

**Home Rule Advisory Group
Climate Change Subcommittee
February 4, 2009
Meeting Highlights**

1. HRAG members in attendance were:

Greg Adams (LACSD-Chair); Bill LaMarr (California Small Business Alliance); Dan McGivney (Eastern Municipal Water District); Mike Wang (WSPA); Jill Whynot (SCAQMD); Curt Coleman (Southern California Air Quality Alliance)

HRAG Members Attending by Phone were:

Tom Pomales (CARB)

Other Attendees by Phone were:

Jean Panek (CARB); Mike Waugh (CARB); Chloe Dao (OCSD);

Other attendees were:

Jeri Voge (SCAQMD); Leila Barker (LADWP); Ron Rex (BP); Lisa Rothbart (OCSD)

2. Update on Low Carbon Fuel Standard Economics

Mike Waugh, Manager, Project Assistance Section, addressed the subcommittee using the same slides he had presented at a workshop on the same subject on January 30, 2009. The methodology of the economic analysis was to: (1) estimate the production costs of gasoline and diesel; (2) estimate the production costs of lower carbon intensity fuels; (3) apply the costs to eight compliance scenarios (five for gasoline and three for diesel) each achieving the required 10% reduction; and (4) calculate a cost effectiveness in dollars per metric ton of CO₂ reduced.

In response to a question, Mike explained that the compliance scenarios were not the GREET model pathways but compliance options, such as using sugar cane derived ethanol (in lieu of corn-based ethanol) and gasoline or sugar cane ethanol and ZEVs to meet the standard, etc.

Mike said another goal of his team was to evaluate the impacts that the new federal renewable fuel standard (RFS2) from the 2007 EISA would have on the LCFS. The federal law required 36 billion gallons of biofuels by 2022.

In response to a question from a subcommittee member on the revised CAFÉ standards in the 2007 EISA, Mike was sure that the Pavley vehicle standards would subsume the CAFÉ standards in the process of lowering vehicle emissions.

Mike explained that staff was using 2007 CEC IEPR (Integrated Energy Policy Report) crude prices of between \$66 and \$88 per bbl while EIA in 2009 was projecting a “middle” point of around \$116/bbl crude in 2020 (prices without taxes).

It was unclear at this point which prices they would present to the Board. All agreed 2008 was a fuel price roller coaster. CARB would rely on the CEC to predict and defend the prices to be used in the final rule analysis. In response to a question, Mike said that the 2007 CEC IEPR numbers (\$88/bbl) were used in the Scoping Plan.

Mike explained that the Antares Group output for the Western Governors Association was the principal document used to establish the costs for the alternative fuels analysis. These data were all rationalized to 50 MGY plants and 2007 dollars to get everything on an equal footing. Since the capital costs of several of the cellulosic ethanol schemes, for example, could not be based on actual operating plants since there were none, staff used computer models to build virtual plants and estimate the capital costs. Some components of operating costs were estimated from those simulations but several items, like labor costs, had to be imported into the program. Mike said that staff realized that production costs were related to crude price. Staff estimated that 15-20% of the production costs were energy related and adjusted the prices used accordingly.

Feedstocks were given various valuations. Corn was \$3.94/bushel while yellow grease was \$.11/lb. Municipal Solid Waste (MSW), actually greenwaste, was given a \$0.00/ton evaluation which caused some discussion among the subcommittee members as to how realistic that pricing was. All biomass was assumed to be collected within a 50-mile radius of the alternative fuel production site.

The co-product credits that result from the production of the fuel are critical for the economic viability of the alternative fuels. For example, from Fischer-Tropsch Diesel, electricity and naphtha is produced from biodiesel, glycerin, and from cellulosic fermentation waste solids that can be burned. From wet mill corn ethanol, almost half the cost of the production side can be recovered with the byproducts.

Shipping costs from the production facility to your local "gas" station for ethanol are fairly high--about \$.21/gallon. Since a gallon has about 2/3 the energy content of gasoline, on a GGE basis, freight costs \$.34 per gallon. The same numbers were assumed for diesel.

Hence gasoline, with taxes removed (8% sales tax plus \$.18 federal tax plus \$18.4 state tax plus approximately \$.01/gallon underground storage mitigation fee) costs \$2.42 per gallon and with the exception of a few cases like yellow grease, the cost for production of alternative fuels is greater than for petroleum-based fuels.

Mike explained that fuel dispensing costs were yet above and beyond the costs established to date. Many of these costs were throughput sensitive. An E85 compatible tank (not a standard gasoline tank) and dispenser and auxiliaries, installed, added to an existing station, costs approximately \$172,000. Installation was about 50% of the cost. When the LCFS gets fully underway, Mike said E85

would appear. Intermediate blends of E15 might appear temporarily, but the greater reductions in carbon intensity in the later years of the rule would require E85.

A new, 7-10,000 psi hydrogen station (not including land) dispensing 1000 kg H₂/day (liquid delivery system capacity) would run around \$2.7MM. Hence the low cost of hydrogen on a GGE basis of \$1.26 delivered would double to \$2.52 /GGE when the dispensing facility costs are factored in. This assumes fuel cell vehicles have been purchased and are available to use the fuel.

A CNG fueling island addition to an existing facility would cost approximately \$373,000, 2/3 of which is the compressor cost.

Mike added that no one was mandated to install these facilities and that staff thought that the oil companies and not the moms and pops would install these systems. One member of the subcommittee thought that the large companies were trying to get out of the retail station business.

A subcommittee member asked if the analyses so far included sensitivities to general price increases across the board. Mike agreed that there was much uncertainty in the future; the economics of the whole alternative fuel program look much better when gasoline is at \$4.50 a gallon. It would be difficult to make this program fly if crude was down at \$20 per barrel.

Mike discussed the federal fuel tax incentives (\$1.01/gal credit to cellulosic producers; for biodiesel produced from waste grease, a credit of \$1.00 per gallon and for CNG, a credit of \$.50/GGE sold). Hence with the substantial federal tax incentives, the higher costs of alternative fuels are reduced to below the costs for petroleum-based fuel. Mike speculated that as the production of alternative fuels became more prevalent, the federal tax incentives would be reduced.

Mike explained that the five gasoline scenarios explored showed an overall savings in the 2014 timeframe. The diesel scenarios became noticeably cost-effective in the 2015 timeframe. It was not clear how profit taking would impact the overall cost-effective calculations of the eight scenarios.

Mike said that the 2007 EISA RFS will bring biofuels to California in greater quantities, but these will contain higher carbon footprints than what is called for in the LCFS. Overall, the 2007 EISA RFS (RFS2) may achieve about half of the LCFS target. For the purpose of the analysis, staff used the historical accurate assumption that Californians consume about 11% of the nation's motor fuel.

An attendee asked if the RFS2 would overtake the LCFS. Mike was not sure there would be a crossover but would have staff look into the issue. Mike did a quick analysis of how federal, state and local revenues would be impacted by the LCFS. On the federal side, more volume would be sold to the consumer because of the alcohol content of the new blends; hence, there would be more excise tax paid,

reduced by the amount of federal tax credits distributed. California would not get more revenues even though more volume was pumped because the excise tax on lower energy E85 is half of that on gasoline. Locally, revenues might be a wash since there would be more volume of less expensive E85 sold.

Mike concluded by saying that the fundamental socioeconomic impact of the LCFS in California would be improved if California can develop its own alternative fuel plants and not send monies to corn-producing states.

3. Update on CARB Staff Proposed GHG CEQA Significance Threshold Approaches

No CARB CEQA staff was present to give this presentation. Jill Whynot stated that CARB staff would be taking their proposal to the Board in April.

4. Report on SCAQMD Greenhouse Gas Activities

Jill Whynot reported that Rule 2701 would go back to the Board on Friday with some local restrictions (distance requirements) imposed on the manure management protocol added in response to some Board members' concerns. PR 2702, also going to the Board on Friday, would have the same local restrictions imposed on the manure protocol. A subcommittee member asked how toxics and criteria pollutants and GHG pollutants were being considered in the protocols. Jill said these determinations would be made on a case-by-case basis but it was not staff's intent to generate GHG credits if significant adverse impacts in environmental justice areas resulted. A subcommittee member asked how the \$15 per ton fee was established. Jill said a best estimate was made by reviewing credit prices on various existing exchanges. The due date for the December release of the RFP dealing with facilitating trades under Rule 2701 is February 20, 2009. In March, there will be a report to the Board on the CEQA threshold being worked on by CARB. With respect to CARB mandatory reporting, Jill said that unfortunately the CARB communications tool, which was to facilitate interfacing with the SCAQMD voluntary GHG reporting system, was not up and running; hence, sources needed to report directly to CARB this year.

5. Approval of Highlights of January 7, 2009 Meeting

With some minor corrections, the highlights were approved.

6. Discussion of California and Other Climate Change Activities

No action was taken under this item.

7. Next Meeting

The next meeting was scheduled for Wednesday April 1, 2009, at 1:30 p.m.

*Please note that because of scheduling conflicts a CCEEB member did not participate in the meeting but the notice was posted and room set aside to accommodate any member of the public who otherwise wished to attend.