Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine H. Reheis-Boyd
President

July 27, 2012

Mr. John Courtis
Manager, Alternative Fuels Section
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
Via e-mail to jcourtis@arb.ca.gov

Re: **WSPA Comments on July 12 Workshop on the Oil Production GHG Emissions Estimator**

Dear Mr. Courtis,

This letter is in response to the California Air Resources Board's (ARB's) July 12th public workshop on the OPGEE estimator tool. The Western States Petroleum Association (WSPA) has provided below a number of preliminary comments in anticipation of the next 15 day package, but direct ARB to our April 30, 2012 letter that contains many similar comments in more detail.

WSPA is a non-profit trade association representing twenty-seven companies that explore for, produce, refine, transport, and market petroleum, petroleum products, natural gas and other energy supplies in California and five other western states.

WSPA has not altered our core position that there should not be ANY crude differentiation treatment within the LCFS, and we want to be clear that providing comments on the workshop in no way should be perceived as a shift in our position on this baseline position.

Overall, WSPA wants any model associated with the LCFS to be consistent and workable. Our conclusion is we consider the use of the OPGEE model for regulatory purposes inappropriate due primarily to data integrity problems which was identified over the past several years as a core, fundamental problem. This is why WSPA did not support the development of a complex differentiation approach.

WSPA has requested a meeting with ARB within the next two weeks to discuss our comments as well as to address some outstanding implementation issues such as:

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

- ARB needs to finalize requirements for crude reporting and credit impacts for 2011.
- ARB needs to provide guidance on what, if anything, the oil industry should be doing for crude reporting and credit impacts for 2012.
- WSPA believes, due to the lack of detailed field data, that ARB will only be requiring crude MCON identities and volumes for 2013 reporting. We request confirmation of this level of obligation. We note that ARB didn't have more detailed data than this when developing the baseline.
- We understand ARB will be the only entity running OPGEE within the context of the LCFS, and ARB will be the official custodian for compliance reasons. Please confirm this understanding.
- We need further details about how a refiner would use the available crude CIs. We need the full list of global crude CIs to purchase crudes intelligently and evaluate (as best we can under the average rule) the impact on our businesses before we purchase crude oil. We reiterate the difficulty ARB's crude oil treatment places on companies that do not have access to detailed crude oil data, nor do they have knowledge about other companies crude purchases in order to be able to assess where the average value may end up every year.
- We need more clarity about the workshop references to continuous updates of crude CIs on baseline/annual updates. How and when will ARB notify our industry of MCON revisions or module changes, and what will be the process to update the crude CIs and targets? This will impose additional challenges since a refiner has to plan crude oil selections in a climate of changing CI values.

Our first set of comments are general, and the second are more specific/technical.

General Comments

False sense of accuracy: OPGEE was created to be a very detailed tool that requires a great many field-specific inputs that are generally unavailable in the public realm. The tool also over-simplifies very complex oil field production processes. As a tool for specific fields that are well-characterized and where field-specific information can be used in lieu of defaults, it may have some utility. However, to estimate average CI values for all crudes run in California refineries, it gives a false sense of accuracy. The output from the model is only as good as the input, and its flexibility to accommodate specific production field details.

Understanding crude data reporting and data availability: There needs to be further discussion about what the regulated parties (i.e. oil companies) are able to provide or acquire in terms of data. Regulated parties are the entities under the jurisdiction of the LCFS, however crude producers are under no obligation to provide competitive, proprietary data. Also, crude is traded on the open market and regulated parties will likely process economic crudes, not just equity production. Many oil companies do not or no longer produce any crude and therefore are concerned that they are placed at a disadvantage in comparison with those companies which may be able to make informed crude selection decisions.

Technical Validation: WSPA strongly recommends additional time be provided for technical validation or peer review in addition what has already been done; and more documentation of the

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

model furnished to make additional review time productive. It is difficult to track formulas from sheet to sheet to figure out what the model is doing. If the outputs from the OPGEE tool are adopted without adequate time to error check, it is highly likely that many errors will be discovered throughout the course of the next few years. ARB needs to outline a process for how these future discoveries will be handled, including possible changes to the baseline and yearly targets for each major change. WSPA also requests ARB/Stanford provide an estimate of the tool's uncertainty.

Yearly Variation: WSPA requests 2009/2010 results from OPGEE to see yearly variations prior to implementation of the tool.

Co-product credits: The OPGEE model used the substitution method instead of the allocation method where associated gas and liquids co-produced with crudes are assumed to replace NG, NGLs and other products in the existing market. The GHG credits given for these co-products were borrowed from the NG pathway in the GREET model. There are several issues with this approach, since the GHG emissions in the GREET NG pathway were calculated based on the allocation method. Certain pathways under CA LCFS also use the allocation method for crediting certain types of co-products. In addition, substitution only works if the co-product production volume is relatively small compared to the whole market. In some production fields, however, both gas and NGLs are in relatively large quantities and could potentially cause market saturation, where the use of the substitution method would become questionable. As mentioned during the workshop, WSPA suggests the OPGEE model be run with both the substitution and the allocation methods and see if there is a material difference in the results.

Technical comments/questions

1. We request that ARB release a completed model for each crude that leads to the indicated carbon intensity. There is a summary table of final crude CI's, and a summary of crude OPGEE inputs, however, in some cases the tool does not return the same CI when the listed inputs are entered by inexperienced users. It is extremely difficult to evaluate the effectiveness of the tool when it is not known which of the other inputs or defaults have been changed.

2. Although the tool allows many features to be turned on or off (such as steam or water flood, downhole pump), there are many components that need that option as well. Some examples include the Amine Treater, Glycol Dehydrator, and the Demethanizer. Some production methods do not have these processes and therefore should not have those GHG emissions attributed to them.

3. The calculations for horsepower to pump fluids into the well appear to only take the pump discharge pressure into account. It is important to consider the pump suction pressure as well, as there are cases of recovered water being sent to a pump at pressure after high pressure separation.

4. The flaring rates obtained from NOAA are not to be considered accurate on an absolute scale, and are not suitable for regulatory purposes. It is not uncommon for NOAA rates to be off by several hundred percent from reliably measured flaring rates. In the event that flaring rates are

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

also reported to a government agency, those reported numbers should be used in place of the NOAA figures.

5. The general assumption that flare combustion efficiency is 95% appears far too conservative, particularly for the larger flares that the NOAA satellites detect. An assumption of 98% flare efficiency would appear more appropriate. For example, there is a Shell Nigerian flaring study that supports 98%.

6. There are a number of crude oil extraction parameters (for example, emissions from drilling, gas compositions, gas-to-oil-ratio, water-to-oil ratio, etc.) which are based on correlations for Canada and/or California, even though California gets most of their imported crude from Alaska, the Middle East, and Central/South America. These correlations may not be applicable to these other locations.

7. In the drilling energy plot (Fig 3.1), why is the energy intensity of drilling in 2005 generally higher than the previous years? We would expect energy consumption to trend down over time, other things being equal.

8. Regarding LUC, the only reference used is Sonia Yeh. Given the debate around this topic, other viewpoints should also be sought out and considered. What, if any, other models/papers for land use change were considered and why were they rejected?

9. Concerning LUC:
   a. What time horizon is used? Is it 100 years- like EPA for LUC?
   b. Is ultimate restoration of the land at the end of the field life taken into account?

10. For Production and Extraction, there seems to be no transmission losses between the prime mover and the pump. These may be small, but should be included.

11. Some of the efficiency defaults (pump, compressor) in Table 3.4 are below the literature range. These should be "typical" (median) values from within that range, not "conservative" values below that range.

12. To calculate default field age, a discovery to production time lag of 3 years is assumed. At a minimum we believe there should be a range of values which might be dependent on other values and be molded into smart defaults, or that there be the flexibility to enter specific data. Generally, the concept of field age is flawed. A field does not simply appear as fully drilled out in a specific year. Development of a field can continue for decades with infill wells drilled on periodic timeframes. Dependent on management of the field – water flood; gas pressure maintenance, etc. Age is not relevant to the energy load of production.

13. The default well productivity excludes low productivity US wells. More than half of California's crude comes from California and Alaska. We believe the low productivity wells should be included.

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

14. When calculating default GOR, API for the pool is calculated by averaging high and low API's. ARB should really average SG, and recalculate API from the average.

15. When dealing with natural gas byproducts of crude production, how is energy input partitioned between crude and NG, especially if NG is sold or used to generate electricity (in a CoGen plant) which is sold back to the grid? If on-site gas displaces gas which would otherwise have been purchased, is there an offset used? (See comment above under General Comments)

16. How are upstream emissions for electricity, diesel, gasoline, fuel oil, natural gas, etc. calculated? There should be local input to account for electricity mix or fuel production where it is actually supplied and used.

17. Three diluents for Dilbit are available. What are the CIs?

18. Diluent from NGL is counted as external NG. What was the CI of the NGL?

19. Natural gas composition for steam generation for TEOR is fixed, when in fact it will vary with location and source. Local inputs should be allowed.

20. What is the 0.5gCO2/MJ "fudge" factor supposed to represent? Why did ARB choose that value since it seems large?

21. The value denominated in **gCO2e/<u>bbl</u>** in cell Bitumen Extraction & Upgrading!M164 is transferred to User Inputs & Results'!G188 as **gCO2e/<u>MJ</u>**. The default sheet is preloaded with a value which suggests that the cell in Extraction & Upgrading is labelled with the wrong units and should be gCO2e/MJ.

22. With regard to flaring emissions, the model contains a cell ('user inputs & results'J99) that allows the user to input their own flaring values. However, the cell is not accessed in any calculation.

23. With regard to venting emissions, if the user input cell is set to zero, emissions are still generated due to "default leaks". What is the basis for these "default leaks"?

24. In the bitumen module, the upstream emissions of natural gas liquids (NGL's) are assumed to be the same as natural gas. However, NGL's do not undergo the same treatment as natural gas (e.g. there is no point in removing sulfur from a diluent that is going to be added to bitumen) and the transport distances for NGL's are much smaller than those for natural gas (most Canadian gas is transported from Alberta to Ontario, whereas NGL's are mostly produced and consumed within Alberta).

25. Section 3.8 of the User Manual clearly states that "…Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE" (page 73). However at the same time, the input assumptions and data sheet ARB used for the Albian Heavy Synthetic (AHS) identifies the crude as a "…partially upgraded dil-synbit..." Given this conflict between

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

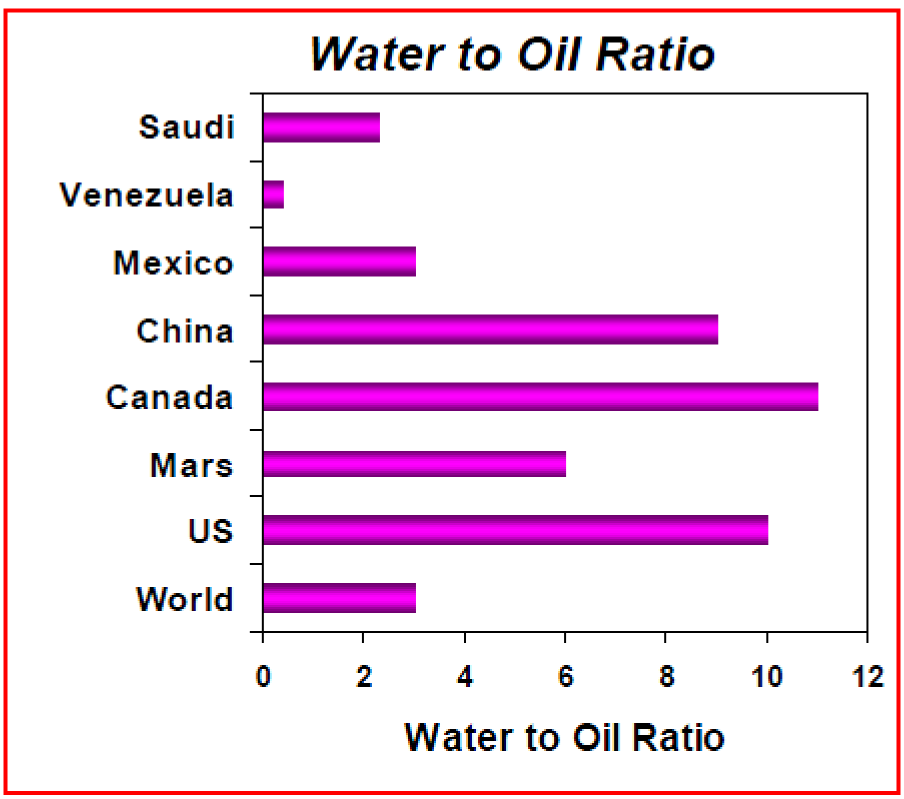
what OPGEE can model and ARB's description of AHS as a "partially upgraded dil-synbit" how can ARB use OPGEE for crudes identified as "dil-synbits"?

2010 Baseline

A few specific examples of concerns we have regarding the inputs used by ARB to develop the 2010 baseline CI values dated July 10, 2012, are summarized below:

1. There is a differing quality of data used for the 2010 baseline – field specific for California from DOGGR reports and simplified MCON estimates for imported crude. The data should be consistent and based on MCONs. Field data will not be uniformly available - even in California. WSPA requests MCONs for California crude production to facilitate MCON reporting and to understand ARB's knowledge of the complex California crude delivery systems. Most of the OPGEE model processes and defaults are based on California production and the request for tests is so a field-to-MCON evaluation can be completed.

2. The vast majority of crudes assessed by ARB staff use many model defaults; however, the available defaults cannot be applied blindly. As an example, Arab Light, which makes up 8% of the 2010 baseline crude volume, is assigned a water-oil ratio of 17.8 which was derived from the "smart default" curve based on field age. This "smart default" was used despite data available to staff that indicates that the water-oil ratio is actually much lower. The chart reproduced below was taken from a presentation by Jacobs Engineering to the Crude Oil Screening Workgroup obtained from ARB's own web site:



1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

The Jacobs data indicates that the water-oil ratio is about 2 for Saudi Arabian crudes. Staff's use of the "smart default" value rather than the Jacobs data, combined with the very high well flow rates (5700 barrels per day per well versus a model default of 188 barrels per day per well) for Saudi Arabian production, results in the model estimating an unreasonable CI value (> 200 gCO2e/MJ) when all of the other field-specific inputs and defaults are utilized. Rather than questioning the "smart default", staff appears to have arbitrarily chosen to increase the assumed well diameter for Arab Light and Arab Extra light to 7.5 inches, which is 3 inches larger than the upper range from the literature reported in the OPGEE documentation. The resulting CI value for Arab Light is 12.5 g/MJ. However, if staff had utilized the Jacobs-based water-oil ratio of 2, then the extraordinary well diameter assumption would not have been necessary and the OPGEE prediction for the CI of Arab Light would have been 7.1 g/MJ - which is still high compared to other estimates, but more reasonable than 12.5 g/MJ.

Given the significant historical consumption of Arab Light by California refiners, WSPA has grave concerns about ARB staff's application of OPGEE to the calculation of the 2010 baseline and the California average. We are also concerned that if the estimate for such a high profile crude could be so far off, the estimates for other crudes that we have not had time to examine may contain similar errors.

3. Basrah Light, which makes up 8% of the 2010 California baseline crude volume, is also assumed to come from wells with a high flow rate (1500 barrels per day per well with a water-oil ratio of 14.4, again based on the "smart default" curve as a function of field age). In that case, ARB has assumed a well diameter of 4 inches. What was the basis of the well diameter estimate? Given that there is a significant difference between the water-oil ratio assumed for Saudi Arabian production from the "smart default" versus available data, we are concerned about the validity of the use of the "smart default" for Basrah Light. Has ARB attempted to validate this estimate with other sources of data?

4. Another parameter that was modified for cases in which wells have a high flow rate is the Productivity Index, which has a baseline value of 3.0. Arab Light and Arab Extra Light are assumed to have a Productivity Index of 75, and Basrah Light is assumed to have a Productivity Index of 15. What is the basis of these estimates?

5. The water-oil ratio has a significant impact on the model results, but the data used to derive the "smart default" values as a function of field age are highly variable and exhibit extreme scatter (see Figure 3.11 in the OPGEE documentation). How confident is ARB that these "smart defaults" are accurately estimating the water-oil ratio for specific fields, particularly in Saudi Arabia and Iraq? Also, the field age appears to be based on the oldest well ever drilled in a given field (e.g., for Arab Light, the assumed age is 56 years). Given the long development timelines and massive size of the fields in some of these locations (e.g., Ghawar in the case of Arab Light), a field age would be much more reasonably based on an average age of the wells as they were brought on stream. As discussed earlier, Arab Light is an example of an unreasonable "field" age being used to calculate an unreasonable (and data-contrary) "smart default" for the water-oil ratio that produces a CI estimate that is out of line with all other work.

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org

WSPA would appreciate an opportunity to discuss these comments in more detail, and ask ARB staff to please coordinate with my staff, Gina Grey at (480) 595-7121 to arrange a follow up meeting.

Sincerely,

c.c. R. Corey – ARB
C. Marvin – ARB
J. Duffy – ARB
A. Brandt – Stanford
G. Grey - WSPA

1415 L Street, Suite 600, Sacramento, California 95814
(916) 498-7752 ▪ Fax: (916) 444-5745 ▪ Cell: (916) 835-0450
cathy@wspa.org ▪ www.wspa.org