed to have the requisite level of sophistication to appreciate the procurement risks of a stressed electricity market, the know-how and leverage to mitigate them, or the ability to absorb those procurement risks when they materialize. Small businesses under 20 kW in demand – such as "mom and pop" grocery stores or hardware stores, *etc.* – would likely not possess the level of

sophistication to protect themselves from the procurement risks of an involuntary return.[9]

For a number of reasons, as discussed below, this unrealistic and unnecessarily high proposal should be rejected by the Commission. Instead, small customers should be defined as those having demand less than 20 kW. Such a finding would in fact be totally consistent with statute, existing Commission precedent and the Utilities' own tariffs.

A. The Public Utilities Code clearly defines a small customer as having maximum peak demand of less than 20 kW.

The P.U. Code already defines what is meant by a "small commercial customer." Section 331(h) provides as follows:

> (h) "Small commercial customer" means a customer that has a maximum peak demand of **less than 20 kilowatts**. [emphasis added]

Curiously, the Utilities' Joint Proposal does not mention Section 331. However, this alone should be sufficient authority for the Commission to determine that Section 331(h) governs for purposes of determining the small customer definition.

B. The Commission has also determined that the 20 kW level is an appropriate threshold for applying the consumer protection rules of the Code.

Similarly, although the Utilities discuss Section 394.25(e) in detail they fail to scroll down to Section 394.5(a) to examine how the Commission has implemented the consumer protection standards it provides. That Section provides, in part, as follows:

> Except for an electrical corporation as defined in Section 218, or a local publicly owned electric utility offering electrical service to residential and small commercial customers within its service territory, each electric service provider offering electrical service to residential and small commercial customers shall, prior to the commencement of service, provide the potential customer with a written notice of the service describing the price, terms, and conditions of the service.

[9] Joint Proposal, at p. 6.

The statute goes on to describe in detail the types of information that should be included in the Section 394.5 notice. However, for purposes of determining what size customer should be covered under the financial security requirement, it is illuminating to note that the Commission has determined that the consumer protection notice need only be provided to customers under 20 kW:

> We believe that an exception to the Section 394.5 notice requirement should be created for those ESPs who only serve medium to large commercial customers and industrial customers. If the ESP negotiates a contract to serve this kind of customer with electricity, and as part of that contract, the parties negotiate to include one or more small commercial accounts (**less than 20 kilowatts**) as part of this contract to supply electricity, the ESP should not have to register with the Commission under Section 394, and should not have to provide this large customer with the Section 394.5 notice.[10]

Therefore, the Commission has already determined that customers needing consumer protection (who presumably are less sophisticated) are those customers with demand less than 20 kW. This fact further reinforces the Joint Parties' position that for purposes of determining the ESP financial security requirement, the 20 kW threshold is appropriate.

C. The Commission's ESP registration and reporting procedures also uses the 20 kW level for determining who is a small customer.

It is notable that the ESP registration process also utilizes the 20 kW level to determine what constitutes a small commercial customer by citing D.99-05-034. The Commission website in fact contains a section entitled "How to Register as an ESP."[11] It provides that:

> The CPUC implemented the framework for ESP registration, specifically applying these requirements to ESPs serving residential and small commercial (**maximum peak demand less than 20 kilowatts**) in Decision No. (D.) 99-05-034 and (D.) 98-03-072. In (D.) 03-12-015, the CPUC extended these requirements to ESPs not previously required to register, as applicable." [emphasis added]

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[10] D.99-05-034, at p. 76 (emphasis added).

[11] *See*, http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/ESPs/RnR/

This same distinction is observed with regard to ESP annual reporting requirements. In a section of the Commission website entitled "ESP Reminders," the Commission directs as follows:

> Section 394.5 Notice filing due July 1st of each year. ESPs serving residential and/or small commercial customers file Section 394.5 Notices and any change notices used during the first half of the year (without a Standard Service Plan). ESPs that either (1) only serve residential and/or small commercial accounts as part of a large customer contract **(incidental load, as explained at pp. 76-77. Conclusion of Law 19, and Ordering Paragraph 17 of D.99-05-34)** or (2) did not market their services or change service to existing customers instead send a letter explaining how (1) or (2) above applies to the ESP, signed by a person with authority to bind the entity.[12] [emphasis added]

Therefore, the Commission has uniformly applied the 20 kW threshold to define small commercial load for purposes of clarifying ESP registration and reporting obligations. This further supports the Joint Parties' position that 20 kW is the appropriate threshold for defining small commercial load.

D. The Utilities use the 20 kW level to define small customers in the demand response context.

In Application ("A.") 06-03-005, the Commission issued D.08-07-045[13] pertaining to PG&E's dynamic pricing proposals. PG&E in fact advocated in that proceeding to have the 20 kW level be the dividing line between small and medium commercial customers:

> The January 23, 2008 Ruling grouped together all small and medium C&I customers with maximum demand less than 200 kW for the purposes of the draft timetable. **PG&E recommended subdividing this group into two groups**: those with maximum demand between 20 kW and 200 kW, referred to here as medium C&I, **and those with maximum demand below 20 kW, referred to here as small commercial**. We have adopted PG&E's proposed divisions in this decision.[14]

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[12] Source: http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/ESPs/esp_reminder.htm

[13] Decision Adopting Dynamic Pricing Timetable and Rate Design Guidance for Pacific Gas and Electric Company, issued August 1, 2008.

[14] D.08-07-045, at p. 21 [emphasis added].

This was reiterated in Conclusion of Law 11 of the same decision.

> It is reasonable to subdivide commercial and industrial customer with maximum load less than 200 kW into two subgroups: those with maximum demand between 20 kW and 200 kW, referred to as medium C&I, and **those with maximum demand below 20 kW, referred to as small commercial**.[15]

SCE has also used 20 kW as the appropriate dividing line between small and medium commercial customers. In the same PG&E GRC proceeding discussed above, SCE filed the following comments characterizing its planned SCE's 2009 GRC Phase 2 Proposal.

> In its 2009 GRC Phase 2, SCE expects to propose the following dynamic rates for its C&I customers:
>
> - **Small C&I (< 20 kW)**: opt-in TOU, opt-in CPP
> - Medium C&I (20 kW to 200 kW): default TOU, opt-in CPP
> - Large C&I (> 200 kW): mandatory TOU, default CPP[16]

Subsequently, SCE's Phase 2 GRC application discussed "Customer Eligibility for CPP" by categorizing, "C&I customers with demands greater than 20 kW and less than 200 kW" as being "medium C&I."[17] SCE's testimony in its Phase 2 GRC application contained the following information:

> Metering, billing, and customer services include the following components for residential**, small commercial (<20 kW),** medium commercial (20-200 kW), medium commercial time of use (20-200 kW), and industrial (>200 kW). . .[18]

The Commission drew precisely the same distinction in the SCE dynamic pricing decision D.09-08-028 in A.08-03-002[19]:

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[15] Id, at pp. 93-94 [emphasis added].

[16] February 28, 2008, Comments of Southern California Edison Company (U 338-E) on Draft Timetable and Rate Guidance Regarding Dynamic Pricing, at p. 5 [emphasis added].

[17] Exhibit SCE-04, at p. d-10.

[18] Exhibit SCE-02, at p. 29 [emphasis added].

[19] Decision Adopting Settlements on Marginal Cost, Revenue Allocation, and Rate Design, issued August 20, 2009.

Small Commercial (≤ 20 kW)
Medium Commercial (21 kW – 199 kW)[20]

This of course offers further support for adoption of the 20 kW level as the appropriate distinction between small and medium commercial customers. It is highly inconsistent for the Utilities to be arguing that small customers should include those with demand of up to 200 kW when in other proceedings they have advocated repeatedly for the 20 kW definition advocated by the Joint Parties. Instead, as advocated by the Joint Parties, the Commission should direct that small customers should be defined as being those customers with average peak load demand of less than 20 kW.

E. The Utilities' tariffs use the 20 kW standard for differentiating between customer classes.

The 20 kW level is also used by the Utilities in their own tariffs for differentiating between small and medium customers. For example:

- PG&E Electric Rule No. 1 provides in part, in its definition section, that: "SMALL BUSINESS CUSTOMER: A non-residential Customer who: (1) **has a maximum billing demand of 20 kW, or less**, per meter during the most recent 12 month period. . ."[21]
- Similarly, in the same Definitions section, PG&E includes the following definition: "SMALL CUSTOMER: Customers on demand-metered schedules (A-10 and E-19V), with **less than 20 kW maximum billing demand** per meter for at least 9 billing periods during the most recent 12 month period; or (2) any

[20] Id, Table 3 at p. 42 in the column labeled Customer Group [emphasis added].

[21] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_1.pdf [emphasis added].

customer on a non-demand metered schedule (A-1 and A-6); or (3) any customer on a residential rate schedule."[22]

- "SCE's Schedule GS-1 is designed primarily for small and medium-sized commercial customers with demands of **20 kilowatts or less**."[23]
- "SCE's Schedule TOU-GS-1 is an optional rate for small-sized commercial customers with electrical equipment, which creates demands of **20 kilowatts or less**."[24]
- SDG&E states that Schedule A – General Service is, "This schedule is the utility's standard tariff for commercial customers with a **demand less than 20 kW**."[25]
- SDG&E also defines eligibility for its critical peak pricing rate schedule EECC-CPP-D by stating, "this schedule is the default commodity rate for customers currently receiving bundled utility service whose maximum demand is equal to or exceeds or is expected to **equal or exceed 20 kW** for twelve consecutive months and whose facility is equipped with the Appropriate Electric Metering, as described below in Special Condition (SC) 19."[26]

It is a foolish inconsistency for the Utilities to maintain that the 20 kW level is appropriate for determining the definition of small customers for everything other than the ESP financial security requirement. In conclusion, use of the 20 kW level as the appropriate definition of small commercial load is firmly rooted in statutory authority, historical Commission precedent, and in

[22] Ibid. [emphasis added].

[23] http://www.sce.com/business/rates/small-business.htm [emphasis added].

[24] Ibid. [emphasis added].

[25] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_A.pdf [emphasis added].

[26] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC-CPP-D.pdf [emphasis added].

the Utilities' own tariffs. Therefore, it should be formally adopted by the Commission for purposes of determining the size of customer for which the "small customer" ESP financial security requirement is to be applied.

F. The "lack of sophistication" argument of the Utilities is neither accurate nor persuasive. It is, however, condescending and reflects a fundamental disconnect between the Utilities and their customers.

The Utilities argue that customers with demands less than 200 kW, "cannot be presumed to have the requisite level of sophistication to appreciate the procurement risks of a stressed electricity market, the know-how and leverage to mitigate them, or the ability to absorb those procurement risks when they materialize." The Utilities provide no evidence or fact to support this patronizing contention – which is not surprising since it is wholly inaccurate. First of all, each and every Direct Access customer must actively and purposefully elect to participate in Direct Access, a fact that by itself shows a high level of business acumen, sophistication and awareness of energy issues. The commercial and industrial ("C&I") customer that explores or utilizes Direct Access can generally be assumed to be more sophisticated than the C&I customer that neither explores nor takes advantage of Direct Access. Direct Access customers tend to be those parties who (a) find energy to be a fundamental element in their cost structures; (b) appreciate the greater and more individualized options as to services and billing offered by ESPs; and (c) prefer competitive options to the "one-size fits all" offerings by the Utilities. As a result, the suggestion that these customers are at all unsophisticated is a gross mischaracterization.

The Joint Parties believe that the fundamental intent of the Utilities' Joint Proposal is to make Direct Access service more costly and therefore less attractive to customers. Advancing that cause by adopting a patronizing stance toward the very customers who would have to bear those increased costs speaks directly to a fundamental disconnect between the Utilities and these

Direct Access customers, and the extent to which the Utilities fail to understand the Direct Access customers' desire to exit utility supply service. The Joint Proposal's attempt to paint Direct Access customers as needing utility protection to make up for their lack of business sophistication is unpersuasive. When coupled with the facts noted in the foregoing sections that the Joint Proposal is contrary to existing statute, the Utilities' own tariffs and current Commission practice pertaining to protection of the interests of small customers, it is clear that the Joint Proposal's 200 kW threshold must be rejected.

III. Affiliation should be deemed to exist when the under 20 kW accounts are served in connection with service to medium or large commercial or industrial customers.

The definition of what constitutes a small customer, as discussed in the foregoing section, is critical. In addition, it is also important that the Commission adopt an appropriate definition of what is meant by the words "affiliated with" in the following excerpt from the Decision:

> However, we also determine that the re-entry fee and ESP financial security requirements for involuntarily returned small commercial and residential DA customers should include a provision to cover their incremental procurement costs. For this purpose, we intend to limit this latter requirement to exclude small commercial DA customers that are affiliated with a large DA customer.[27]

That definition should meet a two-pronged test. It should both (1) be easily implemented; and (2) comport with actual commercial realities.

A. The Utilities' Tax ID proposal does not comport with commercial realities.

The Utilities propose to use customers' federal tax identification numbers ("FTID") to determine whether customers are affiliated. This approach does not meet either prong of the test. The Utilities state that in their experience, "affiliated companies generally use the same FTID."[28]

[27] Decision, at pp. 3-4 [emphasis added].

[28] Joint Proposal, at p. 8.

The experience of the Joint Parties, however, is to the contrary. The Joint Proposal definition of "affiliation" is problematic and does not comport with commercial realities. In fact, affiliated customer accounts are not necessarily covered by the same FTID numbers.

Corporations use a variety of ownership structures for their differing operations. Affiliates, subsidiaries and even individual facilities may be set up as separate entities that do not share the same FTID. Many differing corporate structures are also utilized. Companies may have multiple FTIDs for different business entities even though ultimately they are all owned by the same corporate parent. Likewise, franchise companies that may have sophisticated energy procurement on a collective basis for all of their franchises will still have each individual franchisee have its own FTID.

In fact, only a customer can know all of its affiliations. The Utilities do not share customer data with one another, and so small sites in one Utility's service territory would not necessarily be known by a Utility to be affiliated with large sites in another Utility's service territory. Also, accounts under one FTID may well be affiliated with accounts under another FTID. For example, universities that are members of DACC have research facilities that are built with grant money and operated by the university but may be under a different FTID as far as the utility is concerned. Should the Commission decide that further information on customer practices in this regard is necessary, for example through discussion at possible workshops, DA customers would be willing to provide more information, subject to appropriate confidentiality requirements. However, the essential point to be made here is that the FTID proposal clearly does not comport with commercial realities. Therefore, a better approach must be adopted, that meets both prongs of the test suggested above.

B. The Commission should require small customer self-certification of affiliation with a medium or large commercial or industrial customer.

Rather than the FTID approach contained in the Utilities' Joint Proposal, resolution of this issue should instead be focused on small customers self-certifying their affiliation with a medium or large commercial or industrial customer. This places the burden on the customers and/or their ESPs, as opposed to placing it on the Utilities. Furthermore, it has the advantage of comporting with existing Commission precedent.

As discussed above, D.99-05-034 provided that if an ESP "does not serve small commercial accounts except in an incidental manner" it was exempted from having to provide the Section 394.5 notice "even though a small commercial account is included as part of the contract to supply electricity."[29] The same decision provides in Ordering Paragraph 19 that:

> The exemption from the notice provided for in Public Utilities Code Section 394.5 is adopted for those ESPs who serve small commercial accounts as an incidental part of a contract to supply electricity to medium to large commercial customers or to industrial customers.[30]

The Joint Parties therefore propose that the Commission adopt a self-certification process whereby a customer would be required to provide certification to a utility that its account or accounts were associated with medium or large commercial or industrial direct access customers.

This self-certification could initially be required to be provided by a date certain, such as ninety days following the issuance of a final Commission decision in this phase of the proceeding. Small commercial customers would certify that they are affiliated with a medium or large commercial or industrial direct access customer. The procedure would also need to encompass new accounts set up in the future. This could be accommodated by requiring the

[29] D.99-054-034, at p. 76.

[30] Id, at p, 142.

same customers to make a similar certification within thirty days following the commencement of service to the new account.

Implementation of such a system would meet both elements of the test suggested above, as it would both (1) be easily implemented; and (2) comport with actual commercial realities. Furthermore, it places the bulk of the administrative burden on the customer, where it belongs, rather than on the Utilities. The use of FTID numbers may be a convenient method for the utilities to determine affiliation, but it definitely will not lead to accurate results. Therefore the Commission should adopt the Joint Parties proposal described above.

IV. The Utilities' definitions of small customer and affiliation contain distinct anticompetitive undertones.

By positing too high a threshold for defining small customers and by making it more difficult for a small account to be affiliated with a large one, the Utilities would place a far broader financial security obligation on ESPs, leading to higher costs for Direct Access customers, and making DA less economic. The Utilities are basically making a "backdoor attempt" to reverse significant elements of D.11-12-018, seeking to secure through their Joint Proposal what they failed to obtain in the Decision…namely, placing anticompetitive burdens on their competitors and making Direct Access less economical.

The Joint Parties regret having to make this point. It certainly would have been more productive had the Utilities put forth a Joint Proposal that was more reasonable and less seemingly directed at simply trying to find ways to make the bonding obligation broader and more expensive without any concomitant benefits to ratepayers. Nevertheless, it is certainly reasonable for the Joint Parties to reach this conclusion, when, for example, the Utilities propose a 200 kW level for defining small customers when the law, Commission precedent and their own tariffs each explicitly provide for the far lower and more reasonable 20 kW level.

As noted in D.99-05-034, "in Section 391, the Legislature expressed a need 'to create a market structure that will not unduly burden new entrants into the competitive electric market'…"[31] the full wording of Section 391(e) in fact reads:

> It is important to create a market structure that will not unduly burden new entrants into the competitive electric market, or California may not receive the full benefits of reduced electricity costs through competition.

The Utilities Joint Proposal would indeed unduly burden the competitive electric market and harm Direct Access customers. The Commission should reject this anticompetitive behavior and it should reject the customer size and customer affiliation elements of the Joint Proposal.

V. The financial security requirement calculation methodology requires some modifications.

The Joint Parties note here that the purpose of the FSR is to make up any shortfall the IOUs' bundled customers might incur if an ESP's customers are involuntarily returned to IOU service. It should equal a reasonable estimate of the cost to serve the involuntarily returned customers net of incremental revenue that would be collected from them until they are integrated back into the Utilities' bundled customer procurement. Overall, the Joint Parties find the IOU proposal to be a good start and provides the necessary calculation detail for the Joint Parties (and others) to assess it. Table 1 below outlines the major elements of the IOU's proposal for calculating the FSR, and notes specific modifications that should be required before the FSR is implemented.

[31] D.99-05-034, at p. 75.

Table 1: Bond Methodology Elements

	IOU Proposal for small commercial DA	Support or Modify
Stress Factor	Exclude	Support
Implied Volatility	Exclude	Support
Market procurement costs to be included:		
1. Brownpower using NP/SP 15 forwards	Same as in MPB calculation	Support
2. ResourceAdequacy Adder	*Same as in MPB calculation*	Support
3. Loadshape	*Same as in MPB calculation*	Support
4. RPScompliance cost adder	*Same as in MPB calculation*	Support with qualification
Time period for recovery of incremental procurement costs	Eight months: Two month safe harbor period plus six months	Modify: six months
Negative procurement costs offset administrative costs?	No	Modify: Allow negative procurement costs to offset administrative costs
Bundled Generation Rate (for comparison to market procurement cost)	System Average Generation Rate	Modify: Use actual weighted average generation rate, not system average. Include generation, PCIA, CTC and NSGC
FSR reset frequency	Monthly	Modify: Twice per year
Deadband for resetting FSR	+/- 10%	Modify: +/- 20%
ESP loads	Update ESP load amounts annually, or if it increases 25%	Modify: Update amounts if decreases or increases by 25%
Remedy for failure to meet FSR	Failure to timely post the required FSR would subject the ESP to service termination, based on CPUC order	Support, with due process at the CPUC
FSR posting	With IOU	With CPUC or in CPUC-controlled account

The most significant change in this proposal relative to that advocated in the IOUs' Joint Proposal is with respect to the stress factor and quantitative treatment of volatility. The IOUs appropriately address the Commission's concerns by simplifying the calculation to eliminate any forecast of "stressed market" conditions, including market volatility and confidence intervals. Removing market volatility from the calculation removes much of the complexity and uncertainty in the ESP financial security amounts and helps to ensure that the costs associated with the FSR is reasonable. The Joint Parties fully support this. The Joint Parties also generally

support the market procurement costs that would go into the FSR calculation: the sources and load-shaped weightings of the "brown power" component and the resource adequacy adder, and the recommendation to use the Resource Adequacy ("RA") and Renewable Portfolio Standard ("RPS") adders from the Market Price Benchmark calculation. If an IOU requests a waiver with respect to RPS compliance for involuntary returned load, then the RPS adder in the FSR calculation should be reconsidered.

The Joint Parties also recommend modifying the time over which the incremental procurement costs (the basis for the FSR) is calculated. In their proposal, the IOUs note that "…while incremental procurement costs in an involuntary return can extend well beyond one year, the IOUs propose to shorten the risk exposure duration to eight months to align with the re-entry fee recovery period adopted in D.11-12-018." (p. 9) What the IOUs do not say is that (a) given the revenue generated by small customer generation rates, the incremental procurement costs will not likely exceed the IOU procurement costs for beyond a year; and (b) it assumes that absolutely no customers return to DA service during the safe-harbor period. As observed in the Joint DA Parties' testimony in this proceeding, based on months following the 2000-2001 power crisis, this is a highly suspect assumption.[32] It is much more likely that these customers will retain their DA rights and PCIA vintage and contract with a new ESP. However, rather than attempting to make an explicit assumption concerning what fraction of involuntarily returned customers remain indefinitely on bundled service, the Joint Parties here recommend setting the

[32] *See*, February 25, 2011, Reply Testimony of Mark E. Fulmer on behalf of the Direct Access Parties, at pp. 8-9: "Second, in the only case in California that could be considered catastrophic, the 2000/2001 power crisis, DA customers who were returned to IOU service did not remain on IOU service for a full year, as is implied in the proposed CCA Bond model. Instead, they overwhelmingly returned to DA service. This is clearly shown in the figure below, which graphs the penetration of DA load as a fraction of total IOU load during the crisis. The figure shows DA load bottoming out at about 2% of total load in the spring of 2001, but returning to, and even exceeding, the pre-crisis levels within six months. This further demonstrates the points made earlier that customers see benefits by being served on direct access and they will continue to seek the right DA program if, for some reason, their ESP can no longer serve them."

time over which the incremental procurement costs (the basis for the FSR) is calculated to six months rather than eight.

The IOU proposal would also set any negative incremental procurement costs (*i.e.,* if the Forecast Price of New Power is lower than the IOU System Average Generation Rate) to zero. (p. 12). This implicitly means that a floor is set on the ESP FSR at the incremental administrative costs of processing the involuntary returns. Given that the purpose of the FSR is to provide protection against the costs that Utilities will incur to service the involuntarily returned customers, there is no reason why these two elements of the FSR should not be netted when the procurement costs are negative. To do so unnecessarily inflates the costs of the FSR. Therefore, the Joint Parties would instead set the floor on negative incremental procurement costs such that the net FSR is not less than zero. In other words, the Joint Parties recommend that the negative increment procurement costs be allowed to offset up to 100% of the calculated incremental administrative costs.

As noted earlier, a key element in the FSR calculation is the incremental revenue that the IOU would collect from involuntarily returned customers. The IOU proposal suggests using the system average generation rate (times the kilowatt-hours used by the involuntarily returned customers during an eight-month period). (p 11) The Joint Parties suggest a refinement to that estimate: rather than using the system-average generation rate, use the weighted average generation rate for the customer mix that is being served by the ESP posting the FSR. Using the system average might have been reasonable if the mix of DA customers for which FSR are required roughly matched the IOU's sales mix, but it will not. By reflecting the actual customer mix, the FSR will more accurately reflect the potential liability faced by the IOUs (and the bundled customers) in the unlikely event of a mass involuntary return. For purposes of the FSR

calculation, the bundled generation rate should include the generation rate component (inclusive of the PCIA) and any applicable unbundled generation components such as the Competition Transition Charge ("CTC") and Cost Allocation Mechanism ("CAM") rate elements.

The IOU proposal calls for recalculation of the FSR on a monthly basis and that the amount posted by the ESP would be reset if the recalculated amount differs by more than ten percent from the posted amount. The IOUs propose monthly re-calculations so as to mitigate the risks associated with market fluctuations (p. 13). The Joint Parties find this combination of deadband and recalculation to be administratively burdensome: On a monthly basis, the IOUs would have to calculate the FSR amount for each ESP, provide that amount and calculation documentation to the Commission and to each ESP, and note if the amount is inside or outside of the ten percent deadband. And if outside of the deadband, the ESP would have to increase its surety or have an amount refunded to it. All of this would have to happen well under 30 days for it to be meaningful. The Joint Parties are skeptical that this could occur in a way that is not burdensome to the IOUs, Commission staff and ESPs.

As an alternative, the Joint Parties recommend that the FSR be recalculated twice a year, in November and May, with any adjustments implemented on January 1 or July 1. Furthermore, a deadband of twenty percent is sufficient to protect bundled customers in the event of involuntarily returns. The Joint Parties believe this recommendation is not inconsistent with the elimination of the stress test, as discussed above.

In a related matter, the Joint Proposal calls for the FSR to be posted with the IOU, so that "the IOU will be in the position to 'call' on the instrument within 15 days should the ESP fail to pay the re-entry fees upon IOU demand." (pp. 17-18) The Joint Parties strongly believe that this provides the IOUs too easy of access to the posted FSR amount. The Joint Parties believe that

the Commission should have ultimate control of the funds, and release them to the IOU only after it finds that it is appropriate to do so. Allowing the IOUs to access the funds 15 days after a claimed trigger event would grant them far more discretion than is appropriate. The posted FSR amounts should be held or controlled by the Commission and released to the IOUs only after it has deemed it appropriate to do so.

VI. Conclusion

As noted above, the issues in this proceeding are quite well known, as they were thoroughly discussed in the last phase of this proceeding that led to the recent Decision issued on December 7, 2011. Given its recent issuance, it might have been expected that the clear message sent in that decision would have been received and acted upon by the Utilities in their Joint Proposal. Unfortunately, there are several unreasonable elements of the Joint Proposal that must be modified

The utilities cite no precedent for their 200 kW distinction other than to provide their own interpretation of the verbiage from the December Decision, and to rely on unsubstantiated claims of a lack of "customer sophistication" that begs for utility hand holding or protection. By contrast, the comments provided herein clearly demonstrate multiple areas where both the Commission and the Utilities themselves have used the 20 kW level as an appropriate definition for small customers. Furthermore, the Utilities' claims with respect to the customer lack of sophistication are specious and wholly unwarranted.

Instead, the Commission should direct that with regard to calculation the ESP financial security requirement:

1. Small customers should be defined as being those customers with average peak load demand of less than 20 kW.

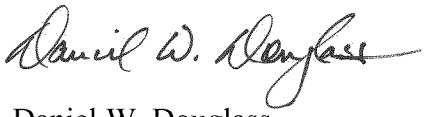
2. For purposes of defining an affiliated small customer account, affiliation should be deemed to exist when the under 20 kW accounts are served in connection with service to medium or large commercial or industrial customers.

3. Such affiliation shall be demonstrated by means of a customer self-certification process, as discussed herein.

4. The financial security requirement calculation methodology should be modified as discussed in Section IV above.

The Joint Parties thank the Commission for its attention to this discussion and requests that the Commission should adopt the foregoing recommendations.

Respectfully submitted,



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AND ON BEHALF OF THE JOINT PARTIES

April 6, 2012