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Date: April 18, 2016

Rajinder Sahota
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Turlock Irrigation District Comments on March 29, 2016 Cap-and-Trade Workshop: Setting Post 2020 Emissions Caps

Dear Ms. Sahota,

Turlock Irrigation District provides the following comments in response to the ARB Staff Workshop on March 29, 2016 to discuss post 2020 emissions caps. TID appreciates the opportunity to provide comments on what is perhaps the most important issue in the development of a post 2020 Cap-and-Trade program. The setting of a cap and the allocation of allowances will directly impact the costs that consumers and ratepayers pay for electricity and other products in California. The cap will also drive GHG emissions reductions in furtherance of the State's ambitious emissions reduction efforts. In striking a balance between these two objectives, the ARB should strive to create a smooth transition into a post 2020 program. The ARB should also acknowledge the disproportionate burden borne by the energy sector as it leads the way to a cleaner more renewable future. The ARB must also recognize that in addition to furthering the State's important GHG objectives, utilities must also ensure that electricity is affordable and reliable for all of California's citizens. Many of the policies inherent in the existing allocation methodologies have proved successful and should be carried forward. In evaluating how the cap will decline over time, the ARB should employ a conservative approach in estimating anticipated emission reductions and the potential for deployment of new low emitting technologies.

With these objectives in mind, TID's comments recommend that: (1) the ARB utilize the existing allowance allocation methodologies to the greatest extent possible; (2) adopt a 2021 cap based on the 1990 emissions level by 2020 goal; (3) if the ARB adopts an initial cap below the existing AB 32 goal for 2020 emissions, then the rate of decline should be set at a flat, straight line in the initial years to account for technology deployment; (4) the ARB should allocate allowances for electric vehicle charging load on a 1:1 proportionate basis for avoided emissions; and (5) the ARB should clarify how it will adjust electric distribution utility allocations to account for industrial sector GHG costs.

1. Existing Allowance Allocation Methodologies Are Fair and Balanced.

In 2010 and 2011, individual utility allocations were among the more controversial and extensively discussed topics. The development of a methodology that addressed the diverse portfolios of California's utilities and the varying levels of ratepayer exposure to GHG costs was challenging. The final allocation methodology was generally supported by a majority of California's utilities. Compromise was reached through a multi-faceted allocation methodology that divided the allowances available to the electricity sector among the electric distribution utilities based on three elements: (1) ratepayer cost burden; (2) energy efficiency accomplishment; and (3) early action as measured by investments in qualifying renewable resources.[1]

Ratepayer cost burden was the primary driver in the calculations and the ARB relied in large part on the supply forms filed in the California Energy Commission's Integrated Energy Policy Report ("IEPR") process. In the absence of several years of verified data under the MRR, the IEPR "S-2 Forms" provided a valuable data set because the S-2 Forms account for the utilities existing portfolios and how those portfolios would change over a ten-year period. The S-2 Forms remain a valuable tool for evaluating ratepayer cost exposure to GHG costs post 2020. The S-2 Forms show relative levels of renewable energy procurement, expected load growth, contract expirations and other factors affecting GHG costs that cannot be accounted for in historic data. The ARB should therefore continue to use the S-2 Forms in conjunction with historic, verified emissions data. The ARB should continue to provide a strong weighting for expected ratepayer costs, since this is the only fair way to account for the diversity of utility supply portfolios across the state. It is also the only way to avoid creating a vast GHG cost disparity among ratepayers in different parts of the state, which could lead to unintended consequences.

In sum, TID supports the ARB's comments at the March 29th Workshop that the ARB intends to continue to allocate allowances employing the same methodology as in the current program (i.e., POUs would receive allowances on behalf of their ratepayer owners and have the option to consign those allowances to auction or to place the allowances in their compliance accounts). The ARB should also retain the allocation percentages among Electric Distribution Utilities (Table 9-3) with only minimal updates based on changed circumstances as demonstrated in verified emissions reports and the S-2 Forms.

2. The ARB Should Adopt a 2021 Cap Based on the 1990 Emissions Level by 2020 Goal.

During the March 29th Workshop, the ARB outlined two possible methodologies for developing the 2021 cap: (1) utilize the 1990 emissions level cap set by AB 32 ("Option 1"); or (2) develop a 2021 cap to account for expected emissions in 2021 ("Option 2"). TID believes the ARB should pursue the first option for at least three reasons. First, Option 1 will enable a smoother transition into the fourth compliance period. Option 2 would result in a substantial

[1] See July 2011 ARB Staff Proposal for Allocating Allowances to the Electricity Sector, available at: http://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf

reduction in the supply of allowances at the outset of the fourth period. Upward market price pressures would result from both a drop off in supply of allowances in 2021 and increased demand in the last triennial compliance period. While upward price pressure is not necessarily a bad thing as it may help drive investment in GHG emissions reductions, the ARB should strive to create a smooth transition to higher GHG prices. Just as utilities try to avoid "rate shocks", the ARB should avoid GHG allowance price shocks. The ARB should therefore strive to create a smooth transition into the 2021 – 2030 program by continuing a subtle but measurable decline from the current 2020 cap, rather than have a significant step down from 2020 to 2021 as is apparent in Option 2.

Second, it is not clear how the ARB calculated the estimated 2021 emissions levels for Option 2 and whether those emissions levels are achievable in the upcoming technology deployment scenario. It appears the ARB has assumed that the rate of decline in GHG emission reductions (as seen in verified emissions to date) will continue at the same rate post 2020. In the electricity sector, much of the emissions reductions were driven by the aggressive penetration of intermittent resources in the 2008 – 2014 timeframe. This was largely due to the steep decline in PV solar panel costs. In order for California to continue to realize a similar reduction in GHG emissions reductions, there are a number of questions that must be addressed. For example: How will California address the challenges of the "duck curve"? Will grid operators, like TID, need to rely on conventional resources to a greater extent in integrating an increasing amount of renewables? How quickly will procurement of incremental renewable energy occur in light of the new and complex Integrated Resource Planning procedures contemplated by SB 350? In adopting a post 2020 cap, the ARB should exercise caution in making assumptions about anticipated emissions levels. Until it is clear that California can achieve the continued rate of decline in emission reductions it has experienced to date, the State should pursue Option 1 because it sets a more reasonable trajectory for emissions levels.

Third, the 2021 cap (and the continued ability to bank allowances) will affect the utilities exposure to GHG costs in the later years of the 2020 – 2030 period. Having a larger cap in the initial years of the 2020 – 2030 period will help mitigate the risks of steep increases in GHG costs that ratepayers will face in the later years as allowances allocations decline significantly in furtherance of the 40% below 1990 emissions levels by 2030 goal. For these reasons, the ARB should take a more conservative approach in setting a 2021 cap based on Option 1.

3. **If the ARB Adopts an Initial Cap Below the 2021 Cap, Then There Should Be No Rate of Decline in the Initial Years of a Post 2020 Program.**

If the ARB adopts a 2021 cap that is considerably below the current, 2020 cap (i.e., Option 2), then the ARB should redesign the cap adjustment factor in the initial years of the post 2020 program. In this scenario, there should be no cap adjustment factor for a period of 3 – 5 years. This will allow utilities (and other regulated entities) to adjust purchases and policies to avoid the price shocks that will come from the steep drop off in allowances that will be needed to meet the 2030 target. By creating a sufficient supply of allowances in the early years of the post 2020 program, the ARB will enable entities enough time to invest in new technologies and procure the renewable energy that will be needed to meet the 2030 GHG emissions target.

4. **<u>The ARB Should Undertake a Broad Assessment of the Electricity Sector's Role in Facilitating Emissions Reductions Across Other Sectors and Allocate Allowances for Electric Vehicle Charging Load and Other Fuel Switching on a 1:1 Proportionate Basis of Avoided Emissions.</u>**

There is no question that vehicle electrification and electrification of certain residential, commercial and industrial processes will play a critical role in the achievement of the State's ambitious climate targets. The 2015 IEPR recognizes the increasing role the electricity sector will play in achieving *state-wide* GHG emissions reductions:

> The electricity sector accounts for about 20 percent of statewide GHG emissions, with about half from electricity imported from out-of-state, whereas the transportation sector is the largest source of GHG emissions, accounting for about 37 percent.[2] Consequently, decarbonizing the transportation sector should be a primary focus of the state's climate goals, and policies in the electricity sector must build on policies to reduce emissions from the transportation sector. For example, new renewable procurement should go hand-in-hand with increased electric loads from electrification of the transportation sector. If they are not in lock-step, then California will not realize the full potential of the GHG reductions from decarbonizing the electricity sector.
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> "Another way to reach ZNE is to replace natural gas appliances, such as gas stoves, water heaters, and space conditioning units, with electric appliances; such fuel-switching is called "electrification."[3]

Similarly, SB 350 recognizes this trend and directs the ARB to "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 should include, but are not limited to, an allocation of greenhouse gas emissions allowances to retail sellers and local publicly owned electric utilities,

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[2] See 2015 IEPR at p. 50.
[3] See 2015 IEPR at pp. 43 and 50, available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=210527

or other regulatory mechanisms, to account for increased greenhouse gas emissions in the electric sector from transportation electrification."[4]

The ARB should work with the CEC to build on the load growth estimates developed in the 2015 IEPR. The agencies should develop load growth estimates to 2030 that account for the trends in electrification of vehicles and other processes. Another way to account for the load growth attributable to vehicle electrification would be to compare two GHG reduction scenarios for the transportation sector and allocate the difference in emissions between the two scenarios to the electricity sector in the form of additional allowances. Under one scenario, the ARB would calculate the GHG emissions reductions from a 50% reduction in petroleum use goal.[5] Under a second scenario, there would be no 50% petroleum reduction goal. The difference between the high-EV / 50% petroleum reduction scenario (1) and the no petroleum reduction goal scenario (2) would be a reasonable way of calculating the GHG emissions reductions attributable to the electricity sector's role in fulfilling the state's petroleum reduction targets.

Alternatively, if the ARB adopts a reported emissions approach, the ARB should ensure that it accounts for avoided emissions in the transportation sector and allocates a corresponding amount of allowances to individual utilities. In other words, for every metric ton of petroleum combustion emissions avoided, the utility responsible for the charging load should receive one cap-and-trade allowance. It is not clear yet how such information could be tracked *and verified* in a way that does not create a significant administrative burden on utilities, their verifiers, and the ARB. This is particularly true for fuel switching in the residential, commercial and industrial sectors from natural gas fired processes to electrified processes. For these reasons TID encourages the ARB to adopt economy-wide projections for electric load shifting and allocate the allowances to the electricity sector as a whole equal to the avoided emissions in the transportation and natural gas sectors.

5. The ARB Should Clarify How It Will Adjust Electric Distribution Utility Allocations to Account for Industrial Sector GHG Costs.

The ARB should clarify how individual utility allocations would change to account for industrial load. For example, will the change in allowances attributable to industrial load be taken off the top of the total EDU allocation and then spread among the EDUs or will it be withdrawn from individual utility allocations depending on the type and amount of industrial customers in the utility's service territory? Assuming the ARB is proposing the latter approach (which would be more equitable), it is not clear yet how the ARB would account for emissions costs imbedded in utility rates. It appears that this potential change is being driven by the perceived disparity between similarly situated industrial customers in IOU and POU service territories. There is a misperception that EITE entities are bearing the full freight of GHG costs because there is no affirmative requirement for the POUs to return allowance revenue to Emissions Intensive Trade Exposed ("EITE") entities. To the contrary, many of the POUs (including TID) have undertaken programs to reduce GHG costs borne by all of their customers

[4] Cal. Health and Safety Code Sec. 44258.5

[5] While the 50% petroleum reduction goal was not ultimately part of SB 350, it is our understanding that the State will still pursue the goal through existing statutory authority.

(e.g., the procurement of renewable energy). Many POUs are vertically integrated and place allowances directly in the compliance costs, which offsets GHG costs that would otherwise be passed on to EITE entities. Thus, just because most POUs have not adopted discreet rebate programs like their IOU counterparts does not mean that the POU ratepayers are not benefiting from the freely allocated allowances. As the ARB continues to explore the proposal to allocate electricity sector allowances to EITE entities, the ARB should evaluate the perceived inequities among industrial customers and evaluate whether the redistribution is necessary in light of the POUs' vertically integrated structures and the requirement on the POUs to use their allowances for the benefit of their ratepayers.

Conclusion

TID is pleased to provide comments early in this process on how the ARB will set its post 2020 cap and allocate allowances among sectors and individual utilities. The cap and the allocation of allowances will directly impact both the GHG emission reduction goals and the costs that consumers and ratepayers pay for electricity and other products in California. As the ARB continues to evaluate a reasonable set of scenarios and assumptions for how California will achieve its GHG targets, the ARB should strive to create a smooth transition into a post 2020 program. The ARB should also acknowledge the disproportionate burden borne by the energy sector as it leads the way to a cleaner, more renewable future. The ARB must also recognize that in addition to furthering the State's important GHG objectives, utilities must also ensure that electricity is affordable and reliable for all of California's citizens. Many of the policies inherent in the existing allocation methodologies have proved successful and should be carried forward. TID looks forward to helping the state achieve its ambitious GHG targets and looks forward to actively participating in the ongoing discussions on these important objectives.

Respectfully Submitted,

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