Los Angeles Department of Water & Power

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September 19, 2016

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

SUBJECT: LOS ANGELES DEPARTMENT OF WATER AND POWER'S COMMENTS ON PROPOSED AMENDMENTS TO THE CALIFORNIA GREENHOUSE GAS CAP-AND-TRADE REGULATIONS

The Los Angeles Department of Water and Power (LADWP) appreciates the opportunity to comment on the California Air Resources Board's (ARB) proposed amendments to the California Cap on Greenhouse Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation).[1] LADWP's comments provide our policy views regarding key regulatory amendments that would extend the Cap-and-Trade Regulation beyond 2020, implement the requirements of the Clean Power Plan (CPP) rule[2] and address implementation issues associated with Renewable Portfolio Standard (RPS) Adjustment provision.

Serving approximately 1.4 million customers in Los Angeles with a generating capacity of over 7,300 megawatts, LADWP is the largest municipal electric utility in the nation, and the third largest electric utility in California. LADWP is a vertically integrated utility, owning and operating a diverse portfolio of generation, transmission, and distribution assets spanning several states. LADWP is making unprecedented major capital investments in the following areas that will result in significant CO_2 emissions reductions on a LADWP system-wide basis:

[1] Air Resources Board, Staff Report: Initial Statement of Reasons (Aug. 2, 2016), https://www.arb.ca.gov/regact/2016/capandtrade16/isor.pdf [hereafter "2016 ISOR"].
[2] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64662 (Oct. 23, 2015) [hereafter "Clean Power Plan" or "CPP"]/

- Replacing all existing coal resources with non- or low-emitting replacement generation;
- Expanding our reliance on renewable energy;
- Modernizing power plants in the South Coast Air Basin;
- Implementing major projects and measures for improving end-use energy efficiency;
- Electrifying the transportation sector; and
- Developing increased capacity for energy storage

LADWP strongly supports the development of a comprehensive and effective regulatory program for reducing greenhouse gas (GHG) emissions from all segments of the economy, including the electric power sector. At the federal level, LADWP supports the full implementation of the CPP rule. To that end, LADWP has joined a group of proactive electric utilities in intervening in support of EPA to defend against legal challenges to the CPP rule. At the state level, LADWP supports ARB's efforts to develop new regulations to implement the ambitious post-2020 emissions reduction goals of the California Cap-and-Trade Regulation and appreciates the opportunity to submit these comments to improve the effectiveness and workability of ARB's regulatory proposal.

Notwithstanding LADWP's support, it is very difficult to assess the full ramifications of the proposed amendments to the California Cap-and-Trade Regulation and whether they are workable, efficient, and provide adequate protections for LADWP's ratepayers, including low income customers because the Regulation is not fully developed, but rather contains over three dozen placeholder clauses and notations of future policy decisions. Many of these placeholder clauses and notations are critical elements of the new regulatory regime that will potentially have major implications for LADWP and other affected entities under the Cap-and-Trade Regulation. To address this issue, we recommend that ARB not rush the regulatory process for amending the Cap-and-Trade Regulation and that, at the very least, the public is allowed sufficient time to comment on the entire rulemaking each time that ARB releases future 15-day amendment packages to the August 2 proposal.

I. POST-2020 ALLOWANCE ALLOCATION TO EDUS

A. Allocation of Allowances to EDUs

LADWP supports ARB's proposal to continue to allocate a substantial portion of allowances in the post-2020 compliance period to electric distribution utilities (EDUs). Doing so has been an important mechanism for mitigating cost impacts of the Cap-and-Trade Regulation to California ratepayers. It has also fulfilled ARB's goal to "provide further incentives to the distribution utilities to meet or exceed the emissions reductions they expect to achieve through implementation of [complementary state] policies."[3] The methodology ARB adopts to determine the number of allowances that will be allocated to each EDU will significantly impact ratepayers. LADWP supports ARB's proposal to base its methodology primarily on expectations of each EDU's cost burden (cost-based allocation methodology).

Below we identify a number of areas of both support and potential improvement of ARB's proposal. It should be noted, however, that substantial uncertainty remains with regard to the proposed allocation approach. ARB has not spelled out, in detail, its proposed methodology and has left blank important components of this piece of the post-2020 program, including the utility-specific allocations for 2021-2026 and the details of the methodology for 2026 and beyond. LADWP will provide additional comments once ARB has further developed its proposal and urges ARB to provide affected utilities sufficient time to analyze and submit comments on those proposed new elements (including their interrelationship with the entire Cap-and-Trade Regulation) once that proposal has been released for public comment.

1. **ARB Should Accurately Reflect the Planned Retirement Date of Intermountain Power Plant in Cost-Based Allocation Methodology**

As part of the cost-based allocation methodology, ARB has assumed that the two existing coal units at the Intermountain Power Plant (IPP) will retire in 2025 and repower as a natural gas combined cycle facility.[4] However, existing power purchase contracts do not expire until 2027.[5] Such contracts include the Power Sales Contract between Intermountain Power Agency (IPA), the entity that holds legal title to IPP, and LADWP and the Excess Power Sales Agreement, which requires LADWP to purchase 88.281% of the available excess power through the end of June 15, 2027 expiration date.

LADWP has set an ambitious goal to replace these two existing coal units several years early. This goal, however, is not a binding obligation to do so. LADWP's ability to meet this earlier date is contingent upon several factors, including the completion of a lengthy permitting process to build the new gas-fired replacement units, material procurement of the components and construction of those replacement units, and final concurrence of all 35 participants of the power sales contracts to terminate those contracts early.

Given the considerable uncertainty regarding the actual retirement date of the IPP units, ARB should incorporate a 2027 retirement date, rather than the aspirational target date

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[3] ARB, Appendix 1: Staff Proposal for 15-day Changes to Address Electricity Sector Allowance Allocation at 2 (Dec. 16, 2010), https://www.arb.ca.gov/regact/2010/capandtrade10/res1042app1.pdf [hereafter "Appendix 1"]..

[4] *See* 2016 ISOR, Appendix F at 2574, ("Adjust allocation after IPP retirement in 2025 for those EDUs with IPP contracts").

[5] *See* Intermountain Power Agency, *About Intermountain Power Agency* http://www.ipautah.com/about/index.asp ("All Purchasers have executed Power Sales Contracts with IPA that provide the basic security for the debt service on all bonds issued by IPA for construction and acquisition of the Project, exclusive of the STS. Additionally, the Purchasers have agreed to pay all Project costs of Operation and Maintenance for Project facilities. The Power Sales Contracts expire on June 15, 2027.").

of 2025, into its cost-based allocation.

Additional reasons why the allocation of allowances through 2027 would be a more equitable approach include the following:

- The process of replacing the two years of IPP generation carries substantial costs. The cost of IPP repowering to natural gas is substantial, and expediting the completion of the repowering early would most likely add to those incremental costs. In the alternative, LADWP would have to replace the coal-fired generation from IPP by purchasing more expensive replacement power (from low- and zero-emitting power resources) on the market. Therefore, even if LADWP is able to exit its contract with IPP two years early, doing so will entail substantial costs, which will have direct and substantial cost impacts on California ratepayers. The purpose of the cost-based allocation is to mitigate this type of cost burden through the allocation of allowances.[6]

- Providing an allocation assuming IPP will be in operation through 2027 also provides EDUs with the proper incentives to exit from high-emitting contracts early. In fact, in 2011, the ARB adopted a resolution directing the Executive Officer to consider amending the Cap-and-Trade Regulation to "provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32."7

2. ARB Should Allocate Allowances Through 2030 and Post-2020 Allocations Should be Based on One Consistent Methodology That Takes the Ratepayer Cost Burden Into Account

ARB has proposed that each EDU's post-2020 allocation will be a set number of allowances for each year of 2021-2026, and that "staff may propose a methodology as part of this rulemaking process" for "Allocation in 2027 and Beyond."[8] ARB has not proposed the specific allocation numbers for 2021-2026,[9] nor has it provided any details on the methodology it would use to allocate allowances in the subsequent years (i.e., 2027 and beyond).

LADWP appreciates that ARB intends to specify the number of allowances that will be

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[6] ARB, Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector at (July 27, 2011), https://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf [hereafter "Appendix A"] ("Cost burden is expected to result from emissions costs associated with fossil, QF, *and non-emitting resources priced at market* being passed from generators and marketers to utility customers") (emphasis added).

[7] ARB, Resolution 11-32 at 11 (Oct. 20, 2011), https://www.arb.ca.gov/regact/2010/capandtrade10/res11-32.pdf

[8] 2016 ISOR, Appendix A at 208 (proposed § 95892(a)(2),(3)).

[9] 2016 ISOR, Appendix A at 216-18 (proposed Table 9-4).

allocated in 2021-2026 as part of the rulemaking process for post-2020 allocation. It is our understanding that ARB would not provide similar individual EGU allowance allocations for the 2027 to 2030 period, but would provide a formula or cap adjustment for EDUs to apply to calculate their allowance allocations. LADWP looks forward to providing comments once these specific numbers—and more detail on the underlying methodology—have been proposed. LADWP urges ARB staff to provide specific information on its methodology to calculate the EDU-specific allocation numbers, such as through a publicly available spreadsheet.

LADWP supports ARB's continued efforts to prioritize the benefits gained from longer-term certainty of allowance allocations. Such benefits would be further enhanced by specifying allocations through 2030. Doing so will enable utilities such as LADWP to make more informed long-term decisions when developing their Integrated Resource Plans. For example, longer-term certainty regarding the availability of allowances will provide utilities with stronger justifications that long-term investments in higher cost, lower carbon resources will not result in unexpectedly higher costs for ratepayers.[10] Furthermore, utilities will better be able to justify near-term plans for further decarbonization in 2027-2030 if they know upfront that doing so will not *reduce* the number of allowances they will ultimately receive in those years. Finally, establishing allowance allocations through 2030 in a single rulemaking, rather than in a series of rulemakings, will reduce the administrative burden on ARB and the public.

LADWP requests that ARB provide more clarity regarding the specific *methodology* that will be used to determine such allocations. While it is LADWP's understanding that ARB intends to use a single methodology for allocating allowances for the entire post-2020 period, ARB's August 2 proposal is unclear on this point. The proposal's language that "staff *may* propose *a* methodology" has left an impression in the proposal that ARB is developing a separate method for allocating allowances during the 2027-2030 period. LADWP urges ARB to adopt the same cost-based allowance allocation methodology for the entire 10-year period to ensure consistency, provide greater regulatory certainty, and minimize administrative complexity.

3. Shifting EDU Allowance Allocations to the Industrial Sector

ARB has proposed to discontinue the allowance allocation associated with energy used at "energy intensive trade exposed" (EITE) facilities to EDUs and instead allocate allowances to EITE facilities representing their electricity consumption using a formula that includes Product-Based Benchmarks (PBB). ARB's stated purpose of this reallocation of allowances is to mitigate electricity cost increases for Cap-and-Trade Regulation compliance costs that would otherwise be borne by EITE sources by providing this supplemental allocation of allowances directly to those sources. Specifically, ARB has proposed to:

[10] Long-term certainty is particularly important for publicly-owned utilities, which require extra lead time in order to obtain approvals from politically accountable governance bodies such as city councils, and which operate under longer procurement time frames.

> ...exclude the emissions associated with electricity sold to industrial covered entities from the calculation of each EDU's 2020 emissions cost burden, calculated using the average annual industrial covered entity purchased electricity from 2013 and 2014 data reported through MRR and an EDU-specific emission factor.[11]

LADWP believes that ARB's proposal is unlikely to accomplish ARB's goal of leakage prevention. For these reasons, ARB should retain the current approach and not shift any allowances from EDUs to EITE sources.

(A) Shifting Allowances to EITE Sources is Unnecessary to Prevent Leakage

ARB has justified its proposal to shift allowances from EDUs to EITEs, in part, in order to "create a level playing field" between investor-owned utilities (IOUs), which are subject to California Public Utilities Commission (CPUC) oversight, and publicly-owned utilities (POUs), which are not. However, this is based on the inaccurate assumption that merely because POUs are not subject to CPUC oversight, they are not obligated to ensure that allowance value flows to ratepayers, including covered industrials (EITE sources). POUs are structured differently from IOUs. First, LADWP and other POUs are subject to local governmental oversight, in lieu of the CPUC regulation that has traditionally applied to IOUs. Second, LADWP and other POUs operate for the exclusive benefit of their retail ratepayers and own and operate a majority of their generation assets on behalf of their ratepayers. For example, LADWP is accountable to the Los Angeles City Council to provide reliable, affordable and clean electricity for its ratepayers. City Council oversight ensures that electricity costs are kept low, and that, whenever possible, important employers in the community such as those that operate EITE sources do not face financial pressure to leave.

Vertically integrated POUs, such as LADWP, use their allocated allowances directly to cover their compliance obligations. Thus, under the current electricity cost-mitigation approach for EITE sources, all of LADWP's ratepayers (including EITE sources) receive the financial benefit of the GHG emission allowances allocated to LADWP. In effect, LADWP is providing leakage protection to covered EITE customers to the fullest extent practicable by providing the lowest possible electricity costs to those customers, enabled by the allowances allocated to LADWP for that purpose.

(B) ARB's Proposed Methodology for Redistributing Allowances to EITE Facilities will Undermine its Leakage Prevention Goals

It is LADWP's understanding that ARB intends to deduct from its otherwise-cost-based EDU allocation a number of allowances based on the amount of electricity sold by LADWP to EITE facilities in its service territory and LADWP's specific emission rate. As mentioned above, the EITE facilities would receive allowances based on a formula that

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[11] ISOR at 43.

includes PBBs. The difference in allowance allocation methodologies results in a transfer of allowances from the EDUs to EITE facilities that would not be on a one-to-one basis.

ARB's proposal does not include a specific methodology for calculating the number of allowances that would be *distributed to* EITE facilities in our service territory. However, some elements of the proposal suggest that ARB's approach would be less effective at reducing leakage related to increased electricity costs than the current framework for leakage prevention that POUs provide (that is, avoiding rate increases). Specifically, the proposal states that "staff is proposing to allocate to all industrial covered entities for the sector-specific emissions associated with purchased electricity *regardless of electricity supplier for the industrial covered entities*."[12] This language suggests that while ARB will deduct from EDUs a specific number of allowances that is based on the EDU's emission intensity, ARB will *not* redistribute those allowances to each EITE entity based on the emission intensity of the EDU that serves it. Such an approach, if adopted, would significantly undercut the "leakage prevention" goal that is currently being met by the cost-based EDU allocation. EITE entities that are located within EDU service territories with a lower than average carbon intensity will be long on allowances distributed to cover their actual electricity carbon costs. In contrast, covered trade-exposed industrial entities that are located in EDU service territories with a higher than average carbon intensity will be short on allowances distributed to cover their actual electricity carbon costs.

If ARB proceeds with this approach, EITE facilities within LADWP's service territory would not receive enough allowances through the benchmarking method to cover the actual carbon costs of the electricity they consume. LADWP estimates that EITE facilities located within LADWP's service territory would experience an *increase in the* cost of doing business in California ranging from $100,000 to $400,000 per year. In aggregate, the increased cost to all EITE facilities within LADWP's service territory would be over $1 million per year. This is a conservative estimate based on the average annual electricity kWh consumption of EITE facilities, the California average electricity emission rate (calculated using 2015 Total System Power as reported by the California Energy Commission (CEC) and the eGRID2012 GHG Annual Output Emission Rate for subregion CAMX), LADWP's 2015 average electricity CO_2 intensity rate, and the current auction floor price of $12.73 per metric ton. The actual cost will increase over time as the cost of allowances increases.

Even if LADWP purchased all of the allowances allocated directly to the EITE entities in its service territory for the purpose of offsetting electricity cost increases, LADWP would face a substantial shortfall in allowances needed to make up for the number deducted from the EDU allocation. This cost would either be borne by the EITE entities, causing additional leakage, or by all LADWP ratepayers (including low income customers), undermining the purpose of the cost-based EDU allocation.

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[12] 2016 ISOR at 34 (emphasis added).

Therefore, the current approach to mitigating electricity cost increases for EITE facilities (and therefore limiting leakage) is preferable to the method proposed by ARB, as it avoids cost increases to EITE facilities (and therefore limits the potential for leakage). However, if ARB nonetheless insists on moving forward with its proposal to increase the industrial allocation level for EITE facilities, it is important that it use a benchmark method based on individual EDU carbon intensity (rather than a statewide benchmark for carbon intensity). Alternatively, an even simpler approach would be first to calculate the number allowances in each EDU territory that will be allocated to EITE entities for purchased electricity, and then to reduce each EDU's allocation by that amount. This alternative approach ensures that there would only be a 1-for-1 reduction in EDU allocation for every extra allowance that EITE entities *in that service territory* receive. However, it would likely require ARB to delay implementation of this change until such time as it is able to determine the appropriate allocation of allowances for each EITE facility. The failure to adopt an alternative approach to either EITE allocation or EDU deduction will result in additional leakage and potentially the loss of significant businesses in LADWP's service territory.

B. Supplemental Allowance Allocation for Electrification

The electrification of the transportation and other sectors of the California economy will be necessary for California to meet its long-term climate goal of achieving an 80 percent GHG emission reduction from 1990 levels by 2050. California has clearly signaled its plans to advance State policies designed to accelerate the electrification of the transportation and goods movement sectors. Electrification is a key priority for LADWP and other EDUs in the South Coast Air Basin. The increased electricity generation needed to power California transportation will necessarily result in increased GHG emissions for which EDUs—and ultimately ratepayers—will be responsible. The resulting increase in EDU load due to this electrification has not been accounted for in ARB's cost-based EDU allocation methodology. In order to ensure that ratepayers are protected from increased costs associated with electrification, a corresponding increase in allowances allocated to the electric power sector during the post-2020 period is required.

Providing allowances for electrification can help to efficiently meet ARB's complementary policy goals and is consistent with California Senate Bill 350 (SB 350).[13] The resulting emission increases in the electric sector due to electrification would be more than offset by substantial GHG emission reductions in other sectors. Providing an allowance allocation for electrification can mitigate the disincentive to invest in electrification.

[13] *See* S.B. 350 § 3 ("The state board shall identify and adopt appropriate policies, rules, or regulations to remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emission reductions in other sectors through increased investments in transportation electrification. Policies to be considered shall include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities, or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification").

In the August 2 proposal, ARB recognized this need and expressed its commitment "to evaluate how increased electrification ... for the post-2020 period should be accounted for in the allocation methodology for EDUs."[14] LADWP applauds ARB's recognition of this need and support's staff's continuing evaluation of approaches for fairly and effectively incorporating transportation electrification into the cost-based EDU allocation methodology.

LADWP urges ARB to consider methodologies that allocate allowances based on projected emission increases due to projected actual use of electrification infrastructure. These additional allowances would be distributed from an allowance reserve specifically established for EDUs that present evidence of increased load to meet projected future increases in transportation electrification in each EDU service territory.

To quantify the number of allowances needed by an EDU, the methodology should rely on EDU-specific generation data and emission factors. For generation data, ARB should first utilize a projection of expected electricity demand increases associated with the utility's electrification efforts. ARB could utilize EDU Integrated Resource Plans developed as part of the SB 350 process or CEC electric utility data. The demand, in the case of electric vehicles, could be based on EDU-specific forecasts of electric vehicle penetration in its service territory, average kwh/mi electric vehicle efficiency ratings taken from published U.S. Department of Energy and U.S. Environmental Protection Agency (EPA) data, and mile per year per vehicle information taken from ARB's EMFAC model. For EDU-specific emission factors, ARB should utilize a three year average of each EDU's system-wide emission rate. Quantification could be updated annually.

After estimating an EDU's projected increase in electricity demand (and GHG emissions) due to electrification, ARB would allow the covered EDUs to hold in their accounts sufficient number of allowances to cover their emissions. This amount of each EDU's allowances would remain available to meet the EDU's compliance obligations. Rather than imposing overly burdensome verification requirements,[15] LADWP recommends that ARB restrict the ability of EDUs to sell or trade those allowances allocated to cover costs associated with electrification.

C. Use of Allowance Proceeds

1. POU Use of Allowances for Compliance

[14] 2016 ISOR at 43.

[15] While *ex post* evaluation of investments in electrification *infrastructure* would be straightforward, it would be extremely difficult to accurately track and quantify whether the forecasted electricity *use* was realized. For example, electric vehicle owners residing in LADWP service territory may not be charging their vehicles at home or within that service territory. Thus, any verification protocol should not be so difficult to meet as to result in the failure to obtain a Mandatory Reporting Regulation positive or qualified positive verification determination.

LADWP strongly supports ARB's proposal to continue to permit POUs to directly use allocated allowances for the post-2020 compliance period. Unlike IOUs, POUs operate for the exclusive benefit of their retail ratepayers and own and operate their generation assets on behalf of their retail ratepayers. POU-owned generation also is generally used only to serve POU ratepayers as part of a vertically integrated electric utility system. Unlike IOUs, POUs do not have subsidiaries that can profit from selling power on the market from their merchant generators. Thus, not-for-profit POUs have no incentive to use allowance allocations to artificially lower the price of the power from their owned resources in order to increase market share. Rather, they have a legal obligation to serve their communities and customers by providing reliable and clean electricity at the most affordable cost. Therefore, the concerns that led to ARB's 2010 decision to require IOUs to consign allowances to auction continue not to apply to POUs.[16]

LADWP supports and appreciates ARB's proposal to remove the obligation that POUs report on the number of allocated allowances that the POU has moved to its compliance accounts.[17] As the proposal states, this is information that ARB already has and reporting it presents an unnecessary burden.

2. Auction Proceeds

LADWP has previously been concerned about ARB proposals implementing a requirement that allowance proceeds be provided to ratepayers on a non-volumetric basis. In its March workshop, ARB staff appeared to indicate their intent to propose restrictions on the use of "allowance value" to provide volumetric—that is, rate—relief to customers. LADWP was concerned that this requirement, if applied to all "allowance value," could limit the ability of vertically integrated POUs, such as LADWP, to utilize allocated allowances for meeting their compliance obligation in the least-cost manner. To that end, LADWP supports ARB's more precise drafting of the proposed requirement that "allowance *auction* proceeds" be provided to ratepayers on a non-volumetric basis.[18]

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[16] *See* ARB, Staff Report: Initial Statement of Reasons at IX-62 (Oct. 28, 2010), https://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf [hereafter "2010 ISOR"] ("Rationale for Section 95892(c). Monetization of allowances through auction is intended to ensure that the amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of electricity ratepayers. This practice will also ensure that freely allocated allowances to a distribution utility will not impact competition in the electricity generation market (where utilities compete with merchant power producers)."); *Id.* at II-32 ("By requiring IOUs to put their allowances up for auction, the regulation maintains the current competitiveness of the deregulated California electricity market. In this way, utility-owned generation and independent generation have equal access to allowances."); ARB, Final Statement of Reasons at 342 (Oct. 2011), https://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf [hereafter "2010 FSOR"] ("In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process.").

[17] 2016 ISOR at 41.

[18] 2016 ISOR at 41;

This proposed language clarifies that POUs may continue to use allocated allowances directly for meeting their Cap-and-Trade compliance obligations, which provides general *rate* relief to ratepayers.

LADWP also urges ARB to clarify that the use of allowance auction proceeds to fund energy efficiency and clean energy projects would constitute a non-volumetric use of those proceeds. It would be administratively burdensome to require that POUs—which consign relatively few allowances to auction—provide the limited proceeds obtained at auction to ratepayers as a lump sum bill credit. Rather, it would be more effective and impose less administrative cost for that money to be invested in energy efficiency and clean energy projects that provide bill relief.

II. RPS ADJUSTMENT

When it designed the Cap-and-Trade Regulation, ARB appropriately recognized that the structure of California's RPS could result in cap-and-trade compliance obligations for zero-emission power that is firmed/shaped prior to delivery. California's RPS program allows a percentage of an EDU's RPS compliance obligation to be satisfied with firmed/shaped renewable electricity. Firmed/shaped renewable electricity is renewable electricity that the EDU pays to be generated but for which it receives substitute electricity which carries a GHG "compliance obligation" as unspecified power.

Consistent with the mandate under AB 32 to work with the CPUC to "minimize duplicative or inconsistent regulatory requirements," ARB addressed this problem by establishing an RPS Adjustment for firmed/shaped renewable energy imported into California. Specifically, the RPS Adjustment reduces EDU Cap-and-Trade compliance obligations for any zero-emission generation that the EDU pays for in order to meet its RPS obligations, but which was not directly imported into California due to transmission constraints or operational reasons. That is, for the purpose of Cap-and-Trade Regulation compliance, the RPS Adjustment treats firmed/shaped renewable energy as zero emission generation, consistent with its treatment under California's RPS.

ARB has recently made or proposed two revisions to the Cap-and-Trade Regulation relating to the RPS Adjustment. As discussed below in greater detail, both of these rule changes will significantly, unnecessarily, and unfairly increase the costs paid by California ratepayers for zero-emission generation, without achieving a corresponding environmental benefit.

A. Revisions to RPS Adjustment for the 2016-2020 Period

ARB staff recently issued guidance on the use of the RPS Adjustment under the existing Cap-and-Trade Regulation.[19] This new guidance that sets a high bar (i.e.,

[19] See ARB Guidance, entitled *Reporting and Verification Guidance for RPS Adjustment Claims for California's Mandatory Greenhouse Gas Reporting Regulation* (ARB RPS Adjustment Guidance), available at: https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/rps-adj-guidance.pdf.

burden of proof) that California electric utilities must satisfy in order to claim the RPS Adjustment credit. Under this new guidance, California electric utilities must demonstrate to the verifier that the original electricity produced by the renewable generating facility did not come into California. California electric utilities often do not have access to that proof because e-tags are confidential and to see the e-tag, the California electric utility must be a party listed on the e-tag. If LADWP is dealing with a middleman, LADWP cannot see the e-tags that show where the original electricity sank. In such cases, LADWP (and similarly-situated California utilities) cannot prove that the original electricity did not come into California and therefore cannot satisfy the burden of proof in order to claim the RPS Adjustment credit. If the California utility cannot claim the RPS Adjustment credit to offset the GHG emissions reported for the imported firmed/shaped RPS-eligible electricity, the utility's customers will end up paying twice: 1) they will have to pay a premium to buy zero emission renewable electricity with all of its environmental attributes in order to satisfy the RPS, and 2) they will also have to pay for Cap-and-Trade compliance obligations for the imported firmed/shaped electricity.

This ARB guidance severely limits the usefulness of the RPS Adjustment and so risks imposing significant additional costs on California ratepayers for zero-emission generation for which they are already paying in order to comply with the RPS mandate. This interpretation will impact EDUs such as LADWP for the next 5 years. ARB should revise its approach to the RPS Adjustment requirements for the 2016-2020 period and continue to apply this corrected approach thereafter during the post-2020 term of the Cap-and-Trade Regulation.

ARB's interpretation of the Mandatory Reporting Rule (MRR) and Cap-and-Trade Regulation has the effect of benefitting power traders that purchase "null" power (which is formerly renewable electricity from which RECs and environmental attributes have been removed) from out-of-state renewable generating facilities and import that electricity into California. Power traders with a portfolio of assets can selectively choose which generation asset that they schedule for delivery into California. Unfortunately, ARB is not enforcing the existing provision of the Cap-and-Trade Regulation that requires an electricity importer to report the associated REC serial numbers in order to claim a compliance obligation for imported electricity based on a specified source emission factor (when RECs are created, which should be for all RPS renewable procurement).[20] By failing to enforce this requirement, ARB is providing power traders a financial incentive to strategically select "null" power from renewable generating facilities for direct delivery into California, thereby increasing their earnings at the expense of California ratepayers. In effect, ARB's interpretation of the MRR and Cap-and-Trade Regulation is providing power traders free GHG emission benefits to which they are not contractually entitled and preventing the California electric utilities that paid for the zero-emission renewable electricity and own the RECs associated with that electricity from claiming the zero-GHG emission benefit under the RPS Adjustment on behalf of its customers. This approach is inconsistent with both the legislative intent of the RPS and

[20] For this reason, LADWP believes that ARB should not finalize the proposed deletion of this existing requirement.

AB 32 laws, as well as the past positions that ARB has adopted to establish and implement the Cap-and-Trade Regulation.

With respect to the intent of the California Legislature, Section 399.11(b) of the Public Utilities Code states that procurement of renewable electricity is intended to provide unique benefits to California and lists those benefits, stating "***each of which independently justifies the program***" (emphasis added). Among the benefits enumerated by the Legislature are ***two*** directly related to GHG reductions—with one benefit described as "displacing fossil fuel consumption in the state"[21] and the other benefit described as "meeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation."[22] This statutory language makes it clear that the Legislature intended the RPS Program to function as a mechanism to reduce GHG emissions from the electric power sector and thereby achieve the GHG emission reduction goals of AB 32. As a result, ARB has a legal obligation to align the two programs and to do so in a manner that provides full credit for the GHG reductions achieved under the Cap-and-Trade Regulation.

This approach was incorporated into ARB's design of the Cap-and-Trade Regulation. Specifically, ARB established a regulatory scheme that provided electrical distribution utilities with no allowances to cover GHG emissions for imported RPS-eligible firmed/shaped renewable electricity. No allowances were allocated because it was assumed there would be no corresponding compliance obligation for any renewable energy imported into California. The RPS Adjustment was established to offset those emissions as a deduction to the Cap-and-Trade compliance obligation, effectively treating this imported RPS-eligible electricity as zero-emission power under the Cap-and-Trade Program. By changing the requirements to claim the RPS Adjustment mid-stream, ARB has effectively "broken" its deal with the California electric utilities to treat all RPS-eligible electricity as zero emission under the Cap-and-Trade Program as was intended when the free allocation was set.

LADWP proposes that ARB provide a supplemental allocation of allowances to cover firmed/shaped imported renewable electricity that does not qualify for the RPS Adjustment credit because the EDU does not have the adequate documentation to prove the original renewable electricity did not come into California. Because this issue is affecting EDUs now, LADWP requests that ARB implement this fix as soon as possible and not wait until the start of the 2020 compliance period. LADWP will continue to work with the California utilities and ARB to develop language/guidance to prevent misreporting of null power and clarify what entities are entitled to claim the zero-emission attributes for imported firm/shaped renewable energy.

B. Revisions to the RPS Adjustment for the Post-2020 Period

ARB has proposed to remove the RPS Adjustment altogether and instead allocate additional allowances to EDUs as part of the post-2020 cost-based allowance allocation

[21] Cal Pub. Util. Code § 399.11(b)(1).
[22] *Id.* § 399.11(b)(4).

methodology. However, as outlined in more detail below, this proposed approach is inadequate for the following reasons:

- while an EDU's imported firmed/shaped electricity may increase over time, the allocation will decline over time due to the cap adjustment factor;
- POUs with grandfathered long-term contracts are permitted to meet a larger percentage of their RPS obligation with firmed/shaped renewable electricity than the proposed methodology takes into account;
- the proposed allocation method does not take into account differences in the volume of imported firmed/shaped electricity between utilities, and
- the proposed allocation method does not make allowance for new contracts for imported firmed/shaped RPS eligible electricity.

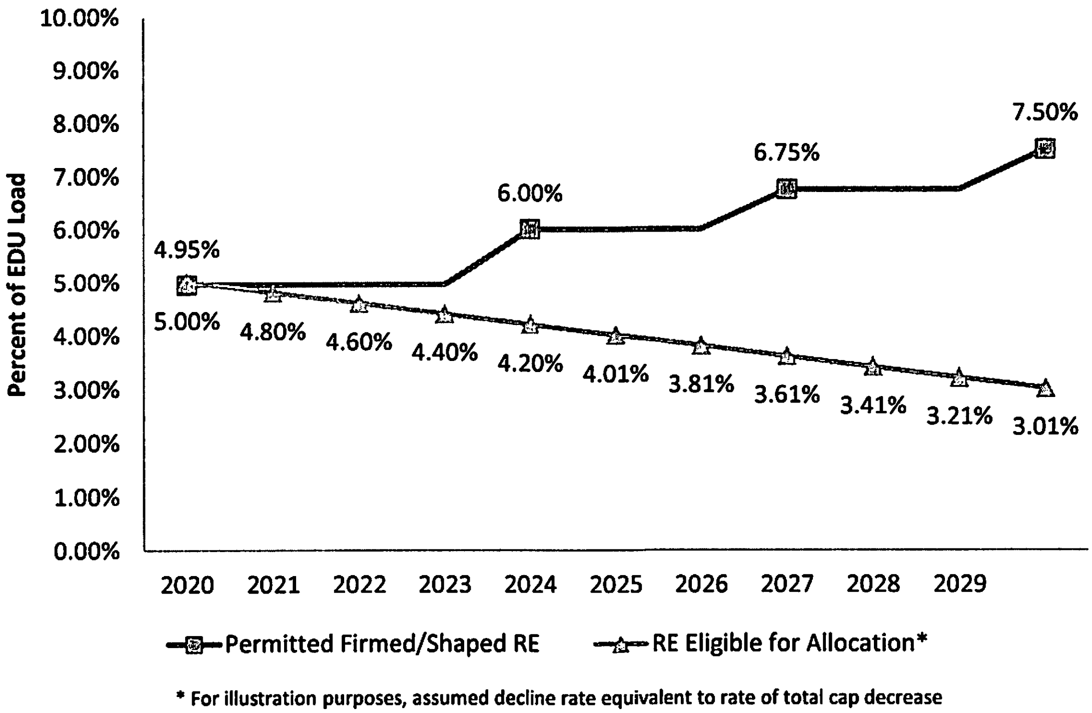
Therefore, LADWP recommends that ARB retain the RPS Adjustment for the post-2020 period. Any post-2020 RPS Adjustment should, as outlined above, ensure that the owner of RECs associated with RPS-eligible firmed/shaped power (and only the owner of such RECs) can claim the RPS Adjustment credit to offset reported GHG emissions

1. ARB Should Retain the RPS Adjustment

ARB's proposed methodology for allocating allowances is not sufficient to address the increased compliance costs that would result from the elimination of the RPS Adjustment.

ARB has not designed its allowance allocation methodology to provide an allowance for every ton of GHGs associated with MWhs of firmed/shaped renewable electricity that would qualify for the RPS Adjustment. California EDUs will face compliance obligations for firmed/shaped power imported into California despite the fact that ratepayers paid for zero-emission renewables. Those added costs may be partially offset by an allocation of allowances to cover the compliance obligations; however, under ARB's current proposal they will not be fully offset because the allocation will decrease over time as the cap adjustment factor reduces the size of every EDU's allocation (in proportion to the reduced emissions cap). By contrast, the number of Cap-and-Trade compliance instruments needed to cover an EDU's firmed/shaped renewable power will increase over time. As indicated in the chart below, category 2 RECs are limited to a specified percentage (generally, 15 percent) of an EDU's RPS compliance obligation, but that RPS obligation grows over time, reaching 33 percent in 2020 and 50 percent in 2030. Therefore, by 2030, up to 7.5 percent of an EDUs generation may come from firmed/shaped renewable energy, but the allowances allocated to cover that generation would be 4.5 percent of the EDU's 2020 expected load times the 2030 cap adjustment factor. That is, by 2030, only a very small fraction of the EDUs load that is associated with zero-emission generation for which compliance instruments may be required will be covered through an allowance allocation.

In order to ensure that California ratepayers are not forced to pay twice for the same zero-emission generation due to California's overlapping regulatory obligations, ARB should retain the RPS Adjustment, modified as outlined above, for the post-2020 period.



2. Suggested Revisions to Allocation Approach

If ARB is, nonetheless unable to retain the RPS Adjustment, it should revise its proposed allocation approach to the renewable energy double payment problem to fully account for the level of firmed/shaped renewable energy that EDUs, including POUs, may legally acquire.

First, as outlined above, the number of allowances that ARB has proposed to allocate to EDUs substantially underestimates the number of compliance instruments that may have to be surrendered for zero-emission power purchased by EDUs. To address this issue, ARB should adopt a more realistic methodology for calculating the number of allowances needed to meet compliance obligations for firmed/shaped renewable generation through 2030. One approach that ARB could adopt is to calculate the number of allowances an EDU requires to offset the cost of these overlapping obligations in a way that ensures that the EDU receives enough allowances to actually cover the amount of compliance instruments the EDU will be required to surrender. For example, rather than allocating allowances for this generation as part of the cost-based allowance allocation, ARB could set aside a separate pool of allowances to be distributed to EDUs based on the amount of emissions attributable to firmed/shaped generation that an EDU is permitted under the California RPS program.

Second, ARB's cost-based allocation approach incorrectly assumes that all EDUs may obtain a maximum of 15 percent firmed/shaped renewable generation as part of their RPS compliance. While this limit is accurate for IOUs, it is not an accurate assumption for POUs. As part of SB 350, California applied the RPS to POUs and generally directed the CEC to adopt regulations to implement the RPS for POUs. Consistent with SB 350,[23] the CEC adopted regulations that apply the RPS to POUs, including regulations that limit the amount of firmed/shaped renewable power POUs can rely on to meet their RPS obligation. However, unlike for IOUs, for which the 15 percent limit applies to all RPS-eligible renewable power, for POUs, this limit applies only to the "Portion of electricity products procured pursuant to a contract or ownership agreement executed on or after June 1, 2010."[24] That is, any otherwise eligible renewable power procured pursuant to a contract executed before June 1, 2010, can be firmed/shaped even though this renewable energy could increase the total amount of firmed/shaped renewable power above the IOU limit of 15 percent. For example, LADWP has four grandfathered power purchase agreements with out-of-state wind farms with firming/shaping delivery arrangements. These four wind farms produce approximately 1.1 million MWh per year.

To the extent ARB finalizes an allocation methodology to protect ratepayers from the cost of overlapping compliance obligations under Cap-and-Trade and RPS programs, it should do so in a way that accurately accounts for the amount of firmed/shaped renewable generation that a POU is permitted for RPS compliance. For example, ARB could adopt a POU-by-POU determination of the allowable level of firmed/shaped renewable generation, and use that generation to calculate the cost-based allocation for each POU.

III. PROPOSED PLAN TO IMPLEMENT THE CLEAN POWER PLAN

As discussed below, LADWP generally supports ARB's proposed backstop mechanism that would be triggered if California fails to meet its CO_2 reduction obligations under the CPP. Specifically, LADWP supports the establishment of a separate cap-and-trade program that would allocate free allowances to CPP-affected electric generating units (EGUs) under the backstop measure based on historic emissions. However, the comments below briefly outline LADWP's recommendations to ARB's proposed methodology for calculating the free allowances that would be allocated to each affected EDU under the backstop measure. In addition, LADWP supports ARB's proposal to allow affected EGUs to trade backstop emission allowances, but recommends that ARB allow for the interstate trading of CPP allowances under the backstop program.

A. Establishment of a Separate Regulatory Program to Implement the CPP Backstop

LADWP believes that in order to implement the CPP backstop, ARB should create and codify a wholly separate cap-and-trade system. This approach makes sense given the low probability of California ever trigging the backstop measure and in order to provide maximal flexibility in implementing the backstop. By establishing a separate parallel

[23] Cal. Pub. Util. Code §399.16(c)(1),(2); *Id.* § 399.15(b)(2)(B).
[24] Cal. Code Regs. Tit. 20, § 3204(c)(4),(8).

program, there is no need to make major changes to the design elements of the California Cap-and-Trade Regulation (such as the carefully crafted rules for emission trading and allocation of allowances). As discussed below, LADWP recommends specific changes to its proposal with respect to compliance with the CPP with respect to the allocation and trading components of the proposed backstop approach.

1. Methodology for the Allocation of Allowances

ARB proposes to use the calendar year immediately preceding the implementation of the backstop (described as "triggering compliance period" in the proposal) as the basis for allocating allowances to EGUs under the backstop program. While LADWP supports ARB's proposal to calculate the backstop allowance allocations based on past emissions levels, we do not believe it is appropriate for ARB to use the year that immediately precedes its triggering when determining allowance allocations. Such an approach would reward the EGUs whose excess emissions caused the sector to exceed the CPP goal. This approach would also result in under-allocating allowances to those EGUs whose emissions had been reduced to well below the level that would be sufficient to meet the CPP goal without triggering the backstop.

LADWP recommends that ARB use a known, pre-CPP multi-year baseline of emissions as the basis for allocating allowances. ARB, for instance, could determine allowance allocation for its backstop program based on the average of affected EGU emissions from 2013-2015. Using this historic baseline would appropriately reflect the relative size and emission-intensity of different EGUs while avoiding the possibility of rewarding those EGUs that are most responsible for triggering of the backstop.

Using a multi-year period[25] would provide a more representative baseline of normal operations than a one-year period, thereby lessening the impacts of unusual circumstances such as forced outages of EGUs, low energy demand, or low hydroelectric supply.

2. Interstate Trading of CPP Backstop Allowances

LADWP supports ARB's proposal to allow EGUs to trade CPP allowances within the backstop mass-based emission budget trading program. However, the backstop proposal would only permit the trading of allowances with other CPP-affected EGUs within California. LADWP believes that there is no reason for ARB to disallow the *inter*state trading of allowances.

LADWP believes that allowing interstate trading under the backstop program is good policy. Most California utilities, including LADWP, supply electricity to their customers from a mix of in-state and out-of-state generation sources, and so interstate trading of compliance instruments will reduce administrative costs. Interstate trading under the backstop program would promote more economically efficient decisions about

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[25] LADWP recommends using at least three full years of emissions data.

generation throughout the West. Such flexibility and economic efficiency will be needed in a backstop situation because the very factors that could lead to excess emissions (unexpectedly high demand and unexpectedly low zero-emission generation)are also likely to complicate utilities' abilities to reduce in-state EGU emissions at a reasonable cost while maintaining reliability.

While it would be more flexible and efficient, interstate trading of CPP allowances under a backstop plan would not be complex; the allowances at issue will be EGU-only allowances created specifically for the CPP. Unlike with trading under state measures plans, the CPP authorizes trading of such allowances between affected EGUs that are subject to linked mass-based plans, and provides for one-for-one adjustments of states' CPP mass-based goals to account for net flows of allowances between participating states.

Finally, there is no legal limitation or requirement that precludes ARB from establishing an interstate trading scheme for the CPP backstop program. The statutory requirements of SB 1018 only apply to the California Cap-and-Trade Regulation and other market-based programs to implement the goals of the AB 32 legislation.[26] This limit, therefore, does not apply to the CPP backstop program because the backstop program is only implemented to assure compliance with federal requirements wholly separate from AB 32. So long as the federal backstop program is kept separate and independent from the Cap-and-Trade Regulation, ARB does not need to demonstrate compliance with SB 1018 requirements in order to authorize interstate emission trading under CPP backstop program.[27]

LADWP recommends that ARB design its backstop program to include authorization of EGUs to trade CPP allowances with other mass-based CPP state programs if the backstop is triggered, and to use allowances from these other programs to comply with California's backstop cap-and-trade requirements.

B. <u>Alignment of the Compliance Dates</u>

While LADWP understands the purpose of ARB's proposal to shorten compliance periods to two years in the post-2020 period in order to meet CPP requirements, LADWP generally supports longer compliance periods in order to provide compliance entities with additional flexibility.

Therefore, LADWP supports ARB's proposal to condition those changes intended to align the Cap-and-Trade Regulation with the CPP on EPA approval of California's CPP implementation plan. To the extent that the Cap-and-Trade Regulation is not serving as

[26] *See* SB 1018, codified at Chapter 39, Statutes 2012 (providing that the prerequisites for interstate trading only apply to a market-based compliance mechanism established pursuant to AB 32 and specified in Sections 95801 to 96022).

[27] For this reason, LADWP recommends that the CPP backstop provisions be codified as a independent regulatory system, located in separate sections of the California Code of Regulations from the Cap-and-Trade Regulation

the basis for California's CPP compliance (such as if the CPP is vacated or in the highly unlikely event that California's plan is deemed unsatisfactory), LADWP recommends retaining the current three year compliance period structure of the Cap-and-Trade Regulation.

Similarly, in the event that the start of the CPP's compliance period is tolled by the Court of Appeals for the District of Columbia Circuit or the United States Supreme Court and extended beyond 2022, LADWP urges ARB to maintain the three year compliance period structure of the Cap-and-Trade Program for as long as possible.

IV. INTERSTATE EMISSIONS TRADING

A. ARB Should Carefully Evaluate Any Proposal to Allow Export of California Cap-and-Trade Allowances

LADWP supports ARB staff's proposed interpretation that any type of linkage—including a "Retirement-Only Agreement"—requires specific Board approval.[28] Such one-directional linkage in which entities in another state use California compliance instruments without the opportunity for California covered entities to use compliance instruments issued by the other jurisdiction could result in substantial numbers of Cap-and-Trade Regulation compliance instruments leaving the state. This could increase the costs of California compliance entities without benefit to California or the environment.

LADWP urges ARB to take special care when approving any such one-way linkages with other states that want to utilize California compliance instruments to comply with their state plan under the CPP or a standalone state program (such as the one being developed by Washington). Such linkages can create substantial accounting complexities under the federal CPP. For example, the CPP appears to prohibit the linkage of any two "state measures" plans. [29]

LADWP urges ARB to invest its resources in potential linkages that provide benefits to *both* California and non-California parties to the linkage agreement—including Retirement-Only Limited Linkages. Such linkages, in contrast to Retirement-Only Agreements, can provide benefits to California ratepayers, including increased compliance instrument liquidity and reduced compliance instrument prices.

B. ARB Should Support Potential for Linkage with Electric Sector-Only Cap-and-Trade Programs

LADWP urges ARB to more clearly express support for the *potential* for the use of allowances issued by jurisdictions with single-sector cap-and-trade compliance programs as California Cap-and-Trade Regulation compliance instruments. LADWP recognizes and supports ARB's interpretation of SB 1018 that any use by California

[28] 2016 ISOR at 20-21.
[29] Clean Power Plan at 648943-894.

covered entities of allowances issued by another jurisdiction will require a formal linkage.[30] However, LADWP urges ARB not to adopt an interpretation of the linkage requirements of SB 1018 that would prevent linkage with another state's program merely because that other program covers a single sector (such as the power sector). We understand that SB 1018 requires the Governor to make a finding that the linked program's requirements "are equivalent to or stricter than those required by" the California Cap-and-Trade Regulation.[31] However, this provision does *not* specify that an equivalent program must cover the exact same sources. For example, another state's program can be as stringent in one sector as the California program is projected to be for that sector, without also covering all other sectors. This is particularly important as other states develop plans to comply with the federal CPP or establish standalone programs to achieve state-specific GHG reduction goals.

While LADWP has outlined concerns about one-way trading above, two-way linkage with CPP states can introduce market efficiencies and substantially lower the cost of compliance for California utilities, while substantially simplifying Cap-and-Trade Regulation compliance obligations with respect to imported power. Any ARB interpretation of the linkage requirements should be made in light of the substantial efficiencies and benefits that Retirement-Only Limited Linkages and two-way linkages can provide to California ratepayers.

V. ADDRESSING DOUBLE REGULATION OF IMPORTED ELECTRICITY

A. Overview

California EDUs rely on significant amounts of imported electricity from neighboring states. These out-of-state power sources serve a critical role in enabling EDUs to meet their obligations to provide reliable, cost-effective electricity to California's business and homes. If other states in the West implement the CPP by imposing limits on GHG emissions from generating facilities in those states, importers of electricity would effectively be required to "pay twice" for each ton of GHGs emitted: once under the California Cap-and-Trade Regulation, and a second time under the other state's CPP implementation plan.

This double-regulation of imported electricity would cause numerous problems, including:

- Higher ratepayer cost burdens;
- Limited flexibility to avoid double-regulation due to long-term contractual constraints;
- Negative impacts on California's local air quality by incentivizing increased in-

[30] *See* CAL. GOV'T CODE § 12894(e) (defining link to include "an action taken by the State Air Resources Board . . . that will result in acceptance by the State of California of compliance instruments issued by any other governmental agency . . . for purposes of demonstrating compliance with the" Cap-and-Trade Program).
[31] *Id.* § 12894(f)(1).

state generation;
- Negative impacts on trade-exposed industries due to higher electricity cost that would result from double regulation; and
- Risks for California's ability to comply with the CPP if double regulation incents significant shifts from out-of-state generation to in-state generation.

Similar problems would occur if neighboring states, such as Washington, were to adopt stand-alone GHG regulatory programs that are designed to achieve state-specific GHG emissions reduction goals.

To solve the double-regulation issue, CARB should modify the compliance calculation for electricity importers in section 95852(b)(1)(B) of the Cap-and-Trade Regulation by adding an adjustment factor for electricity sources from facilities that are regulated under neighboring states' CPP implementation plans. With this modification, entities that import electricity from facilities that are regulated under a neighboring state's CPP implementation plan would not be required to surrender allowances for the same electricity under the California Cap-and-Trade Regulation.[32] The adjustment would not apply to unspecified electricity imports or imports from facilities that are not covered under the CPP. Although not specifically discussed in these comments, this proposed solution discussed below for addressing double regulation due to the CPP would also apply to address similar problems resulting from stand-alone state GHG regulatory programs to achieve state-specific GHG emissions reduction goals.

This adjustment is allowed under AB 32, and would be similar to other adjustments to the compliance calculation that are already included in the Cap-and-Trade Regulation. Therefore, ARB should implement this solution as one important component of its ongoing process to extend the Cap-and-Trade Regulation and in a manner that is coordinated with the State's CPP implementation plan.

The discussion below explains this solution in greater detail.

B. <u>The Problem: Overlapping Regulation of Imported Electricity</u>

Many EDUs in California rely on significant amounts of imported electricity from neighboring states. These out-of-state power sources serve a critical role in enabling EDUs to meet their obligations to provide reliable, cost-effective electricity to California's business and homes. For example, in 2014, nearly a third of the electricity used to serve ratepayers in California came from electricity that was generated outside of

[32] Although this section focuses primarily on the double-regulation that would arise if a neighboring state establishes a mass-based CPP plan that imposes an allowance-holding requirement on affected fossil-fueled electric generating units, many of the same issues discussed in this section of the comments would also arise if neighboring states or EPA impose rate-based plans to comply with the CPP. This would occur because a rate-based plan would impose a requirement for affected generating facilities to hold emission rate credits to the extent that their actual CO_2 emissions were above the applicable CO_2 emission rate limitation.

California.[33] Although LADWP and other EDUs have been divesting from high-emitting generating facilities in neighboring states, EDUs in California will continue to rely on significant amounts of fossil-fueled out-of-state generation to meet their service obligations and maintain affordable electric rates.

GHG emissions from out-of-state generation are currently regulated by the California Cap-and-Trade Regulation. Under this regulation, electricity importers must surrender compliance instruments to account for the GHG emissions associated with the electricity they import. In the future, other states are expected to also regulate the same electricity under implementation plans adopted to comply with the federal CPP. When Arizona, Nevada, Utah, Oregon, and other states in the West implement the CPP, emissions associated with imported electricity will be double-regulated—once under the California Cap-and-Trade Regulation and a second time under each state's CPP implementation plan.[34]

Imposing these overlapping regulatory obligations are problematic for a number of reasons:

- **Higher Ratepayer Burden.** In-state generation would face only one GHG regulatory obligation under the Cap-and-Trade Regulation; however, imported electricity would face two obligations—one imposed by California, and the second imposed under a neighboring state's CPP plan. Importers would therefore be required to pay the costs associated with two overlapping GHG requirements, whereas in-state generators would only pay the costs associated with the California Cap-and-Trade Regulation. This situation will create a strong, perverse incentive to shift power purchases from otherwise relatively low-cost imports to higher-cost in-state generation sources. (This incentive would occur even in cases where the GHG emissions associated with electricity production at in-state and out-of-state generation are equivalent, such as between two natural gas combined cycle facilities.) Such shifting from out-of-state generation to in-state generation will lead to market inefficiencies and expose California consumers to higher electricity rates without necessarily achieving any incremental GHG reductions.

- **Limited Flexibility to Avoid Double-Regulation.** For many EDUs, such as LADWP, that own out-of-state generation, shifting generation from out-of-state to in-state energy sources may not be possible in the short- to medium-run due to contractual constraints, as well as health and environmental considerations in

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[33] Cal. Energy Comm'n, Energy Almanac, *Total Electricity System Power* (2014), http://energyalmanac.ca.gov/electricity/total_system_power.html.

[34] As noted above, these comments focus primarily on the double-regulation that would arise if a neighboring state imposes a mass-based CPP plan that relies on a cap-and-trade-style approach for the electric sector. However, many of the same issues would arise if neighboring states or EPA impose rate-based plans to comply with the CPP given that a rate-based plan would impose a similar requirement for affected generating facilities to hold emission rate credits to the extent that their actual CO_2 emissions exceeded the applicable CO_2 emission rate limitation.

- California. For example, entities in the South Coast Air Basin are already subject to stringent limits on ozone precursors and particulate matter. These requirements already place strict limitations on the amount of electricity EDUs in Southern California can generate. In LADWP's case, it will most likely not be feasible for LADWP to shift all of its fossil-fueled generation from out-of-state to California due to these constraints. As a result, LADWP and other EDUs may not be able to avoid the added costs of complying with these overlapping regulatory obligations, and could be required to recover their costs by increasing its retail electricity rates. This increase in rates would not be associated with any improvement in environmental quality or increase in GHG reductions.

- **Impacts on California's Local Air Quality.** Even if some EDUs could shift from imported electricity to in-state generation to avoid the double-regulation, this shift could have major ramifications for local air quality. If in-state generation were to become more cost-effective than out-of-state generation due to double-regulation of imported electricity, in-state generation from fossil-fueled generators would be expected to increase due to this price signal. This increase in generation from in-state fossil-fueled generation could result in substantially greater emissions of air pollutants in California than would be the case without this double-regulation. Such a significant increase in emissions not only presents major compliance challenges to electric utilities in the South Coast, but also is likely to increase substantially the cost of compliance with these stringent emissions limits.

- **Impacts on Trade-Exposed Industries.** EDUs that are currently importing electricity are faced with two compliance options that would increase the cost of electricity. One option is to pay twice for GHG emissions attributable to imported electricity; the other would be for EDUs to shift their generation to relatively more expensive in-state generation in order to avoid the double-regulation of imports. Under either option, trade-exposed industries in California that are served by those EDUs would face higher electricity costs, which could exacerbate leakage and harm the economy by causing these industrial facilities to move out of California. This result would undermine the goals of AB 32.

- **Risks for Clean Power Plan Compliance.** California will be required to limit generation from in-state fossil-fueled generating units under the CPP. To the extent that California adopts a state measures plan to comply with the CPP, a significant shift from out-of-state generation (which does not impact California's ability to meet its emission goal) to in-state generation (emissions from which are counted toward California's CPP goal) could lead emissions from affected power plants to exceed California's CPP goal. This increase in in-state generation could result in the triggering of backstop measures, which could complicate the State's ability to comply with the CPP.

Because many California EDUs rely on imported power and expect to continue to do so in the future, this issue will become critical if the CPP goes into effect and the Cap-and-Trade Regulation is not revised to address this issue of duplicative GHG regulation.

Therefore, it is crucial that ARB address this issue in the context of the upcoming rulemaking to extend the Cap-and-Trade Program.

C. Policy Design Principles for Addressing the Double-Regulation Issue

The following are four key principles that should guide ARB's development of any solution to address the double-regulation issue:

Principle 1. **Avoid Double-Payment.** California's consumers should not "pay twice" for each ton of carbon dioxide emissions attributable to the imported electricity that they consume.

Principle 2. **Avoid Economic Inefficiency.** The State should avoid imposing economically inefficient incentives for electric utilities in California to limit their use of imported electricity.

Principle 3. **Provide Flexibility.** The GHG regulation of imported electricity should be flexible and account for major changes in neighboring state GHG regulatory programs over time.

Principle 4. **Maintain Environmental Integrity.** The environmental integrity of the California Cap-and-Trade Regulation should not be compromised under any GHG regulatory approach that is developed to address the double-regulation of imported electricity. Any solution to the double-regulation issue should ensure that California can continue to meet its state-wide GHG reduction goals.

D. The Solution: Modify the Cap-and-Trade Compliance Calculation to Adjust for Emissions Accounted for in Other States

1. The Rationale Behind the Cap-and-Trade Program's Electricity Importer Provisions

As ARB stated in the Initial Statement of Reasons for the 2010 Cap-and-Trade Regulation, AB 32 requires ARB to account for and reduce emissions from both in-state generation and electricity imports.[35] The electricity importer provisions in the Cap-and-Trade Program were implemented to ensure that the Program would reduce GHG emissions associated with electricity generated out-of-state and imported to serve California load. At the time these provisions were implemented, neighboring states did not regulate GHG emissions from generating facilities located outside California. Therefore, meeting AB 32's goal of reducing emissions associated with all electricity consumed in California necessitated using the Cap-and-Trade Regulation to set an overall tonnage cap on GHG emissions and impose an allowance-holding requirement to ensure that regulated sectors met the cap. Among other things, these requirements

[35] *See* 2010 ISOR at II-10 (citing Cal. Health & Safety Code § 38530(b)(2)).

had the effect of providing a price signal to utilities to reduce the GHG emissions associated with the generation of electricity from out-of-state facilities serving California load.

2. The Rationale for Requiring Importers to Surrender Allowances Does Not Apply Where a Neighboring State Also Imposes Carbon Costs on the Same Generation

As ARB has previously recognized, there is no need to impose a regulatory obligation on imported electricity if the GHG emissions associated with that electricity are already regulated under another GHG program. For example, ARB's 2010 Cap-and-Trade ISOR explained that if New Mexico or another state in the West were to implement a GHG reduction program, ARB would need to adjust the Cap-and-Trade Regulation to avoid double-counting emissions from imported electricity.[36] Where emissions associated with electricity imports are already regulated under another state's GHG program, the other state's program provides an incentive for generators to reduce emissions associated with imported electricity. Because these producers already face a GHG reduction requirement, there is no need for ARB to provide a duplicative incentive (in the form of the electricity importer allowance surrender obligation) that would effectively serve the same purpose as the neighboring state's GHG regulatory program.

In fact, AB 32 specifically requires ARB to consider and—to the extent possible—avoid duplicative regulations. ARB is directed by the statute to consult with the CPUC "in order to ensure that electricity and natural gas providers are not required to meet *duplicative* or inconsistent regulatory requirements."[37] ARB is also required to consult with other states to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.[38]

Therefore, the need and justification for imposing a compliance obligation on imported electricity is not applicable in cases where the GHG emissions associated with the imported electricity are already being regulated. It is also inconsistent with ARB's statutory obligations to avoid duplicative regulatory requirements. On the other hand, continuing to regulate imported electricity when the emissions associated with this electricity are already being regulated by another state's program would cause a range of problems for California EDUs and their ratepayers (as described above in Section VI.B) while providing no additional environmental benefit.

3. ARB Could Eliminate This Double-Regulation by Modifying the Cap-and-Trade Compliance Calculation

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[36] *See* 2010 ISOR at II-43-44.
[37] Cal. Health & Safety Code § 38501(b) (emphasis added). *See also id.* § 38561(a) (requiring ARB consultations "to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, *nonduplicative*, and can be implemented in an efficient and cost-effective manner") (emphasis added); *id* § 38562(f).
[38] Cal. Health & Safety Code § 38564.

To avoid double-regulating imported electricity, ARB should adjust the compliance calculation for electricity importers in section 95852(b)(1)(B) of the Cap-and-Trade Regulation. Specifically, ARB should adopt a new covered emissions adjustment factor to deduct from an electricity importer's compliance obligation any emissions for which the importer has already surrendered an emission allowance.[39] With this modification, entities that import electricity from facilities that are required to comply with a neighboring state's CPP implementation plan would not be required to surrender allowances for the same generation under the California Cap-and-Trade Regulation.

This covered emission adjustment factor would be limited to emissions associated with electricity imports from facilities that are covered by a neighboring state's CPP implementation plan. It would not apply to imports from facilities that are excluded from the CPP, such as simple cycle combustion turbines, units that are modified or constructed after the applicability date of the CPP, and certain other excluded facilities.[40] (However, if a neighboring state decided to impose GHG reduction obligations on these facilities—*e.g.,* by capping emissions from both new and existing power plants—these facilities would also be eligible for the covered emission adjustment factor.) This adjustment also would not apply to unspecified imports for which the generating source cannot be identified. Imports of unspecified power and imports from specified sources that are not covered by a neighboring state's GHG reduction requirements would continue to count toward an electricity importer's compliance obligation. Also, this adjustment factor would not alter the existing requirement under the MRR that electricity importers report emissions associated with all electricity imports.

4. To Ensure Environmental Integrity, ARB Would Need to Adjust the Cap to Account for the Imported Electricity Adjustment

In establishing the Cap-and-Trade Regulation emission budget, ARB first determined a

[39] The solution described in this section would also work in cases where a neighboring state imposes a rate-based CPP implementation plan. However, additional adjustments to the mechanism may be required to reflect the fact that the compliance burden under another state's rate-based plan is a requirement for affected electric generating facilities to hold emissions rate credits (and not allowances) to the extent that their actual CO_2 emissions exceed the applicable CO_2 emission rate limitation.

[40] In certain limited cases, it is possible that a single facility would consist of some units that are covered by the CPP and others that are exempt. For example, a single facility site could consist of a mix of natural gas combined cycle units (which would be regulated under the CPP) and simple cycle turbines (which are exempt from the CPP). Under the MRR and WECC-wide e-tagging conventions, such a facility would typically be registered and reported as a single specified source. In this situation, MRR reports based on e-tags may not provide sufficient information to determine whether imported power was produced by a CPP-regulated unit at the facility or by an exempt unit. To address the potential for double-regulation in these cases, ARB could provide a *partial* deduction that reflects only the proportion of facility power generated by the CPP-regulated units. In this case, importers would only receive a deduction for the portion of the facility that is double-regulated, and would still be responsible for surrendering California allowances for the portion of the facility that is exempt from the CPP. Information on each unit's annual generation is already reported to EPA and ARB (this information is already being used by ARB to calculate average facility-wide emission factors). Therefore, it would be relatively simple for ARB to determine the proportion of each facility that would be eligible for the deduction.

desired emission level for covered sectors that would be consistent with AB 32's goal of reducing GHG emissions to 1990 levels by 2020.[41] This determination took into consideration all GHG sources that would be subject to a compliance instrument surrender obligation under the Regulation, including those sources of GHG emissions associated with electricity imports.[42] As such, any significant changes to the scope of covered emissions sources will have an impact on the environmental integrity of the State's GHG reduction goals unless the overall cap established by the Cap-and-Trade Regulation—and therefore, the total number of allowances that are allocated and auctioned—is revised to reflect that certain imports are no longer subject to the GHG emission cap set for California.

Therefore, beginning in the year that the CPP goes into effect, ARB should reduce the size of the cap to account for the expected reduction in total covered GHG emissions due to the imported electricity adjustment described above.[43] The GHG emission cap should be reduced prospectively in order to provide a clear price signal to market participants and to facilitate long-term planning. In order to determine the size of the cap reduction, ARB could utilize MRR data to determine the percentage of emissions associated with imports in a particular representative year (such as 2016 or 2020). Alternatively, ARB could model expected future emissions associated with imports under the current Cap-and-Trade Regulation and adjust the cap to account for the projected level of imported electricity that would likely be excluded from the cap.

One method for reducing the cap would be to reduce the allocation to EDUs by an amount that corresponds with the expected number of compliance instruments that will no longer be required to meet compliance obligations associated with imported electricity.

By reducing the cap to account for emissions that are regulated by other states but retaining the requirement to report emissions associated with imports, ARB can ensure that California will continue to be able to meet its obligations under AB 32 and SB 32 to reduce statewide GHG emissions (including those associated with imported electricity) by 40% below 1990 levels by 2030.[44]

E. <u>Discussion of Legal Issues</u>

While it would necessitate some changes to the current Cap-and-Trade Program regulations, addressing the overlapping regulation of imported electricity as outlined above is well within ARB's legal authority under AB 32.

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[41] *See* 2010 ISOR, Appendix E at E-5 (2010), http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appe.pdf.

[42] ARB, *Climate Change Scoping Plan Appendices Volume I* at C-16 to C-17 (2008), http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf.

[43] Reducing the size of the cap is not equivalent to changing the overall state-wide emission reduction goals established by AB 32 and SB 32.

[44] Importantly, LADWP is not recommending any changes associated with the MRR. All electricity imports—and emissions associated with those imports—would continue to be reported.

1. AB 32 Does Not Require Electricity Importers to Surrender Allowances

AB 32 does not, by its terms, require the Cap-and-Trade Program— the "market-based compliance mechanism" authorized by AB 32—to regulate any particular source of emissions. Although AB 32 establishes a number of requirements for such a program,[45] California law contains no explicit requirement to include emissions associated with electricity imports in the Cap-and-Trade Regulation.[46] Rather, ARB has relatively wide discretion in setting requirements for regulated entities in order to meet the GHG emission target specified by AB 32.[47] Although ARB is required by law to adopt reporting regulations that "*account for* greenhouse gas emissions from all electricity consumed in the state, including . . . from electricity generated . . . outside the state,"[48] no provision of law requires ARB to *impose an allowance surrender obligation* for the emissions associated with imported electricity. ARB can continue to require entities to *account for* GHG emissions attributable to imported electricity without also requiring that importers surrender allowances for the GHG emissions associated with those electricity imports.

The Cap-and-Trade Regulation is not the only policy that ARB may consider when adopting regulations to comply with AB 32's emission reduction targets. AB 32 requires ARB to "adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions *in furtherance of achieving the statewide greenhouse gas emissions limit*,"[49] which is defined to include emissions from imported electricity.[50] However, AB 32 does *not* require the market-based mechanism to be the only regulatory mechanism to meet this statewide emission limit.[51] Rather, the Cap-and-Trade Regulation is only one component of ARB's overall approach to achieving statewide emission reductions.[52] In determining how best to achieve the State's GHG emission goals, ARB has discretion to take into account the effect of regulations imposed by other states on emissions associated with imported electricity, including other states' plans to implement the carbon dioxide reductions required by the CPP. ARB could make a regulatory determination that the control of GHG emissions from imported electricity is already occurring under regulatory programs administered by neighboring states and, as a result, there is no need for California to adopt additional

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[45] *See* Cal. Health & Safety Code § 38562(d)(1)-(2).

[46] *See* Cal. Health & Safety Code §§ 38570-38574 (related to Market-Based Compliance Mechanisms);

[47] Cal. Health & Safety Code § 38570(c) ("The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits").

[48] *See* Cal. Health & Safety Code § 38530(b)(2) (emphasis added).

[49] Cal. Health & Safety Code § 38560.5(c); *see also id.* § 38562(a)

[50] *Id.* §§ 38505(n) and (m).

[51] Cal. Health & Safety Code § 38570(a) ("The state board *may include* in the regulations adopted . . . the use of market-based compliance mechanisms to comply with the regulations") (emphasis added).

[52] *See, e.g.*, ARB, 2030 Target Scoping Plan Update Concept Paper, at 2 (June 17, 2016), *available at* http://www.arb.ca.gov/cc/scopingplan/document/2030_sp_concept_paper2016.pdf (discussing the suite of State programs California is using to reduce GHG emissions).

regulations that duplicate those regulations. As Section V.D of these comments explain, AB 32 requires ARB to avoid imposing duplicative GHG regulations.

In fact, ARB has already interpreted AB 32 in such a way as to permit it to take into account interactions between the Cap-and-Trade Regulation and complementary state energy policies, western electric market realities, and regional climate policies by reducing or eliminating compliance obligations for electricity importers under a number of specific circumstances.[53] Therefore, it would be reasonable for ARB to conclude that regulating emissions from imports that are already being regulated in another state is unnecessary for achieving the statewide emissions limit and, furthermore, would impose a duplicative regulation on the utilities that rely on this imported electricity. Such a finding would be consistent with ARB's long-exercised legal authority.

In sum, while ARB must clearly adopt regulations that further AB 32's goal of reducing California GHG emissions—including emissions associated with imported power—it need not adopt regulations that impose duplicative requirements on importers.

2. The AB 32 Requirement to Minimize Leakage Can Be Addressed Without Double-Regulation of Emissions from Imported Electricity

In adopting regulations to establish the Cap-and-Trade program, ARB is directed to "minimize leakage," but only "to the extent feasible."[54] The current requirement that importers of electricity surrender compliance instruments contributes to minimizing leakage from the electric sector that could occur if in-state generation shifts out-of-state.[55] However, regulation of emissions from imported electricity under the Cap-and-Trade Regulation is not the only means of addressing leakage. Consequently, ARB's obligation to minimize leakage is not a bar to eliminating the double regulation of imported electricity.

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[53] *See* Cal. Code Regs. tit. 17, § 95852(b)(1)(B) (related to the linked jurisdiction emissions adjustment); Cal. Code Regs. tit. 17, § 95852(b)(4) (related to the RPS adjustment); Cal. Code Regs. tit. 17, § 95852(b)(5) (related to the Qualified Export adjustment). Note that it would be appropriate and legally permissible to authorize adjustments consistent with those allowed for linked jurisdictions without requiring neighboring states to undergo formal linkage. Linkage permits the cross-border use of allowances and therefore automatically incorporates many design features of linked jurisdiction's GHG emissions trading systems such as price mitigation measures. *See* J. Jaffe, M. Ranson, & R.N. Stavins, *Linking tradable permit systems: A key element of emerging international climate policy architecture*, 36 ECOLOGY L.Q. 789, 799-802 (2010), *available at* http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1910&context=elq. As such, linkage appropriately requires a finding that the stringency of the linked jurisdiction's emissions trading system is commensurate with the California Cap-and-Trade Program. However, because the adjustments described in these comments are significantly more limited, they will not result in such effects on the California Cap-and-Trade market and thus may be implemented without the need to link with a neighboring jurisdiction.

[54] Cal. Health & Safety Code § 38562(b).

[55] *See* 2010 ISOR, Appendix D at D-620 to D-621, http://www.arb.ca.gov/regact/2010/capandtrade10/capv2appd.pdf.

It is important to note that AB 32 does not require the Cap-and-Trade Regulation to *eliminate* leakage. It merely requires ARB to implement "feasible" measures to "minimize" leakage. The approach outlined above—in combination with CPP regulatory requirements on out-of-state generators and complementary California policy—clearly meets this requirement. Because the adjustment factor described above would only apply to electricity imports from facilities whose GHG emissions are also being regulated under neighboring states' programs, there is little risk that entities would shift generation from California facilities to these regulated facilities in neighboring states.[56] Existing requirements, such as the Cap-and-Trade Regulation's resource shuffling rules,[57] SB 1368 emission performance standard, and the California RPS program will also provide additional incentives to continue reducing GHG emissions associated with out-of-state generation. Conversely, were ARB to fail to adopt a solution that avoids double-regulation of electricity imports, this policy could exacerbate leakage as industrial and commercial customers shift their businesses (and emissions) to states with lower electricity costs.

Therefore, the approach described in these comments, when combined with other state programs, represents a reasonable approach to minimizing leakage. This approach would avoid imposing duplicative costs on electricity importers and their customers, would avoid encouraging local industry to relocate its production and emissions out-of-state, and would be feasible to implement while minimizing leakage. To the extent ARB may be concerned with the potential for the solution described in these comments to lead to leakage, ARB can and should continue to monitor changes in the Western electricity market to determine whether any leakage is occurring. Further adjustments or policy approaches could be implemented if there is evidence of leakage.[58] This approach would be consistent to the one taken with respect to leakage under the initial Cap-and-Trade Regulation.[59]

In sum, unless changes are made to the current regulatory structure, the

[56] Limitations on the applicability of the approach outlined above, including limiting the compliance obligation adjustment to *specified sources* that are specifically *covered* under a state's Clean Power Plan state plan—i.e., not simple cycle turbines or electric generators subject only to the New Source Performance Standards at 40 C.F.R. pt. 60 subpt. TTTT (the Carbon Pollution Standards rule for new and modified units)—will further limit the potential for leakage.

[57] *See* Cal. Code Regs. tit. 17, § 95852(b)(2).

[58] One notable example could involve ARB applying a "discount factor" for the GHG emissions associated with imported electricity that would negate any incentive to shift emissions out-of-state. By allowing entities to deduct a portion of the emissions associated with imported electricity, ARB would reduce the extent to which these entities pay twice for the same emissions, while at the same time reducing the incentive to shift generation to out-of-state facilities. As a general matter, there are several possible approaches for setting the discount rate. One approach could involve in ARB setting the discount rate at a rate that reflects the relative stringency of California's program as compared to neighboring states' CPP targets. Another option could be a cost-based approach tied to the ratio of carbon prices in the two programs that would equalize any marginal economic incentives to shift generation to neighboring states.

[59] *See, e.g.,* 2010 ISOR at IV-9 ("As part of implementation of the cap-and-trade program, ARB will monitor whether leakage is occurring. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine what additional safeguards, possibly including border adjustments, should be implemented.").

implementation of the CPP and other regional carbon policies could result in numerous difficulties for California ratepayers and industry that would not be justified by any improvement in the environment or public health. To address this issue, ARB should modify the Cap-and-Trade Regulation to exclude emissions from out-of-state facilities that are already regulated under neighboring states' CPP implementation plans. This adjustment, which is consistent with ARB's obligations under California law, would maintain the environmental integrity of the Cap-and-Trade Regulation while resolving the problems associated with double-regulation of electricity imports. ARB should adopt this solution as part of the ongoing process to extend the Cap-and-Trade Program beyond 2020.

VI. GHG Accounting of EIM Secondary Dispatch

ARB has identified a concern that the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) is facilitating increased GHG emissions that are not currently accounted for under the MRR or Cap-and-Trade Regulation. Specifically, emissions associated with "secondary dispatch"—generation sources that would serve California but-for the rerouting of low-emitting generation into California by the EIM dispatch algorithm. We understand that CAISO and ARB staff are working together to further evaluate this issue. However, despite the fact that ARB's analysis is based on a limited set of data, staff has proposed amendments that would extend the accounting reach of the California GHG program to non-participating entities and impose additional allowance surrender obligations (and therefore compliance costs) on certain California EDUs.

LADWP is following this issue and looks forward to additional follow up by ARB and CAISO on this important matter. LADWP has not developed a full position on the particular proposal ARB staff have briefly outlined in the short time available. However, LADWP believes that any change to the MRR and Cap-and-Trade Regulation should maintain economic incentives to invest in and generate clean energy. Changes that merely impose additional compliance obligations on entities that are generally unable to exercise sufficient control over emission sources will do little in the long-run to address this issue. At the same time, changes that discourage EIM expansion and participation could result in foregone system-wide emission reductions. LADWP believes that it is more important to develop an efficient and effective compliance program that drives substantial long-term GHG emission reductions than to ensure that every single ton of GHG emissions is ploddingly accounted for. LADWP supports comments made by SCPPA outlining why any accounting of emissions associated with secondary dispatch should also account for emission *reductions* associated with the displacement of out-of-state emitting generation by in-state renewable energy exports.[60]

LADWP believes that this issue has not been fully considered by CAISO, and

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[60] Recent analysis by CAISO indicates that EIM dispatch reduced overall GHG emissions during January-June 2016; and that the secondary dispatch GHG emissions associated with EIM transfers into CAISO to serve load were offset by GHG emission reductions associated with EIM transfers *out of* the CAISO.

stakeholder engagement has been limited given the short timeframe and relatively brief statement of reasons related to ARB staff's proposal. Unlike many other issues, there is no deadline for addressing emissions associated with secondary dispatch. Given the high cost of disruption of the regional electric-market integration process, ARB staff should not rush through this rulemaking and should provide sufficient opportunity for ARB, CAISO and stakeholders to understand and more fully analyze the problem and proposed solutions.

Finally, LADWP would like to note that the complicated issues raised above regarding the double regulation of imported electricity will be made even more complex to the extent ARB decides to regulate emissions associated with secondary dispatch. These emissions would be from generation sources located outside of California—often in states that do, or are expected to adopt state-specific GHG regulatory programs, whether on their own or in response to the CPP. To the extent that secondary dispatch emissions occur in states that already regulate GHGs, the Cap-and-Trade Regulation should treat those emissions in the same way emissions from sources that are actually imported into California are treated. That is, so long as those emissions are regulated by a state or federal program, they need not carry a California Cap-and-Trade Regulation compliance obligation.

VII. OTHER TECHNICAL COMMENTS

A. Section 95803(a). Electronic Signatures

LADWP supports ARB's proposal to accept *electronic* signatures for the submission of required information, including attestations by account representatives and agents, disclosure of corporate associations, changes in facility ownership, and other submissions.[61]

B. Section 95803(b). Submission Deadlines

ARB has proposed a new Section 95803(b) that would add a default submission deadline for all information requested by the Executive Officer of 10 calendar days,[62] with the exception of specific provisions that state a specific date or period of time (e.g. September 1 of each year, 30 calendar days). Because the deadline is set in calendar days, it is possible that entities would have a maximum of 7 business days to gather and submit information, and as few as 5 days during holidays. This level of time is likely too short to comply with information requests of any complexity. LADWP recommends that ARB establish submission deadlines that are tied to the nature of the requested information. ARB could set a specific reasonable deadline for an information request at the time the request is made rather than a blanket one-size-fits-all requirement. Alternatively, ARB could establish a more reasonable default submission deadline such as 30 calendar days or the approximate equivalent in business days.

[61] 2016 ISOR at 67; 2016 ISOR Appendix A at 67 (proposed § 95803(a)), 90-91, 101, 109.
[62] 2016 ISOR Appendix A at 67 (proposed § 95803(b)).

C. Section 95830(e)(1) and (4). Updating Registration Information

ARB proposes to add a new Section 95830(e)(1) to clarify the timing for updating registration information for registered entities. When there is a change in information registrants have submitted to ARB (e.g. change in directors and officers at an entity), registrants must update the registration information within 30 calendar days of the change. ARB in the ISOR states that it considers the "frequency of updates to be reasonable and necessary to ensure adequate market monitoring activities."[63]

Although LADWP has been complying with the 30 calendar day reporting requirement, LADWP proposes that ARB allow electronic submittal of the registration information changes and allow updating of registration information on a quarterly basis, instead of within 30 days, to reduce paperwork and streamline the process. For large entities such as LADWP, there are periods of times when the registration information with respect to changes to directors and officers needs to be updated on an almost monthly basis. The current process requires the registrant to type the information into the form, have an authorized person sign the form, and then mail the original signed form to ARB. Similar to ARB's proposals in this rulemaking to accept electronic signatures, LADWP recommends electronic submittal to streamline the process. Quarterly updates to registration could be timed such that updated information would be available to ARB prior to the quarterly auctions to address market monitoring concerns.

LADWP understands the importance of timely registration and always endeavors to update registration information as required by the Cap-and-Trade Regulation deadlines. However, the Regulation, as reorganized and clarified by the proposed amendments, leaves open the possibility that an entity's ability to comply with the program could be placed in jeopardy for a failure to update registration information, including for unintentional or minor violations of the updating requirements. Section 95830(e)(4) states that "an entity that fails to update registration information by the applicable deadline is subject to the restriction or revocation of its tracking system accounts pursuant to section 95921(g)(3),"[64] which, as amended, clarifies that when a registered entity has its holding account revoked or suspended it "may not hold compliance instruments or register with the accounts administrator for another set of accounts in any capacity."[65] All existing compliance instruments would have to be sold or retired.[66] For example, if LADWP updated the name of one of its officers in CITSS 31 days after the new officer had been appointed,[67] our tracking system accounts could be restricted, in which case all compliance instruments would have to be retired and we would not be permitted to establish new accounts. This would completely prevent us from complying

[63] 2016 ISOR at 111
[64] 2016 ISOR Appendix A at 84.
[65] 2016 ISOR Appendix A at 226.
[66] 2016 ISOR 226 ("If registration is revoked or suspended the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation").
[67] 2016 ISOR at 64-65.

with the Cap-and-Trade Regulation, or from operating in service of our customers as we are legally required to do.

These potential consequences for a single short-term or unintentional failure to update registration information are severe. While we realize that ARB would not necessarily exercise its discretion to the maximum possible extent in such cases, the possibility of such severe consequences and the lack of any standards governing the exercise of ARB enforcement discretion present an unfair risk for unintentional paperwork violations.

LADWP requests that ARB revise this provision to provide more reasonable penalties and clearer standards that govern the exercise of discretion regarding what penalties apply to what violations.

D. Section 95858(c). Compliance Obligation for Under-Reporting in a Previous Compliance Period

ARB has proposed to change the date by which additional compliance instruments must be surrendered to account for the under-reporting of emissions in a previous compliance period. Whereas the current regulation requires surrendering compliance instruments within six months, ARB's proposed change would require that compliance instruments be surrendered at the next compliance event.[68] This change would provide less certainty than the current six month deadline. LADWP requests ARB provide clarification on what "next compliance event" means.

E. Section 95892(b)(3). POU Allowance Distribution Form

Under Section 95892(b)(3), POUs and electrical cooperatives receiving a direct allocation of allowances must inform ARB by completing a *Publicly Owned Utility or Electricity Cooperative (Co-op) Account Allocation Distribution Form* of the accounts in which the allocations are to be place. This process requires the POU to complete the form, have an authorized person sign the form, then mail the original signed form to ARB. If the POU or electrical cooperative does not submit the distribution preference by September 1, ARB automatically places all directly allocated allowances for the following year into the entity's Limited Use Holding Account. This means that the POU or electrical cooperative would be required to consign its entire allowance allocation to auction. For a vertically integrated POU that uses its allowance allocations to cover its emissions associated with generating station operation, this means that the POU would have to consign all of its allowances to auction, and at the auctions also try to buy them back. LADWP believes that the consequences of not filling out the form by the deadline are administratively costly. As stated in previous comments, LADWP recommends that a POU allowance distribution preference form should remain valid until updated, rather than having to submit a new distribution preference form every year.

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[68] 2016 ISOR Appendix A at 141.

F. Section 95910. Auction of GHG Allowances

ARB is proposing to revise its authority to auction those allowances that have been consigned to it. ARB had previously been required to auction allowances; however, ARB's proposed revision would give it discretion to do so.[69] LADWP believes that this change could permit ARB to not auction allowances that have been consigned to it for that purpose, at its discretion, without any standards for deciding when to exercise this discretion.

To the extent that ARB is concerned with its authority to auction allowances from closed accounts,[70] it should do so by explicitly *adding* this authority rather than removing the non-discretionary duty to auction all allowances consigned to the current auction.

G. Section 95920(b)(5)(B). Trading

LADWP supports ARB's proposed clarification that an entity that exceeds its holding limit is not in violation unless it fails to take the available corrective action within five businesses days.[71] To the extent that an entity exceeds its holding limit and avails itself of the 5 day grace period, it should not be penalized as a violator so long as it performs corrective action before the end of the grace period.

VIII. CLOSING

LADWP appreciates the opportunity to provide these comments. If you have any questions, please contact me at (213) 367-0403 or Jodean Giese at (213) 367-0409.

Sincerely,

Mark J. Sedlacek

Mark J. Sedlacek
Director of Environmental Affairs

JG:vf
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[69] 2016 ISOR Appendix A at 234 (proposed § 95910(c)(1)(C).
[70] 2016 ISOR at 213
[71] 2016 ISOR at 258.