



December 5, 2019

Jim Duffy  
California Air Resources Board  
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Dear Jim,

Thank you for the opportunity to provide comment on the BP Cherry Point co-processing application posted on 11/19/2019. We believe this pathway represents another innovative fuel production pathway spurred on by the LCFS program. We would like to thank CARB for including common sense conditions in this application including requiring  $^{14}\text{C}$  to determine the renewable content and requiring the fossil component of the fuel to generate a debit upon importation. Furthermore, we appreciate the opportunity to raise some questions related to the pathway which are not addressed in any of the publically available material. We hope that our comments will assist staff as they attempt to provide an accurate carbon intensity score for this application and future co-processing applications. To this end, we have divided our comments into two primary sections, feedstock and process; these two sections are then subdivided into more specific topics.

## **Feedstock**

### **Transportation Distance**

We are concerned that this pathway does not reflect the full transport distance of the animal fat which will be sourced under this pathway. We agree that the 0.14 G  $\text{CO}_2\text{e}/\text{MJ}$  that is calculated represents the 38 mile truck distance from Vancouver to BP. However, that distance does not account for the significant distance the animal tallow must be moved before it arrives in Vancouver. To our knowledge, there are no slaughter operations that are located in Vancouver, and therefore any tallow would likely be sourced from operations located in Alberta and Saskatchewan. Therefore, under the site-specific feedstock rules, this portion of the supply chain must also be accounted for. Based on our accounting, this would be an additional 750 miles of rail transit, or more than 0.55 g  $\text{CO}_2\text{e}/\text{MJ}$ .

### **Rendering Operation**

The application reports a carbon intensity for rendering of 16.49 g  $\text{CO}_2\text{e}/\text{MJ}$ . The GREET Model contains a default CI for rendering at 18.94. No explanation for the reduced rendering CI is provided. It could be inferred that BP either utilized the BC hydroelectricity grid in their model or reduced the electricity demand to achieve a reduced emission factor. We believe that either change would require a Tier 2 Joint application.



## Refining process

The proposed CI for this pathway is 26.92-27.65 g CO<sub>2</sub>e/MJ, depending on if you look at the CARB staff summary or the BP application. This CI is far lower than the stand-alone tallow based renewable diesel pathways that are currently approved, which range from 30.00-51.90 g CO<sub>2</sub>e/MJ<sup>1</sup>. While the low feedstock CI plays into this, see comments above, a significant portion of the difference can primarily be attributed to the extremely low processing CI of 8.70 g CO<sub>2</sub>e/MJ that was calculated by BP.

## Hydrogen Demand

There are three primary components to a renewable diesel production process's carbon intensity: natural gas, electricity, and hydrogen, of which hydrogen often makes up 70-80% of the total CI. BP reported a CI of 8.70 g CO<sub>2</sub>e/MJ which is significantly lower than the 11.34 g CO<sub>2</sub>e/MJ reported in CA-GREET 3.0 for tallow-based renewable diesel. If it was assumed that 100% of the reported 8.7 g CO<sub>2</sub>e/MJ CI came from hydrogen, that would equate to 5.67 SCF/lb of feedstock, assuming the higher yield reported in the pathway. Based on our internal calculations, this value is less than the stoichiometric hydrogen demand which is approximately 5.77 SCF/lb of feedstock. This is far below a more typical hydrogen demand for renewable diesel which is approximately 7.55 SCF/lb feedstock. Furthermore, if one takes the tallow consumption and hydrogen demand listed in the BP air permit, one would calculate an allocated CI much closer to what is in CA-GREET 3.0. We have included this calculation as an attachment to our comments. This discrepancy would lead one to believe that there are additional variables between the baseline scenario and the co-processing scenario which were not held constant.

The primary function of the diesel hydrodesulfurization unit (DHDS) is to remove sulfur and, to a lesser extent, nitrogen from the vacuum gas oil and other straight-run diesel streams so that the fuel can meet ULSD sulfur specifications. If the sulfur and nitrogen levels of the petroleum stream differed between the baseline and co-processing scenarios that could result in a significantly lower incremental hydrogen demand.

Finally, we are concerned that the method of hydrogen monitoring is inadequate. We do not believe that a bi-weekly grab sample is robust enough given that hydrogen demand would be the single largest source the process carbon intensity. We believe that a more frequent or, optimally, constant hydrogen monitoring should be required.

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<sup>1</sup> Diamond Green Diesel received a 30.00 CI in their 2017 application. Neste Porvoo received a CI of 51.90 in their 2019 application.



### **Additional Process Energy**

When accounting for additional energy beyond hydrogen, i.e. electricity and natural gas, the BP application has a significantly smaller system boundary than a stand-alone renewable diesel facility. For example, a stand-alone facility is required to account for the ancillary energy required to run pumps, product fractionation units, tank heating, etc. None of these items seem to be accounted for in the BP LCA. Clearly this energy is still required for the renewable portion of the co-processed diesel stream, and it is inconsistent to ignore this energy utilization for co-processing pathways yet require it for stand-alone pathways.

### **Yield**

The conditions laid out by CARB require BP to maintain a volumetric yield of 0.90-1.10 barrels of renewable diesel per barrel of tallow. We believe the upper bound of this range is far too high. Based on our internal calculations, when accounting for just paraffins and propane, hydrotreated tallow leaving the DHDS unit may have a yield as high as 1.0. If the higher range of the yield is achieved, that would result in increased hydrogen demand and thus a high CI. This yield assumes minimal decarboxylation. There is no doubt that the BP facility will have a better yield compared to a stand-alone facility due to the lack of isomerization, however it is highly improbable to achieve a yield better than 1.0 given the extent of decarboxylation that will occur in the reactor. We encourage CARB to either add a temperature correction requirements as a condition or consider using a mass yield in place of a volumetric condition.

### **Emission Factors**

This application appears to have two separate system boundaries. The first system boundary is around the hydrotreater and appears to be where the CI debits (energy use) are calculated. There also appears to be a second, much larger system boundary encapsulating the reformer and hydrogen recovery system wherein credits are given. While these two boundaries aren't necessarily inconsistent with each other, it does make correctly accounting for the CI much more difficult. For example, it appears that the off-gas leaving the DHDS is given a hydrogen displacement credit. This is appropriate if the hydrogen in the off-gas stream is recovered and reused for additional hydrogenation. However, it appears that the remaining hydrocarbons in this stream are combusted for process heat in the SMR and are also given the hydrogen displacement credit. We contend that this is inappropriate. The residual off-gas, wherever it is combusted, should be modeled as natural gas or refinery fuel gas; which would be consistent with how CARB is applying their book-and-claim rules for biomethane, requiring that the thermal energy necessary to heat the SMR be treated as natural gas.

BP's air permit also states that increased flaring at the refinery will occur due to increased catalyst degradation associated with co-processing. Since this is outside of the narrow system boundary CARB has drawn for debits, these flaring emissions, which BP states are directly related to co-processing, do not appear to be captured in the facilities CI.



Below we have included some potential conditions that CARB could apply to this pathway in order to calculate a more accurate carbon intensity. If the agency has any questions regarding our comments or proposed conditions, we ask that you please reach out to us.

Potential Additional Conditions:

- Ensure that if the CI for the rendering operation has been changed, the full application reflects a Tier 2 joint application. 95488(b)
- Expand the system boundary to include hydrogen demand upstream of the DHDS unit, or
  - Do not provide displacement credits within the pathway given the inconsistent system boundary application. 95488.6(a)(2)(D)
- Require inline, continuous monitoring of hydrogen coming into, and leaving the hydrotreater. 95488.8(a)(1)
- Apply a standard natural gas and electricity factor to this pathway based on the CA-GREET 3.0 renewable diesel pathway.

Sincerely,

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