ALCANTAR & KAHL, LLP

August 11, 2011

Chairman Mary Nichols and Members of the Board
Office of Climate Change
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Treatment of Electricity Use and CHP Generation for Energy Intensive Trade Exposed Entities in Greenhouse Gas Cap-and-Trade Market

Dear Chairman Nichols and Members of the Board:

The Energy Producers and Users Coalition[1] (EPUC) offers these comments to address the treatment of combined heat and power generation (CHP or cogeneration) and bundled utility electricity service under the AB 32 cap-and-trade (C-T) regulation. EPUC CHP facilities provide thermal and electric energy to capped entities such as refineries and oil and gas production operations, which are considered energy intensive trade exposed (EITE) industries. EPUC members have the potential to develop additional CHP capacity, depending on market conditions and the removal of existing development barriers. Beyond these CHP interests, EPUC members purchase substantial quantities of bundled investor owned utility (IOU) and publicly owned utility (POU) electricity services to serve their demand.

These comments offer important refinements to CARB's current draft regulations to eliminate CHP disincentives and minimize emissions leakage. In particular, the regulations should be modified to:

- ✓ Include indirect electricity and thermal emissions in the calculation of product benchmarks to avoid distortion of the benchmarks and to avoid creating a disincentive to CHP operation and development;
- ✓ Eliminate the disincentive to new CHP generation created under the regulations in the transition from bundled utility service to CHP self-generation;
- ✓ Direct that allowances allocated to the utilities for the benefit of their ratepayers be used, in part, to cover the indirect emissions of EITE customers and thereby minimize the potential for leakage.

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1 EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC, Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

- ✓ Clarify its use of heat and power adjustment factors in benchmark calculations;
- ✓ Revise the definition of "cogeneration" to ensure alignment with the existing regulatory framework that permits CHP to deliver energy "over the fence" from the generating site;
- ✓ Memorialize CARB's intent to order electric generation facilities in existing contracts to renegotiate terms where pass-through of GHG compliance costs is not currently permitted; and
- ✓ Consider CHP impacts from Assistance Factor reductions in the second compliance period.

Each of these issues is discussed below.

1. Indirect Emissions Should Be Included in Product Benchmark Calculations to Avoid Distorting the Benchmark and Creating Disincentives for Combined Heat and Power Facilities.

Appendix J to the October 28, 2010, Initial Statement of Reasons (ISOR) addresses free allowance allocation to EITE facilities through product benchmarking. Appendix J explains that under product benchmarking, "*the benchmark is a function of the quantity of GHGs released per unit of industrial product output*."[2] While it would be logical to assume that the amount of GHG released per unit of output would include all emissions -- both direct and indirect -- CARB's recent revisions to the regulation suggest otherwise. Appendix B to the July 25, 2011, revised regulation (Revised Regulation) proposes to exclude from the product benchmark calculation indirect emissions associated with "*power purchased.*"[3] The proposal appears to be based on the concern that reflecting indirect emissions would compensate an EITE facility for these emissions through the benchmark. Consequently, if grid power users receive benchmark compensation *and* utility compensation for indirect emissions, they could receive double recovery for the same emissions costs.

CARB's concerns are misplaced. While complications arise from separate treatment of direct and indirect emissions in allowance allocation, these issues do not need to be solved in the benchmark calculation. The primary goal should be first to get an accurate benchmark that reflects all emissions arising from the facility's production. If necessary, depending on the outcome of the CPUC's allocation process, adjustments can then be

[2] Appendix J, at J-26.

[3] It is not clear whether "power purchased" means only grid power purchased from a utility or also power purchased "over the fence" from a third-party under Public Utilities Code §218(b)(2). For the same reasons supporting inclusion of indirect emissions from grid power, indirect emissions from "over the fence" transactions should be included.

made to the benchmark award to prevent double recovery. Moreover, the exclusion of indirect grid power emissions from the benchmark calculation would turn the state's goal of supporting CHP operation and development on its head, incentivizing purchased power over the continued operation and development of CHP.

For these reasons, EPUC recommends that all emissions, whether direct or indirect, be included in the calculation of a product benchmark. Once the benchmark is established, CARB can then address the potential for duplicative compensation through the adjustment of benchmark allocations.

a. Excluding Indirect Emissions from Grid Power Distorts Product Benchmarks.

The aim of the product benchmark should be to determine the emissions intensity of producing a unit of output. The true emissions intensity is a function of both direct, on-site emissions and indirect emissions for energy consumed in production. Exclusion of indirect emissions thus leads to a distortion of a facility's and a sector's emissions intensity.

A simplified electricity-related example demonstrates the distortion. Assume that the benchmark is calculated as a weighted average of the emissions intensity of the facilities in the sector, where the numerator is emissions and the denominator is output. Assume further that there are only two facilities – A and B – in the sector. Finally, assume that Facility A and Facility B have the same output and the same electricity use of 60 MW. Facility A self-generates the full 60 MW of output, creating a corresponding amount of direct GHG emissions, while Facility B self-generates 15 MW and uses 45 MW of power purchased from the utility. Under CARB's current proposal, the GHG emissions of 100% of electricity use for Facility A would be included in the benchmark calculation because they would be direct emissions. For Facility B, however, only 25% of the electricity–related emissions would be direct and included in the benchmark. Averaging these electricity emissions in the benchmark numerator is like averaging apples and oranges, distorting the result. The benchmark in these circumstances would reflect emissions for only 37.5 MW of electricity use per facility, while the actual average electricity used to produce each facility's output is 60 MW. The calculated average GHG emissions intensity benchmark would be lower than the true benchmark, i.e., one calculated using 100% of emissions associated with Facility A and Facility B output. As discussed below, this distortion would have a material effect on CHP self-generation.

b. Excluding Indirect Emissions from Grid Power Creates a Significant Disincentive for Continued Operation or Development of CHP Facilities.

CARB has expressed clear support for the continued operation of existing and development of new CHP generation. The Scoping Plan estimates that reliance on

CHP can generate 6.7 $MMTCO_2e$ in emissions reductions. Resolution 10-42 calls for appropriate incentives to increase reliance on CHP:

> *BE IT FURTHER RESOLVED that the Board directs the Executive Officer to review the treatment of combined heat and power facilities in the cap-and-trade program to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power.*

Despite these clear directives, the regulations fail to establish any specific measures to encourage CHP. Moreover, excluding indirect emissions from grid power in the product benchmark calculation will strongly discourage continued operation of existing and development of new CHP.

The example in section a. above can be used to illustrate the CHP disincentive embedded in the benchmarking methodology. As explained above, if indirect emissions are excluded from product benchmark calculations, the effect will be to depress the benchmark to a level that fails to reflect the full scope of electricity GHG emissions resulting from a unit of output. Depressing the benchmark in this way will affect grid purchasers and self-generators differently. A grid power purchaser under this scenario could receive full compensation for its electricity emissions even with a depressed benchmark because its benchmark award will be separately supplemented with a utility allowance value allocation. A CHP self-generator, in contrast, can look only to its benchmark award to cover its emissions costs. If the benchmark is artificially depressed by the exclusion of certain electricity emissions, a CHP self-generator is highly unlikely to receive sufficient coverage of its electricity-related emissions. The natural effect will be to drive self-generators and their steam hosts toward a combination of boilers and grid power and away from CHP. Not only will this limit efficiency and reliability, it will put additional strain on the electricity supply and transmission system. For this reason, the product benchmark proposal runs contrary to the Scoping Plan and Resolution 10-42, which seek to encourage retention of existing and addition of new CHP facilities.

c. Recommendation: CARB Should Include Indirect Emissions in the Product Benchmark.

A variety of solutions could be applied to the problem created for CHP by excluding indirect electricity emissions from the product benchmark. Only one solution, however, would achieve all of CARB's goals: <u>including indirect GHG emissions in the product benchmark calculation.</u> Indirect emissions from grid electricity purchases would be incorporated into the benchmark at the rate of 0.431 MT for each MWh of grid electricity consumed by a customer during the baseline period, ensuring that both imports and exports are accounted for using the same proxy. Under this approach, the benchmark would most accurately reflect the sector's GHG emissions intensity. The benchmark could then be used to determine allowance allocations to all facilities, regardless of their electricity supply sources. The direct/indirect distinction would arise through an adjustment of the allowance award to reflect compensation received by a facility directly from the electric utility for indirect emissions.

CARB may be tempted to assume that a correct "price signal" for grid power would also solve this problem. This approach, however, would leave EITE grid power users burdened with the full cost of indirect GHG emissions and would run contrary to CARB's objectives of avoiding leakage. By definition, EITE entities cannot recoup GHG costs from their product markets due to the significant potential for leakage. Declining to allocate the allowance value out of the desire to ensure a price signal could also run contrary to the goal of mitigating the AB 32 rate impact on utility customers. Finally, it would do nothing to correct the accuracy of the benchmark as a measure of emissions intensity.

For these reasons, CARB should make clear that all electricity-related emissions – direct emissions, grid power emissions and third-party emissions[4] -- will be included in calculating a product benchmark.

2. Draft C-T Regulations Should Eliminate the Disincentive Created by the Regulations in the Transition from Bundled Utility Service to CHP Self-Generation.

The current regulatory scheme will discourage new CHP, not only by excluding indirect emissions in benchmarking, but by failing to address the treatment of allowances when a facility shifts from grid power to self-generation. Assuming the CPUC implements the AB 32 goal of minimizing leakage, an EITE entity purchasing grid power will receive allowance value directly from its distribution utility to offset the GHG compliance costs embedded in electricity rates. If the EITE then decides to invest in additional CHP capacity, it will be responsible for increased direct GHG compliance costs and will lose its share of allowance value from the utility. Not only could it lose the existing allowance value from the utility, it would likely not receive an increase in allowances through benchmarking, since the benchmark[5] award once set will vary only with product output. As a result, the EITE entity's share of allocated allowance value will decrease even though it will face increased direct emission compliance costs. This is antithetical to encouraging new CHP development.

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4 Third-party emissions arise when one facility purchases power from a nearby CHP generating over private distribution wires under Public Utilities Code section 218(b)(2).

5 Staff has noted that benchmark values will not be recalculated over the course of the C-T program. If indirect emissions are not included in the benchmark calculation and an EITE facility adds self-generation after the benchmark has been established (increasing its direct GHG emissions), the sector benchmark will not adjust to reflect the overall increase in the sector's direct emissions. This penalizes all facilities in the sector and is an additional incentive to include indirect emissions in the benchmark calculation.

To avoid this CHP disincentive, CARB should require electric utilities to continue providing EITE ratepayers a share of allowance value once they leave utility service. This approach makes sense in light of CARB's approach to allocation of allowances to utilities; if the customer's load was a part of the 2008 usage CARB employed to calculate the 97.7 MMT electric utility allocation, it should take a proportional share of that allocation with it as it leaves the utility system. To reflect this change in the regulations, the following new language should be added to Section 95892(d)(3):

> *Investor owned utilities shall continue to provide an energy-intensive, trade-exposed customer a share of auction proceeds to offset the greenhouse gas compliance costs based on historic usage if the customer leaves the system to be served by combined heat and power.*

Two other approaches could be used. First, designing a product benchmark that both includes indirect emissions and adjusts for direct compensation of grid users by their utility could mitigate some of the impact. Second, a methodology that provides a CHP adder to the applicable industrial benchmark could provide mitigation. Without a shift of allowances from the utility sector to the relevant EITE industrial sector, however, these approaches would result in short-changing the CHP developer and provide an undue windfall to the electricity sector.

3. C-T Regulations Should Provide Clear Guidance to the CPUC Regarding Use of Electricity Sector Auction Revenues to Mitigate Trade Exposure and Minimize Leakage.

The proposed regulation contemplates allocation of 97.7 MMT of allowances to the state's electric utilities for the benefit of all of their ratepayers. While CARB has offered guidelines for the allocation of the allowance value to utility customers, the weight of these guidelines and CARB's role in the allocation process remains uncertain. Specifically, it is not clear whether or how CARB plans to ensure that the AB32 goal of minimizing leakage is met in the utility allowance allocation process.

CARB faces very specific limitations in implementing AB 32.[6] In particular, in its effort to generate the maximum technologically feasible reductions in a cost-effective manner, CARB is also obligated to minimize leakage.[7] As a result, whether it implements AB 32 single-handedly or delegates some implementation authority to another agency such as the CPUC, it is obligated by law to ensure that the program, as a whole, minimizes leakage.

CARB has an obligation to ensure that AB 32 goals, including the goal of minimizing leakage, are carried through to the C-T program implementation. The language of AB

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6 Ca. Health and Safety Code, Section 38562(f).
7 Ca. Health and Safety Code, Section 38562(b)(8).

32 clarifies that CARB is the agency in charge of implementing the statute in order to reduce statewide emissions:

> *It is the intent of the Legislature that the State Air Resources Board coordinate with state agencies, as well as consult the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing this division*.[8]

While CARB must seek input and expertise of the CPUC and other state agencies to limit duplication in regulatory requirements,[9] the ultimate responsibility for achieving the statutory goals rests on CARB's shoulders.

It is not clear how CARB intends to ensure achievement of the goal of minimizing leakage in the utility allowance allocation process. Neither the regulation nor Resolution 10-42 expressly direct the CPUC or municipalities to ensure that the allowance allocation methodology protect EITE entities and thereby minimize leakage. As noted above, CARB is fully within its jurisdiction to condition its provision of allowances to the utilities on treatment of EITE ratepayers in a way that will minimize leakage and also preclude any chance of double-recovery.

One could argue that CARB's role in the utility allowance allocation is limited once the allowances have been allocated to the utilities, since the legislature provided that nothing in the statute affects the authority of the Public Utilities Commission.[10] This argument, however, misses an important distinction. The CPUC's role is clearly limited under Public Utilities Code Section 701 to regulating California's public utilities.[11] The goal of minimizing leakage through the protection of EITE entities, however, is unrelated to public utilities; it is a goal directed toward preventing shifts of manufacturing activity to facilities outside of the state and thereby creating emissions leakage. While it is possible that the CPUC will strive to limit leakage, this is not its traditional role. Accordingly, to ensure that electricity sector allowances are used in a manner that fulfills AB 32 objectives, CARB must condition its allowance allocation to the electricity sector on the use of allowance value to offset EITE indirect GHG compliance costs reflected in utility power rates. Moreover, the regulations should clarify that if the auction value of the 97.7 MMT allowances is not used to offset EITE indirect costs, CARB will withhold allowances needed to cover EITE indirect costs from the electricity sector allowance allocation so that the allowances can be allocated to EITE customers directly by CARB.

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8 Ca. Health and Safety Code, Section 38501(f).

9 Ca. Health and Safety Code, Section 38501(g); Ca. Health and Safety Code, Section 38561(a); Ca. Health and Safety Code, Section 38562(f).

10 Ca. Health and Safety Code, Section 38593(a).

11 Pub. Util. Code §701; Utility Consumers' Action Network v. Public Utilities Comm'n, 120 Cal.App.4th 644, 649 (2004).

To ensure that the regulations will limit emissions leakage consistent with AB 32, the following revisions should be incorporated into the current set of draft regulations:

(d) Limitations on the Use of Auction Proceeds and Auction Value.

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(3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(A) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

(B) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.

(C) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012.

<u>(D) Investor owned utilities shall use auction proceeds to offset the greenhouse gas compliance costs reflected in the rates charged to energy-intensive, trade-exposed customers consistent with the goal of AB 32 to limit emission leakage.</u>

Table A. Adjustment Factors to Account for Indirect Carbon Costs and Carbon Cost Recovery

Energy Type	Adjustment Factor	Basis	Applied To
Heat	0.0663 metric ton $CO_2e/MMBtu_{heat}$	Assumes that an 80% efficient natural gas boiler sets the carbon cost recovery rate in the market for heat.	Heat sold and heat purchased
Power	0.431 metric ton CO_2e/MWh	Assumes that a 42% efficient natural gas plant sets the carbon cost recovery rate in the power market.[7]	Power sold only[8]

4. CARB Should Clarify the Use of Emissions Values in Assigning CHP Emissions to CHP Thermal and Electric Energy Products.

Appendix B to the Revised Regulation discusses the general methodology employed in developing benchmarks for allowance allocation. It discusses "*Adjustment Factors*" that should be used to account for indirect carbon costs and address carbon cost recovery, identifying adjustment factors for heat and power in Table A:

Appendix B explains that *"[i]n the development of the product benchmarks, adjustment factors were used to account for the carbon costs embedded in energy flows as shown in Table A*." Presumably, these factors were used to assign CHP emissions to thermal and electric energy products to adjust emissions in or out of the numerator of a facility's emissions intensity. For example, if a facility that has an onsite CHP plant exports power to a utility or third party, the facility's MRR would be adjusted to remove emissions associated with those exports.

While CARB may have chosen appropriate values to use for each product, it is not clear how the values were used. One approach is to use a residual method. For example, thermal emissions from a facility could be determined residually by taking the CHP facility's total emissions and subtracting electricity emissions, calculated using the power adjustment factor (0.421 MT/MWh). Alternatively, electricity emissions could be determined residually by taking the facility's total emissions and subtracting thermal emissions, calculated using the heat factor (0.0663 MT/MMBtu). The second approach is to use the two adopted factors together to create a proportional assignment of emissions in a manner similar to the California Climate Action Registry (CCAR) methodology. Under this methodology, electricity emissions are determined as follows:

$$E_{TO} - (((O_{TH}/.8)/(O_{TH}/.8 + (O_E/.42)) * E_{TO})$$

Where:

E_{TO} = CHP Facility's Total Emissions
O_{TH} = CHP Thermal Output in MMBtu
O_E = CHP Electrical Output in MMBtu

EPUC recommends that CARB employ its adopted factors using the CCAR methodology, which offers the most moderate results among the options. There may be an inclination as a result of the CHP Settlement to use the power adjustment factor (8125 Btu/kWh or 0.431 MT/MWh) in a thermal residual calculation. CARB should avoid this result for three reasons. First, the heat rate employed in the CHP Settlement of 8125 Btu/kWh was intended to reflect an "avoided" heat rate, not an actual CHP heat rate. Second, the 8125 Btu/kWh factor is relevant under the CHP settlement only through mid-2014; using a factor that is relevant for only 18 months of an 8 year program does not seem balanced. Third, the electric residual method using 8125 Btu/kWh can result in distorted thermal efficiencies. For example, assuming a CHP with a simple cycle heat rate of 11,600 Btu/kWh and a 1.5 heat to power ratio, the residual electric method at 8125 Btu/kWh would allocate only 30% of the total emissions to steam. This compares with a thermal allocation of 49% under the 80% boiler residual method, 41% under the traditional CCAR method (using a 42% efficiency) and 60% under the CPUC's output method.

For these reasons, EPUC recommends employing the adopted heat and power adjustment factors in the CCAR methodology for purposes of splitting thermal and electric emissions from a CHP facility.

5. The Cogeneration Definition Must Be Revised to Ensure Alignment With the Existing Regulatory Framework

The revised regulation modifies the definition of "cogeneration." The revision creates an ambiguity in the definition and fails to ensure alignment with the current California regulatory framework that defines and governs cogeneration.

The Revised Regulation defines cogeneration in a manner that requires "onsite generation":

> *(47) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve* ***onsite*** *generation of electricity and useful thermal energy and some form of waste heat recovery.*

The use of the term "onsite," which is not defined in the regulation, creates an ambiguity. The ambiguity arises from the fact that some facilities use cogeneration thermal or electric energy that is not produced on their site, but delivered "over the fence", on the site of another entity. Public Utilities Code (PUC) Section 218 permits "over-the-fence" transactions when electricity is delivered by the generator for:

> *(1) Its own use or the use of its tenants.*
> *(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto ….,*

The use of the term "onsite" in the current cogeneration definition could be interpreted to exclude these over-the-fence transactions that are currently permitted. To eliminate any ambiguity that could adversely impact the current regulatory framework governing cogeneration, the following modification should be incorporated into the regulation's definition of cogeneration:

> *(47) "Cogeneration" means …. energy. Cogeneration must involve ~~onsite~~ the generation of electricity and useful thermal energy and some form of waste heat recovery.*

6. CARB Resolution Language Should Provide Guidance Regarding Treatment of Existing Power Sales Contracts That Do Not Provide Pass-Through of GHG Costs

The current draft regulations do not provide any resolution to those entities with existing power sales contracts that do not allow recovery of GHG costs. CARB has stated that it would address this issue and suggested it would provide special treatment to facilities unable to contractually pass through these costs.[12] Despite these reassurances, the current regulations provide no recourse for facilities in these existing contracts. Instead, at the July 15, 2011 workshop, CARB staff recommended that affected parties renegotiate the terms to these agreements.

The absence of direction in the regulation fails to recognize that, without express guidance, entities lack the bargaining power to bring contractual counter-parties to the negotiating table. As one party noted at the July 15, 2011 workshop, until CARB demands a change to these contracts, even the investor-owned utilities believe they lack the authority needed to discuss new terms. While CARB may prefer that contracting parties renegotiate and resolve these issues without administrative intervention, a statement of intent – at a minimum -- may help parties who otherwise will be left to bear the full compliance costs of AB 32 regulations with no recourse but to terminate their contract.

To assist those facilities with existing contracts not allowing pass-through of GHG compliance costs, the following intent language should be included in CARB's board resolution:

> *<u>WHEREAS there are parties with existing contracts which do not allow pass-through of GHG compliance costs, and the implementation of the cap-and-trade program may impose additional costs on parties beyond those that would have been imposed prior to implementation of AB 32;.</u>*
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> *<u>BE IT FURTHER RESOLVED that the Board intends for parties in existing contracts that do not allow pass-through of GHG compliance costs to renegotiate the terms of these contracts to ensure cost pass-through.</u>*

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[12] See ISOR, at II-32 n. 22 ("*Some generators have reported that some existing contracts do not include provisions that would allow full pass-through of cap-and-trade costs. These contracts pre-date the mid-2000s and many may be addressed through the recently announced combined heat and power settlement at the California Public Utilities Commission. Staff is evaluating this issue to determine whether some specific contracts may require special treatment on a case-by-case basis.*")

7. CARB Should Consider CHP Impact from Assistance Factors Reductions in the Second Compliance Period.

The adjustments recommended in these comments should prevent creating additional disincentives for EITE CHP for the first compliance period. In the second compliance period, when assistance factors are dropped for some sectors and direct emissions coverage is reduced, CHP GHG emissions for serving on-site load will not be fully covered. If grid power purchases continue to receive coverage, incentives again will be strongly tilted toward grid power. It will be important for CARB to address the issue of CHP disincentives in advance of the second compliance period to prevent impairment of the Scoping Plan's goal of maintaining and expanding the state's CHP fleet.

EPUC appreciates your consideration of these recommendations. Please contact us with any questions.

Very truly yours,

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