The following document is the first rough draft of the technology assessment chapter that will be incorporated into the final review report that is due to the Board in December. There are several sections that are still under review by ARB staff along with interested panelists. After this draft is completed, the Panel will have another opportunity to comment. This review will happen when this section is consolidated into a draft report that is expected to be released to the Panel in October.

This document has been developed using the workplan as guidance, though for the sake of grouping similar topics together, covers several areas called out in the regulation. This chapter specifically tries to answer the questions related to technology advances since the last staff report, the concept of ultralow carbon fuel provisions, the advisability of including provisions for those fuels, and possible ways to incentivize those fuels. Volumes and projections will be covered in the chapter pertaining to "Supply and Impact on State Fuel Supply."

IV. Technology Assessment

The technology assessment section of this programmatic review deals primarily with analysis of technology that is available to help fulfill the requirements of the LCFS, as of 2011, and the technology that is expected to come on line in the next several years, as well as any hurdles or barriers to market penetration of these technologies. Integral to this section are topic 4 (advances in production), topic 5 (ultralow carbon fuels), and topic 11 (hurdles and barriers). Thus, elements from each of these topics have been integrated into this chapter.

A. Advances in Technology

1. Current technologies

a. Gasoline and Diesel

[Will include a discussion of refinery types in California.]

b. Ethanol derived from grains and sugars

Since the original staff report was published in 2009, facilities producing ethanol from corn have been increasing the efficiency of their facilities. These plants incorporate modern plant design developed by ICM, which results in less energy use in the plant. The reduction in energy use is derived from incremental improvements in multiple portions of the facility, including increases in ethanol yield, lower electricity use, and more efficient process equipment. In some cases the reduction in carbon intensity (CI) can be attributed to use of low carbon intensity inputs, such as biogas rather than CNG-powered equipment. Facilities utilizing these technologies have been applying for custom CI values through the Method 2A/2B process[1]. Table XX lists the plants that have CI values approved that are below the published value for Midwest corn ethanol produced in a similar fashion.

[1] For more information see: http://www.arb.ca.gov/fuels/lcfs/2a2b/2a-2b-apps.htm

[Table XX. INSERT TABLE OF NEW CI VALUES]

c. Biodiesel derived from crops and waste fats and oils

Biodiesel is defined as a fatty acid methyl ester derived from vegetable oils or other renewable feedstocks. Biodiesel is a currently commercially available fuel, supplying in 2010 about 5 million gallons of fuel in California, and about 350 million gallons of fuel in the U.S.

The primary feedstocks available for biodiesel production in California are waste vegetable oil, animal fats, inedible corn oil, and soybean oil. Of these feedstocks, waste vegetable oil, animal fats, and inedible corn oil are waste feedstocks and result in biodiesel of very low carbon intensity. The majority biodiesel production facilities in California are designed primarily to use these waste feedstocks.

According to the LCFS staff report, California biodiesel production facilities have a combined nameplate capacity of about 35 million gallons. Analysis conducted during this review estimates that there are facilities with about 70 million gallons of nameplate production capacity in California as of 2011.

f. Biogas

It has been projected that biogas generation could expand based upon the current sources of biomass and agricultural waste products. EPA's joint program, AgSTAR, projects that the number of anaerobic digesters could increase by at least tenfold. Various studies by CEC and other California agencies suggest that biogas could displace diesel use by a few billion gallons depending on biomass allocation and technological availability.

Most renewable natural gas is being produced outside the state and transported into California for use. Current methods utilize truck or rail lines to carry the renewable natural gas (RNG) to the state, but depending on the distance and volumes, the method is quite costly. Transport of RNG into the state through pipelines would reduce those costs; the estimated transportation costs project to be $0.75 to $2.50/ MMBtu. Projects within the state that are utilizing biomethane include Waste Management's Altamont Facility and the Hilarides Dairy. There are other dairies operating anaerobic digesters; however, in most scenarios that energy is being converted to electricity. Waste Management's facility produces 13,000 GPD of LNG that support both the facilities energy needs and the fleet of waste haulers. The Hilarides Dairy in Lindsay generates its own fuel from anaerobic digestion lagoons, providing energy to its facilities and equipment.

There are several barriers to bringing biogas to market, including: the low cost of fossil natural gas; the strict limits on landfill gas because of vinyl chloride contamination; other pipeline standards restricting entry; the cost of building an interconnect at each biomethane production facility and disincentives towards gas production while incentivizing conversion to electrical production over direct pipeline injection. Permitting requirements in California can be more time-intensive and require an increase in capital investments due to their thorough nature; this may cause hesitation when constructing a biomethane gas processing and distribution station.

Currently, a two million dollar investment is required to use an RNG source to build an interconnect line into the public utility pipelines. Possible solutions for this problem would be having a standardization of the interconnects or attaching a rate-based developer cost to each interconnect to reduce the long-term costs of potential products. Currently there are over a thousand sites where biomethane could be produced but would require a one billion dollar investment to connect them into the pipeline.

In current situations where interconnects are not feasible, the fuel requires additional processing before transport. The costs associated with this endeavor require gas to be liquefied (compression and chilling costs) and then transported to another location for fueling. Biomethane gas is rarely generated in the same location that is effective for fueling a fleet; exceptions may be landfill and dairy equipment. In some instances, the pipeline may accept the gas into their system; however, with only one buyer the purchase price is not nearly as lucrative if there were multiple bidders for the gas.

The current federal tax credits incentivize the production of electricity on site when biomethane is produced, but this is highly inefficient and may cause more emissions than if the gas were injected into the pipeline where a major natural gas electric power generation unit was converting the energy. If the same incentives were applied to both electrical generation and injection of renewable gas to the pipeline, the ability to sell to more than one buyer would generate additional security in the market. Note that the production of electricity from RNG sources is becoming more difficult in non-attainment air districts. Basins such as the South Coast Air Basin have stringent limits on criteria pollutants such as particulate matter and NOx in an effort to make progress towards attaining healthy air quality.

Overall capital investors need more assurances that the market will be stable to properly plan and allocate funding or incentives. Investors seek certainty to avoid poor investment decisions in the future; these uncertainties may be the result of a new barrier being established or additional incentives, which are directed towards competing fuels or technologies.

f. Natural Gas

While there have not been technological advances in the production of natural gas or the infrastructure for delivery, natural gas use in the transportation sector—both as compressed natural gas (CNG) and liquefied natural gas (LNG)—has increased over the last few years. Table 1 below shows the consumption of natural gas as transportation fuel in California between 2006 - 2009. The consumption has increased at an average rate of nine percent per year. This increase could be attributed to potential fuel cost savings from natural gas relative to traditional fossil fuels, such as gasoline and diesel. On an energy-equivalent basis, natural gas fuel is less expensive than gasoline or diesel. If these fuel savings are maintained, the economic driving force for natural gas use should continue to increase.

Table 1
Natural Gas Consumption in California, 2006-2009

Year	Transportation Fuel (CNG &LNG) (Million Cubic Feet)
2006	9,900
2007	11,000
2008	11,700
2009	13,100

Source: U.S. Energy Information Administration

The use of natural gas provides additional benefits besides economic, such as emission reductions for greenhouse gases, criteria pollutants, and toxics. Another factor that has been an important role for increased fuel consumption was the expansion of the natural gas vehicle (NGV) population. These NGVs can be categorized into two vehicle classes: light duty vehicles (LDVs) and heavy-duty vehicles (HDVs). Table 2 displays the NGV population from 2006 - 2009, these values have been estimated from the California Department of Motor Vehicles' (DMV) database.

Table 2
Natural Gas Vehicles in California, 2006-2009

Year	LDVs	HDVs	Total
2006	15,490	7,650	23,140
2007	14,510	8,330	22,840
2008	14,770	9,830	24,600
2009	15,220	11,150	26,370

Source: California DMV

During this four-year span, the population of HDVs has increased by more than 45 percent, while the population of LDVs has slightly decreased. Implementation of fleet rules and the available financial incentives have assisted the growth of HDVs. Although LDVs still outnumber HDVs (school and transit buses, line-haul and refuse trucks), the majority of natural gas is consumed by HDVs. Generally, HDVs will travel greater distances and consume more fuel based upon their heavier loads and powerful duty cycles.

h. Electricity

The largest deployment of electric vehicle infrastructure in history is currently underway through the U.S. Department of Energy's (DOE) Electric Vehicle (EV) Project. The Project includes the installation of approximately 7,000 residential chargers and 1,600 public chargers in California. The Project provides the opportunity to evaluate EV use and the effectiveness of charging infrastructure.

Electric vehicle growth may be further monitored through an existing state regulation proposed to include electricity. The Clean Fuels Outlet (CFO) mandates alternate fuels' infrastructure when a certain number of vehicles using that alternative fuel are on the road. Proposed modifications would include hydrogen stations and monitoring electric vehicle growth to better understand infrastructure challenges and needs.

Staff estimates that in 2011, there will be 5,000 to 11,000 electric vehicles operating in California. This includes full-electric vehicles like the Nissan Leaf and Tesla Roadster, and plug-in hybrids like the Chevy Volt. Based on typical annual miles traveled using electricity supplied from the California grid, a battery-electric vehicle could earn about two credits in 2011, while a plug-in hybrid could earn one-and-a-half credits in 2011 (one credit is equal to one $MTCO_2e$). The projected total number of credits available in 2011 for the electricity-fueled miles traveled by these vehicles is 8,000 to 22,000 $MTCO_2e$. The potential value of the credits for all electric vehicles statewide in 2011, based on a range of $15 to $50 per credit, could range from $114,000 to $1,100,000.

As the annual CI standards tighten throughout the decade, the amount of credits earned by EVs diminishes because of the smaller difference between the CI of electricity and the CI of the lower standard. For example, in 2020, when the CI standard is 10 percent lower than 2010, staff estimates that battery electric vehicles would earn approximately 1.7 credits per vehicle, while plug-in hybrids would earn 1.3 credits per vehicle. The number of credits projected for the year 2020 varies considerably based on the projected number of electric vehicles. LCFS illustrative scenarios were based on 490,000 to 1,780,000 electric vehicles (both battery and plug-in hybrid) in 2020. Based on these scenarios, LCFS credits available in 2020 could be 700,000 to 2,500,000 $MTCO_2e$. Compared to the total reduction of CO_2e in 2020, credits could be 3 to 10 percent of the total reduction. The potential value of the credits based on a range of $15 to $50 per credit, could range from $10 to $124 million.

h. Hydrogen

Currently, hydrogen stations are funded through ARB Hydrogen Highway (seven locations, 60-140 kg/day) and CEC AB 118 funding (eight locations, 100-240 kg/day). Hydrogen infrastructure challenges: Fuel Cell Vehicle (FCV) roll-out projections are based on infrastructure in-place ahead of vehicles; good station coverage is needed to boost consumer confidence in FCVs; early stations are costly; and government funding needed to offset capital and operations and maintenance (O&M) when demand is low.

2. Near-term future technologies

This section groups the fuels and conversion technologies expected to be available for commercial use in the 2015 timeframe. In addition to the fuels listed below, we expect that CNG, hydrogen, and electricity will play a larger role as the technologies become more robust and their availability increases.

a. *Ethanol derived from lignocellulosic biomass*

The traditional pathway to produce lignocellulosic ethanol from biomass is through hydrolysis and fermentation. This process is similar to production of ethanol from grains, except that it is significantly more difficult to hydrolyze lignocellulose than starch. An alternative pathway involves gasification of lignocellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer-Tropsch synthesis or by fermentation techniques. More background on types of technologies can be found in Chapter III of the staff report. More information on facilities and volumes can be found in Chapter 5 of this report. U.S. EPA reduced the cellulosic biofuels portion for the RFS2 from 250 million gallons to 6 million gallons for 2011. EIA suggests that a more likely 2011 production total for cellulosic biofuels is approximately 4 million gallons. U.S. DOE is still processing grants to help stimulate cellulosic biofuels.

b. *Others*

[Will include additional fuels, updates to come]

3. Long-term future technologies

This section discusses the fuels and conversion technologies that are expected to be available on a commercial scale after 2020.

a. *Algal biofuels*

Algae are generally considered a very attractive potential feedstock for fuel because of the possibility of relatively high yields compared to conventional crops. There are generally two methods of producing fuel from algae that are currently being explored. The first method is to modify the algae such that it grows as much biomass as quickly as possible and then to process the algae biomass in a gasification facility. The second method is to modify the algae to produce as much oil as possible and then to harvest the oil either by skimming of secreted oil or by destruction of the algae followed by collection. Both of these processes are still in the research and development stage of production.

Some estimates place algae's potential yield as high as 6,500 gallons of biofuel per acre, compared to about 600 gallons per acre for the most productive conventional crops. Additionally co-placement with high CO2 emitting facilities holds promise due to the potential of algae to sequester the CO2 emissions during growth. However, there are no commercial scale facilities producing algae.

b. *Biobutanol*

As a renewable fuel, butanol has a number of advantages over ethanol. Butanol has higher energy density than ethanol, can be mixed with gasoline in more flexible proportions than ethanol, and is less corrosive, less volatile, and less water soluble than ethanol. As a result, butanol can be transported through existing fuel pipelines. However, the incomplete combustion of butanol can result in small amounts of butyric acid, which has a strong odor. Biobutanol is produced by fermentation of sugar using either genetically modified organism or carefully selected naturally occurring micro-organisms. On the horizon is the possibility of producing biobutanol using lignocellulosic material in a way similar to lignocellulosic ethanol production.

Currently biobutanol is not available in commercial quantities. Three companies are currently pursuing biobutanol production in the U.S.: Butamax- a joint venture of BP and DuPont, Cobalt biofuels, and Gevo.

c. *Others*

[Seeking panelist input, will be updating]

B. Investments in Low Carbon Fuels [Bob Epstein, et al.]

1. Funding for Advanced Biofuels
   a. Venture and finance data – by quarter, series, category, region, company
      i. Strategic investments
      ii. Venture capital
2. DOE Guarantees
   a. Funds distributed in 2009-2010
   b. Funds distributed in 2010-2011
   c. Projected funds
3. Policies, programs & tax incentives utilized by advanced biofuels
   a. USDA Loan Guarantees
   b. AB 118
   c. VEETC
   d. Others (as provided by E2 workgroup)
4. Production data by company
   a. Market regions
   b. Fuel type
   c. Projected quantity

C. Ultralow Carbon Fuels

The LCFS is a market- and performance-driven regulation designed to provide a durable framework that uses market mechanisms to spur the steady introduction of lower carbon fuels. The primary objective of the LCFS is to ensure lower carbon intensity fuels are used in the California fuels market. The framework establishes market-driven performance standards that fuel producers and importers must meet each year beginning in 2011. One standard is established for gasoline and the alternative fuels that can replace it. A second similar standard is set for diesel fuel and its replacements. Each standard is set to achieve an average 10 percent reduction in the carbon intensity of the State's transportation fuels mix by 2020.

Currently, the LCFS does not contain any special provisions for the use of ultralow carbon fuels; these are treated like all other fuels subject to the LCFS (i.e. they are given a CI commensurate with their lifecycle GHG emissions). The concept of incentivizing the use of ultralow carbon fuels, with provisions specific to these fuels, was discussed during the development of regulation. However, such fuel-specific incentives ultimately were not included because the Board, as well as a fair portion of stakeholders, believed at the time of the hearing that the LCFS should remain fuel-neutral. It was thought at the time that the inclusion of provisions for ultralow carbon fuels would create “winners and losers” within the program and make the LCFS less driven by market forces and performance and more driven by incentives and mandates. Additionally, incentives such as credit multipliers, presumably would impact the real-world reductions that would otherwise be achieved under the program.

With that being said, the LCFS relies on the development of ultralow carbon fuels in order to meet the 2020 goals, and we will undoubtedly need them to meet any State targets set for post-2020. The fuels generally have very low CIs. Thus, they have the potential to generate credits under the LCFS. In recognition of this, the LCFS regulation (section 95489(a)(5)) directs the Executive Officer, as part of the program reviews, to consider the advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used.

3. Incentives

If we are not seeing the development of these fuels in sufficient volumes based solely on the need for regulated parties to comply with the LCFS, special provisions within the regulation may aid in their development and ought to be discussed. However, because the LCFS is still in the infancy of its implementation, it is premature to determine how companies will comply with the more stringent goals of the later years of the program. If their main choice of compliance is banking credits in the earlier years when the regulation goals are less stringent, perhaps the LCFS will need to include special provisions to further encourage the development of ultralow carbon fuels. For that scenario, we have identified and discussed below several possibilities for incentivizing ultralow carbon fuels.

[Discussion of the several possibilities: multipliers, mandatory % of fuel pool consisting of ULCFs, specified shelf-life for credits achieved in early years, etc. Panelist input needed.]

However, as indicated above, we believe it is premature to recommend such adjustments given that the program is in its early stages. Further, if such incentives are proposed in the future, we would need to evaluate at that time the impacts the incentives may have on stakeholders.