<u>COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY TO THE CALIFORNIA AIR RESOURCES BOARD ON ITS PROPOSED 15-DAY MODIFICATIONS TO THE CAP-AND-TRADE REGULATION, RELEASED JULY 25, 2011</u>

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I.

INTRODUCTION AND EXECUTIVE SUMMARY

Southern California Edison Company ("SCE") respectfully submits its comments on the California Air Resources Board's ("ARB's") Proposed 15-Day Modifications to the Cap-and-Trade Regulation, released on July 25, 2011 ("July 2011 Proposed Modifications").[1] The July 2011 Proposed Modifications recommended changes to the Proposed Regulation to Implement the California Cap-and-Trade Program released on October 28, 2010 ("October Proposed Draft Regulation"). SCE recognizes ARB staff's efforts to revise the regulation and appreciates the willingness to work openly with stakeholders in crafting a cap-and-trade regulation that successfully implements the Global Warming Solutions Act of 2006 (Assembly Bill 32; Stats. 2006, Chapter 488), more commonly known as Assembly Bill ("AB") 32.[2]

The July 2011 Proposed Modifications reflect the efforts of ARB staff to incorporate many of the suggestions offered by stakeholders, including SCE, to revise and improve the October Proposed Draft Regulation. SCE appreciates the release of ARB's detailed allowance allocation proposal,[3] which provides an equitable allocation method based on customer cost burden, energy efficiency accomplishment, and early action as measured by investments in renewable resources.[4] SCE values the opportunity to further review the draft regulation language issued by ARB in the July 2011 Proposed Modifications, and offers comments and additional suggested revisions to that document.

SCE provides recommendations and suggested revisions on the following key issues: (i) a robust and well-tested cap-and-trade market design, (ii) the volumetric return of auction revenue

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1 California Air Resources Board, Proposed 15-Day Modifications to the Cap-and-Trade Regulation, July 25, 2011, *available at* http://www.arb.ca.gov/regact/2010/capandtrade10/candtmodreg.pdf ("July 2011 Proposed Modifications").

2 Cal. Health and Safety Code § 38500 et seq.

3 *See* July 2011 Proposed Modifications, Table 9-3, at A-124.

4 *See* July 2011 Proposed Modifications, Appendix A, "Staff Proposal for Allocating Allowances to the Electric Sector," July 27, 2011, at 2.

to customers, (iii) changes to the definition of electricity importers, (iv) the requirements for replacement electricity, (v) the Holding Limit calculation and the beneficial holding language, (vi) electricity imports, specifically the rules regulating resource shuffling and qualified exports, (vii) the Allowance Price Containment Reserve ("Allowance Reserve") structure, (viii) compliance rules addressing voluntary renewable electricity as well as offset and allowance usage, and (ix) penalty provisions.

A strong cap-and-trade market design is vital to the success of the cap-and-trade program. SCE supports the Joint Utilities Group in recommending that ARB adopt a roadmap and market-readiness checklist before beginning the program. ARB should also undertake a detailed study of the impacts of default emissions factors on the regional electricity markets.

SCE reiterates its position that auction revenue be returned volumetrically to customers, rather than via a fixed rebate. A volumetric approach is preferable because it is a less expensive and more equitable way to reduce emissions, will garner broad public support for future cap-and-trade programs, and is more likely to result in a successful GHG reduction program. SCE has strong concerns with the current draft language that requires auction proceeds from consigned allowances to be used for ratepayer relief using a fixed credit or rebate. This requirement is outside the scope of ARB's authority, because rate design issues are exclusively within the California Public Utilities Commission's ("CPUC's") authority. The CPUC is addressing the question of allowance revenue return in its Rulemaking ("R.") 11-03-012.[5] Thus, although ARB cannot stipulate how auction revenues are returned to electric utility ratepayers, ARB should endorse a volumetric approach as the most equitable and prudent approach for this landmark GHG program.

The current definition of "electricity importers" in the July 2011 Proposed Modifications, which assigns "electricity importer" status to a downstream purchaser within ARB's jursidction when the original purchasing-selling entity ("PSEs") is outside of ARB's regulatory authority,

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[5] R.11-03-012, Order Instituting Rulemaking to Address Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions, ("GHG OIR"), filed March 24, 2011.

could lead to unintended and unfair consequences and should be modified. Not only is the definition inconsistent with the fundamental principle that the cap-and-trade regulation is source-based, but it could also lead to California load being assessed GHG compliance costs twice for the same electricity imports. The electricity markets would be distorted and provide out-of-state importers with a financial windfall. If, as some others have indicated, the California Independent Systems Operator has language in its Tariff that addresses this issue, then the cascading compliance obligation is unnecessary and should be deleted.

SCE supports the proposal to allow replacement electricity used to "firm and shape" out-of-state variable renewable electricity to qualify for the specific emission factor of that variable renewable resource. However, some of the requirements placed on the replacement electricity in order to qualify for that specific emission factor should be revised. First, the rules for replacement electricity should not apply to renewable contracts executed before the cap-and-trade regulations are adopted. Moreover, ARB should remove the condition that replacement electricity be sourced from the same balancing authority as the variable renewable resource. In addition, ARB should delete or clarify the requirement that the deliverers of the replacement electricity have a contract with the suppliers, as this requirement could significantly increase costs to SCE's customers. Lastly, ARB should clarify or delete the requirement that the replacement electricity be used to "meet hourly load."

SCE supports the inclusion of Holding Limits for compliance entities, which are designed to address concerns regarding market manipulation. However, for sizeable compliance entities such as SCE that have a large GHG price exposure, including a large indirect GHG price exposure, the Holding Limit calculation proposed in the July 2011 Proposed Modifications is insufficient. Adjusting the Holding Limit formula will mitigate the risk of rate impacts to electricity customers. SCE recognizes that ARB staff has created the beneficial holding concept to attempt to address these concerns. SCE maintains that increasing to the Holding Limit is the best solution, still, SCE encourages ARB to revise the beneficial holding language as proposed below in order to create a more workable framework for the GHG market.

ARB has developed a number of rules regulating imports of electricity into California. SCE agrees that compliance entities should not engage in resource shuffling to falsely receive credit for emissions reductions that have not occurred. However, the definition of resource shuffling should be revised to exclude situations where a covered entity either unknowingly engages in activities that resemble resource shuffling, or adjusts its portfolio for valid economic dispatch reasons. SCE supports the qualified exports rule for netting the GHG emissions of electricity imported and exported within an hour, and suggests that ARB establish a default emissions factor for those qualified exports.

SCE recognizes that ARB staff significantly revised the Allowance Reserve structure following the release of the October Proposed Draft Regulation and the comments submitted by stakeholders. SCE submits additional ways in which ARB could further improve the Allowance Reserve. These include clarifying the clearing price for filled bids, creating a method to refill the Allowance Reserve, offering a stable price ceiling in addition to the price floor, and keeping additional allowances (those unsold allowances at quarterly auctions) from being placed in the Allowance Reserve.

ARB's proposed cap-and-trade regulation appropriately provides covered entities with a range of methods to fulfill their compliance obligation, including the use of offsets and voluntary renewable electricity in addition to allowances. In order to achieve cost-effective emissions reductions as required by AB 32, ARB should ensure an ample supply of offsets, revise the offset reversal provisions, and allow covered entities the flexibility to apply the 8% quantitative limit on offsets over the entire eight years of the cap-and-trade program. SCE proposes three conditions that ARB should impose on voluntary renewable electricity allowances: the allowances must represent RPS-eligible procurement, the allowances should be retired rather than directed toward alternative uses, and excess allowances should be returned to the market via the auction. In addition, SCE suggests that ARB clarify that covered entities can use any compliance instruments issued to date in order to satisfy their compliance obligation.

Finally, SCE thanks ARB for modifying and clarifying the penalty provisions, which created excessive and unbounded penalties that exposed covered entities to far too much risk. However, further improvement is needed. SCE requests clarification of some of the calculations for untimely surrender penalties, due dates, and civil/criminal penalties.

II.

A ROBUST AND WELL-TESTED CAP-AND-TRADE MARKET DESIGN MUST BE IN PLACE BEFORE THE LAUNCH OF THE CAP-AND-TRADE PROGRAM

California continues to lead the way in developing a greenhouse gas ("GHG") cap-and-trade market. The successes and failures of this market will be observed throughout the nation and the world. As SCE pointed out in its December comments on the October Proposed Draft Regulation, it is critical that the cap-and-trade market features and systems be adequately structured and tested in order to avoid possible catastrophic consequences similar to the 2001 energy crisis.[6] Thus, SCE strongly supports the one-year delay of the compliance elements of the cap-and-trade program. This delay will allow additional time for ARB to improve its market structure, test its systems, and create stronger protections against market manipulation while maintaining the environmental integrity and important leadership position of this program.

In its Summary of Proposed Modifications, ARB staff noted that certain activities, such as allocation, auction, and trading, will begin in 2012, and requested comments on which program elements should begin in 2012 and what advantages there are to phasing in various components during 2012.[7] SCE and other utilities in the Joint Utility Group[8] have been working closely with ARB staff to assist in this market design. Based on lessons learned from both the

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6 Comments of Southern California Edison Company to the California Air Resources Board on Its Proposed Regulation to Implement the California Cap-and-Trade Program ("SCE December 2010 PDR Comments"), December 10, 2010, at 1-5.

7 ARB Notice of Public Availability of Modified Text and Availability of Additional Documents, at 20, *available at*: http://www.arb.ca.gov/regact/2010/capandtrade10/15daynot2.pdf.

8 The Joint Utility Group is a coalition of investor-owned and publicly-owned utilities that meets regularly to discuss issues relating to the cap-and-trade regulation and the cap-and-trade market implementation.

California energy crisis and the launch of a new California power trading market in 2009,[9] the Joint Utility Group has provided a suggested roadmap, timeline, and checklist of market readiness steps that ARB should take before the auctions begin and the market goes live. Rather than focus here on which program elements should begin in 2012, SCE strongly recommends that ARB staff make certain that sufficient steps are taken and adequate protections are put in place to ensure a properly functioning market.

Before launching the cap-and-trade market, ARB must take the additional but crucial step of analyzing the effect of import and export emissions rates on regional electricity markets. SCE recognizes the significance of capturing emissions associated with imported electricity. However, ARB should not go forward without a detailed analysis of the possible market-changing effects of such default emissions factors. Because emissions factors do not exist today, may vary by location, and may vary depending on whether the delivery is an import or export, the power market's responses to these new economic signals could cause significant changes in power flows and market conditions throughout the Western Electricity Coordinating Council ("WECC"). In addition, transmission congestion, locational market prices, and the economics of existing or potentially new transmission will be affected. SCE recommends that ARB work with an experienced consultant to model the impacts of its default emissions factors on the power system and Western power markets before finalizing the cap-and-trade market design.

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[9] Before the California Independent Systems Operator ("CAISO") launched a new nodal power trading market known as the Market Redesign and Technology Upgrade ("MRTU") on April 1, 2009, CAISO held a formal process with a roadmap and market readiness checklists similar to those proposed by the Joint Utility Group.

III.

THE IOUS SHOULD BE DIRECTED TO RETURN ALL REVENUES DIRECTLY TO CUSTOMERS ON A VOLUMETRIC BASIS

ARB has requested comments on Section 95892(d),[10] which requires auction proceeds from consigned allowances to be used only for ratepayer relief. Specifically, Section 95892(d)(3)(B) states that "to the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate."[11] Likewise, Section 95892(d)(3)(C) states that " . . . these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012."[12]

SCE supports the use of all GHG allowance revenues received pursuant to auctions under the cap-and-trade program for customer rate relief. However, SCE disagrees with Section 95892(d) and the "fixed rebate" language in particular because it exceeds the scope of ARB's authority. Moreover, apart from the fact that ARB lacks authority to promulgate this "fixed rebate" language, the "fixed rebate" approach will not achieve the most equitable, cost-effective policy outcome for cap-and-trade. Rather, allowance revenues should be returned to customers in proportion to the costs incurred by such customers for GHG compliance, or "volumetrically," rather than through the use of a fixed rebate. Furthermore, all of the allowance revenues should be returned directly to customers, rather than funneled to other programs.

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[10] ARB Notice of Public Availability of Modified Text and Availability of Additional Documents, at 20, *available at* http://www.arb.ca.gov/regact/2010/capandtrade/15daynot2.pdf.

[11] July 2011 Proposed Modifications, § 95892(d)(3)(B), at A-122.

[12] July 2011 Proposed Modifications, § 95892(d)(3)(C), at A-122.

A. The "Fixed Rebate" Language Used in ARB's Regulations Exceeds ARB's Authority, Because Rebate and Rate Design Issues Are Within the Exclusive Jurisdiction of the CPUC

The "fixed rebate" language in Section 95892(d) exceeds the scope of ARB's authority. Pursuant to AB 32, ARB's authority to design the ARB regulations includes the ability to mandate the "distribution of emissions allowances where appropriate."[13] Accordingly, ARB may provide, in the ARB's proposed cap-and trade regulation, for the allocation of free emissions allowances to the electric utilities. However, AB 32 does not grant ARB authority to direct how investor-owned utilities ("IOUs") should use revenues earned from the sale of emissions allowances. It is the CPUC that has the exclusive authority over this rate-setting function.

The California Constitution provides that "[a] city, county or other public body may not regulate matters over which the Legislature grants regulatory power to the Commission."[14] Accordingly, as to matters over which the CPUC has been granted regulatory power, the CPUC's jurisdiction is exclusive.[15] The purpose of this exclusivity is to promote uniformity throughout the State and eliminate conflicting regulations.[16] Pursuant to the California Constitution, the Commission has general regulatory authority to fix rates and assure that rates and allocation of costs are just and reasonable, and nondiscriminatory.[17] Likewise, the Public Utilities Code grants the Commission specific authority to fix and design rates.[18] Accordingly, the CPUC's jurisdiction over rate-setting and rate design is exclusive.

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[13] Cal. Health and Safety Code § 38562(b)(1).

[14] Cal. Const., art. XII, § 8.

[15] *City of Anaheim v. Pacific Bell Telephone Company,* 119 Cal. App. 4th 838, 842 (2004), *Southern Cal. Gas Co. v. City of Vernon*, 41 Cal. App. 4th 209, 215 (1995).

[16] *City of Vernon,* 41 Cal. App. 4th at 215.

[17] *See generally,* Cal. Const., art. XII, § 5. *See Pacific Bell Wireless, LLC v. Pub. Utils. Comm'n of State of Cal.,* 140 Cal.App.4th 718, 736 (2006) ("The Constitution confers broad authority on the commission to regulate utilities, including the power to fix rates . . .").

[18] Pub. Util. Code, § 451 (providing for just and reasonable rates, charges and services), 453 (prohibiting the granting of preference or advantage to any corporation or person), §§ 453.5, 792.5 (guiding the Commission's use of refunds, rebates and balancing accounts), and § 701 (providing the Commission with a broad authority to

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Furthermore, the express language of AB 32 makes clear that nothing in AB 32 "affects the authority of the Public Utilities Commission."[19] Likewise, AB 32 requires ARB to "consult" with the CPUC in the development of the regulations as they affect electricity and natural gas providers "in order to minimize duplicative or inconsistent regulatory requirements."[20] The "fixed rebate" language in the ARB regulations attempts to curb the authority of the CPUC to determine how allowances will be incorporated into rates. Furthermore, the language creates a risk of inconsistent regulatory requirements, should the CPUC choose to take a different approach than ARB. Accordingly, the "fixed rebate" language should be removed from the regulations and no alternative suggestions should be included on revenue uses.

1. <u>A Volumetric Method Is A Better Way to Return Allowance Values to Customers than a Fixed Rebate Approach</u>

a) <u>A Fixed Rebate Is an Expensive and Flawed Way to Reduce Emissions</u>

ARB's stated reason for supporting a "fixed rebate" rather than a volumetric approach is to send a retail level price signal.[21] This approach is problematic for several reasons. First, ARB should focus its implementation efforts on the wholesale level, as this is where the most effective price signal in the cap-and trade market will take place. For instance, under cap-and-trade, owners of conventional, GHG-emitting generation will incorporate the cost of procuring their allowances into their electricity costs, making this generation more expensive and less

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do all things necessary in carrying out its regulatory duties, including ensuring just and reasonable allocation of costs and nondiscriminatory treatment). *See also, Schell v. Southern Cal. Edison Co.,* 204 Cal. App. 3d 1039, 1046 (1988) (holding that the issue of what rate to charge certain residential customers was clearly within the exclusive purview of the CPUC as part of its "continuing jurisdiction over rate making and rate regulation in provision of baseline service to residential customers of the electric and gas corporations").

19 Cal. Health and Safety Code § 38593(a).

20 Cal. Health and Safety Code § 38562(f).

21 *See* ARB Proposed Regulation to Implement the California Cap-and-Trade Program, Part I, Volume I, Staff Report: Initial Statement of Reasons (October 28, 2010) (the "2010 ISOR"), Appendix J, available at: http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm (follow "Appendix J: Allowance Allocation" hyperlink).

competitive in the market. It is at this wholesale level where electricity deliverers then make short- and long-term decisions about what resources are most economical to dispatch. A GHG price signal may, in many cases, affect these dispatch decisions. A retail price signal would simply duplicate this signal at the electricity customers' expense, without resulting in significant reductions in energy consumption.

Second, the use of a retail-level price signal is not a cost-effective method of reducing emissions, relative to other emissions reductions options. The cap-and-trade program establishes a cap on total GHG emissions levels and allows regulated entities to select among various approaches as to how to operate below that cap. The marginal cost of emissions reduction will be established by the market-clearing price of allowances, but is generally expected to be around \$20/ton. Assuming electricity rates of 15 cents/kWh and marginal emissions rates of 0.5 tons/MWh, then the price elasticity of demand – the percentage change in energy consumption caused by a percentage increase in price – would have to be -15[22] in order for a retail price signal approach to be cost-competitive with other emissions reduction options that are estimated to cost \$20/ton.[23] In reality, price elasticity of demand runs from -0.1 to perhaps -0.8 for electricity,[24] meaning that retail consumers are much less responsive to marginal price increases than they would need to be for retail price increase to be a cost effective means of reducing GHG emissions. Therefore, using a retail price signal approach to reducing GHG emissions would have an overall negative and disproportionate impact on rates and ultimately, would be a very costly measure for ARB to select.

Furthermore, total GHG reductions are capped under the cap-and-trade structure; therefore, if emissions reductions are made by way of rate increases, these reductions will not be

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22 An elasticity of -1 means that a 1% increase in price will result in a 1% decrease in demand, thus an elasticity of -15 means that a 1% increase in price would result in a 15% decrease in demand.

23 This estimate is between the floor and reserve prices established by ARB under the cap-and-trade program.

24 See Azevedo et al, "Residential and Regional Electricity Consumption in the U.S. and EU: How Much Will Higher Prices Reduce CO2 Emissions?" Electricity Journal Volume 24, Issue 1, Jan/Feb 2011 at 29 (estimating that "a 10 percent price increase in residential electricity price in the U.S. could be expected to result in a 2.5 percent reduction in CO_2 emissions from residential electricity consumption.").

made through other cap-and-trade programs. Accordingly, if a fixed rebate method is used as a way to reduce GHG, it will take the place of other, more cost-effective methods of achieving emissions reductions.

Third, the fixed rebate will not send an accurate or effective price signal due to SCE's current residential rate structure. Pursuant to the Public Utilities Code, there is a cap on the amount that the rates of customers in the first two tiers may increase.[25] Because of this structure, Tier 1 and Tier 2 customers will experience no rate increase as the result of cap-and-trade. Customers in Tiers 3, 4, and 5 will bear all the costs associated with cap-and-trade. In addition, these higher tiers have already been bearing the costs of other energy efficiency and renewables programs (as well as any market-based electricity procurement cost increases) since 2001 when the CPUC multi-tiered rate structure became effective. In this environment, the fixed rebate will not achieve the stated goal of setting a price signal that accurately reflects the environmental costs of GHG emissions. At the lower tiers, there is a risk that a fixed rebate will actually set a negative price signal: lower tier customers will see a rate decrease due to cap-and-trade and so, according to the price signal proponents' own logic, will have an incentive to *increase* energy consumption. A fixed rebate will not prevent "dampening the price signal" any more than a volumetric return, rather it would simply strengthen the price signal for certain tiers and eradicate it for others.

b) <u>A Volumetric Return of Revenue to Customers is a More Equitable Way to Achieve GHG Emissions Reductions than a Fixed Rebate</u>

Another reason to avoid a fixed rebate approach is that it does not lead to a fair outcome. As already explained, the tiered residential rate structure in California has prevented Tier 1 and Tier 2 rates from increasing since 2001, Tier 3 rates that are double Tier 2 rates, and Tier 5 rates

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[25] Cal. Public Utilities Code §§ 739.1, 739.2 and 739.9.

that are three times as high as the Tier 1 rates. The fixed rebate would only exacerbate this disparity.

Furthermore, a requirement that IOUs use a fixed rebate approach would be unfair, effectively putting IOUs rates at a disadvantage vis-à-vis publicly held utilities rates since publicly held utilities are not restricted in how they use allowances revenues.

Finally, while the fixed rebate is, in part, intended to redistribute wealth from high-income to low-income customers, it will, in certain cases, lead to the opposite result. For example, low-income customers who do not qualify for the California Alternate Rates for Energy ("CARE") program[26] but who use high volumes of energy will be subject to a disproportionately high electricity rate, while high-income, low-usage customers will receive a payout. This is because electricity usage is not a strong proxy for income.[27] For example, in SCE's service territory, a disadvantaged customer living in the high desert may be paying Tier 5 rates, whereas a wealthy resident on the coast could be paying Tier 1 rates.

c) **A Volumetric Approach Will Garner Broad Public Support for This and Future Cap-and-Trade Programs**

By mitigating the cost impacts of the cap-and-trade programs on all customers, a volumetric approach will also achieve the critical goal of garnering broad public support for GHG cap-and-trade programs. There is a limit to the extent to which customers can be made to feel the pain of GHG emissions while still being expected to support cap-and-trade. Likewise, if the cap-and-trade program is administered in a way that is perceived to be unfair, such as if some customers are bearing all of the costs of the program, this will not garner broad public support for the program.

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26 The CARE program is set forth in Public Utilities Code § 739.1.

27 Borenstein, Severin, Presentation Slides from 2008 POWER conference, "How Much Does Increasing-Block Electricity Help Low-Income Customers?" a*vailable at* http://www.ucei.berkeley.edu/POWER-08/Files/02borensteinslides.pdf.

One of the stated goals of AB 32 is to complement efforts to achieve and maintain cap-and-trade programs in other jurisdictions, including other state programs and a national program.[28] For years, efforts to establish a federal cap-and-trade program have met opposition in large part due to concerns that the program would be too costly to electricity customers. While a state-level program will aid in cutting overall emissions, a federal program is critical to ensure large-scale reductions are achieved in accordance with international protocols. In the current economic landscape, the most important use of allowance revenues will be direct bill relief to customers which would avoid of a customer backlash of the cap-and-trade program. The best way for California to establish its leadership and "have far-reaching effects by encouraging other states, the federal government, and other countries to act"[29] is to achieve targeted GHG reductions in a manner that is as seamless and invisible to consumers and the economy as possible. A volumetric return of GHG allowance value is critical to achieving this end.

For all of these reasons, ARB should remove Sections 95892(d)(3)(B) and 95892(d)(3)(C) and the CPUC should reject a fixed rebate approach and, instead, adopt a volumetric approach.

2. In Order for a Volumetric Return to Be Most Effective, All Allowance Revenues Should be Distributed to Customers, Rather Than Funneled into Other Programs

The cap-and-trade program was selected as the primary vehicle for reducing emissions across California. This method was chosen over a carbon tax or a traditional "command-and-control" approach, whereby the government mandates specific approaches in the hope that these approaches will yield an intended outcome. The ARB selected this market-oriented approach in

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[28] Cal. Health and Safety Code § 38501(c) (stating that the cap-and-trade program is intended to continue a tradition in California of "environmental leadership by placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases." See also, Cal. Health and Safety Code § 38501(d) (stating that "action taken by California to reduce emissions will have far-reaching effects by encouraging other states, the federal government, and other countries to act.")

[29] Cal. Health and Safety Code § 38501(d).

order to avoid many of the pitfalls that attend command-and-control measures. For example, command-and-control measures lack emissions-reductions certainty. These measures also tend to be much less cost-effective at reducing emissions because the implementers of these measures must forecast which approaches will be most cost-effective to implement, rather than relying on industry experts (through a market) to make this determination.[30] Accordingly, using allowance revenues to fund command-and-control programs, such as energy efficiency, low-income assistance and renewable energy, rather than remitting the funds back to customers through direct bill relief, goes against the market-based approach of the cap-and-trade program.

Furthermore, these additional programs are duplicative, as there are already programs in place to support energy efficiency, assist low income customers, and promote renewable energy generation. Moreover, there is no reason to believe that these programs are not already being adequately funded. A determination of whether the CARE program, for example, should be expanded, is a determination that is more appropriately made by through that program. Additionally, to the extent that ARB is merely directing that allowance revenues be funneled through the programs already in place, it would be impossible to ensure that these funds flow back to customers in an equitable manner.

IV.

ARB MUST REVISE THE CURRENT DEFINITION OF "ELECTRICITY IMPORTERS"

Section 95802(a)(84) of the July 2011 Proposed Modifications defines "electricity importers" as "marketers and retail providers that hold title to imported electricity."[31] For electricity delivered between balancing authority areas, "the entity that holds title to delivered electricity is identified on the [North American Electric Reliability Corporation] NERC E-tag as

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[30] *See* 2010 ISOR at IV-3 – IV-4.

[31] July 2011 Proposed Modifications, § 95802(a)(84), at A-15. The same definition is found in Proposed 15-Day Modifications for the Mandatory Reporting Regulations, § 95102(a)(118) at 26, *available at* http://www.arb.ca.gov/regact/2010/ghg2010/mandatory15dayreg.pdf.

the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California."[32] In addition, when PSEs are not subject to ARB's regulatory authority¸ the electricity importer is defined as "the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB."[33]

SCE explains below how a portion of this definition is (i) inconsistent with a source-based point of regulation, which is the key principle behind ARB's cap-and-trade program structure; (ii) could cause California load to be assessed GHG costs twice, while allowing electricity importers who are not subject to ARB's regulatory authority to earn a windfall profit, and (iii) result in unintended consequences for the GHG emissions profiles of California electricity as well as for the wholesale electricity market. Specifically, ARB should delete the provision in Section 95802(a)(84) designating (when a PSE is not subject to the regulatory authority of ARB) the electricity importer as the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. In other words, ARB should ensure that sellers of energy into the CAISO balancing authority have the GHG obligation at all CAISO interties, regardless of whether the intertie is physically located in California or another state. Downstream purchasers or recipients of imported electricity that played no direct role in importing that electricity should not be asked to shoulder the compliance burden related to the GHG emissions of imported electricity. The entity that made the discretionary decision to sell power into California is the entity that must bear the financial obligations arising from that decision.

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32 July 2011 Proposed Modifications, § 95802(a)(84), at A-15 to A-16.
33 *Id.* at A-16.

A. Allowing GHG Obligations to Be Transferred to the Immediate Downstream Purchaser or Recipient that Is Subject to the Regulatory Authority of ARB is Inconsistent with a Source-Based Point of Regulation

ARB designed its cap-and-trade program as fundamentally "source-based." In other words, ARB planned to regulate the GHG emissions in the electricity sector at the "source," or when the electricity is generated in the state or imported into the state, rather than when consumed. Consistent with this concept, ARB's point of regulation for the electricity sector is identified as the first deliverer of electricity, who is defined as "the operator of an electricity generating facility in California or an electricity importer."[34] SCE fully supports the first deliverer concept as a key element of ARB's cap-and-trade program design.

However, the portion of the definition of "electricity importers" that allows GHG obligations to be transferred "downstream" is inconsistent with ARB's source-based cap-and-trade program design for the electricity sector. Automatically transferring the compliance obligation downstream only some of the time would result in ARB regulating some emissions at the source and regulating other emissions where the electricity is consumed. Such a hybrid concept is fundamentally flawed and incompatible with how the electricity markets will internalize the cost of GHG emissions in making economic dispatch decisions.

Accordingly, ARB should revise its definition of electricity importer to be in harmony with the source-based design of the cap-and-trade program for the electricity sector. ARB should reaffirm that it will consistently require the entity who imports the electricity into California to comply with the cap-and-trade program requirements, rather than the purchaser or recipient of that imported electricity.

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[34] July 2011 Proposed Modifications, § 95802(a)(97), at A-18.

B. ARB's Definition of "Electricity Importers" Could Cause California Load to Be Assessed GHG Costs Twice for Electricity Sold Into CAISO's Markets at Interties that Are Physically Located in Another State

SCE's concern with the definition of "electricity importers" arises from the fact that California state boundaries do not exactly correspond with the CAISO balancing authority area, particularly at intertie points where a seller can bid into the CAISO's wholesale electricity markets. Many interties, which are also Points of Delivery ("POD") within CAISO, are physically located outside the state of California. Compounding this problem is ambiguity regarding which party has ownership of, or title to, electricity as it crosses California's borders. The boundary mismatch, combined with the ambiguity of title, creates a distinct possibility that the compliance obligation will shift downstream from a seller at these PODs to the recipient of that imported electricity.[35]

In CAISO's wholesale electricity markets, all supply bids, including supply bids at interties or PODs that are physically located out of state¸ are cleared against all demand bids in aggregate. However, CAISO does not match or associate any particular import bid with any cleared demand bids. CAISO does not establish any clear link or connection between a seller and a buyer. When a seller's bid in the CAISO market clears¸ and at the time the seller's scheduling coordinator schedules the electricity for delivery into CAISO, then the CAISO's E-tagging conventions seem to require the *seller* to identify an eventual point of delivery that may be within the state border.[36] It is impossible to infer with any certainty who was the specific purchaser or recipient of that imported electricity. Under the current definition, ARB would likely label all of the aggregated load in CAISO as the "importer."[37] Yet this load will have no

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[35] SCE here echoes ARB's apparent concern that ARB may not be able to impose the GHG cap-and-trade compliance obligation on the sellers who transact in CAISO markets at out-of-state interties or POD.

[36] Some PODs such as CAISO, SP 15, or NP 15 seem to have indefinite geographical boundaries, and it is therefore unclear whether their footprints extend beyond California borders.

[37] Under such circumstances, even though the load is being labeled as the "importer," the load has no role in selecting which electricity (high, medium, low, or zero GHG emissions) should be imported into California. This decision is solely made by the CAISO's clearing markets based on the seller's bid.

prior indication that the electricity it is receiving was imported and has a corresponding GHG obligation.[38] Only CAISO can know how much electricity has been bid at the interties and by whom, and can be aware of how many imports will be matched with demand bids.

Passing on the GHG obligation to load without their knowledge is also duplicative. The marginal supply bid, which sets the market clearing price, will reflect the cost of emissions from marginal generator (which may be either an internal generator or an import subject to cap-and-trade regulations). The entity that purchases this power to serve load, such as SCE, would then pay this cost. Then, if ARB were to impose the cost of GHG emissions related to imported electricity onto the load that receives the imported electricity, the load would have to pay for such emissions twice: once via the market clearing price and again in procuring allowances to cover its compliance burden. At the same time, the seller who sold the imported electricity into the CAISO markets would earn a windfall profit by receiving the market clearing price with an embedded GHG emissions mark-up, without actually incurring any GHG emission compliance costs. This perverse outcome must be avoided.

C. ARB's Definition of Electricity Importer Would Result in Unintended Consequences

A cap-and-trade program works under the fundamental principle that the emitter bears the cost burden and thus has an incentive to take proactive steps to make informed choices. Moving the compliance obligation to a downstream buyer is inconsistent with this fundamental principle. A downstream buyer has no upfront awareness of the GHG obligation, no ability to reject the imported electricity, and no ability to choose a less GHG-intensive product. As discussed earlier, from a financial perspective, these rules would create a windfall for sellers at any out-of-state intertie point while increasing costs to California load. Not requiring certain PSEs to

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[38] This is true even for bilateral trades (such as if a different PSE is identified as a downstream purchaser on an E-tag), because the purchaser was likely agreeing to buy market energy only for delivery at acceptable delivery points such as SP 15, and may not be aware that the market energy it was agreeing to purchase was imported from another balancing authority area.

submit allowances for their imports would give these PSEs a distortionary market advantage. If a PSE who schedules an import is not responsible for GHG compliance, then it will not have to include any GHG costs in its bids, and will be able to place much lower bids compared to in-state generation, even comparatively less GHG-intensive in-state generation. PSEs not regulated under the cap-and-trade rules that did not previously import electricity into California will then have every incentive to exploit this opportunity, and will change their behavior to import significant and market-altering volumes of electricity. The result will be the displacement of low-GHG in-state electricity with higher-GHG imports.

In addition, if certain sellers are able to avoid GHG costs by bidding into CAISO markets at specific nodes, then these sellers can arguably source the most GHG-intensive electricity and deliver it to California without bearing any consequences. Electricity markets would be artificially distorted as well, because certain sellers would be able to increase their sales at interties by bidding low, which could lead to congestion at these interties. These sellers would be able to gain this advantage simply because they would not have the same incremental cost profile due to the GHG regulatory rules. Such outcomes are totally inconsistent with the intent of AB 32. In order to protect against this misappropriation of cost and market distortions, the sellers of the energy to CAISO must have the GHG obligation at all CAISO interties.

D. CAISO's Tariff Requirements Appear to Imply that the Cascading Compliance Obligation Provision in Its Cap-and-Trade Regulations Is Unnecessary, and Should Therefore Be Deleted

SCE recently participated in an industry roundtable discussion[39] where CAISO staff offered their views suggesting that CAISO's tariff provisions, in conjunction with NERC E-tagging conventions and North American Energy Standards Board ("NAESB") definitions, make it clear that sellers at out-of-state interties do indeed deliver the electricity into California.

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[39] Western Power Trading Forum sponsored an Electricity Roundtable on the California Cap-and-Trade Program on August 2, 2011, at the California Chamber of Commerce in Sacramento ("WPTF Electricity Roundtable").

CAISO appears to believe that ARB would be able to rely on these provisions to conclude that the seller who imported electricity at an out-of-state POD within CAISO is always the first deliverer in California. If so, the provision pushing the compliance obligation downstream in Section 95802(a)(84) is unnecessary and should be deleted.

At the roundtable discussion, CAISO indicated that its Tariff governs all aspects of bidding and scheduling of energy and ancillary services on the CAISO-controlled grid, including, without limitation, the financial and technical criteria for Scheduling Coordinators, bidding, settlement, information reporting requirements and confidentiality restrictions.[40] CAISO has also indicated that each Scheduling Coordinator is responsible for submitting interchange schedules prepared in accordance with all NERC, Western Electricity Coordinating Council ("WECC"), and CAISO requirements, including providing E-Tags for all applicable transactions pursuant to WECC practices.[41] NERC's E-tagging specifications provide that paths identified on NERC E-tags define the flow of both energy flow and fiduciary responsibility.[42] Financial path components are referred to as market segments, while physical path components are called physical segments. Market segments are financial responsibilities for the receipt and/or delivery of the energy. Market segments represent those portions of the path that are associated with the tracking of title and responsibility; a physical segment is always associated with a parent Market Segment. The NAESB defines a PSE as the entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services.[43]

SCE respectfully requests that ARB delete this portion of the definition of an electricity importer and make corresponding changes to its cap-and-trade regulation to make clear that the sellers of electricity in the CAISO markets, and not the purchasers or the recipients of imported electricity, are responsible for compliance with the cap-and-trade program.

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40 CAISO Presentation at WPTF Electricity Roundtable, at 5.
41 *Id.*
42 *Id.* at 6.
43 *Id.* at 8.

V.

ARB SHOULD MODIFY THE DEFINITION OF AND CONDITIONS FOR REPLACEMENT ELECTRICITY

Sections 95802(a)(237) and 95852(b)(3) together allow replacement electricity that substitutes for electricity from an out-of-state variable renewable resource to qualify for the specific emission factor of the underlying variable renewable resource.[44] SCE supports this proposal, but disagrees with the definition of replacement electricity and the conditions ARB has imposed on the replacement electricity to qualify for the specific emissions factor of the underlying variable renewable resource.

Replacement electricity is typically used in the electricity industry to "firm and shape" out-of-state renewable resources. Through this "firming and shaping," SCE and other electricity providers are better able to integrate renewable resources into the California grid, meet Renewables Portfolio Standard ("RPS") goals, lower the emissions profile of California, and maintain reliable operations of the electricity system, and efficiently trade electricity. ARB's July 2011 Proposed Modifications define replacement electricity as "electricity delivered to a first point of delivery in California to replace electricity from variable renewable resources in order to meet *hourly load requirements.*"[45] It also places restrictions on the source of this electricity, stating that "the physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag[46] for the replacement electricity *must be located in the same Balancing Authority Area*"[47] and that deliverers of the replacement electricity must "have a *contract*, or ownership relationship, with the supplier of the replacement electricity."[48] Finally, if replacement electricity meets these requirements, it can be assigned the emissions

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[44] July 2011 Proposed Modifications, § 95802(237), at A-39 and § 95852(b)(3), at A-82.

[45] July 2011 Proposed Modifications, § 95802(237), at A-39 (emphasis supplied).

[46] NERC E-tag is defined as "North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas." July 2011 Proposed Modifications, § 95802(164), at A-27.

[47] July 2011 Proposed Modifications, § 95802(237), at A-39 (emphasis supplied).

[48] July 2011 Proposed Modifications, § 95852(b)(3)(A), at A-82 (emphasis supplied).

factor of the variable resource or the emissions rate of the difference between the original replacement electricity emissions rate and the default emissions rate.[49]

A. The Rules for Replacement Electricity Should Not Apply to Existing Contracts

SCE has a number of contracts with out-of-state variable renewable generators that were executed before ARB staff introduced the concept of replacement electricity in July of 2011. SCE requests that existing contracts with out-of-state variable renewable generators be "grandfathered," with all replacement electricity products associated with these facilities automatically counted as zero emissions regardless of how, when, or from where SCE contracts for the replacement electricity. Doing so would recognize the decisions and often long-term commitments made to variable renewable resources across the West prior to ARB's implementation of the cap-and-trade. It also recognizes that when these contracts were signed, additional costs to customers for GHG treatment of replacement electricity services were not contemplated. Furthermore, in SCE's case, renewable generators, who are reducing WECC-wide emissions, would not exist except for the power purchase agreements and long-term financial commitments that SCE and its customers have made.

Applying new rules to these contracts would significantly affect the value of existing renewable resources. It is neither operationally nor economically feasible to expect SCE or its counterparties to revise its contracts to comport with these new rules. SCE and other early supporters of renewable resources across the West should not be penalized for proactively undertaking renewable procurement pursuant to the RPS and other state goals. Accordingly, ARB should provide for a limited carve-out to the cap-and-trade rules for the subset of renewable resources that are outside of California and which were executed prior to adoption of these regulations. That limited set of resources should be allowed to count replacement

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[49] July 2011 Proposed Modifications, § 95852(b)(3)(C), at A-82 (emphasis supplied).

electricity with a facility-specific emissions factor tied to the renewable resource for the life of the contract, regardless of how, when, or from where such replacement electricity is procured.

B. ARB Should Not Require Replacement Electricity to Be Sourced from the Same Balancing Authority as the Variable Renewable Resource

Currently, Section 95802(237) of the July 2011 Proposed Modifications requires that the physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement energy must be located in the same balancing authority area.[50] SCE recommends that ARB should remove this requirement because it is unmanageable from an operational perspective.

First, the balancing authorities in which these renewable resources are located may not have the volume of replacement electricity sources necessary to accommodate the need for managing such generation. This may be due to local balancing authority needs, if dispatchable resources are needed to support local system load and cannot be exported. Alternatively, many renewable resources are concentrated in a few balancing authorities, which will create an increased demand for "replacement electricity" on top of local balancing needs.

Second, the physical transmission path availability from renewable resource balancing authorities into California is limited. Transmission constraints that could limit SCE's ability to import renewable electricity would also apply to replacement electricity sourced from this same region.

Third, most electricity products that are currently traded in the western power markets do not identify the ultimate source of electricity (nor the balancing authority) at the time of the transaction. Replacement electricity required to firm and shape variable renewable resources is generally procured in these markets using these "standard products." Requiring the source to be located in the same balancing authority would thus force market participants to create new, "non-

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[50] July 2011 Proposed Modifications, § 95802(237), at A-39.

standard" products that specify a balancing authority in its terms. This would bifurcate the common electricity products currently being traded, which may reduce market liquidity, leading to more expensive transactions, which in turn would affect rates.

Fourth, E-tags are created after the fact. The conventions for specifying the source of electricity on an E-tag are less defined than for other E-tagging conventions, such as specifying transmission or market paths. ARB's requirement may lead to potential gaming of the E-tag rules, should parties decide to list sources on an E-tag that inaccurately represents the true nature of the replacement electricity.

1. Regional Restrictions Are Not Necessary Because ARB Has Already Addressed Resource Shuffling in the July 2011 Proposed Modifications

At ARB's most recent cap-and-trade workshop held on July 15, 2011, ARB staff identified two main reasons for including these regional restrictions on replacement electricity. First, ARB is concerned about "resource shuffling," where compliance entities attempt to lower their compliance burdens by using high-emitting resources as replacement electricity. However, this concern is already addressed in the draft language prohibiting resource shuffling[51] and through the equation used to calculate any given replacement electricity emissions factor. In addition, the ARB's method of reducing the emissions burden associated with replacement electricity prevents compliance entities from lessening their compliance burdens by anything more than the default emissions rate per megawatt hour ("MWh") imported, regardless of the source of the replacement electricity. Thus, using high-emitting resources like coal as replacement electricity will result in higher compliance burden mitigation as compared to the use of unspecified, system energy. Therefore, ARB has already restrained resource shuffling, making it unnecessary to impose further these unnecessary regional requirements on compliance entities.

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[51] July 2011 Proposed Modifications, § 95852(b)(1), at A-80 to A-81.

2. Linkage with Other Cap-and-Trade Programs Can Be Addressed Without Regional Restrictions

ARB has identified the effect on future linkages with other cap-and-trade programs as a second reason for regional restrictions on replacement electricity. SCE agrees that when out-of-state regions with renewable resources that export to California link to California's cap-and-trade program, these renewable resources should no longer be able to be "replaced" with electricity from unlinked jurisdictions. Rather than imposing preemptive regional restrictions, however, SCE recommends that ARB address linkages as they arise. For example, ARB could include provisions that only allow replacement electricity sourced from outside the jurisdiction of the linked program. This allows greater operational flexibility while maintaining the integrity of the cap-and-trade program by accurately capturing the emissions associated with electricity imports.

C. ARB Should Clarify or Delete the Requirement that First Deliverers of the Replacement Electricity Must Have a "Contract" With Suppliers of the Replacement Electricity

Section 95852(b)(3)(A), requiring first deliverers of replacement electricity to have a contract or an ownership relationship with the supplier of the replacement electricity, is confusing and may be unnecessary. Nearly all commercial transactions involve a contract; even electricity transactions conducted over the telephone are done so with an underlying enabling agreement. SCE urges ARB to clarify what would constitute a contract in order to satisfy this requirement or delete the requirement entirely.

To clarify the term "contract," SCE recommends that ARB allow for considerable flexibility in defining "firming and shaping" contracts. If an entity must have a "long-term"[52] contract with the supplier of the replacement electricity, this would effectively require entities such as SCE to outsource the firming and shaping of out of state renewables to third-party

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[52] See SCE's comments in Section VI(B)(1) below on the reasons for defining "long-term" contracts as contracts of one year or more.

service providers at a sizable cost. Because it is typically more efficient and cost-effective for SCE to self-manage these activities, SCE currently does so for its out-of-state renewable generation. Therefore, ARB's contractual restriction could significantly increase costs to California electricity customers. SCE recommends that ARB revise its language in order to allow utilities the flexibility to manage out-of-state renewable firming and shaping in the most efficient and cost-effective manner possible, or delete the provision entirely, especially for grandfathered projects.

D. ARB Should Clarify or Delete the Requirement that Replacement Electricity Be Used to "Meet Hourly Load Requirements"

Finally, SCE requests clarification on Section 95802(237), requiring that replacement electricity be used to "meet hourly load requirements," as it is currently unclear how this provision is to be monitored or applied. All electricity transactions, including imports, are conducted to meet the customers' hourly load requirements. In their July 15 Workshop, ARB staff indicated that out-of-state variable renewable electricity generation and its replacement electricity, if any, could be accounted for over the course of one year. SCE strongly supports this annual true-up period, as it fits well with the current operational paradigm used to firm and shape renewable electricity as well as maintains consistency of the treatment of variable renewable resources under the RPS.

VI.

ARB SHOULD REVISE THE HOLDING LIMIT OR THE BENEFICIAL HOLDING LANGUAGE TO ACCOUNT FOR SCE'S LARGE GHG PRICE EXPOSURE

A. Current Holding Limits Are Insufficient for Large Compliance Entities and Expose SCE Customers to Significant Risk of Fluctuating GHG Prices

Section 95920 creates Holding Limits, or a maximum number of GHG allowances that a regulated entity can hold at any point in time.[53] SCE recognizes that Holding Limits were incorporated in the cap-and-trade regulation partially in response to SCE's and other stakeholders' concerns about market manipulation. SCE appreciates ARB staff's attention to this matter and is confident that Holding Limits will work to serve that purpose. However, SCE has a number of concerns with the Holding Limits language in the July 2011 Proposed Modifications, which, as currently drafted, could place SCE customers at significant financial risk.

First, SCE is very concerned about the small size of the Holding Limits[54] relative to SCE's total annual GHG price exposure. This substantial difference will make it extremely difficult to effectively hedge SCE customers' exposure to fluctuating GHG prices. In addition, SCE has a relatively low direct compliance obligation (for which it must retire compliance instruments) relative to its contractual obligations and electricity market price exposures (which are both financial exposures rather than compliance obligations). As such, SCE cannot mitigate its GHG price exposure by simply transferring compliance instruments into its Compliance Account and thereby take advantage of the Limited Exemption laid out in Section 95920(d)(2)(A)(H) to avoid approaching its Holding Limit.

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53 July 2011 Proposed Modifications, § 95920(a), at A-157.

54 *See* July 2011 Proposed Modifications, § 95920(d), at A-158.

Accordingly, SCE proposes a simple solution: the ARB should revise the Holding Limit calculation to be the greater of 1) the current formula contained in the July 2011 Proposed Modifications,[55] or 2) a compliance entity's allowance allocation[56] for that same year. This modification would allow SCE and other similarly situated compliance entities with large GHG price exposures to more effectively manage their exposure, but would also avoid market manipulation concerns that might arise through more general Holding Limit increases.

1. SCE Customers Are Exposed to GHG Prices

Because the hedging value of any ARB-allocated allowances is still uncertain,[57] SCE customers are exposed to fluctuating GHG prices in three ways: compliance obligations,[58] contractual obligations,[59] and electricity market price exposure[60] (collectively, "Total GHG Price Exposure").

As a percentage of its Total GHG Price Exposure, SCE has a relatively low compliance obligation and relatively high contractual obligation and electricity market price exposure. This is a result of the relatively small fleet of GHG-producing power plants that SCE owns relative to its customers' total electricity demand. The restructuring of California's electricity markets in 1996 resulted in SCE and the IOUs divesting most of their fossil-fueled generation. For SCE,

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[55] July 2011 Proposed Modifications, § 95920(d), at A-158.

[56] The allowance allocation can be thought of as a rough proxy for GHG price exposure.

[57] At this time, allocated allowances cannot be counted towards SCE's supply-side position because SCE is required to consign them to the ARB auction. As noted above, the use of auction proceeds from this consignment will be determined in R.11-03-12. If these proceeds are not returned to SCE customers or are used to fund projects SCE customers would not have otherwise funded, these allocated allowances provide no direct hedge value to SCE's total GHG price exposure and SCE must buy all of its GHG compliance instruments and hedging products using other customer funds.

[58] SCE's compliance obligation to surrender compliance instruments, under the regulation as currently drafted, is incurred through GHG emissions from its utility-owned generation and imported electricity for which SCE is the first deliverer into California.

[59] SCE's contractual obligations refer to the contractual commitments to provide compliance instruments or their financial equivalent to counterparties (such as tolling counterparties), for contracts where SCE has assumed the cost of AB 32 compliance.

[60] Electricity market price exposure is the exposure to fluctuating GHG prices inherent in SCE's residual net position ("RNP") for electricity. Because electricity generators and first importers of electricity into California have the compliance obligation for these emissions, the wholesale market price for electricity will increase to reflect this added cost of production. Therefore, if SCE's RNP is short, meaning SCE will have to buy electricity to meet its customer demand, SCE's customers will be exposed to the risk of GHG prices increases.

this included the sale of its natural gas-fired fleet. Subsequently, SCE shut down its coal-fired Mohave Generating Station in 2005, and the sale of its share in the coal-fired Four Corners Generating Station is pending. By 2013, SCE will be left with a direct compliance obligation from only its 1050 megawatt ("MW") natural gas-fired Mountain View combined cycle facility and four 50 MW natural gas-fired peaker plants.

To meet SCE's approximate peak customer demand of 23,000 MW and average annual customer demand of 10,000 MW,[61] SCE must therefore enter into contracts with a variety of generators. Although many of these generators have compliance obligation in the cap-and-trade program, SCE still bears a contractual obligation through these agreements (including tolling agreements) in which SCE assumes the financial obligation for GHG compliance.

In addition to this contractual obligation, SCE customers are exposed to fluctuating GHG prices through the impact of GHG costs on forward electricity prices. For example, if GHG compliance instrument prices increase, SCE's cost of entering into new contracts to provide electricity to its customers will also increase.

2. SCE's Total Annual GHG Price Exposure is Much Larger than the Holding Limit

SCE's annual Total GHG Price Exposure is several times larger than the Holding Limit in the first compliance period and significantly higher than the Holding Limit in the second and third compliance periods. This total economic burden of compliance was recognized in the allowance allocation process for regulated utilities. ARB staff used publicly-available data to forecast SCE's direct compliance obligation and then added allowance cost for all purchased power. As such, SCE's allowance allocation is a reasonable proxy for the costs and market exposure that SCE customers face. Thus in order to be able to manage this total economic

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[61] Edison International 2010 Annual Report, *available at* http://www.edison.com/files/EIX_AR10.pdf.

exposure effectively, SCE believes it is reasonable that its Holding Limit reflect its annual Total GHG Price Exposure and requests that ARB increase the Holding Limit as proposed below.

a) SCE Cannot Mitigate Much of Its Customer Price Exposure by Transferring Allowances to its Compliance Account

Because SCE's compliance obligation is a relatively low percentage of its Total GHG Price Exposure, it cannot take advantage of the same mechanisms as other compliance entities to manage its GHG price exposure within the Holding Limit. Another large utility that owns most or all of its generating resources, and therefore whose compliance obligation is a large percentage of its total GHG price exposure, could simply move a large volume of its allocated allowances directly to its Compliance Account, effectively using its Compliance Account to bank allowances for its current and even future obligations. Unlike SCE, this utility would be able to manage its GHG price exposure without the threat of exceeding its Holding Limit. SCE cannot do this because most of its exposure is through its contractual obligations and the electricity market price exposure, rather than through a compliance obligation. Therefore, SCE cannot mitigate a majority of its exposure by putting compliance instruments into its Compliance Account. As drafted, the Holding Limit would place SCE's customers at significant financial risk, especially compared to other market players.

3. Adjusting the Holding Limits Will Mitigate the Risk SCE's Customers Currently Face

To address the potential risk to SCE's customers, SCE proposes a simple modification to the formulas in Section 95920(d)(1):

(1) The number given by the following formula:

Holding Limit = <u>the greater of</u>

<u>1)</u> 0.1*Base + 0.025*(Annual Allowance Budget – Base)

In which:

"Base" = equals 25 million metric tons of CO_2e<u>, or</u>

2) an individual utility's allowance allocation for that same year as defined in Table 9-3.

This modification would allow SCE, and other similarly situated compliance entities with large GHG price exposures and relatively small GHG compliance obligations, to more effectively manage their risk without increasing market manipulation concerns (as with broader Holding Limit increases). While other options may exist, SCE's proposal is a simple and fair way to create an appropriate Holding Limit.

B. SCE Offers Comments on and Revisions to the Beneficial Holding Language

Sections 95802(27) and 95834(a)(2) define and establish a beneficial holding relationship, or a principal-agent relationship for holding compliance instruments.[62] Section 95920(h) seems to indicate that beneficial holding by an agent will not apply to the agent's Holding Limit.[63] SCE appreciates the efforts from ARB staff to address concerns regarding the Holding Limit for those entities which may need to hold compliance instruments on behalf of other entities with which they have long-term electricity delivery contracts. After the Proposed Draft Regulation was released, SCE and others expressed concern (detailed in the previous section) that these long-term contracts may not explicitly determine which party has the responsibility to surrender compliance instruments, and that the Holding Limit established in the October Proposed Draft Regulation did not take these contracts into account. In response, ARB staff created the concept of beneficial holding relationships, and is requesting comments on whether the proposed requirements address these concerns.[64] SCE offers its comments below.

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62 July 2011 Proposed Modifications, § 95802 (27), at A-7, and § 95834(a)(2), at A-71 to A-72.
63 July 2011 Proposed Modifications, § 95834(a)(2), at A-71 and § 95920(h), at A-161.
64 Notice of Public Availability of Modified Text and Availability of Additional Documents, Section N, released July 2011, at 7-8, *available at* http://www.arb.ca.gov/regact/2010/capandtrade10/candt15daynot2.pdf.

1. The Beneficial Holding Language Requires Some Clarifications Regarding Ownership, Long-Term Contracts, and Earmarking of Compliance Instruments

SCE maintains that the best solution to the Holding Limit problem is to revise the Holding Limit, as detailed in its proposal above**.** Short of this revision, however, there are a number of issues that need to be addressed and clarified in the beneficial holding proposal in order to make it a workable solution for the market. SCE requests that ARB clarify: 1) the application of beneficial holding toward the Holding Limit of the agent and principal; 2) its definition of an agent and a principal, and specifically clarify what it means for a principal to have "ownership" of compliance instruments held by an agent; 3) its definition of a "long-term contract" and its relationship to the beneficial holding section; and 4) its requirement that compliance instruments be "earmarked" for a specific principal at the time of purchase.

First, SCE requests that ARB clarify how beneficial holding will affect the calculation of the Holding Limit of the principal and that of the agent. Section 95920(h) states that the "application of the holding limit will treat beneficial holding by an agent as part of the holding of the owner."[65] SCE reads this to mean that beneficial holding, even if technically located in the holding account of the agent, will count toward the holdings of the principal or "owner." SCE recommends that ARB clarify this application of the Holding Limit.

Second, the definition of "Beneficial Holding" in Section 95802(a)(27) as "the holding of a compliance instrument in the holding account by one entity in which another entity has an *ownership interest*" requires some revision.[66] As ARB is aware, SCE (and other electrical distribution utilities) have signed a number of contracts with generators that require it to make generators "whole" for the GHG obligation that they incur when the utility dispatches their facilities in order to serve load. In other words, SCE has a contractual obligation to provide this

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[65] July 2011 Proposed Modifications, § 95920(h), at A-161.

[66] July 2011 Proposed Modifications, § 95802(a)(27), at A-7 (emphasis supplied).

counterparty either with physical allowances or an equivalent financial payment. However, while SCE is contractually responsible via either method for covering a generator's GHG obligation, there is no language in SCE's contracts with these generators that designate "ownership interest" of any of SCE's compliance instruments. The lack of ownership designation is significant because SCE's pro forma and existing contract language provides SCE the option of compensating generators for their GHG obligation (incurred as a result of dispatch) through financial settlement rather than compliance instruments. Tying "ownership" of a compliance instrument to a specific generator in a beneficial holding relationship would remove any flexibility that SCE would have to financially settle the GHG obligation. This flexibility is significant for allowing SCE to satisfy its contractual obligations at least cost, contributing to an efficient GHG market, and ensuring that electricity customers' rates are minimized. Without such flexibility, SCE's participation in any beneficial holding relationships would be severely restricted, limiting SCE's ability to effectively manage its GHG contractual obligations at least cost, and potentially raising the cost of compliance for SCE and other parties.

Third, it is unclear from the draft language whether an electrical distribution utility can only enter into a beneficial holding relationship when SCE has entered into a long-term contract with that entity.[67] SCE requests that ARB clarify that language, which states that an agent in a beneficial holding relationship "may not *also* serve as the agent" in another without a long-term contract.[68] This can be read to say that an agent may enter into one beneficial holding relationship without a long-term contract, but cannot enter into more than one such relationship. Either way, ARB's proposed definition of "Long-Term Contract" as one entered into before January 1, 2006 with a term of "five years or more"[69] raises a number of serious issues. Under the current Long-Term Procurement Plan approved by the CPUC, SCE is only permitted to

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67 *See* July 2011 Proposed Modifications, § 95834(a)(2)(B), at A-72.

68 *Id.* (emphasis supplied) ("An entity serving as agent in this type of a beneficial holding relationship may not also serve as the agent in a beneficial holding relationship with an entity with whom it does not have a long-term contract for the delivery of electricity").

69 July 2011 Proposed Modifications, § 95802(a)(150), at A-25.

procure products for a term of up to five years (excluding renewables and/or combined heat and power ("CHP") contracts). This definition would exclude most if not all of SCE's existing and future power agreements with generators that would require allowances in the cap-and-trade program from participating in any beneficial holding relationships. .

Fourth, mandating the disclosure of earmarking of compliance instruments to a particular generator at the time of purchase[70] would limit the usefulness to SCE of entering into a beneficial holding relationship. As noted earlier, SCE's pro forma and existing contractual language provides SCE with the option of using financial means to settle its GHG obligations to dispatching generators, and this provision would restrict that valuable flexibility. In addition, this pre-procurement earmarking will effectively require agents to predict how many compliance instruments they will want to transfer to their principals. This will lead to speculation, which could result in over-procurement of allowances by compliance entities for their principals, which in turn could raise allowance prices and tie up the market if allowances are no longer unavailable for long-term transfer.

2. **<u>ARB Should Revise the Definition of Long-Term Contract to "One Year or More," Remove the Concept of "Ownership" of Compliance Instruments by a Principal, and Adjust the Timing for Disclosure of a Beneficial Holding Relationship</u>**

SCE proposes a number of modifications to address these issues with the draft language on beneficial holding. First, ARB should modify the definition of "Long-Term Contract" in Section 95802(a)(150) from "five years or more" to instead read "…a contract for the delivery of electricity for the term of one year or more." This period is consistent with that used in SCE's solicitations, but will exclude short-term and spot contracts for the delivery of electricity. ARB should also clarify the requirement for a long-term contract for a beneficial holding relationship.

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[70] *See* July 2011 Proposed Modifications, § 95834(b)(1), at A-72.

Second, ARB should remove the concept of "ownership" of compliance instruments by a principal, and replace it with a "Beneficial Holding Account" for each registered agent. The allowances placed in the Beneficial Holding Account could, at any point, be transferred to a party with whom the agent has a "Long-Term Contract" (as revised above). In order to ensure that these allowances are indeed used only to meet contractual GHG obligations, allowances could not be removed from this account for any other use.

Third, ARB should revise Section 95834(b) to require the agent to disclose only the transfer of compliance instruments from an agent's Beneficial Holding Account to the Holding Account of the principal. Under the current draft rules, SCE and other entities acting as agents would have to predict their principals' needs and earmark compliance instruments for specific principals upon acquisition. Instead, agents should be able to respond to defined needs from their principals and disclose this information after the fact.

These changes to the beneficial holding framework would maintain the efficacy of Holding Limits for restricting market manipulation, while providing more value and much-needed flexibility for electrical distribution utilities and ensuring that GHG compliance costs are paid for at least cost to their customers.

VII.

ARB SHOULD CLARIFY ITS RULES FOR CONVENTIONAL IMPORTS

A. ARB Should Clarify Its Definition of Resource Shuffling

Section 95802(a)(245) defines resource shuffling as "any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred," and identifies two situations where delivery of electricity to the California grid is considered resource shuffling.[71] Section 95852(b)(1) describes resource shuffling as "a form of fraud."[72] SCE supports ARB's

[71] July 2011 Proposed Modifications, § 95802(a)(245), at A-40.
[72] July 2011 Proposed Modifications, § 95852(b)(1), at A-80.

discouragement of resource shuffling, which is consistent with AB 32's direction that emissions reductions be "real."[73] However, it is entirely possible that an entity may inadvertently commit resource shuffling, under the rules as currently written, without any fraudulent intent or scheme to receive an unearned emissions reduction. For example, a simple human error in reporting or interpretation of a rule could result in the appearance of resource shuffling. SCE agrees that truly fraudulent resource shuffling should be addressed, but notes that it will often be premature to immediately conclude that fraud is involved.

In Section 95802(a)(245)(A), ARB identifies one resource shuffling scenario, where electricity is delivered into the California grid for which "an emission factor below the default emission factor is reported…for a generation source that has not historically served California load (excluding new or expanded capacity)," and that "during the same interval(s), electricity with higher emissions was delivered to serve load" outside California's cap-and-trade program.[74] The proposed language incorrectly assumes that an individual regulated compliance entity has full knowledge of how the electricity that it places into the market will ultimately be used (or where it will "sink to load"). Once electricity is sold to another counterparty, the seller has no control over where, how, or when the electricity will sink to load, or whether it will be sold again. Also unclear is what ARB means by "new or expanded capacity."[75] Compliance entities will need a reference date from which to calculate "new or expanded capacity," or they may unknowingly engage in activities that seem, under these rules, like resource shuffling. SCE recommends that ARB introduce such a date and clarify this rule.

Section 95802(a)(245)(B) outlines a second scenario in which "electricity… replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards" adopted pursuant to Senate Bill

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[73] Cal. Health and Safety Code § 38562(d)(1).
[74] July 2011 Proposed Modifications, § 95802(a)(245)(A), at A-40.
[75] *Id.*

1368. Again, there is no reference date from which to calculate whether electricity had "previously" served load. In addition, this provision may penalize compliance entities for decisions made prior to the release of this revised regulation. For example, if a compliance entity had decided before the beginning of the cap-and-trade program to fully divest itself of generation from a higher-emitting facility, it could be considered resource shuffling as currently defined under the draft rules. Moreover, this scenario restricts utilities from adjusting their portfolios for valid economic dispatch reasons. A number of factors contribute to this economic valuation, many of which could change over the coming years due to forces outside the control of ARB or any compliance entities. ARB should be careful to not restrict an electricity deliverer's ability to procure the least-cost electricity (assuming the GHG costs are adequately incorporated into these prices).

To address these issues, SCE recommends the following changes to the language:

Section 95802(a)

> (245) "Resource Shuffling" means any <u>intentional</u> plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:
>
> > (A) An emission factor below the default emission factor is reported pursuant to MRR[76] for a generation source that has not historically served California load (excluding new or expanded capacity <u>and grandfathered contracts</u>). <u>New or expanded capacity is relative to capacity as of 01/01//2012.</u> And, during the same interval(s), <u>the same entity reporting the lower emissions delivers</u> electricity with higher emissions ~~was delivered~~ to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or
> >
> > (B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that ~~previously~~ served load in California <u>prior to 01/01/2012;</u> except when:
> >
> > > <u>(1)</u> the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards

[76] MRR refers to ARB's Mandatory Reporting Regulation, draft language for which has been released simultaneously with ARB's cap-and-trade regulation. It is available at http://www.arb.ca.gov/regact/2010/ghg2010/mandatory15dayreg.pdf.

adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), or
(2) the contract with the resource was terminated prior to 01/01/2012.

Section 95852(b)

(1) Resource shuffling is prohibited~~, ~~ and is a violation of this article~~ and is a form of fraud~~. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling.

B. SCE Supports the Qualified Exports Concept and Suggests that ARB Clarify the Calculation of an Emissions Rate for Exports

Sections 95802(218) and 95852(b)(6)-(7) define "Qualified Exports," which are those exports that occur in the same hour as electricity imports.[77] Once this amount has been calculated, emissions associated with qualified exports may be subtracted from those of the associated imports using an equation described in Section 95852(b)(7).[78] SCE supports this treatment of qualified exports, as it accurately addresses the complexities of electricity contracting and trading structures where power can be separately imported and exported within an hour. For compliance entities that must deal in these complex markets, this treatment of qualified exports will help to maintain fungible and efficient electricity markets and avoid undue compliance costs. SCE supports the one-hour time slot for netting qualified exports with imports, as it aligns well with current energy scheduling and marketing practices.

In order to ensure that these rules are effectively and properly applied, ARB should clarify how the emissions burden of qualified exports will be calculated. In Section 95852(b)(7), this emissions burden is subtracted from specified and unspecified imports. However, ARB does not appear to have articulated how emissions for qualified exports will be calculated. ARB

[77] July 2011 Proposed Modifications, §95802(218) at A-36 and § 95852(b)(6), at A-83.
[78] *See* July 2011 Proposed Modifications, §95852(b)(7), at A-83.

should be aware that the emissions rate for exports is often unknown. Exports, for purposes of this rule, will likely be sourced or purchased in California,[79] but the specific source may be unknown. Current E-tag practices for exports often list a generic power source, such as "SP 15 System." ARB has not stipulated what emissions rate should be used for this or other generic system power. Without an understanding of the emissions rate for system-sourced power exported from California, the qualified exports rule can not be applied.

To address this situation, ARB needs to determine what emissions rate(s) it will use for qualified exports from unspecified sources. SCE believes that using a single "qualified export emissions rate" for all exports originating from California will lead to unintended consequences, including gaming opportunities and market changing behavior, especially if there is a difference between the default emissions factors for imports and exports. For example, if imported electricity originating from the BPA balancing authority, which has a much lower default emissions factor, is allowed to be offset with a qualified export with a higher default emissions factor, it will take fewer MWh of qualified exports to fully offset all of the emissions from such imported energy.

SCE suggests that ARB develop rules similar to those for default imports, such that unspecified exports that sink in BPA balancing authority receive an emissions rate of 0.0856 metric tons per MWh, while exports to other balancing authorities should receive an emissions rate of 0.428 metric tons per MWh.[80] However, ARB should not use the intertie location as a proxy for the final power sink, as power that passes through a specific intertie does not necessarily sink in that region. In addition, ARB has not determined how compliance entities will be able to allocate their total qualified exports to their imports. Once again, such allocation

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79 Alternatively, they may be "wheeled" transactions, in which a California entity first imports electricity and then exports it later. However, this electricity will not raise the same problems, as it will have a defined emissions rate due to the fact that it was imported.

80 Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emission, MRR Section 95111(b)(1), at 104, and Section 95111(b)(3) at 106, *available at* www.arb.ca.gov/regact/2010/ghg2010/mandatory15dayreg.pdf.

is important if a compliance entity will have imports in any given hour that have originated from a variety of specified and unspecified sources with different emissions factors.

In part due to the complexity of this issue, SCE recommends (as noted above) that ARB should take steps to analyze and model the implications of GHG regulations on power markets and power flows. Thorough modeling is necessary to inform ARB and other stakeholders what the impact ARB's cap-and-trade program could have on the power markets and WECC-wide power flows, and to help ARB preserve a functioning, efficient, and secure market.

VIII.

THE IMPROVED ALLOWANCE RESERVE STRUCTURE STILL FACES SIGNIFICANT CHALLENGES FOR COST CONTAINMENT

Section 95913, governing the sale of allowances from the Allowance Reserve, was updated in the July 2011 Proposed Modifications to clarify the bidding process.[81] As SCE has stated in previous comments, the bidding process for the Allowance Reserve should identify each regulated entity's maximum willingness-to-pay for Allowance Reserve allowances.[82] Once this willingness-to-pay is identified, in order to facilitate low-cost compliance, all bids should flow down to the lowest available price level. In essence, entities with a higher willingness-to-pay should not necessarily have to pay more for these allowances if they are available at lower prices, which SCE believes was the intent of the changes to Section 95913. SCE supports the increased flexibility, allowing bids to be filled from the lowest tier first, but ARB should clarify Section 95912(f)(1) to confirm that the clearing price for filled bids is the tier price, not the bid price.

In addition, ARB should outline a method for repopulating the Allowance Reserve in the event that it is stressed, or when at least one-third of the allowances in it are sold. As a mechanism to contain compliance costs, the Allowance Reserve can only be successful if there is

[81] July 2011 Proposed Modifications, § 95913(e) and (f), at A-144 to A-145.
[82] SCE December 2010 PDR Comments, at 26.

sufficient supply of compliance instruments available for regulated entities. It is crucial that ARB have a method in place well before the Allowance Reserve approaches any level of stress, as efforts to evaluate the situation then will be too late to offer any resolution.

Further, as SCE has previously recommended,[83] the Allowance Reserve should offer a stable price ceiling in addition to the price floor. While the Allowance Reserve operates to provide allowances at a set price to regulated entities, unless there is a determined method to repopulate the Allowance Reserve, the market cannot be assured that there is any real long-term cost containment.

The Allowance Reserve is not the proper place for any allowances unsold at auction,[84] paid as penalties, or removed from the Voluntary Renewable Electricity Reserve Account. In each of these cases, the allowances should be returned to the general market via quarterly auction.

First, ARB staff has expressed concern that returning allowances unsold at auction to future auctions would only continue to produce an oversupply of allowances in these future auctions. However, due to the intrinsic nature of discrete quarterly auctions, allowance demand and resultant auction clearing prices will likely fluctuate significantly in response to external factors. Even if allowance demand is thin in one quarter, it may not always be thin. Instead, the quantity demanded in future auctions will respond to many conditions, such as weather, fuel prices, or offset availability. For example, the electricity industry may demand more allowances than average in the third quarter of a very hot year as electricity demand increases across the state. However, compliance entities may not have been able to predict such weather-related conditions in previous auctions and procure enough allowances to fill their high need. Simply because demand in the market was not high enough to clear at $10, the regulated community should not then be forced to pay Allowance Reserve prices – $40 or more – in the future.

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[83] SCE December 2010 PDR Comments, at 21-23.
[84] *See* July 2011 Proposed Modifications, § 95911(b)(4), at A-133.

Second, SCE strongly supports the change in Section 95857(d)(1)(a), which places excess emissions allowances paid as penalties back into the market through the next quarterly auction, rather than in the Allowance Reserve.[85] Placing the penalty allowances into the Allowance Reserve would impose an additional marginal cost increase on the rest of the regulated community that had nothing to do with the original penalty.

Third, while the voluntary renewable electricity provisions[86] can provide a way to recognize the emission reductions from voluntary renewable energy procurement, any allowances not retired under such a program should be returned to the market in a timely manner. As with all allowances returned to market, these allowances should be placed in a quarterly auction rather than the Allowance Reserve in order to maintain market-based costs for these allowances.

IX.

ARB SHOULD REVISE ITS REGULATION TO ASSIST COVERED ENTITIES TO MEET THEIR COMPLIANCE OBLIGATIONS THROUGH OFFSETS, VOLUNTARY RENEWABLE ELECTRICTY, AND ALLOWANCES

A. ARB Must Design an Offset Policy that Will Promote Efficient Emissions Reductions

1. Before Restricting Offset Use, ARB Should Recognize All Emission Reductions under AB 32

Sections 95970 to 95988 address ARB offset credits and registry offset credits.[87] ARB has also issued four Compliance Offset Protocols based on earlier-developed Climate Action

85 July 2011 Proposed Modifications, § 95857(d)(1)(A), at A-101.
86 *See* July 2011 Proposed Modifications, § 95841.1, at A-74 to A-77.
87 July 2011 Proposed Modifications, §§ 95970-95988, at A-167 to A-258.

Reserve protocols that contain project eligibility criteria for various offset projects.[88] SCE continues to be concerned that ARB's offset policies are being implemented in a manner that will reduce the number of eligible offset projects brought to market. Furthermore, regulated entities may not be able to use offsets for the full 8% of emissions reductions authorized in the regulation.

Despite concerns from other parties, covered entities will not be able to substantially avoid direct emissions reductions using offsets. Currently, an overwhelming majority of the emissions reductions under AB 32 are already being achieved directly within California by regulated entities. According to the updated emissions reductions estimates released by the ARB in June 2011, more than 3 out of every 4 tons of GHG emissions reduced will come from direct command-and-control measures, all of which are located in California.[89] Thus, the cap-and-trade program will compromise a relatively small share of the emissions reductions required to comply with AB 32, and the share of reductions due to offsets will be even smaller. Yet offsets, assuming sufficient supply, still have enormous potential to provide significant cost containment opportunities for the California emissions market.

SCE offered detailed suggestions for implementation of ARB's offsets program in its December 2010 comments on the Proposed Draft Regulation.[90] This process includes many steps such as the development and approval of protocols, verification services, third-party registries, offsets projects registration, and offsets certification and listing. Rather than repeat those suggestions, SCE refers ARB staff to those earlier comments. The ARB offset program must be fully in place for the first compliance period in order to provide real cost containment, and SCE strongly urges ARB staff to take the necessary steps to ensure a robust supply of offsets

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[88] *See* Compliance Offset Protocol for Urban Forest Projects Staff Report, October 13, 2010, at 1-2 (*available at* http://www.arb.ca.gov/regact/2010/capandtrade10/cappt2.pdf).

[89] California Air Resources Board, Supplement to the AB 32 Scoping Plan Functional Equivalent Document, June 13, 2011, Table 1.2-3 "Estimate of Emissions Reductions Needed from Proposed Scoping Plan Measures Not Yet in Place" *available at* http://www.arb.ca.gov/cc/scopingplan/document/Supplement_to_SP_FED.pdf

[90] *See* SCE December 2010 PDR Comments, at 28-32.

by the first compliance period. SCE encourages the ARB to develop offset rules that will enable the State to achieve its AB 32 emission reduction goals efficiently and effectively.

2. The Offset Reversal Provisions Should Be Revised

Section 95985(b)(1) allows ARB to invalidate an offset within 8 years of issuance if ARB has determined that information provided to ARB related to an offset project "was not true, accurate, or complete."[91] SCE requests that ARB add further detail on what is meant by "true or accurate." As currently written, ARB could reverse offsets for even clerical errors. SCE believes that this is not the intent of this provision, and requests that ARB clarify these provisions. Furthermore, in the event that ARB chooses to reverse an offset as a result of information that is not true or accurate, ARB should first require that the entity most directly responsible for the incorrect information or fraud to retire instruments equal to the offset in question. The regulation should clearly state that in the event that ARB is able to obtain replacement compliance instruments from the "bad actor" project developer or verifier, these replacement compliance instruments will be retired by ARB, leaving the validity of the original offsets unchanged. In this way, the environmental integrity of the program persists without undue hardship to downstream purchasers of offsets from these projects.

Section 95985(b)(6) provides that if an offset is certified by two different verifiers (after three years), then ARB may invalidate the offset within five years of issuance rather than the usual eight years.[92] SCE supports this move toward limiting offset invalidation as this will create more market confidence and has the potential to lower compliance costs. However, SCE strongly recommends that ARB further adjust its provisions in the following ways:

§ 95985

(b)

(6) If an offset project is verified ~~after three years of~~ <u>at any time after</u> ARB offset credit issuance by a different offset verifier, ARB may <u>no</u>

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[91] July 2011 Proposed Modifications, § 95985(b)(1), at A-243.
[92] July 2011 Proposed Modifications, § 95985(b)(6), at A-243.

> <u>longer</u> invalidate ~~within five years of issuance of~~ the ARB offset credits covered by an Offset Project Data Report.

These changes will increase confidence in the offset markets while maintaining the environmental integrity of the fully verified offsets.

Section 95985(b)(7) provides that in itself, an update to a Compliance Offset Protocol "will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol."[93] SCE applauds ARB's inclusion of this section; in order to promote the most effective and efficient offset reductions, the regulated community must have confidence that ARB will not reverse the approval it gave to an offset project or offset after it has been verified. However, SCE recommends that ARB add explicit language to this section stating that a protocol change cannot in any way influence a decision to reverse an offset.

> (7) An update to a Compliance Offset Protocol ~~in itself,~~ will not <u>in any way</u> result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol.

3. <u>Regulated Entities Should Have the Flexibility to Use Offsets Up to Eight Percent of Reported Emissions over the Entire Eight Years of the Cap-and-Trade Program</u>

Section 95854 was revised in the July 2011 Proposed Modifications to clarify that the quantitative usage limit on offsets is 8% per compliance period, rather than on an annual basis. SCE thanks ARB staff for making this clarification to address stakeholder concerns about offset supply. However, SCE continues to have serious concerns about offset supplies in the first two compliance periods, which would limit compliance entities from using the offsets toward the full 8% of emissions reductions authorized in the regulation. Offsets are a critical source of cost containment for regulated parties under AB 32. By contrast, concerns over concentrated offset use later in the cap-and-trade program are misguided, given that climate change is a global, long-

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[93] July 2011 Proposed Modifications, § 95985(b)(7), at A-244.

term challenge, and the share of offsets retired in any particular compliance period is neither relevant nor environmentally important.

As the regulated community anticipates the increase in offset supply in the later years of the program, ARB should allow covered entities the flexibility to use offsets up to 8% of reported emissions to date over the eight years of the program. In doing so, ARB would be assured that the use of offsets would never exceed 8% of the entity's compliance obligation to date, while affording flexibility to minimize the cost of compliance over the entire term of the cap-and-trade program. SCE proposes the following changes to the regulation language:

> § 95854. Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits
>
> (a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.
> (b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:
>
> $$O_O/S \text{ must be less than or equal to } L_O$$
>
> In which:
> O_O = Total number of compliance instruments identified in section 95854(a) submitted <u>since January 1, 2013</u> to fulfill the entity's <u>total</u> compliance obligation ~~for the compliance period~~ <u>through the current compliance year.</u>
> S = Covered entity's <u>total</u> compliance obligation <u>beginning January 1, 2013 through the current compliance year</u>.
> L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

B. <u>Voluntary Renewable Electricity Can Play an Important Role in Reducing GHG Emissions</u>

Sections 95841.1 and 95831(b)(6) were added to the cap-and-trade regulation to clarify the role of voluntary renewable electricity in reducing GHG emissions and supporting increased voluntary investment in renewable resources.[94] Voluntary renewable electricity refers to renewable electricity that is not used for RPS compliance.[95] Section 95831(b)(6) creates a Voluntary Renewable Electricity Reserve Account to set aside allowances that may be retired to account for voluntary renewable electricity.[96] Section 95841.1 explains the program requirements and calculations for voluntary renewable electricity.

SCE maintains, as in prior comments and public statements, that any voluntary renewable energy incentives must satisfy some specific conditions.

First, in order to qualify for the retirement of allowances from the Voluntary Renewable Electricity Reserve Account, the voluntary renewable energy procurement must satisfy the same rules as utilities in order to show mandatory renewable energy purchases as zero emission. ARB has indicated that any renewable generation must be California RPS-eligible. SCE encourages ARB to clarify that any voluntary renewable energy purchase must satisfy the same rules as the compliance market to be recognized as zero emissions under the cap-and-trade program.

Second, SCE supports ARB's decision to use allowances retired in the amounts matching emissions reductions due to voluntary renewable energy procurement for retirement and not direct them to alternative uses.

Third, any allowances in the Voluntary Renewable Electricity Reserve Account that are not retired on behalf of voluntary renewable energy procurement should be returned to the market via the quarterly state auction in a timely manner. SCE recommends that any year that the number of current year vintage allowances in the Voluntary Renewable Electricity Reserve Account exceeds the number of allowances retired under this program, these excess allowances should be returned to market through the next quarterly auction.

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94 July 2011 Proposed Modifications, § 95841.1, at A-74; *see also* Notice of Public Availability of Modified Text and Availability of Additional Documents, at 8.

95 July 2011 Proposed Modifications, § 95841.1, at A-74.

96 July 2011 Proposed Modifications, § 95831(b)(6), at A-62.

C. Regulated Entities Should Be Able to Retire Any Compliance Instruments Issued to Date

Section 95856(b) governs the compliance instruments valid for surrender in the cap-and-trade program.[97] SCE recommends that ARB clarify the language to indicate that a compliance entity wishing to retire allowances may use any compliance instruments available at that time. As currently written, it is unclear whether compliance instruments from the last year of a compliance period may be used to fulfill a compliance obligation from the first year of that period. For example, there is confusion as to whether a compliance instrument issued in 2014 could be retired at the end of the compliance period (e.g., 2015) to satisfy a 2013 emissions obligation. SCE suggests the following modifications:

§ 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

(b)

(2) To fulfill any compliance obligation, a compliance instrument must be issued from ~~an~~ any allowance budget year up to and including the year during which the compliance obligation is calculated and surrendered, unless;

SCE believes that these refinements to the draft language will increase the necessary clarity.

X.

ALTHOUGH IMPROVED, THE PENALTIES PROVISIONS REMAIN DUPLICATIVE, VAGUE, AND EXCESSIVE

Sections 96013 and 96014 address penalties and violations of the cap-and-trade rules.[98] In its earlier comments on the Proposed Draft Regulation, SCE noted that the draft penalty provisions were confusing, duplicative, and excessive, and requested that ARB revise and clarify

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[97] July 2011 Proposed Modifications, § 95856(b), at A-96 to A-97.
[98] July 2011 Proposed Modifications, § 96013, at A-280, and § 96014, at A-281.

these provisions.[99] SCE appreciates the many changes made to the cap-and-trade and reporting regulations to address these concerns. For example, Section 95107 of the MRR now assesses penalties on a per day basis, rather than a per ton per day basis.[100] ARB has also modified the penalty provisions to allow compliance entities more time to submit its untimely surrender obligation[101] and, only then, to assess violations under Health and Safety Code Section 38580.[102] In addition, the July 2011 Proposed Modifications limit penalties by calculating the untimely surrender obligation only once per annual or triennial compliance obligation. SCE appreciates this added clarity and constraints on the previously unbounded penalty calculations.

However, certain sections remain duplicative, vague, and excessive. Specifically, while the untimely surrender obligation will be calculated only once per annual and triennial obligation, violations are still accrued daily.[103] In ARB's earlier Discussion Draft, released July 7, 2011, this section had been edited to calculate violations per 45 day period.[104] Those edits have been removed from the July 2011 Proposed Modifications. SCE supports the Discussion Draft language and recommends that ARB revert to the 45-day period calculation.

SCE requests additional clarification on Section 95857 (b)(4), which addresses the due date of the untimely surrender obligation. In the current language, this obligation is due five days after "the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed."[105] SCE is pleased that ARB recognizes the importance of allowing compliance entities enough time and opportunity to procure any necessary additional allowances, avoiding severe market shocks. This language, however, is

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99 SCE December 2010 PDR Comments, at 34.

100 Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emission, MRR Section 95107, at 88-89, *available at* www.arb.ca.gov/regact/2010/ghg2010/mandatory15dayreg.pdf.

101 *See* July 2011 Proposed Modifications § 95857(b)(4), at A-99.

102 *See* July 2011 Proposed Modifications § 95857(c)(1), at A-99; § 96014(b), at A-281; § 96013, at A-280.

103 July 2011 Proposed Modifications, § 96014(b), at A-281.

104 July 2011 Discussion Draft, § 96014(b), at A-276, *available at*. http://www.arb.ca.gov/cc/capandtrade/meetings/072011/cap-and-trade-discussion-draft.pdf.

105 July 2011 Proposed Modifications § 95857(b)(4), at A-99.

confusing and should be clarified. SCE reads "the applicable surrender date" to be the annual or triennial compliance due date. As this deadline is now November 1 for all entities and all compliance obligations, it seems unnecessary to have this complex calculation. For instance, the provision could retain the exact same deadline outcome if it instead stated that the obligation is due "the 17th business day of the first month of the quarter" (or five days after the auction). SCE requests that ARB clarify these provisions to provide certainty to regulated parties.

Lastly, the July 2011 Proposed Modifications retain some excessive penalty provisions. Specifically, Section 96013 retains the reference to the penalty provisions in Health and Safety Code Section 38580. As SCE previously noted, these provisions provide a menu of criminal and civil penalties that can range from fines of $1,000 to $1,000,000, and up to a year in county jail or state prison.[106] These fines are between 200 to 100,000 times expected allowances prices. Such excessive penalties are not necessary and will not serve to deter bad actors. SCE recommends that ARB develops a more reasonable fine structure.

XI.
CONCLUSION

SCE appreciates this opportunity to provide its comments to ARB on the July 2011 Proposed Modifications. SCE recommends that ARB staff revise its cap-and-trade regulation in accordance with the principles and suggested modifications outlined herein.

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[106] SCE December 2010 PDR Comments, at 34.

Respectfully submitted,

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