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Filed Electronically

RE: TID Comments on March 2, 2018 Workshop to Discuss SB 350 Integrated Resource Plans

Turlock Irrigation District ("TID") submits the following comments and responses on the California Air Resources Board's ("ARB") March 2, 2018 workshop to discuss SB 350 Integrated Resource Plans, and the implementation of LSE Specific GHG Targets

TID BACKGROUND

TID was organized as the first Irrigation District in California on June 6, 1887 and is beginning its 130th year of operation. TID currently serves a retail electric customer base of just over 100,000 customers and provides irrigation water to over 5,800 growers and nearly 150,000 acres of farmland. Of the 11 communities that TID serves, seven are classified as Disadvantaged Communities, and a majority of our service territory is in the top 20% of Cal Enviroscreen 3.0 impacted communities. TID remains committed to working towards the State's climate and clean energy goals while providing reliable, low-cost electricity to our ratepayers

DISCUSSION

1. **As discussed at the workshop, the proposed Electric Sector GHG Targets are for planning purposes only, and are not compliance obligations subject to enforcement.**

The CARB workshop presentation highlighted the "sources of uncertainty in Electric Supply and Demand". Electric utilities have historically planned for the variable nature of electric demand, with an eye towards ensuring that it could be reliably served at less than a moment's notice. With the advent of the State's Renewable Portfolio Standard, Greenhouse Gas emissions reductions goals, continued Energy Efficiency developments, proliferation of distributed solar, and the ever increasing electrification across multiple sectors, the ability to accurately plan for the future has become exponentially more complex for electric utilities. This is particularly true for those utilities, like TID, that operate their own Balancing Authority Area and have a host of

regulatory requirements to reliably operate their BA. SB 350 and the statutory framework for the IRP Planning process recognize the uncertainty faced by utility planners. SB 350 was intended to give State Agencies, local governing boards, and policy makers an informed body of information of what Electric Utility planners face in an evolving energy landscape and uncertain future and how the utilities will meet long term GHG targets.

For the SB 350 IRP process to be effective, it must be harmonized with the State's myriad environmental goals; especially the 2030 GHG target set by SB 32. In the development of the Cap & Trade regulations, the Electric Sector was allocated GHG allowances based on the expected cost burden of complying with the emissions reductions goals of SB 32. Cap & Trade was chosen as a GHG reduction measure because it recognized that the most cost-effective path to deep emissions reductions is to allow compliance entities to trade emissions permits (allowances) amongst one another. Due to the evolving and interconnected roles of GHG reductions across different economic sectors (e.g., commercial/industrial, transportation and the electricity sector), the state must allow flexibility for electricity sector load to grow. Some sectors have lower abatement costs than others, and it must be recognized that the GHG targets assigned to each utility are for planning goals, and are not a rigid compliance requirement. The State has already ensured that the 2030 emissions reductions goals for sectors covered by Cap & Trade will be met by the simple fact that the amount of GHG allowances are limited and declining in line with the state-wide cap. TID supports the establishment of GHG Target ranges that are flexible, and account for all of the variables that could come into play.

2. **The Targets being established for the Electric Utility Sector highlight how the electricity sector has done much more than any other sector towards achieving the State's emission reduction goals. The ARB should also consider unique impacts of electric load grown on TID's IRP planning process.**

The electric sector has by far achieved more reductions than any other covered sector under Cap & Trade, and the electricity sector is expected to do far more than any other sector going forward. Within the electric sector, GHG Reductions in the 2030 Scoping Plan are expected to be anywhere from 51-72% below 1990 emissions.[1] TID is on the higher end of the spectrum when it comes to GHG Targets (In terms of % of required emission reductions), due to the fact that TID operates as a Balancing Authority and is fully resourced to serve load within its Balancing Authority. After the energy crisis in 2001, TID investigated and ultimately decided on becoming its own Balancing Authority in order to ensure that TID electric demand could be served reliably, and would not be subject to the interruptions in service so prevalent around the State during the Energy Crisis. As a result, TID ratepayers invested in new efficient natural gas power plants located within the Balancing Authority Area. TID's ratepayer owners invested in the Walnut Energy Center, a 250 megawatt (MW) combined cycle power plant in 2005, and the Almond II

[1] See 2017 ARB Scoping Plan at page 31, available at: https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

Power plant, which consists of three 58 MW simple cycle turbines in 2012. TID must run these plants at certain times of the year in order to satisfy our obligations as a Balancing Authority. To meet NERC reliability standards, there are times when TID must run its facilities even though it is uneconomic to do so. TID's ability to reduce generation from these plants is therefore informed both by GHG planning principles, GHG costs and TID's obligations as a BA.. TID is fully resourced because of our commitment to be a Balancing Authority, which means that as TID increases RPS procurement and otherwise fulfills the directives of SB 350, TID is simply adding energy that TID it doesn't need or can't use due to reliability requirements (even though it is helping the State meet the emission reduction goals). The 3 GHG Targets proposed by the CEC for TID would call for reductions of approximately 56% (53 MMT Electric Sector Scenario), 65% (42 MMT Scenario), and 75% (30 MMT Scenario) below TID 2014 retail emissions. From a gross emissions standpoint, the emissions reductions targeted are in fact much steeper. Adoption of a 30 MMT 2030 scenario at this time may not be feasible for BA's like TID. Therefore, TID recommends removing the 30 MMT Scenario from the discussion and utilizing a range from 42 to 53 MMT or higher in order to accurately represent the existing legislative mandates and the need for flexibility by BA's like TID.

3. **The GHG benefits of firmed & shaped RPS eligible electric imports must be harmonized amongst the CEC, CPUC, and ARB Processes.**

The GHG treatment of Portfolio Content Category 2 and Portfolio Content Category 0 electric power imports should be harmonized amongst the various state GHG accounting methodologies and plans. As TID understands it, Pathways set the statewide target, and the cap-and-trade allocation tables would be used to divide the statewide target among LSEs. Both Pathways and the Cap-and-Trade presumed a 50% RPS being entirely GHG free. In actuality, utilities are allocated emissions for PCC-2 and PCC-0 "firmed and shaped" RPS transactions and then rely on the RPS adjustment to ensure that there is not a cap-and-trade compliance obligation for this procurement. At this time, it does not appear that the CEC or the CPUC will actually account for the RPS adjustment when they direct utilities on how to account for utility-specific emissions in their individually filed IRPs. This will create a disconnect in the implementation of the IRP GHG targets because the adopted goals will presume that a utility's entire RPS portfolio is GHG free, but when the individual GHG accounting metrics are applied when the utility makes its IRP submittal, there may be GHG emissions attributed to a portion of the utility's RPS procurement. The GHG emissions attributed to the utility will be compared against an LSE-specific goal that presumes the all RPS eligible energy is GHG-free. This disconnect is germane to the ARB's current consideration of the IRP GHG targets because GHG accounting methodologies that are under CEC and CPUC purview through IRP implementation and LSE-specific IRP GHG targets set in this proceeding are interrelated and dependent on one another. The current proposals

would not achieve consistency among the state energy agencies' programs and this issue should be squarely addressed in this forum

4. **Responses to Stakeholder questions posed in the ARB presentation:**

a. *Does this range reflect the appropriate breadth for planning purposes given the factors affecting electricity demand and supply?*

Until an established methodology for quantifying the increase in load due to electrification is developed, and the associated cost burden on Utilities is understood, it is difficult to predict whether the GHG range is appropriate. In considering this uncertainty, ARB should establish a mechanism for GHG Allowances to flow from other Sectors to Electric Utilities as the California economy as whole transitions from fossil fuels to electricity.

b. What factors should be considered in picking a point estimate within the range for implementation purposes?

It doesn't make sense to pick a "point estimate" within the Scoping Plan ranges because they are forward looking and already account for the uncertainty inherent in long planning. With all of the uncertainties, volatilities, and intermittencies of Utility supply and demand these uncertainties will be even more pronounced as the RPS requirements increase. For that reason a single point is not appropriate. The ranges should be updated every 5 years, as the ARB suggested on slide 11 of the workshop presentation.

c. What other assumptions about future electricity demand and supply should be considered?

As mentioned above, the effect of economy wide electrification must be considered. Some other potential topics that could have an effect on future electric demand and supply include energy storage, demand response, the "duck curve", and the "free ridership", or diminishing effect of, Energy Efficiency measures over time.

d. Is there a need to apportion the GHG planning target to CEC and to CPUC as well as to LSEs and POUs?

SB 350 directs ARB to establish a GHG reduction target for the electric sector and for each IOU, POU, ESP and CCA.[2] SB 350 does not direct the ARB to apportion any share or obligation to the CEC or CPUC. SB 350 does not provide the CEC with a statutory directive to assign GHG targets to POU's. Of further concern is the mention on Slide 11 of ARB's presentation that the "CPUC and CEC may use their inherent regulatory authority to further implement or impose IRP requirements on LSE and POUs within the GHG ranges established by CARB".

CONCLUSION

TID appreciates the ARB/CEC/CPUC efforts in establishing the SB 350 IRP GHG Target ranges. There is some work to be done in harmonizing these targets/methodologies across the state agencies. TID looks forward to working with the ARB to help craft consistent, clear regulations that provide all LSEs with the flexibility they need to address an uncertain future.

Sincerely,

Dan B. Severson

Turlock Irrigation District

[2] Cal. Pub. Util. Code §§ 454.52(a)(1)(A), 9621(b)(1)