COMMUNITIES FOR A
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ENVIRONMENT

24 October 2011

LCFS Program Review Advisory Panel
California Air Resources Board (ARB)
1011 I Street
Sacramento, California 95814

Electronic Submission

Low Carbon Fuel Standard (LCFS): Request for LCFS Program Review Advisory Panel consideration and recommendation regarding petroleum fuels carbon intensity values

Dear Advisory Panel members,

As you know, accurate carbon intensity (CI) estimates for transportation fuels are critical to the efficacy of the LCFS, and refined petroleum fuels currently dominate the transport fuels mix. However, CI estimates for gasoline (CARBOB) and diesel (ULSD) were derived by methods that do not account for emissions from *refining* denser, higher sulfur crude oils, or those from burning the resultant by product petroleum coke *(1, 2)*. Such differences in refinery emissions are not accounted for by the proposed High Carbon Intensity Crude Oil (HCICO) estimates either, as ARB Staff acknowledged during its 17 February 2011 HCICO workgroup meeting.

ARB also acknowledges that crude feed quality drives refinery emission intensity, and that California refinery crude supplies are changing now *(3),* but ARB Staff has not quantified impacts of crude quality on refinery emissions and, in fact, has not gathered the data necessary to do so *(4)*. This comment applies peer reviewed data and methods that are applicable to U.S. and California refining *(5–7)* to estimate the potential error from omitting emissions associated with energy intensity and coke by-production from refining denser, higher sulfur crude, thereby providing quantitative support for the need to revise petroleum fuels CI values to account for emissions.

Background brief

Briefly, making gasoline, diesel and jet fuel from denser, higher sulfur crude requires putting more of the crude barrel through aggressive carbon rejection and hydrogen addition processing. That takes more energy. Burning more fuel for this energy increases refinery emissions. Differences in refinery crude feed density and sulfur content explain 90–96% of differences in CO_2 emission intensity observed across U.S. and California refineries and predict average 2004–2009 statewide refinery emissions within 1% *(5, 6)*. Differences in refined product slates, refinery capacity utilization, and the mix of fuels burned in refineries are not confounding factors *(5, 6)*.

Petroleum coke is a by product that is created in larger amounts as refineries make motor fuels from denser crude *(5)*. Statewide, California refines denser crude than any other major U.S. refining region, and California refinery yield of total (catalyst and marketable) petroleum coke is roughly twice that of the East Coast refining region (PADD 1), which runs lighter and lower sulfur crude *(Ref 7: see Table 2-1; Att. 1)*. Coke is the dirtiest burning major refinery fuel *(5, 6)*. In addition to burning this refinery by product in refineries, refiners sell "marketable" petroleum coke, primarily for use as fuel in other industries such as cement and power plants *(8)*.

By 2020, some 70–75% of current California refinery crude input will *not* be from existing, declining sources of crude production in California and Alaska, and could foreseeably be replaced by some combination of heavy oil and natural bitumen from tar sands *(6, 7)*.

Emissions from increased refinery energy intensity associated with denser, dirtier crude.

Table 1 shows average observed refinery energy and emission intensities among U.S. refining regions and years and those predicted by refinery crude feed density and sulfur content. These results are based on recently published, peer reviewed data and methods *(5–7),* and on reasonably foreseeable scenarios in which 70% of current statewide crude input is replaced by various blends of heavy oil and tar sands bitumen. Potential future crude feed quality is based on the current average for California-produced crude *(7)* and the average density and sulfur content of heavy oil and natural bitumen as defined by USGS *(9)*.

Observed refinery energy and emission intensities are strongly and positively associated with crude feed density and sulfur content among U.S. refining regions and years *(5, Table 1)*. Emission predictions for current and potential future annual average California crude feed density and sulfur content shown in Table 1 are by partial least squares regression on these U.S. data *(5)* based on the model documented in recently published work *(5, 6)*. Observed statewide emissions are within the 95% confidence of prediction in four of six years *(Table 1)* and are within 1% of the prediction as a six-year average *(6)*. Emissions reported for 2008 by the individual California facility reporting the highest emission intensity are also within 1% of the confidence of prediction based on crude feed quality *(Martinez 2008 in Table 1)*.

Crude feed quality drives substantial differences in refinery emissions. Observed annual average refinery emissions intensity ranges by 93%, from 257 to 497 kg/m^3. Further, the high end of the observed emission intensity range (497 kg/m^3) approaches the low end of the range predicted by potential future statewide average crude feed (559 kg/m^3) within 11% *(compare Martinez 2008, upper bound to 70/30 HO/CA blend, lower bound)*. Accounting for the full range of heavy oil/bitumen blends that could replace the 70% of 2020 California crude feed no longer supplied by existing sources and the 95% confidence of prediction, statewide average refinery emission intensity could reach 559–879 kg/m^3 crude refined *(Table 1)*.

Currently (2004–2009), statewide refinery emissions average 379 kg/m^3 *(7)*. Thus, this 559–879 kg/m^3 emission potential would exceed the current statewide emissions rate by 47–132%. At the current average statewide refinery crude throughput (102.94 MM m^3/y) *(7)* this represents a mass emission increase of 18-51 million tonnes/year.

Table 1. Direct refinery CO_2 emissions observed, and predicted based on energy intensity.

		EI	density	sulfur	cap.	prod.	fuel mix	Obs. Emit	Predictions (95% conf. interval)			
PADD	Year	(GJ/m^3)	(kg/m^3)	(kg/m^3)	ut. (%)	ratio	(kg/GJ)	(kg/m^3)	(GJ/m^3)	(GJ/m^3)	(kg/m^3)	(kg/m^3)
1	1999	3.451	858.20	8.24	90.9	3.668	81.53	281	2.877	3.604	235	294
1	2000	3.430	860.18	8.00	91.7	3.489	80.34	276	2.987	3.711	240	298
1	2001	3.518	866.34	7.71	87.2	3.479	81.85	288	3.198	3.919	262	321
1	2002	3.426	865.71	7.45	88.9	3.605	81.08	278	3.152	3.870	256	314
1	2003	3.364	863.44	7.43	92.7	3.321	81.51	274	3.133	3.853	255	314
1	2004	3.416	865.44	7.79	90.4	3.397	81.46	278	3.209	3.927	261	320
1	2005	3.404	863.38	7.17	93.1	3.756	81.23	277	3.048	3.772	248	306
1	2006	3.440	864.12	7.17	86.7	3.522	80.40	277	3.054	3.780	246	304
1	2007	3.499	864.33	7.26	85.6	3.443	82.28	288	3.067	3.800	252	313
1	2008	3.551	863.65	7.08	80.8	3.400	83.26	296	2.972	3.733	247	311
2	1999	3.368	858.25	10.64	93.3	4.077	78.11	263	2.984	3.711	233	290
2	2000	3.361	860.03	11.35	94.2	4.132	77.56	261	3.104	3.832	241	297
2	2001	3.396	861.33	11.37	93.9	4.313	77.46	263	3.126	3.863	242	299
2	2002	3.393	861.02	11.28	90.0	4.345	77.90	264	3.068	3.796	239	296
2	2003	3.298	862.80	11.65	91.6	4.281	78.00	257	3.195	3.922	249	306
2	2004	3.376	865.65	11.86	93.6	4.167	77.25	261	3.369	4.098	260	317
2	2005	3.496	865.65	11.95	92.9	4.207	77.27	270	3.362	4.089	260	316
2	2006	3.738	865.44	11.60	92.4	3.907	75.84	284	3.380	4.095	256	311
2	2007	3.800	864.07	11.84	90.1	4.161	75.55	287	3.270	3.989	247	301
2	2008	3.858	862.59	11.73	88.4	4.333	74.97	289	3.154	3.875	236	291
3	1999	4.546	869.00	12.86	94.7	3.120	71.61	326	3.759	4.476	269	321
3	2000	4.563	870.29	12.97	93.9	3.120	71.87	328	3.813	4.531	274	326
3	2001	4.348	874.43	14.34	94.8	3.128	72.43	315	4.086	4.803	296	348
3	2002	4.434	876.70	14.47	91.5	3.251	72.71	322	4.140	4.859	301	353
3	2003	4.381	874.48	14.43	93.6	3.160	72.81	319	4.076	4.794	297	349
3	2004	4.204	877.79	14.40	94.1	3.228	73.43	309	4.213	4.930	309	362
3	2005	4.205	878.01	14.40	88.3	3.316	73.24	308	4.149	4.873	304	357
3	2006	4.367	875.67	14.36	88.7	3.176	74.15	324	4.067	4.798	302	356
3	2007	4.226	876.98	14.47	88.7	3.205	74.93	317	4.127	4.856	309	364
3	2008	4.361	878.66	14.94	83.6	3.229	74.48	325	4.165	4.915	310	366
5	1999	4.908	894.61	11.09	87.1	2.952	70.27	345	4.713	5.451	331	383
5	2000	5.189	895.85	10.84	87.5	3.160	69.09	358	4.725	5.460	326	377
5	2001	5.039	893.76	10.99	89.1	3.231	69.38	350	4.648	5.380	322	373
5	2002	4.881	889.99	10.86	90.0	3.460	69.15	338	4.450	5.178	308	358
5	2003	4.885	889.10	10.94	91.3	3.487	69.40	339	4.422	5.153	307	358
5	2004	4.861	888.87	11.20	90.4	3.551	69.89	340	4.410	5.140	308	359
5	2005	4.774	888.99	11.38	91.7	3.700	69.88	334	4.409	5.151	308	360
5	2006	4.862	887.65	10.92	90.5	3.615	69.32	337	4.331	5.060	300	351
5	2007	5.091	885.54	11.07	87.6	3.551	69.12	352	4.235	4.953	293	342
5	2008	4.939	890.16	12.11	88.1	3.803	68.39	338	4.456	5.191	305	355
Calif. average, 2004			899.23	11.46	93.0	3.633	70.82	354	4.881	5.632	346	399
Calif. average, 2005			900.56	11.82	95.0	3.801	71.06	358	4.937	5.721	351	407
Calif. average, 2006			899.56	11.73	91.5	3.845	72.65	384	4.861	5.616	353	408
Calif. average, 2007			899.84	11.89	88.3	3.814	71.43	401	4.866	5.603	348	400
Calif. average, 2008			902.00	12.85	91.0	4.087	71.02	383	4.980	5.759	354	409
Calif. average, 2009			901.38	11.70	82.9	4.045	70.54	397	4.837	5.564	341	392
Martinez 2008[a]			932.08	9.86	91.0	4.087	71.02	497	6.076	6.931	432	492
70/30 HO/CA blend[b]			948.39	22.59	90.8	3.469	73.77	--	7.576	8.595	559	634
70/30 NB/CA blend[b]			1001.73	34.98	90.8	3.469	73.77	--	10.419	11.920	769	879

EI: refinery energy intensity; fuel energy consumed/vol. crude refined (GJ/m^3).
Cap. ut.: operable refinery capacity utilization as defined by U.S. EIA (%).
Prod. ratio: products ratio; ratio by vol. of gasolines, distillate, kerosenes and naphtha to other products.
Fuel mix emission intensity measured from reported data as detailed in *Ref. 7,* Table 2-1 (kg/GJ).
70/30 HO/CA: 2020 crude feed is 70/30 blend of heavy oil/California-produced crude.
70/30 NB/CA: 2020 crude feed is 70/30 blend of natural bitumen/California-produced crude.
California-produced crude quality is 2004–2008 average from *Ref. 7,* Table 2-3.
Average heavy oil and natural bitumen densities and sulfur contents from USGS *(5, 9).*
[a] Prediction uses average 2004-2008 Calif. capacity utilization, products ratio & fuel mix inputs.
[b] Prediction uses average 1999–2008 U.S. capacity utilization, products ratio & fuel mix inputs.
All other data from *Ref. 5,* Table S1; and *Ref. 7,* Table 2-1.

Emissions from petroleum coke created as a by product of refining denser, dirtier crude.

The projection of potential future emissions in Table 1 is limited to emissions from fuels consumed by refineries and assumes no change in the average mix of fuels *(5–7)*. However, refining denser, higher sulfur crude increases by-production of petroleum coke *(5),* which is burns dirtier than other refinery fuels *(5, 6),* and also is sold for use by other industries as fuel *(8),* thereby causing additional direct and/or indirect emissions. Fuel cycle CI estimates should account for emissions from burning the excess coke created by processing denser, higher sulfur oils *(10)*. The current statewide refinery coke yield, and that predicted for the same range of future denser, higher sulfur crude feeds analyzed above, are shown in Table 2.

Crude feed density and sulfur content can explain the near-doubling of coke yield observed across U.S. refining regions *(compare PADDs 1 and 5 in Table 2),* and predicts currently observed average California refinery coke yield reasonably well *(Table 2)*. This currently observed California coke yield (7.1–7.6%) is twice that observed in East Coast Petroleum Administration Defense District (PADD) 1 (2.9–3.3%). For the same reasonably foreseeable future blends of 70% heavy oil/natural bitumen and 30% current California production analyzed above, this analysis predicts future California refinery coke yield in the range of 13.5–20.8% *(Id.)*. At current average California refinery crude throughput (102.94 million m^3/y) *(7),* this 5.1–13.8% increase in yield represents a 5–14 million m^3/y increase in petroleum coke. CO_2 emissions from burning that coke increment could total 21–59 million tonnes/year, based on energy and emission factors for petroleum coke from recently published work (38.98 GJ/m^3 HHV; 107.74 kg/GJ CO_2) *(5)*.

California refineries do not stockpile this contaminated by product. Because they sell the coke they create in excess of that burned in refineries for fuel at a discount (accounting for the cost of otherwise disposing it), so that fuel shuffling driven by excess coke by-production will displace investment in zero-emission renewable energy, it can be argued that all the emissions from burning this future excess count as new emissions. On the other hand, it can be argued that only a portion of the predicted excess coke emissions should be counted because some of the excess coke will replace equally dirty-burning coal or will be calcined using less-dirty fuels, and process improvement might partially curb excess coke by-production. For purposes of this comment to the Panel, the low end of the range of emissions from excess coke (21 million tonnes/year) is conservatively assumed. Again, these emissions would be *in addition to* the 18–51 million tonne/year from increased refinery energy intensity associated with denser, dirtier crude.

Conclusion

Despite the conservative assumption that emissions from excess coke will not exceed 21 million tonnes/year, emissions from burning more total fuel for added processing energy combined with those from creating and burning more of the resultant coke by product could increase emissions associated with refining denser, higher sulfur crude by 39–72 million tonnes/year. At the average direct emissions from refineries statewide (39 MM tonnes/y 2004–2009) *(7)* and the percentage of fuel cycle emissions from refining that ARB's gasoline "pathway" analysis estimates (14.4%) *(1),* fuel cycle emissions total approximately 271 MM tonnes/year, and this 39–72 MM tonnes/y increment represents a total petroleum fuel cycle emissions increase of 14–27%.

Table 2. Refinery coke yield observed and California coke yield predicted by crude quality (R^2 0.97).

U.S. data:		*y* observed	*x* (explanatory variable) data observed			coke yield predicted (95% confidence)		
		total coke	crude den-	crude sul-	capacity util-	lower bound	prediction	upper bound
PADD	year	(% yield)	sity (kg/m^3)	fur (kg/m^3)	ization (%)	(% yield)	(% yield)	(% yield)
1	1999	3.1	858.20	8.24	90.9	2.6	3.0	3.4
1	2000	3.0	860.18	8.00	91.7	2.7	3.1	3.4
1	2001	3.3	866.34	7.71	87.2	3.0	3.4	3.8
1	2002	3.1	865.71	7.45	88.9	2.9	3.3	3.7
1	2003	2.9	863.44	7.43	92.7	2.7	3.1	3.5
1	2004	3.1	865.44	7.79	90.4	3.0	3.3	3.7
1	2005	2.9	863.38	7.17	93.1	2.6	3.0	3.4
1	2006	3.0	864.12	7.17	86.7	2.7	3.1	3.5
1	2007	3.2	864.33	7.26	85.6	2.8	3.2	3.5
1	2008	3.3	863.65	7.08	80.8	2.7	3.1	3.5
2	1999	4.2	858.25	10.64	93.3	3.3	3.7	4.0
2	2000	4.3	860.03	11.35	94.2	3.6	4.0	4.4
2	2001	4.3	861.33	11.37	93.9	3.7	4.1	4.5
2	2002	4.1	861.02	11.28	90.0	3.7	4.0	4.4
2	2003	4.2	862.80	11.65	91.6	3.9	4.3	4.6
2	2004	4.3	865.65	11.86	93.6	4.1	4.5	4.9
2	2005	4.5	865.65	11.95	92.9	4.1	4.5	4.9
2	2006	4.4	865.44	11.60	92.4	4.0	4.4	4.8
2	2007	4.3	864.07	11.84	90.1	4.0	4.4	4.8
2	2008	4.3	862.59	11.73	88.4	3.9	4.3	4.7
3	1999	4.8	869.00	12.86	94.7	4.6	5.0	5.4
3	2000	4.8	870.29	12.97	93.9	4.7	5.1	5.5
3	2001	5.3	874.43	14.34	94.8	5.4	5.8	6.1
3	2002	5.7	876.70	14.47	91.5	5.6	6.0	6.4
3	2003	5.7	874.48	14.43	93.6	5.4	5.8	6.2
3	2004	5.9	877.79	14.40	94.1	5.6	6.0	6.4
3	2005	6.0	878.01	14.40	88.3	5.7	6.1	6.4
3	2006	6.2	875.67	14.36	88.7	5.5	5.9	6.3
3	2007	6.0	876.98	14.47	88.7	5.6	6.0	6.4
3	2008	6.0	878.66	14.94	83.6	5.9	6.3	6.7
5	1999	6.1	894.61	11.09	87.1	5.8	6.2	6.6
5	2000	6.3	895.85	10.84	87.5	5.8	6.2	6.6
5	2001	6.0	893.76	10.99	89.1	5.7	6.1	6.5
5	2002	6.0	889.99	10.86	90.0	5.4	5.8	6.2
5	2003	6.2	889.10	10.94	91.3	5.4	5.8	6.2
5	2004	6.1	888.87	11.20	90.4	5.5	5.9	6.2
5	2005	6.2	888.99	11.38	91.7	5.5	5.9	6.3
5	2006	6.0	887.65	10.92	90.5	5.3	5.7	6.1
5	2007	5.8	885.54	11.07	87.6	5.2	5.6	6.0
5	2008	6.1	890.16	12.11	88.1	5.8	6.2	6.6
California data:			data inputs for California predictions					
Cal. avg. 2004		7.4	899.23	11.46	93.0	6.2	6.6	7.0
Cal. avg. 2005		7.7	900.56	11.82	95.0	6.4	6.8	7.2
Cal. avg. 2006		7.4	899.56	11.73	91.5	6.3	6.7	7.1
Cal. avg. 2007		7.1	899.84	11.89	88.3	6.4	6.8	7.2
Cal. avg. 2008		7.4	902.00	12.85	91.0	6.8	7.2	7.6
Cal. avg. 2009		7.6	901.38	11.70	82.9	6.5	6.9	7.2
70/30 HO/CA blend			948.39	22.59	90.8	12.4	13.0	13.5
70/30 NB/CA blend			1001.73	34.98	90.8	19.1	20.0	20.8

Prediction for replacement by heavy oil (HO) and natural bitumen (NB) at avg. 1999–2008 U.S. capacity utilization. 70/30 HO/CA crude feed: 70/30 blend of heavy oil/Calif.-produced crude. 70/30 NB/CA crude feed: 70/30 blend of natural bitumen/Calif.-produced crude. California-produced crude quality is the 2004–2008 average *(Ref. 7 at Table 2-3).* Avg. heavy oil and natural bitumen qualities are from USGS *(5, 9).* All other data from *Ref. 7 at Table 2-1.* Total (market & catalyst) coke yield predicted by crude density and sulfur content and refinery capacity utilization; analysis by partial least squares regression on the U.S. (PADDs) data shown.

The carbon intensity values in the LCFS for CARBOB (95.86 g/MJ) and ULSD (94.71 g/MJ) are lower than those in the LCFS for the California marginal electricity mix of natural gas and renewable energy (104.71 g/MJ) and for compressed hydrogen from on-site reforming of natural gas (98.30 g/MJ) *(11)*. However, even the low end of the range of percentage increase in total petroleum fuel cycle emissions that is likely to result from refining denser, higher sulfur crude by 2020 in California (+14%) would increase the CARBOB and ULSD values to 109.28 and 107.97 g/MJ respectively, which is higher than those electricity and hydrogen CI values. Thus, failure to account for emissions associated with refining denser, higher sulfur crude oils in the LCFS CI values could have the perverse effect of supporting inherently more carbon-intensive fuels. Moreover, it could allow the dominant transport fuels to increase emissions by amounts that would overwhelm the 10% reduction in total fuel cycle emissions sought by the LCFS.

Addressing higher carbon intensity crude only at the crude production (extraction) step in the fuel cycle—as the LCFS attempts—cannot account for or prevent the *refining* of denser, higher sulfur crude. Emissions from extraction and refining are affected by different factors. The geology and viscosity of oil deposits drive the energy and emission intensities of oil extraction: crude feed density and sulfur content drive the energy and emission intensities of refining.

In sum, substantial evidence strongly supports revising the LCFS carbon intensity values to account for emissions from increasing refinery energy intensity and coke by-production associated with making gasoline and diesel from denser, higher sulfur crude oils. Please consider making a formal Advisory Panel recommendation for the ARB to take this needed action.

Respectfully submitted to the Panel on 24 October 2011

Greg Karras
Senior Scientist

Attachments: ARB response to request pursuant to the California Public Records Act *(4)*.
Karras, 2010. *Env. Sci. Technol.* 44(24): 9584–9589 *(5).*
Union of Concerned Scientist, 2011. *Technical Analysis Final Report (6)*.
Union of Concerned Scientist, 2011. *Technical Analysis Technical Appendix (7)*.

Copy: Interested organizations and individuals

References cited

1. *Detailed CA-GREET pathway for California reformulated gasoline blendstock for oxygenate blending (CARBOB) from average crude refined in California, Version 2.1;* California Air Resources Board: Sacramento, CA.

2. *Detailed CA-GREET pathway for ultra low sulfur diesel (ULSD) from average crude refined in California, Version 2.1;* California Air Resources Board: Sacramento, CA.

3. *Response to Comments on the Supplement to the AB 32 Scoping Plan Functional Equivalent Document;* Air Resources Board: Sacramento, CA. 19 August 2011. See pp. 106-67, 106-68.

4. Correspondence from Alexa Barron, Public Records Coordinator, Office of Legal Affairs, California Air Resources Board, to Greg Karras, Senior Scientist, Communities for a Better Environment. Response to request dated May 19, 2001 regarding average density and total sulfur content of crude oil inputs to California refineries. 23 June 2011.

5. Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24): 9584–9589. DOI 10.1021/es1019965. (http://pubs.acs.org/doi/abs/10.1021/es1019965.)

6. *Final Report: Oil Refinery CO_2 Performance Measurement;* Union of Concerned Scientists: Berkeley, CA. Technical analysis prepared for the Union of Concerned Scientists by Communities for a Better Environment . Karras, G., 2011; September 2011.

7. *Technical Appendix: Oil Refinery CO_2 Performance Measurement;* Union of Concerned Scientists: Berkeley, CA. Technical analysis prepared for the Union of Concerned Scientists by Communities for a Better Environment . Karras, G., 2011; September 2011.

8. U.S. Energy Information Administration (EIA). www.eia.gov/petroleum/data.cfm.

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10. Keesom et al., 2009. *Life cycle assessment comparison of North American and imported crudes;* File No. AERI 1747; Alberta Energy Research Institute: Calgary, Alberta; www.albertainnovates.ca/energy/major-initiatives/lca.

11. *Proposed Final Regulation Order, Amended LCFS Regulation;* Calif. Air Resources Board: Sacramento, CA. August 22, 2011. *See* tables 6 and 7 (“Lookup” tables).