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POTENTIAL LOW-CARBON FUEL SUPPLY TO THE PACIFIC COAST REGION OF NORTH AMERICA

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Abbreviations used

ANL	Argonne National Laboratory
BEV	Battery Electric Vehicle
BGY	Billion Gallons Per Year
BTS	Billion Ton Study
CAFE	Corporate Average Fuel Economy
(C)ARB	(California) Air Resouces Board
CARBOB	California Reformulated Reformulated Blendstock for Oxygenate Blending
CBO	Congressional Budget Office
CCS	Carbon Capture and Storage
CEC	California Energy Commission
CFS	Clean Fuel Standard
CNG	Compressed Natural Gas
CNGV	Compressed Natural Gas Vehicle
CO_2e	Carbon Dioxide EquivalentDOE Department of Energy
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
FCEV	Fuel Cell Electric Vehicle
FCV	Fuel Cell Vehicle
FFV	Flex Fuel Vehicle
FQD	Fuel Quality Directive
FTE	Full Time Employee
GAIN	Global Agricultural Information Network
GHG	Greenhouse Gas
GREET	The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
HEV	Hybrid Electric Vehicle
HVO	Hydrotreated Vegetable Oil
ICCT	International Council on Clean Transportation
ICE	Internal Combustion Engine
IEA	International Energy Agency
ILUC	Indirect Land Use Change
ISOR	Initial Statement of Reasons
LCFS	Low Carbon Fuel Standard
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MGY	Million Gallons Per Year
MJ	Megajoule
MSW	Municipal Solid Waste
$MtCO_2e$	Million Metric Tons of Carbon Dioxide Equivalent
NAS	National Academy of Science
NESCAUM	Northeast States for Coordinated Air Use Management
NHTSA	National Highway Traffic Safety Administration
NREL	National Renewable Energy Laboratory
ODEQ	State of Oregon: Department of Environmental Quality
OECD	Organisation for Economic Development and Cooperation

PCC	Pacific Coast Collaborative
PEV	Plug-in Electric Vehicles
PHEV	Plug-in Hybrid Electric Vehicles
RFS	Renewable Fuel Standard
RLCFRR	Renewable and Low Carbon Fuel Requirement Regulations
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SRC	Short Rotation Coppice
UCO	Used cooking oil (yellow grease)
USDA	U.S. Department of Agriculture
VEETC	Volumetric Ethanol Excise Tax Credit
VMT	Vehicle Miles Traveled
WSDE	Washington State Department of Ecology
ZEV	Zero Emission Vehicle

Executive summary

To contribute toward mitigating climate risk and promoting diverse energy sources, governments around the world are looking to accelerate the deployment of alternative fuels. Many new fuel and vehicle technologies are available, and many governments are implementing incentives and standards to shift away from petroleum-based fuels. Four jurisdictions of the North American Pacific Coast region – British Columbia, California, Oregon, and Washington – have been among the global leaders in charting out a path toward lower-carbon transportation with low-carbon fuel standards. While two of these jurisdictions, British Columbia and California, have active programs already, key questions remain regarding what the available supplies of low-carbon alternative energy sources are, and how quickly they can be deployed.

This study assesses the viability for fuel providers to supply increasing amounts of low-carbon transportation fuels to British Columbia, California, Oregon, and Washington through 2030. The study includes a comprehensive review of the scientific literature on low-carbon biofuels, natural gas, electricity, and hydrogen that have potential to replace gasoline and diesel usage in road transportation. This analysis is novel in its evaluation of fuel availability across the four jurisdictions simultaneously, in its consideration of potential resource and industry constraints that impact fuel deployment timing, and its quantification of fuel carbon intensity according to the adopted fuel policy lifecycle carbon ratings. Ultimately the analysis considers a range of scenarios to reflect varying technology advancement, policy promotion, and industry investment. Scenario assumptions range from low to high cases for parameters including the deployment of cellulosic fuels, deployment of natural gas vehicles, deployment of electric drive vehicles, typical biofuel blend rates, carbon savings available from first generation biofuels, and availability of hydrotreated renewable diesel.

The findings from the analysis on scenarios for increased alternative fuel deployment, summarized in Figure ES.I, indicate that there is the potential for alternative low-carbon transportation fuels to significantly contribute to greenhouse gas reductions through 2030. Although the various fuel pathways each have unique deployment constraints that will affect near-term fuel deployment, all eight scenarios analyzed delivered between 14% and 21% carbon intensity reduction from 2010 levels by 2030. For context, the scenarios are compared against an illustrative region-wide composite policy target for the four jurisdictions' fuel carbon intensity policies. Within any of the four individual jurisdictions, lesser or greater emission reductions (e.g., above 10% carbon intensity reduction by 2020) than the aggregated region-wide values that are shown would be possible depending on the varying mix of policy, market, and fiscal incentives that were at play.

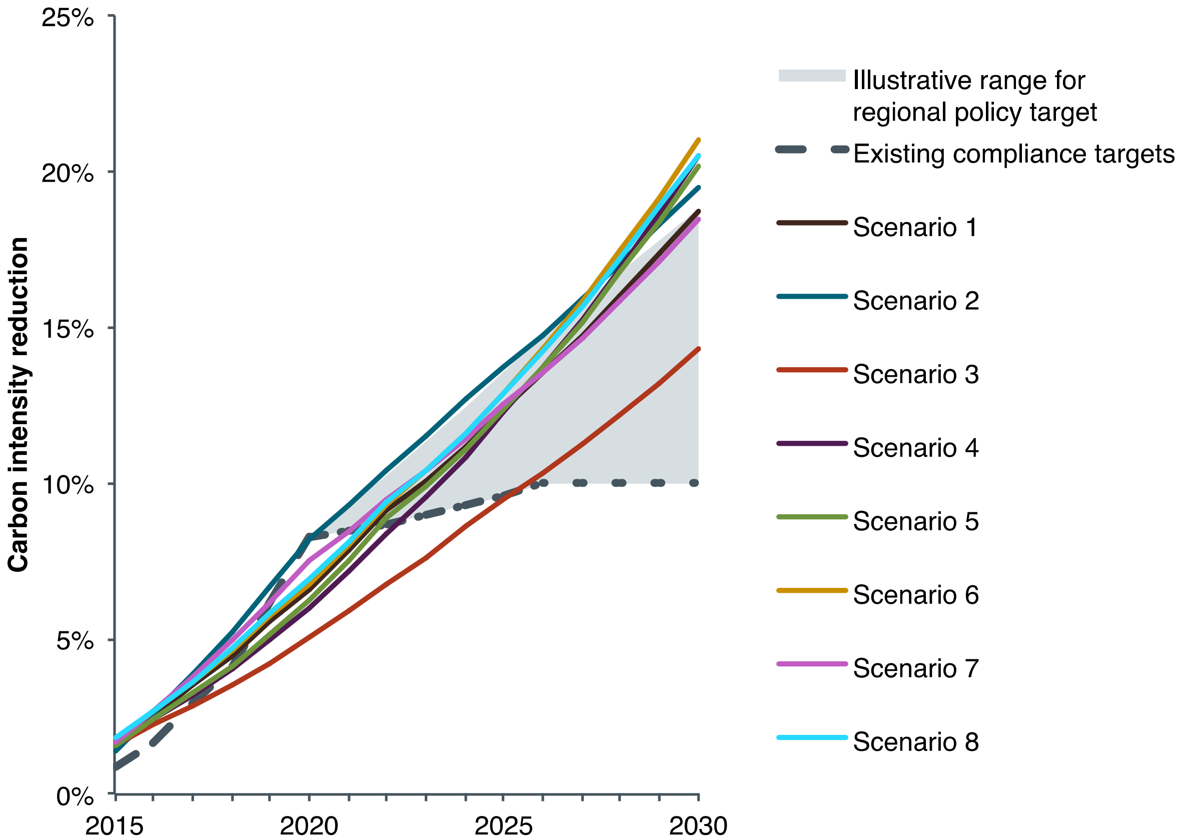


Figure ES.I. Fuel carbon intensity reduction from 2015-2030 from fuel deployment scenarios for the Pacific Coast region (British Columbia, California, Oregon, Washington)

This analysis also provides additional resolution into the relative contributions of various fuel pathways and technologies toward reducing greenhouse gas emission into the future, as shown in Figure ES.II. The figure illustrates how diverse fuel mixes can each deliver significant fuel carbon reductions in the 2030 timeframe. Scenarios with relatively strong deployments of advanced biofuels (e.g., Scenarios 4 and 5), electricity and hydrogen (Scenarios 6 and 8), and first-generation biofuels and HVO (Scenarios 1 and 2) each deliver comparable and substantial reductions in greenhouse gas emissions of 14-21% from road transportation in British Columbia, California, Oregon, and Washington by 2030. If breakthroughs occur in all the fuel areas simultaneously, or if deployment of a single technology were to greatly exceed the higher cases presented here, then greater carbon reductions would be possible. As the results shown are region-wide, there is the potential for greater or lesser carbon intensity reductions than shown within any given jurisdiction.

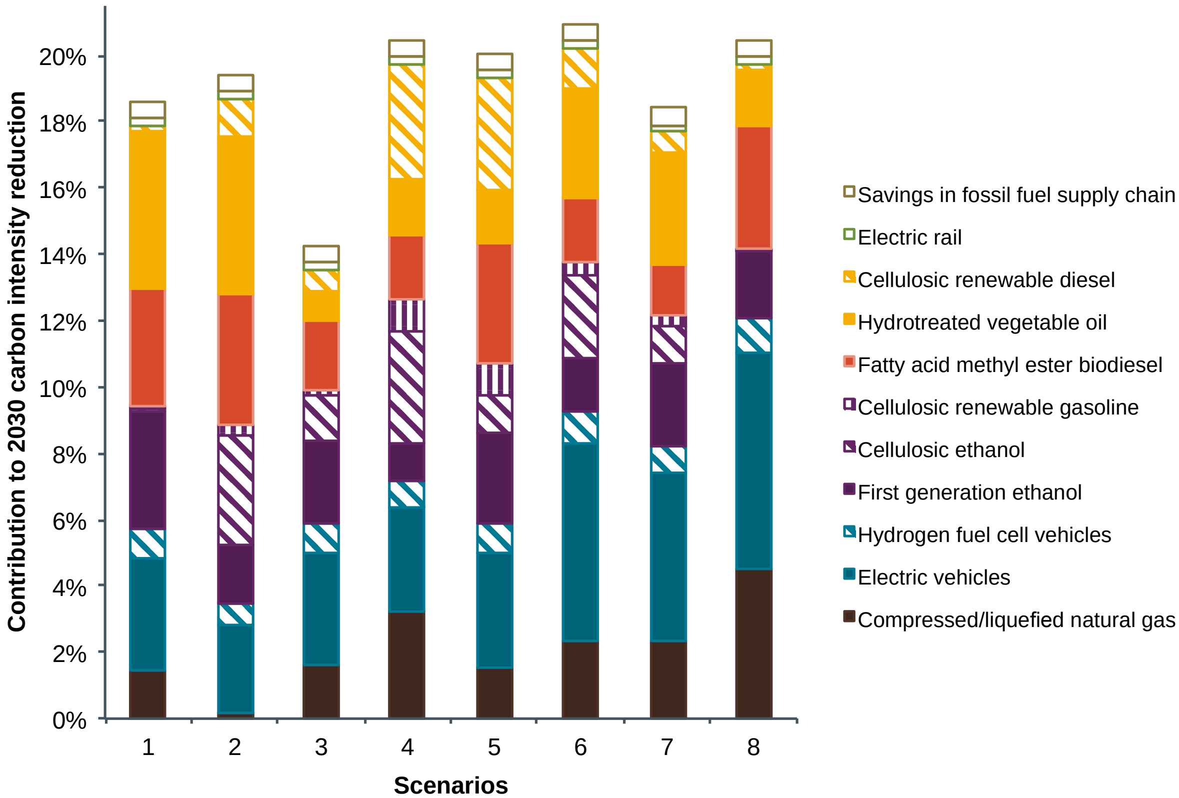


Figure ES.II. Fuel carbon intensity reductions by 2030 from eight alternative fuel deployment scenarios for the Pacific Coast region (British Columbia, California, Oregon, Washington)

Based on the findings above, we draw the following four conclusions.

Available low-carbon fuels could grow to replace up to 400,000 barrels worth of gasoline and diesel use per day by 2030, representing a factor of three increase from today and a quarter of the Pacific Coast region's road transportation energy demand. First-generation biofuels (e.g., sugarcane ethanol), second-generation biofuels, advanced cellulosic and drop-in biofuels, renewable and fossil natural gas, electricity in plug-in electric vehicles, and hydrogen in fuel cell vehicles are viable alternative fuels with the potential for substantially increased deployment in the 2020-2030 timeframe. The findings from this analysis indicate that the deployment of these alternative fuels could result in the replacement of 290-410 thousand barrels of oil equivalent per day of petroleum-based fuels in 2030.

Substantial greenhouse gas emission savings are available across the four jurisdictions from the deployment of emerging low-carbon fuels. Pacific Coast region-wide fuel carbon intensity reductions of 14-21% are achievable from increased deployment in new fuels, while accounting for lifecycle carbon emission effects, known resource and supply chain constraints, vehicle technology, and increased travel demand. The scenarios analyzed in this report would amount to reducing road transportation's climate emissions by 43-64 million tons of carbon dioxide equivalent reduction per year, by 2030.

The Pacific Coast region's regulatory targets for reducing the carbon intensity of transport fuel can be met in a variety of ways. The results show a variety of possible low-carbon fuel mixes that would successfully meet the carbon intensity reduction goals for 2020 as described within in California's Low Carbon Fuel Standard, Oregon and Washington's Clean Fuel Standards, and British Columbia's Low Carbon Fuel Requirements. Six of the eight scenarios analyzed would be consistent with full compliance with regulatory targets between 2015 and 2020. These scenarios also demonstrate a wide variety of potential fuels that could be used for compliance. For example, in 2020, the compliance-consistent scenarios include between 100 and 1,200 million gallons (diesel equivalent) of natural gas, between 600 and 1,200 million gallons of ethanol from sugarcane, between 550,000 and 860,000 plug-in electric vehicles using grid electricity, between 300 and 600 million gallons of renewable diesel and between 20 and 300 million gallons gasoline equivalent of cellulosic fuel.

Fuel providers and regions could pursue a diversity of low-carbon fuel strategies. The scenarios in this analysis reveal that many different fuel and vehicle strategies could deliver substantial climate and oil-reduction benefits. The diversity provides a large degree of flexibility and optionality for achieving carbon intensity reductions that are broadly consistent with the jurisdictions' policy goals. For example, substantial aggregate fuel carbon intensity reductions could be achieved with many combinations of electric-drive vehicles, renewable and natural gas vehicles, advanced cellulosic biofuels, lower carbon first generation biofuels, and increased supply of renewable diesel. This suggests that delivering on decarbonization goals does not require a dramatic breakthrough in any one particular technology. This also suggests that different fuel providers in the jurisdictions could focus more heavily on different alternative fuels and achieve similar climate and petroleum-reduction benefits.

While the potential is there for a rapidly growing low-carbon fuel supply, it is clear that strong regulatory signals will be a key driver for low-carbon fuel investments. Recognizing the prevailing market and technology uncertainties, the continued adoption of clear regulatory policy signals through low-carbon and clean fuels standards across British Columbia, California, Oregon, and Washington through 2025, or even 2030, will promote the types of investments that are inherent in the alternative fuel deployment scenarios analyzed in this study. The scenarios in this study are broadly consistent with the analyses that have been conducted by and for government agencies in their consideration of low-carbon fuel policies. The scenarios analyzed go well beyond business-as-usual industry and market activity and would likely be dependent upon some mix of direct regulatory and fiscal policy support.

Several key factors are beyond the scope of this analysis and warrant further investigation. Issues beyond this report's analytical scope include the role of non-road carbon reduction in the transportation sector, including liquefied natural gas in marine applications, biofuel use in the aviation sector, electrification for transit and other off-highway applications, fossil refinery upgrades, and upstream fossil fuel carbon reductions. In addition, further study would be necessary to better understand questions about the potential implications of the scenarios in this study on carbon credit prices, and vice versa. Further study would be necessary to match the particular, and yet evolving, provisions of the four jurisdictions' fuel policies. In reviewing the biomass supply potential, it is noted that this study does not attempt to systematically apply sustainability screenings on specific feedstocks. However, we note that the referenced studies apply varying levels of consideration of sustainability. Comparing the various studies using consistent sustainability assumptions is an area of potential further study. Potential future shifts in business-as-usual travel activity have not been analyzed. Finally, analyses like this could be increasingly important in understanding the potential for low-carbon fuels beyond the Pacific Coast region, as other governments become similarly motivated.

1. Introduction

To contribute toward mitigating climate risks, promoting diverse energy sources, and reducing petroleum expenditures, governments around the world are looking to implement new policies to promote alternative fuels. Many new fuel and vehicle technologies are available and emerging, and many governments are implementing a system of incentives, regulatory standards, and public-private partnerships to accelerate the shift away from petroleum-based fuels.

Four jurisdictions of the North American Pacific Coast region – British Columbia (BC), California (CA), Oregon (OR), and Washington (WA) – have been among the global leaders in charting out a path toward lower-carbon transportation by developing low-carbon fuel standards. The four jurisdictions have acted in many diverse ways that include providing incentives to promote industry development, building infrastructure to support lower-carbon technologies and businesses, developing policies that regulate changes from business-as-usual practices, and creating programs that align consumer action with lower-carbon and fuel-saving goals. Among the many actions that these four jurisdictions have committed to is the adoption of low-carbon fuel standards. As stated in the October 2013 *Pacific Coast Action Plan on Climate and Energy,* the four jurisdictions commit to the following –

> **Adopt and maintain low-carbon fuel standards in each jurisdiction.**
>
> Oregon and Washington will adopt low-carbon fuels standards, and California and British Columbia will maintain their existing standards. Over time, the governments of California, British Columbia, Oregon, and Washington will work together to build an integrated West Coast market for low-carbon fuels that keeps energy dollars in the region, creates economic development opportunities for regional fuel production, and ensures predictability and consistency in the market. (PCC, 2013)

Such low-carbon fuel standards would incrementally reduce the carbon intensity (CI) of the fuels that are deployed in the region to power the transportation sector. The success of these regulations relies on the ability of fuel suppliers to bring alternative low-carbon fuels (e.g., natural gas, electricity, biofuels, and hydrogen) to market, as well as possibly deliver other carbon reductions in the fossil fuel supply chain (e.g., innovative upstream emission reductions). Each of the four jurisdictions has its own data collection, analysis, and stakeholder input gathering processes that are underway as part of their consideration of their own jurisdiction-specific standards (see, e.g., BCMEM, 2014; CARB, 2014d; ODEQ, 2014; WSDE, 2014).

A number of major research studies are important in helping inform the four jurisdictions in their consideration of low-carbon fuel policies. Broader global and national-scale research provides the context for resource availability, global technology development, and technical vehicle-side constraints (e.g., NLCFSP, 2012; Solecki, 2012; NRC, 2011; Parker, 2011; Searle and Malins, 2014; Searle et al., 2014; E4tech, 2014; Malins, 2013; U.S. DOE, 2011). More particular to the Pacific Coast jurisdictions, government agencies and research groups have assessed the availability of low-carbon fuels in British Columbia, California, Oregon, and Washington (see e.g., BCMEM, 2013; CARB, 2011; Farrell and Sperling, 2007; ODEQ, 2011; OFBWG, 2012; WSDE, 2011; Pont et al, 2014; Tittman et al., 2010; Yeh et al., 2009).

Given that these four jurisdictions are looking to shift toward lower-carbon transportation fuels in parallel, it is critical to understand how the supply of various low-carbon fuels can be simultaneously deployed to contribute to the future goals for the region as a whole. This work builds from the previous jurisdiction-specific, national, and international research on alternative fuel availability. A key question, as more governments take an active interest in reducing climate emissions, is what are the available supplies of low-carbon alternative energy sources, and how quickly can they be deployed. The purpose of this study is to comprehensively analyze the best available scientific and industry data to present potential fuel supply outcomes in the Pacific Coast region from 2015 through 2030.

1.1. Scope

This study assesses the potential of fuel providers to supply increasing amounts of low-carbon transportation fuels to British Columbia, California, Oregon, and Washington from 2015 through 2030. The study includes a comprehensive review of the scientific literature on available and emerging low-carbon biofuels, natural gas, electricity, and hydrogen that have potential to replace gasoline and diesel usage in road transportation. This analysis evaluates fuel availability across the four jurisdictions simultaneously, in its consideration of potential resource and industry constraints that impact the fuel deployment timing, and its quantification of fuel carbon intensity according to California's adopted fuel lifecycle carbon intensity ratings. To acknowledge the inherent uncertainty over the next fifteen years, eight discrete scenarios are analyzed that reflect varying plausible low, medium, and high deployment of each of the major alternative fuel areas across the four jurisdictions. The analytical scenarios span a range of possibilities that reflect varying combinations of technology advancement, policy promotion, and industry investment.

Several factors that will influence the supply of low-carbon fuels are beyond the scope of this assessment. The study does not include any direct economic analysis and does not explicitly predict or assume any particular carbon prices under the regulatory low-carbon fuel standard or future cap-and-trade carbon policies. The analysis is focused on potential fuel supply and its connection to regional fuel carbon intensity; however there are differences between the analytical modeling here and some details of the adopted, proposed, and contemplated fuel carbon policies in the four jurisdictions. As an example, the study scope specifies that carbon intensity ratings used in the study should be based on analysis by the California Air Resources Board for the California Low-Carbon Fuel Standard (CARB, 2012a, 2014b, 2014e). This means that British Columbian supply is assessed based on California carbon intensity factors which include indirect land use change, rather than using British Columbia's own current regulatory carbon intensity ratings.

The study takes the adopted U.S. and Canada vehicle fuel efficiency standards as a given and makes no effort to analyze changes to the formally adopted vehicle regulations. Also, this analysis incorporates incrementally increasing travel demand over time as reflected in the VISION model (see Chapter 4), and does not incorporate policies or economic changes that could shift the business-as-usual upward trend. The report is focused on region-wide scenarios and therefore it does not analyze likely differences between rates of low-carbon fuel deployment for each of the four jurisdictions. Also, this study is focused on alternative fuels that have the ability to replace road-based transportation fuels and excludes non-road fuels (e.g., liquefied natural gas to replace marine bunker fuels and biofuel use in the aviation sector). We have not included the potential for supply of advanced technology fuels that are still an unclear distance from commercialization. The study therefore does not consider algal fuels, or fuels from direct solar synthesis. Finally this study does not seek to assess the potential for a number of other related potential carbon reduction actions (e.g., electrification for transit, fossil refinery upgrades, and upstream fossil fuel carbon reductions) that could be relevant in the jurisdictions' policy frameworks.[1]

[1] Moderate literature-based rates of credit generation through these options are however included when compliance with existing and potential regulatory targets is discussed.

2. Background

The jurisdictions in the Pacific Coast region are each subject to a range of broader market and policy factors that affect both the alternative fuels and vehicles that are supplied to the market. Petroleum-based transportation fuel demand and supply are impacted by world oil prices, fuel taxation, and many other factors. These factors, in turn, directly impact the investment and supply of alternative fuels in the market. Overall travel activity, which is driven by oil prices and broader economic factors, greatly impacts the aggregate demand for fuels. More particular to this study, several policy-driven fuel and vehicle trends are underway.

Alternative fuels and vehicle technologies are linked in numerous ways. The expected long-term increase in vehicle efficiency is among the more critical long-term structural changes in overall fuel consumption in North America. Adopted federal U.S., Canada, and California vehicle greenhouse gas (GHG) and Corporate Average Fuel Economy (CAFE) standards are expected to reduce new automobile fuel consumption per mile by nearly half from 2008 to 2025 (Canada, 2014; CARB, 2011; U.S. EPA and NHTSA, 2012). This, in turn, will reduce U.S. oil consumption by over 3 million barrels of oil equivalent per day by 2030 (U.S. EPA and NHTSA, 2010, 2012). In addition, the Zero Emissions Vehicle (ZEV) program along with complementary fiscal incentives and infrastructure deployment, are resulting in greater deployment of electric drive vehicles in California, Oregon, and Washington (Jin et al., 2014; CARB, 2011; NESCAUM, 2013, 2014). In addition, fuel blending requirements, incentives, and fuel price dynamics play critically into the deployment and use of biofuels and natural gas in vehicles.

Several fuel-related policies are also directly influencing alternative fuel investments. The federal U.S. Renewable Fuel Standard mandates the use of certain categories of biofuels, and thereby provides incentives for investment in new cellulosic biofuel technologies. Simultaneously, historically biofuel producers and blenders have qualified for a range of tax credits. In context of this analysis of fuel carbon intensity, fuel carbon standards and the level of industry investment in alternative low-carbon fuels are likely to be major drivers. By creating value for lower-carbon intensity fuels, the low-carbon fuel policies in the Pacific region will help to shape the supply of fuels available in the 2015-2030 timeframe. Additional economy-wide carbon pricing or carbon limits (e.g., from California's cap-and-trade system) would also increase the attractiveness of lower-carbon fuel investments.

Recognizing that many fuel providers are pursuing differing alternative fuel deployment strategies, and the multitude of other market and vehicle factors, the four jurisdictions' fuel carbon policies are fuel-neutral performance standards that would promote all the available and emerging low-carbon fuels. Each of the four jurisdictions will set its own compliance schedule based on locally appropriate aspirations to reduce fuel carbon intensity. Figure 2.1 summarizes the four jurisdictions' low-carbon policies that are adopted, or assumed here for comparison purposes, for the scenario analysis below. The California Low-Carbon Fuel Standard (LCFS) and British Columbia Renewable and Low-carbon Fuel Requirements Regulation (RLCFRR) both target 10% carbon intensity reductions by 2020. The Oregon and Washington Clean Fuel Standards, starting later in the decade, are expected to target 10% carbon intensity reductions by 2026.

Table 2.1. Four Pacific Coast region low-carbon fuel policies and carbon intensity for comparison in this analysis

JURISDICTION	LOW-CARBON FUEL POLICY	FUEL GREENHOUSE GAS EMISSION INTENSITY TREND CONSIDERED IN THIS ASSESSMENT
British Columbia	Renewable and Low-carbon Fuel Requirements Regulation	• 10% reduction by 2020 • Illustrative 0 to 1 percentage point per year additional reduction beyond 2020
California	Low-Carbon Fuel Standard	• 10% reduction from 2010 to 2020 • Illustrative 0 to 1 percentage point per year additional reduction beyond 2020
Oregon	Clean Fuel Standard	• 10% reduction from 2015 to 2026 • Illustrative 0 to 1 percentage point per year additional reduction beyond 2026
Washington	Clean Fuel Standard	• Considering 10% reduction from 2015 to 2026 • Illustrative 0 to 1 percentage point per year additional reduction beyond 2026

In order to better understand the possible implications of each scenario modeled in this study, an approximate 'composite' compliance schedule is considered, representing the aggregate carbon intensity reduction required by regulation for the entire region as a whole. The composite fuel carbon intensity change is approximated according to the weighting of the four jurisdictions' vehicle miles traveled based on 2012 U.S. Federal Highway Administration data and 2009 Statistic Canada data (FHWA, 2013; Statistics Canada, 2014a). It is based on the anticipated compliance schedules for each jurisdiction, with the added assumption of an annual increase of 0 to 1 percentage points in the carbon saving requirement in all subsequent years (after 2020 for CA and BC, after 2026 for OR and WA). This means that, for instance, the California LCFS is assumed to reach an average fuel carbon intensity reduction between 10 and 20% in 2030, while the Oregon CFS would reach a 10 to 14% average fuel carbon intensity reduction by that time. This potential increase in ambition beyond proposed targets is included for illustrative purposes only, and of course in reality the longer term compliance schedules will be set by each jurisdiction with regard to the status of the low-carbon fuel market in the region. The regional and composite fuel carbon intensity reduction schedules are shown in Figure 2.1. Note that for California the compliance schedule is based on the proposed revisions in the Initial Statement of Reasons for the anticipated 2015 LCFS re-adoption (CARB, 2014f).

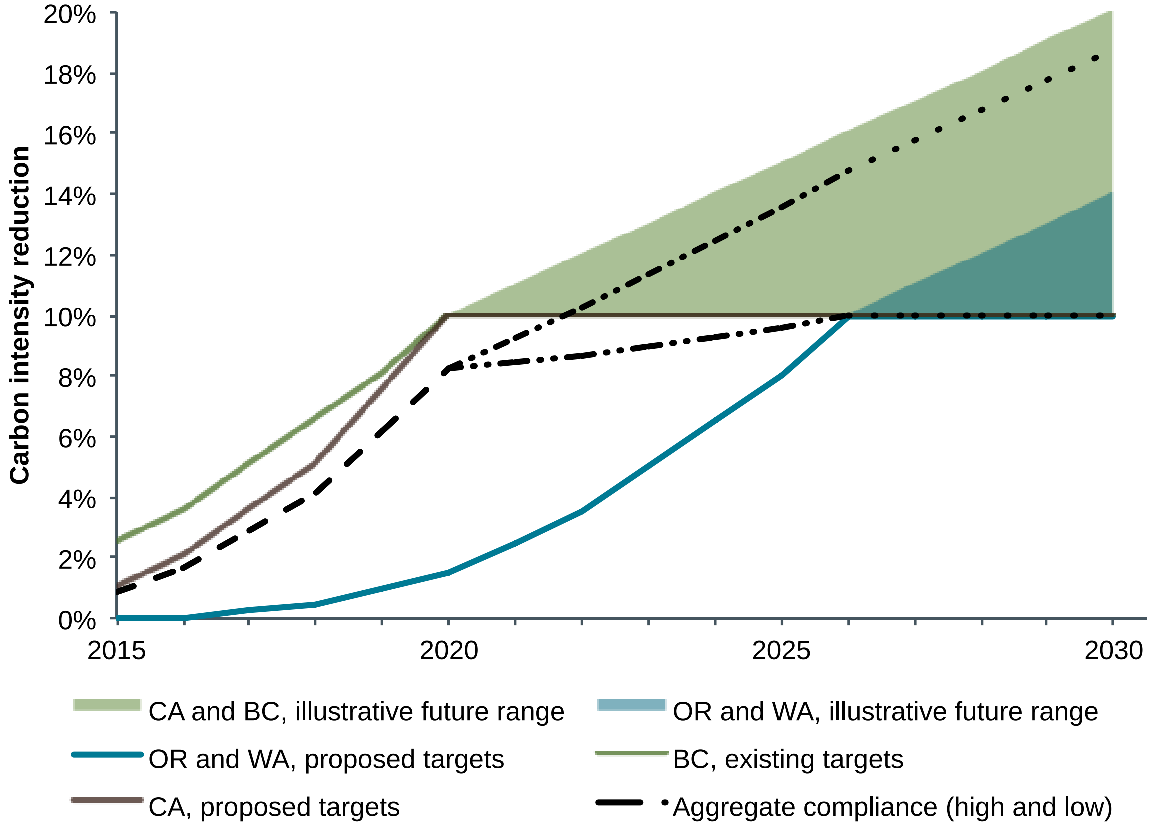


Figure 2.1. Illustrative compliance schedules for fuel carbon intensity reduction from road transportation fuels in the Pacific region from 2015 to 2030, as compared to 2010 levels

3. Literature review

This section reviews the literature that is related to the potential to supply the Pacific Coast region with an increasing amount of low-carbon fuels across major alternative fuel areas in the 2015-2030 timeframe. The section reviews and summarizes major findings on the availability of currently produced and emerging-technology biofuels (Section 3.1), biomass availability (Section 3.2), cellulosic biofuel plant deployment rate (Section 3.3), the consumption of E85 in flex-fuel vehicles (Section 3.4), electricity and hydrogen in electric drive vehicles (Section 3.5), natural gas consumption and vehicle deployment (Section 4.6), and propane (Section 3.7).

3.1. Biofuel availability

3.1.1. California Air Resources Board, LCFS program review report

The ARB LCFS program review report (CARB, 2011) does not provide projections for biofuel availability or consumption over time, but does provide scenarios for biofuel supply in California that would allow the LCFS carbon intensity reduction target to be met. The scenarios are split into gasoline and diesel. The gasoline scenarios involve some combination of ethanol and drop-in fuel supply, and the diesel scenarios involve a combination of biodiesel and hydrogenated renewable diesel. In the gasoline scenarios, the total 2020 ethanol supply ranges from 2.0 to 4.4 billion gallons, with a drop-in gasoline supply up to 2 billion gallons for the highest scenario. The feedstocks vary between cellulosic, sugarcane, and corn by scenario (Table 3.1).

Table 3.1. Gasoline substitute supply volumes by scenario in ARB LCFS program review report

SCENARIO	2020 FUEL SUPPLY (billion gal)				
	Corn ethanol	Cane ethanol	Cellulosic	Total ethanol	Drop-in
Gasoline 1	0	0.76	2.16	2.92	0
Gasoline 2	0	0	2.35	2.35	0
Gasoline 3	0.36	2.73	0.93	4.02	0
Gasoline 4	1.46	2.08	0.89	4.42	0
Gasoline 5	0.98	0.54	0.59	2.1	0.78
Gasoline 6	0.47	0.63	1	2.1	0.72
Gasoline 7	0.65	0.69	0.89	2.23	0.73
Gasoline 8	1.61	0.98	0.68	3.26	0.51
Gasoline 9	0.65	0.69	0.89	2.23	0.73
Gasoline 10	1	0.54	1.11	2.64	0.53
Gasoline 11	0.44	0.45	1.07	1.96	1.96

In the diesel pool, the total 2020 biodiesel supply is about 770 million gallons, with variation in feedstock between soy, used cooking oil, canola, corn oil, and tallow (Table 4.2).

Table 3.2. Diesel substitute supply volumes by scenario in ARB LCFS program review report

SCENARIO	2020 FUEL SUPPLY (million gal)					
	Soy biodiesel	UCO biodiesel	Canola biodiesel	Corn oil biodiesel	Tallow renewable diesel	Other drop-in renewable diesel
Diesel 1	345	425	0	0	0	0
Diesel 2	258	388	123	0	0	0
Diesel 3	269	354	115	31	0	0
Diesel 4	265	320	115	35	35	0
Diesel 5	283	262	115	38	0	71

As well as fuel consumption scenarios, the report covers potential penetration of flex-fuel vehicles (FFVs) in California to 2020 and the associated use of E85 fuel. The 2020 results vary across the scenarios from 810,000 vehicles and 0.33 billion gallons of E85 to 4.6 million vehicles and 3.14 billion gallons of E85. In the first case (Scenario 2) California gets relatively low FFV use, and those vehicles use E85 about 50% of the time before 2018 and about 60% of the time after. In the latter case (Scenario 4), California gets very high FFV use using E85 100% of the time. Scenario 11 provides a half-way point between these low and high bound cases. In this case, California assumes that about 2 million FFV are up and running in 2020 and use E85 about 50% of the time for a total E85 volume usage of 0.68 billion gallons.

3.1.2. CBO, The Renewable Fuel Standard: Issues for 2014 and Beyond

The Congressional Budget Office (U.S. CBO, 2014) produced a review of issues in the Renewable Fuel Standard (RFS) in response to concerns about the feasibility of compliance with the RFS and about impacts on food and fuel prices. CBO considers three scenarios for 2017. First, full compliance with the renewable fuel volume targets from the Energy Independence and Security Act (EISA), but waiving the cellulosic volume down to 170 million gallons; second, freezing compliance at proposed 2014 levels; and third, an immediate repeal of the standard. CBO note that achieving the EISA volumes in 2017 would require a dramatic increase in ethanol supply, and an accompanying roll-out of infrastructure to support the use of ethanol volumes beyond the blend wall. They also note that cellulosic fuel production capacity is not expanding at the rate required to meet the 2017 target. Moving adequate volumes of ethanol to market in 2017 to meet the standard would also result in increased diesel and E10 prices, but require substantially reduced E85 prices.

3.1.3. National Research Council, Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy

3.1.3.a. Potential to fulfill the RFS2

National Academy of Sciences (NRC, 2011) finds that there is little doubt of the capacity of the corn ethanol and biodiesel industries to meet their individual mandates; thus, this section largely focuses on the availability of feedstocks for cellulosic and advanced biofuels. The National Research Council (NRC) reviewed various model estimates, which generally predict a sufficient supply of biomass, focusing on studies by UC Davis, U.S. Environmental Protection Agency

(EPA), United States Department of Agriculture (USDA), and the Biomass Research and Development Initiative (BRDI). UC Davis' National Biorefinery Siting Model (NBSM) (Antares Group, 2009) has estimated that a sufficient amount of biomass, 500 million tons (conventional as well as cellulosic and waste), could be available, including crop and forestry residues, dedicated energy crops, municipal wastes, and conventional crop-based feedstocks. This estimate is at the high end of those given in more recent papers by Parker. The NAS note that results from the NBSM are based on the assumption that all feedstock must be located within a 100-mile radius of a biorefinery. This model has predicted that the RFS2 could be met with a biofuel price of \$2.90 gge^{-1} (per gallon gasoline equivalent); however, this estimate is lower than others reviewed in the literature and does not account for the opportunity cost of cropland.[2] Biorefineries are predicted to be located primarily in the Eastern states, but some facilities are modeled in the Pacific region.

Using the model FASOM, the U.S. EPA in the Regulatory Impact Analysis for the RFS predicted that enough feedstock would be available to meet the requirement of 16 billion gallons of cellulosic ethanol, mainly relying on corn stover, woody biomass, and sugarcane bagasse. Production was predicted to be concentrated in the Midwest and Southeastern states, but some biofuel plants processing municipal solid waste (MSW) and forest residues are predicted in the Pacific region.

A USDA report (USDA, 2010) estimated that the RFS2 could be met using 27 million acres of cropland (6.5% of all current U.S. cropland), but did not provide estimates of the different types and amounts of biomass that would be needed. About one billion gallons per year of production is expected in the Northwest (Washington and Oregon plus Montana, Alaska and Idaho) with very low production volumes in the West, including California.

Finally, the BRDI used the POLYSYS[3] model framework to estimate that a total of 191-240 million tons of cellulosic feedstock would be available by 2022, a sufficient amount of produce 20 billion gallons of cellulosic ethanol. As with other studies, the BRDB predict the development of biofuel from forestry residues in the Pacific Northwest.

NAS finds that although several models have predicted the physical availability of a sufficient amount of conventional and cellulosic ethanol feedstock by 2022, there remain several uncertainties regarding market supply of cellulosic feedstocks: competition for feedstocks with the electricity sector (which is also required to use some renewables in most states), competition with the livestock sector (using agricultural residues as animal bedding), the possibility of diseases and pests reducing yields, uncertainty in the prediction of future yield increases, and social barriers (farmers may not be willing to grow certain feedstocks). Additionally, the economic viability of a sufficient supply of cellulosic material at a price affordable to biofuel producers is highly uncertain.

3.1.3.b. The economic viability of meeting RFS2

As of January 2011, the capacity of existing corn grain ethanol facilities was 14.1 billion gallons yr^{-1} and is estimated to be 15 billion gallons yr^{-1} by 2012. Thus, production capacity is almost guaranteed to be able to meet the RFS2 target for conventional ethanol by 2022. Similarly, existing biodiesel facilities are expected to reach adequate capacity to meet the biodiesel target within the next few years. The focus is therefore on the viability of cellulosic and advanced ethanol.

[2] That is, the model does not consider the revenue foregone by using land for bioenergy crops rather than other uses.
[3] See http://www.agpolicy.org/polysys.html

NRC find that biomass will not likely be available at a sufficiently low price to meet the cellulosic requirement of RFS2 in 2022 with the current policy outlook: “without policy intervention, no [cellulosic or advanced] feedstock market is feasible in economic terms.” The price for which farmers will be willing to sell cellulosic feedstocks will be higher than the price biofuel producers will be willing to pay. The NRC used the Biofuel Breakeven model (BioBreak) to assess costs and feasibility of local and regional cellulosic biofuel markets. BioBreak calculates the biofuel producer’s willingness to pay (WTP) and the farmer’s willingness to accept (WTA) for cellulosic ethanol, allowing both parties to break even, as well as the price gap between the WTP and WTA. In the real economy, we expect that biofuel supply will only develop when both the biofuel processor and the biomass producer are able to make money from the deal.

The NRC evaluated seven feedstocks: corn stover, alfalfa, switchgrass, *Miscanthus*, wheat straw, short-rotation woody crops (SRWC), forest residue, as well as rotations among some of the crops. Depending on feedstock and region and assuming an oil price of \$111 barrel^{-1} and no policy incentives, WTAs range from \$75 to \$133 dry ton^{-1} with switchgrass and *Miscanthus* being generally more expensive than other feedstocks. Costs at the farm gate are comparable between POLYSIS and BioBreak, on the order of \$50 per dry ton. These farm gate prices are a little lower than those identified by Khanna et al. (2010), which reach over \$100 in some cases. BioBreak is rare among models predicting the economics of cellulosic biofuel production in that it includes the opportunity cost of farmland used to produce feedstocks. This, along with the use of prices to the refinery gate rather than at the farm gate, makes the BioBreak cost estimates higher than most other studies. Unlike some other models, BioBreak also correlates biomass prices to oil prices – meaning that the model expects a higher WTA, not only a higher WTP, when oil prices rise.

In the absence of policy incentives, WTPs range from \$24-27 dry ton^{-1} and thus, there is a large price gap of \$49-106 dry ton^{-1}. However, this price gap is only in place in the absence of any policy incentives. Including the value of the cellulosic biofuel producers’ tax credit should reduce the price gap, making cellulosic biofuel production from corn stover, wheat straw, short rotation coppice and forestry residues financially viable. Inclusion of the Biomass Crop Assistance Program (part of the 2008 Farm Bill) would result in economic viability of all the other feedstocks as well – however, the continuation of those policies was considered uncertain by NAS (both were at the time scheduled to lapse in 2012).[4] The value signal from state LCFSs was not considered in the NAS study, but would have a similar effect. A quick calculation suggests that a \$100 per ton of carbon dioxide LCFS credit price could add about \$50 of value per dry ton of feedstock for a cellulosic fuel rated at 30gCO_2e/MJ. Even on its own, this could be enough to close the gap between WTA and WTP for some feedstocks. Combined with support from the RFS and other incentives, the signal will be proportionately stronger.

Beyond policy support, all the considered feedstocks would also become economically viable were oil prices to rise to \$191 barrel^{-1} by 2022. However, NAS considered such prices unlikely. Finally, the price gap is also sensitive to the conversion rate of biomass to fuel. Expansion of certain technologies such as high-yield pyrolysis could increase the WTP and thus decrease the price gap.

Finally, it is important to note that the novel status of the cellulosic biofuel industry increases the investment costs associated with cellulosic plants. As NAS notes, “none of these projects has yet to be demonstrated commercially, implying that they are high-risk investments,” which “usually require higher returns or leveraging of capital to reduce the risk.” Increasing the

[4] It should be noted that the cellulosic biofuel producers’ tax credit expired December 31, 2013 and it is uncertain whether it will again be extended. The Biomass Crop Assistance Program has been renewed.

investment costs as compared to those assumed in BioBreak would tend to reduce WTP further. Thus, even given that in principle the available incentives may be adequate to bridge the gap between WTA and WTP for feedstocks, the capacity of producing cellulosic biofuels is unlikely to meet the RFS2 mandate absent major technological innovation or a change in policy incentives.

3.1.4. UC Davis NextSTEPS report, Three Routes Forward for Biofuels (2014)

The UC Davis NextSTEPS biofuel report (Fulton et al., 2014) provides three characterizations of the possible development of the alternative fuels market in the U.S. These are an ‘incremental’ route, a ‘transitional’ route, and a ‘leapfrog’ route. In the incremental route, improvements would be delivered at existing biorefineries but there would be no significant scaling up of cellulosic production. In the transitional route, cellulosic biofuel capacity would be expanded by adding small units as bolt-ons to existing biorefineries (for instance adding corn stover ethanol capacity to corn ethanol plants). Finally, in the leapfrog routes, development would happen through large new standalone biorefineries not connected to existing corn ethanol capacity.

The report contrasts incremental improvements that tend to be low financial risk that have shorter payback periods and deliver emissions reductions in the short term with leapfrog technologies that have high financial risk and longer payback periods but that offer the prospect of the deepest carbon savings in the long term.

In the incremental case, UC Davis assumes that a growing proportion of corn ethanol and soy biodiesel facilities will adopt improved processes delivering a cumulative emissions reduction of about 30 gCO_2e/MJ compared to standard practice. By 2030, compared to 2014, these technologies can be rolled out to between an extra 5 and 8 billion gallons of corn ethanol capacity (i.e., well above likely Pacific region corn ethanol demand). Cellulosic ethanol from bolt-on technologies offer from 0.7 to 1.4 billion gallons of potential. The leapfrog potential has the greatest uncertainty – the low value is about 1 billion gallons by 2030, the high value 8 billion gallons. The leapfrog high case is based on historical growth in corn ethanol production, with 2016 cellulosic fuel volumes matching 1999 corn ethanol volumes. The low case assumes a delay of five years before that start point is reached, and half the rate of increase. The potentials are shown in Figure 3.1.

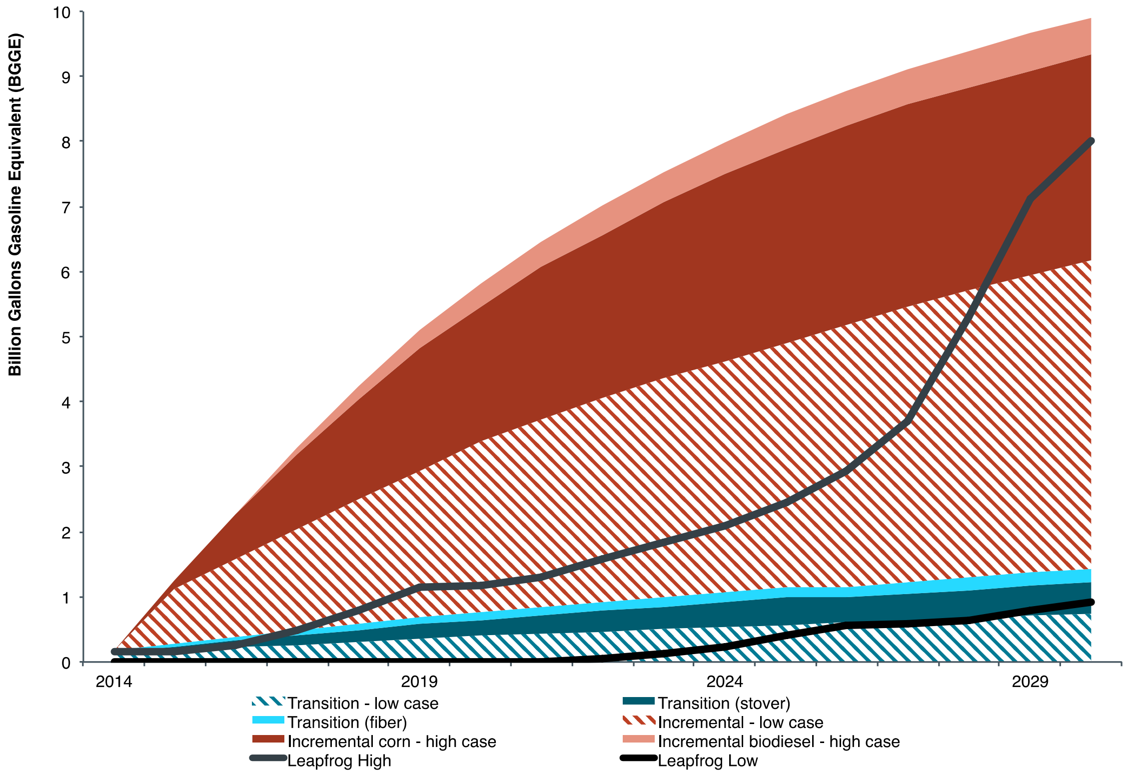


Figure 3.1. Potential supply of biofuels in the incremental, transitional and leapfrog cases described in Fulton et al. (2014)

3.1.5. USDA, GAIN report: Brazil Biofuels Annual 2014

Brazil is currently a major source of sugarcane ethanol, largely used domestically but also exported. It is also a potential source of cellulosic ethanol. USDA's 2014 Global Agricultural Information Network (GAIN) report on the Brazilian biofuel sector (USDA, 2014) notes that the current blend level in Brazil is set to E25. Conventional ethanol production is forecast to rise back towards 2010 levels next year (about 27 billion liters against a 40 billion liter nameplate capacity, with about 24 billion liters being consumed for transportation fuel domestically), with 162 million liters of cellulosic ethanol capacity also coming online.[5] The trend for conventional production since 2012 has been for more plants to close than to open, but the reduction in total capacity has been modest and capacity is still well above production. 2015 total exports are forecast at 1.8 billion liters.

The only active cellulosic fuel plant in Brazil at the moment is Granbio in Alagoas, which became operational last month with an 82 million liter nameplate capacity that USDA expects to be reached some time next year. The feedstock is sugarcane straw and bagasse. Two additional plants are expected by the end of 2015, with capacity of 40 million liters each.

[5] This assumes that three announced plants all achieve full capacity in 2015, and is therefore likely overstated.

3.1.6. U.S. EIA Annual Energy Outlook

The Annual Energy Outlook (AEO) (U.S. EIA, 2013, 2014a) represents the U.S. Energy Information Administration's prediction for the development of the U.S. energy market for the next 25 years (to 2040). In the reference case, biomass based diesel demand rises to 1.9 billion gallons to meet the RFS requirement and then levels off in both years' reports. The AEO 2014 assumes that cellulosic fuel consumption will grow from near zero in 2014 to a bit over 200 million gallons in 2021, beyond which it is held constant. This reflects an assumption in the EIA modeling that, even if EPA increases the cellulosic mandate above this level, the value of cellulosic waiver credits will be such that suppliers prefer to buy the waivers and supply extra advanced biofuel than supply the mandated volumes of cellulosic fuels. This is a departure from the AEO 2013 in which it was assumed that the supply of both cellulosic ethanol and other cellulosic biofuels would continue to increase beyond 2022 (see Figure 3.2. In the 2013 scenario, drop-in cellulosic biofuel production rises to 9 billion gallons ethanol equivalent per year in 2040, achieving 1 billion by 2030. Cellulosic ethanol production is low in both AEO 2013 and AEO 2014, and in the 2013 report, the sum of all U.S. domestic advanced ethanol production (including cellulosic as well as, for instance, low-carbon sorghum grain ethanol) reaches only 400 million gallons by 2030.

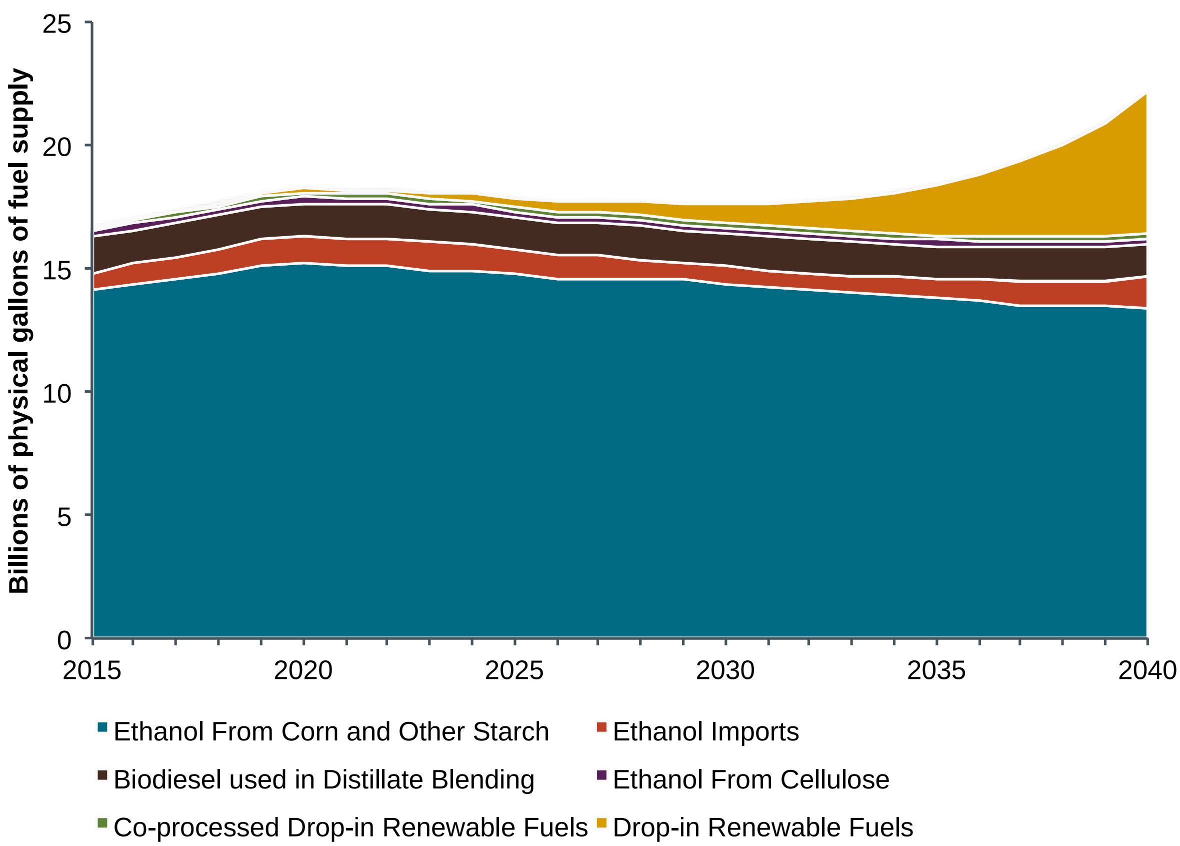


Figure 3.2. Biofuel supply according to U.S. EIA AEO (2013)

California is expected to draw a disproportionate fraction of "advanced" renewable fuels (defined as those with carbon savings of 50% or greater) due to the pull exerted by the Low-Carbon Fuel Standard, as shown in Figure 3.3. In 2020, this is about half of total U.S. advanced fuel, but the fraction falls to about a third by 2030. This assumes that the LCFS is not tightened beyond 2020.

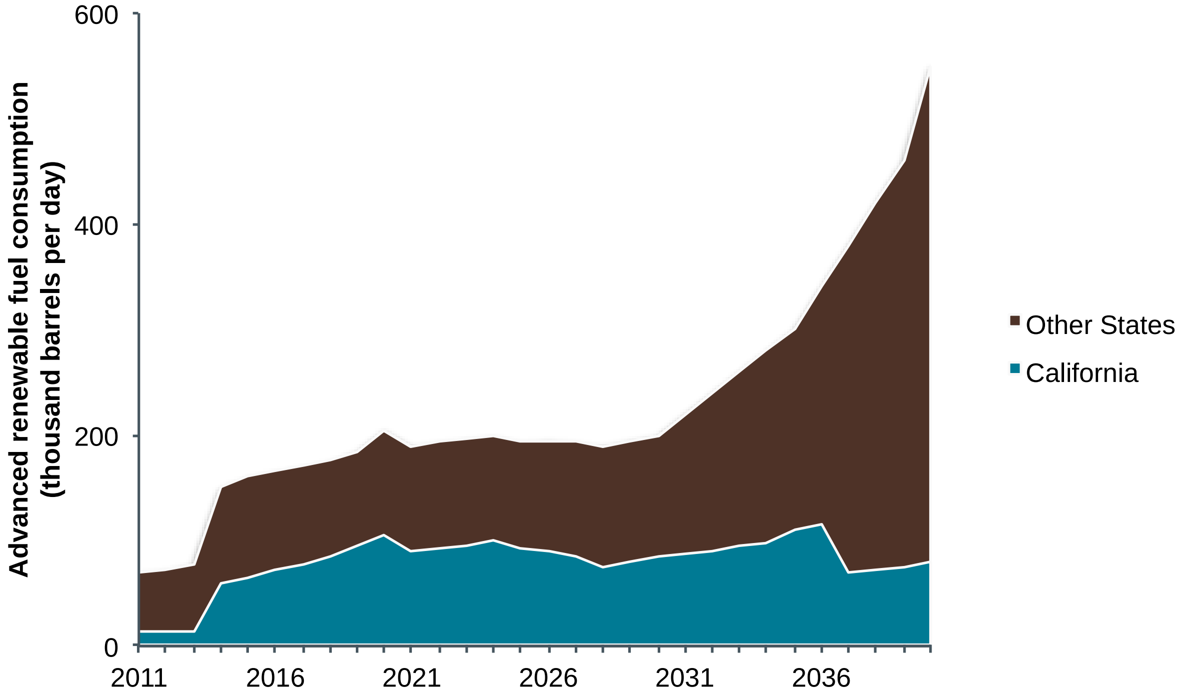


Figure 3.3. Consumption of advanced renewable fuels to 2040, California vs. other states

Source: EIA AEO (2013)

3.1.7. Life Cycle Associates (Pont et al, 2014) – A Clean Fuel Standard in Washington State

This report for Washington State includes an assessment of potential fuel availability to the state. It is noted in this study that once a Clean Fuel Standard is implemented in Washington, it will likely be competing with the rest of the Pacific region for low-carbon fuels, and therefore the study assumes that 14% of available fuel is available to Washington (matching Washington's share of regional gasoline and diesel consumption). The total assumed 2026 availabilities are shown in Table 3.3.

Table 3.3. Availability of fuel in 2026 to Washington State (Pont et al., 2014)

FUEL PATHWAY	2026 POTENTIAL SUPPLY*	NOTES
Ethanol		
Conventional	Abundant	13 BGY consumed in 2013 nationwide
Lower CI Corn	Abundant	Of 93 corn ethanol producers selling into California's market, 80 are utilizing a modified low CI pathway
Sorghum/Wheat (Corn+)	40 MGY	Over 200 MGY has come to California. Assume supply grows at 3%/year and 14% comes to Washington
Sugarcane	146 MGY	EIA projection for 2026 (14%) is 146 MGY. This is based on RFS2 modeling – more available 2023+ if needed.
Molasses	20 MGY	ARB has registered ~ 100 MGY. Assume grows 3%/yr and that Washington receives up to 14%.
Cellulosic	63 – 300 MGY	Low end is EIA projection for RFS2, high end is UC Davis "Leapfrog" potential (assumes half of total cellulosic volume is as ethanol)
Cellulosic Gasoline and Diesel (combined)	**55 – 200 MGY (gasoline equiv)**	**Low end is EIA projection for RFS2, high end is UC Davis "Leapfrog" potential (assumes 50% of total cellulosic volume is as gasoline/diesel)**
CNG		
Fossil	As needed	Limited by vehicle sales and refueling station capacity
Renewable	170 MGY (diesel equivalent)	16 MGY existing capacity
Hydrogen	Sufficient	Limited by vehicle sales and refueling station capacity
Electricity	Sufficient	Limited by vehicle sales and charging infrastructure
Biodiesel	**Sufficient**	**In-state production capacity is 108 MGY. A B15 blend in 2026 requires ~ 73 MGY.**
Used cooking oil, tallow	22 MGY	Washington state feedstock supply
Vegetable Oil	100 MGY	Washington biodiesel production capacity available for vegetable oils
Renewable Diesel	**0**	**Assume that California attracts all renewable diesel**

**Physical gallons unless otherwise stated*

On conventional fuel, Lifecycle Associates assume that corn ethanol will be abundantly available including at lower carbon intensities. Washington currently operates at about 9.5% ethanol in gasoline, but it is assumed that an increase to E15 is possible. Biodiesel should also be available in sufficient quantities to meet demand, which is presumed to be limited by a B15 blend wall. Production capacity is currently at 108 million gallons in the state, however there are not adequate in state vegetable oil resources to supply this capacity. About 3 million gallons of canola oil can be produced in state, and there are 6-8 million tons of potential used cooking oil supply and 10-12 million tons of potential tallow supply. To meet the 73 million gallons per year of demand associated with a B15 blend, additional feedstock or biodiesel would need to be imported. This would presumably be largely either as corn oil or as soybean oil from the Midwest. No limit is assumed on soy oil supply, while total U.S. corn oil potential is set at 140 million gallons per year. Lifecycle Associates assume that no renewable diesel will come to Washington, as technical characteristics of California diesel give it added value in the California market.

3.1.7.b. Cellulosic fuel

The Life Cycle Associates study follows the EIA AEO 2013 cellulosic biofuel projection. The 2014 projection is rejected on the basis that the ‘flatline’ assumption in AEO 2014 is unrealistic given the expectation of ongoing support for cellulosic fuels. The analysis assumptions are shown in Figure 3.4.

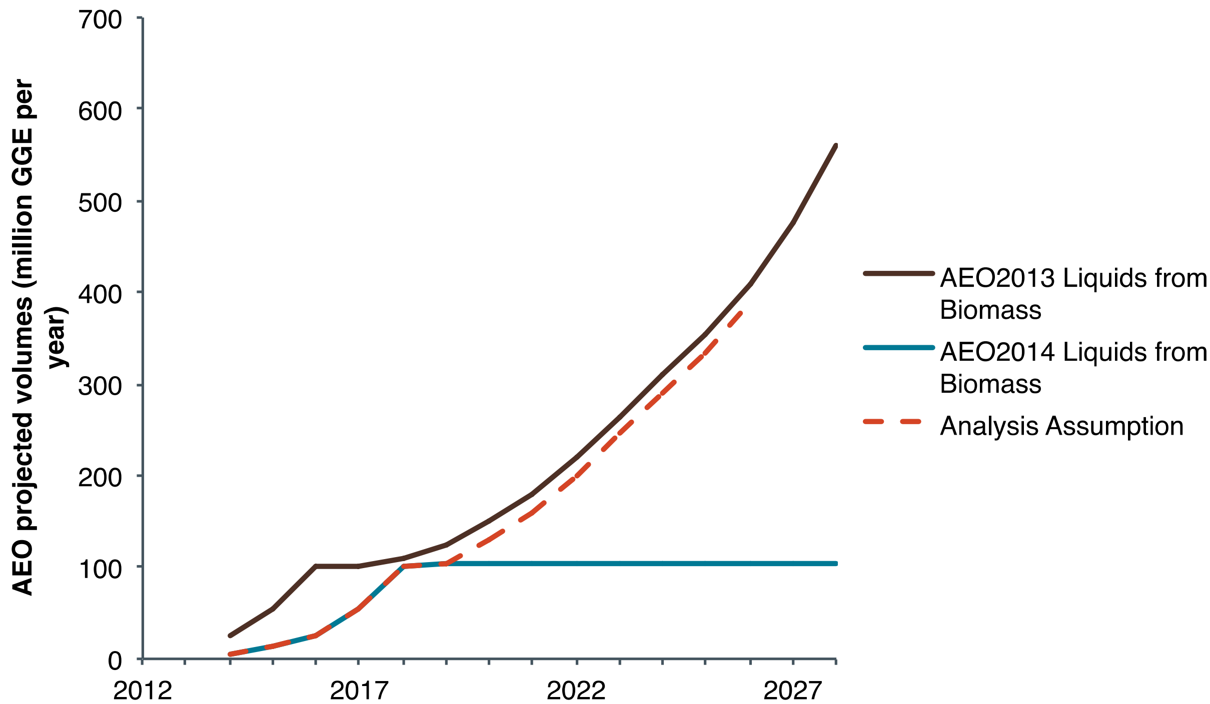


Figure 3.4. EIA cellulosic biofuel consumption projections, and the Lifecycle Associates assumption

Life Cycle Associates also references several other studies. Solecki et al. (2013) predict 500 million gallons of gasoline equivalent cellulosic capacity in 2016, while the NextSTEPS biofuels report by UC Davis identified the potential for 2.8 billion gallons of cellulosic fuel by 2020 in the ’leapfrog’ case. Assuming that all cellulosic fuel is available to the Pacific region, and that 14% of that is available to Washington, Lifecycle Associates posit a range of 2026 availability from 100 to 400 million gallons.

3.1.8. ICF – Updated Compliance Scenarios for an Oregon Clean Fuel Standard

As part of the 2010 rulemaking on the Oregon Clean Fuel Standard, TIAX was commissioned to develop Oregon specific business as usual and compliance scenarios. ICF (2014) were commissioned to update these scenarios in 2014 to take account of new data and changes in the intervening four years. They were given a mandate to consider fuels ‘currently available in commercial quantities.’ ICF considered four compliance scenarios for the 2025 target, based on two levels of biodiesel blending (B2 and B5) and on two technology pathways – advanced vehicle technology and higher biofuel blending. ICF assume that E10 remains as the blend limit for ethanol in gasoline, and also included potential E85 consumption.

In the alternative vehicle technology scenario, large contributions are made by low CI corn ethanol (100 million gallons in 2025), sorghum ethanol (100 million gallons in 2025), sugarcane ethanol (50 million gallons in 2025) and soy biodiesel (24 to 34 million gallons depending on the blend limit). The use of electricity in vehicles increases and becomes a major compliance driver, with 25 million gasoline equivalent gallons in 2025, and natural gas use also increases to over 90 million gallons of diesel equivalent, half of it renewable. In 2025, the passenger vehicle fleet includes about 90,000 BEVs and over 100,000 plug-in hybrids.

In the biofuel scenario, more credits are banked in the early years of the mandate, including those from tallow renewable diesel and waste oil renewable diesel. Electricity supply grows more slowly, and natural gas use is only around 10 million diesel equivalent gallons, hardly any of it renewable. In the B5 case, waste oil biodiesel grows to 30 million gallons.

3.1.9. Biofuels Digest's 'SuperData'

The Biofuels Digest's Gold Access SuperData dataset provides details of 311 planned cellulosic biofuel and biochemical facilities globally, including expected first year of production and production capacities to 2018. If all of these projects were delivered on time and at full capacity, global production would approach 6 billion gallons by 2018 (as shown in Figure 3.5). Of that, over 3 billion gallons of capacity would be in the U.S., with 143 million gallons of capacity in the Pacific region. This would include three commercial scale facilities in California, one in Oregon and one in British Columbia.

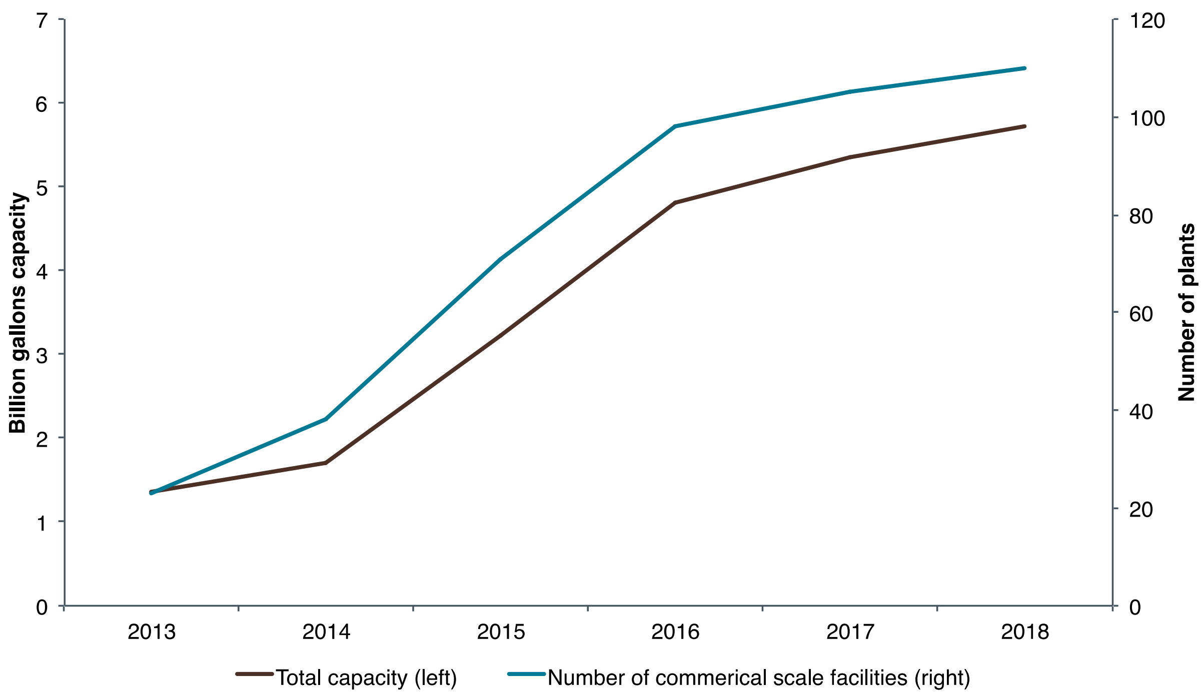


Figure 3.5. Production capacity and number of plants of 3 million gallons per year capacity or greater, according to Biofuels Digest

3.1.10. E2 Environmental Entrepreneurs, Advanced Biofuel Market Report (2013)

E2's annual advanced biofuel market reports provide an indication of the state and expectations of the advanced biofuel industry in the U.S. and Canada. E2 (2013) provide low end capacity estimates based on only counting facilities that have demonstrated progress, while the high-end estimates include all projects identified, discounting some capacity estimates. The E2 report focuses on new technologies (cellulosic, algal, etc.) but also includes biodiesel from non-virgin oils. In the short term, the largest capacity is in waste-oil biodiesel (over 700 million gallons in 2013, rising to a billion gallons in 2016). The expected rate of deployment for cellulosic drop-in fuels is greater than that for cellulosic ethanol – rising to 400 million gallons of drop-in fuel by 2016 in the 'low' case, compared to 200 million gallons of ethanol. The total advanced biofuel capacity estimate for 2016 is 1.6 billion gallons in the low case, and 2.3 billion gallons in the high case. The low case has 43 advanced biofuel facilities operational by 2016. Note that this is somewhat below the 2015 expectation laid out in the 2012 advanced biofuel market report – this reflects the challenges that many advanced biofuel companies continue to face in moving to commercial production. E2 note that there are not currently any planned cellulosic butanol facilities, but identify this as a future opportunity. E2 note that according to ICF (2013) California will require one billion gallons of advanced biofuels by 2020 to achieve the LCFS – this is below E2's expected production.

3.1.11. ICF, California's Low-Carbon Fuel Standard: Compliance Outlook for 2020

ICF's Compliance Outlook report (ICF, 2013) was prepared for the California Electric Transportation Coalition, the California Natural Gas Vehicle Coalition, Environmental Entrepreneurs, the Advanced Biofuels Association, the National Biodiesel Board and Ceres. It includes a 'reference' scenario and two LCFS compliance scenarios.

On conventional ethanol, ICF note several process innovations that have allowed corn ethanol producers to report lower carbon intensities in California (similar to those listed in the incremental scenario in the NextSTEPS report). The four routes to reduced emissions are shifting to wet distillers' grains, shifting to natural gas for power, use of cogeneration and part switching to lower carbon intensity feedstocks. Sugarcane ethanol is another compliance option for LCFS with potentially high availability. ICF argue that 1) Brazil has sufficient capacity to meet demand for ethanol, 2) the fuel is priced competitively with corn ethanol, and 3) there is potential to lower the carbon intensity of sugarcane ethanol further. In 2012, 530 million gallons of sugarcane ethanol was exported to the U.S. from Brazil. ICF allow for up to 500 million gallons to be imported for use in the California market. Organisation for Economic Co-operation and Development (OECD) forecasts that by 2020 Brazil's net exports of sugarcane ethanol will reach 2.5 billion gallons. Note that this is in the context of growing domestic consumption (heading to 10 billion gallons by 2020), and thus this export capacity assessment relies on robust growth in production. OECD predicted in 2012 that by 2014 production would be exceeding 2010 levels – as noted in the Brazil biofuels annual 2014 GAIN report, this growth rate has not been achieved. ICF also note that California would have to compete with other markets for Brazilian cane ethanol, notably the European Union where the Fuel Quality Directive (FQD) applies an LCFS-like carbon intensity reduction target. Higher tariffs and transportation costs may limit the appeal of the European market, but "it seems likely that exports of Brazilian sugarcane ethanol to the EU will increase to comply with the FQD."

For cellulosic ethanol, ICF's production projections were developed in coordination with E2, and thus heavily based on the E2 (2013) advanced biofuels market report. ICF assume 600 million gallons of cellulosic fuel capacity in place by 2020, but that most plants will not be located in California. Assumptions about whether fuel will be available to California are informed by infrastructure and transportation cost limitations (e.g., ICF assume that no fuel would reach California from the Ineos facility being constructed at Vero Beach, Florida).

ICF also considered options to increase ethanol volumes used in California. They considered the potential for the introduction of E15, and the wider use of E85. E15 is seen as the more promising route to increased ethanol market size, despite questions about how long it may take to roll out E15 as the standard fuel grade. By 2018, 90% of Californian light-duty vehicles should be E15 compatible, allowing an additional 600 million gallons of ethanol to be blended.

On the biodiesel side, the supply of corn oil biodiesel to California has increased rapidly in recent years and there is a potential for over 700 million gallons production in the U.S. as a whole. The compliance scenarios include 175-240 million gallons of corn oil biodiesel in California, plus 50 million gallons of biodiesel from waste grease. The B5 market will saturate at about 200 million gallons per year. Higher blends are possible but would involve infrastructure investment and consideration of manufacturers' engine warranties. As well as biodiesel, California is currently receiving imports of tallow-based renewable diesel from Neste Oil's facility in Singapore, with 100 million gallons of imports predicted for 2013. The fraction of the facility's production that can be sent to California is currently limited by the lack of a palm oil pathway under the LCFS. Additional renewable diesel capacity is expected in Louisiana from Diamond Green, with a nameplate capacity of 137 million gallons.

3.1.12. The California Council for Science and Technology, California's Energy Future – The Potential for Biofuels

This report from Youngs and Somerville (2013) considers the opportunity for biofuels to contribute to California's 2050 goal of reducing carbon emissions by 80% across the whole economy. It is a corollary report to the 2011 study, "California's Energy Future – The View to 2050."

The report considers two demand cases cross referenced to three supply cases, all for 2050. The demand cases are business-as-usual (i.e., high fuel demand, not including expected efficiency savings and electrification) and "realistic" (i.e., reduced fuel demand). The three supply cases are first a combination of E10 and B20 as standard fuel blends, second the full adoption of E85 and B85, and finally a case in which drop-in biofuels replace conventional gasoline and diesel entirely. The study found that for business-as-usual increases in transportation fuel demand, no supply scenario was adequate to support the 80% carbon emissions reduction goal. However, for reduced energy demand (16 billion gge of liquid fuel demand rather than 44 billion gge in the business-as-usual case), the E85/B85 and drop-in biofuel supply cases may be able to reach the emissions reduction goals. The study does not provide a detailed consideration of the deployment rate for cellulosic fuel production that would be implied by these supply scenarios. It does however consider feedstock supply, concluding that by 2050 between 40 and 100 million tons of dry biomass may be available in California, largely from agricultural and forestry residues. This feedstock supply would only be adequate to meet between 3 and 10 billion of the 16 billion gallons gasoline equivalent (bgge) of liquid fuel demand in the "realistic" demand scenario. This implies that to achieve these levels of biofuel consumption, either feedstock of biofuel would need to be imported. Given the logistical challenges to biomass feedstock transportation, the study concludes that it is more likely for imports to be of liquid fuels. One potential source of liquid fuels would be Brazil, where the report anticipates over 100 billion gallons gasoline equivalent production capacity by 2030, 67 bgge from sugarcane and 45 bgge from sugarcane residues with cellulosic technology. Of this, the study suggests 7.5 bgge may be available to California in 2050.

3.2. Biomass availability

3.2.1. U.S. Department of Energy, Billion-Ton Update

3.2.1.a. Energy crops

The Billion-Ton Study Update (U.S. DOE, 2011) considers energy crops in three classes: perennial grasses, annual energy crops, and woody crops (either as single rotation or for coppicing). The perennial energy crops considered most promising in the Billion-Ton Study Update, henceforth BTS, are switchgrass, *Miscanthus*,, and energy cane. The annual energy crop is sweet sorghum, and the most promising woody energy crops are poplar, southern pine, eucalyptus, and willow. The potential crop areas are determined with the POLYSYS model, which allows conversion of cropland to energy cropping where the economics of energy crops are more favorable, and allows conversion of pasture and cropland pasture to energy cropping for counties east of the 100th Meridian (it is assumed that counties east of here have enough rainfall to allow forage intensification, while counties to the west do not). Primary land-use shares by state are shown in Figure 3.6. Economics are based on a comparison of production costs. Factor inputs vary by region.

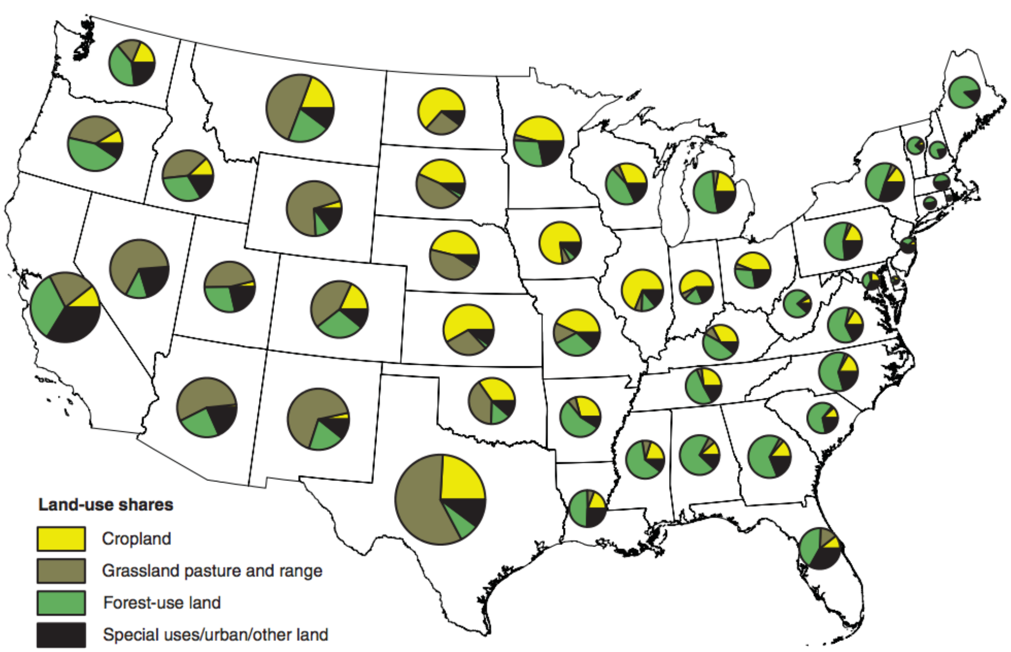


Figure 3.6. Primary land uses in the U.S. by state (Lubowski et al., 2005, via the BTS)

The result of the baseline modeling in the BTS is that by 2030 very substantial quantities of biomass from energy crops could be available, given adequate farm gate prices. In total, at $80 per dry ton about 450 million tons availability is forecast (Figure 3.7). At $60, the availability is closer to 350 million tons, while at $40 the availability could be comparatively low (about 30 million tons). The predicted potential in the Pacific states is a tiny fraction of this – only about 130,000 tons in 2030 in the $80 scenario, based on some perennial grass production in Washington and woody crops grown in Oregon and Washington. In the highest yield case, the availability would be approximately doubled at $60 per ton, to 700 million tons.

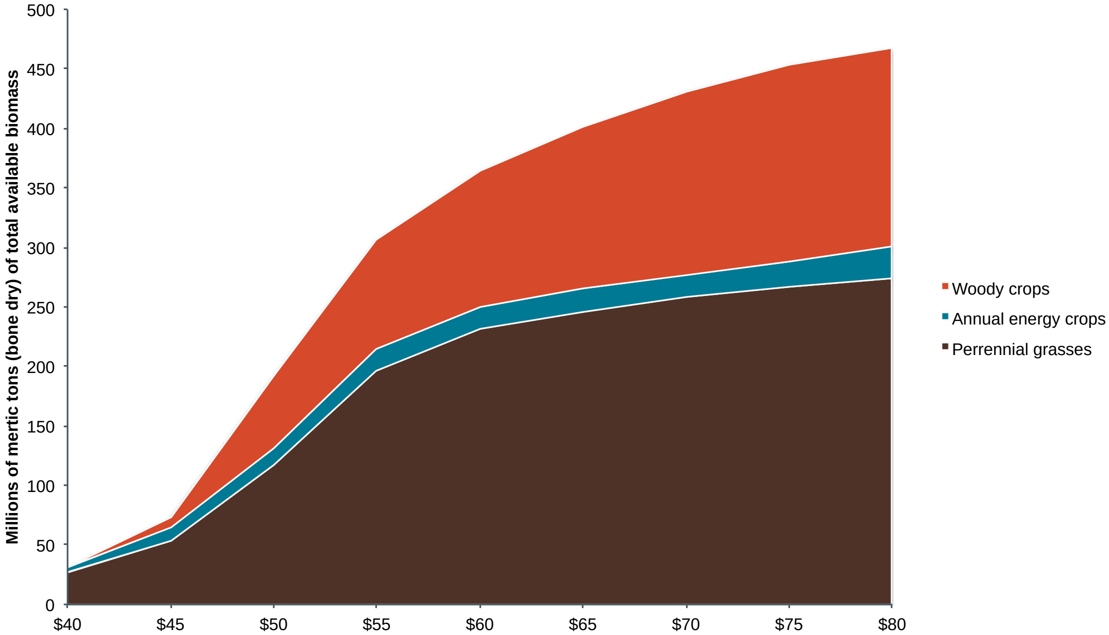


Figure 3.7. Biomass availability in the U.S. 2030 for perennial grasses and annual energy crops, BTS baseline scenario

3.2.1.a.1. Yield

The BTS considers three scenarios for future energy crop yield growth, based on expert input from a workshop held by the DOE. Most participants projected yield increase around 1% per year for herbaceous energy crops including *Miscanthus*, and switchgrass. Expectations of woody energy crop yields were more evenly spread in the range 1-4%. The baseline scenario in the BTS assumes 1% yield increase per year for both energy crops and food crops. The high yield scenarios assume 2% yield growth for food crops, and consider 1, 2 and 4% yield growth scenarios for energy crops.

The BTS states that switchgrass yields can vary from 2 to 9 dry short tons per acre (about 4 to 20 metric tons per hectare). However, it admits that, “Switchgrass yields have not been demonstrated at full scale-up plots and extrapolation of demonstration plot yields to full-production scale plots is risky.” Table 3.4 shows the range of yields for both the baseline case and the high yield cases. The yields characterized as “low end of the yield range” by BTS are comparable to the yields identified as reasonable in Searle and Malins (2014). The high yield scenarios are rather optimistic, and thus we propose to focus on the baseline results for the supply scenarios analysis.

Table 3.4. Growth trajectories from the BTS for perennial grass yields, with various initial yields

	INITIAL YIELD	BASELINE (1%) YIELD GROWTH			HIGH (2-4%) YIELD GROWTH		
	2012	2017	2022	2030	2017	2022	2030
Low end of yield range	4.4	4.7	4.9	5.3	4.9 - 5.3	5.3 - 6.7	6.4 - 9.1
	6.7	7.1	7.3	8	7.3 - 8	8.2 - 9.8	9.6 - 13.6
	8.9	9.3	9.8	10.7	9.8 - 10.9	10.9 - 13.1	12.7 - 18
	11.1	11.8	12.2	13.3	12.2 - 13.6	13.6 - 16.5	15.8 - 22.5
	13.3	14	14.7	16	14.7 - 16.2	16.2 - 19.8	19.1 - 27.1
Middle of yield range	15.6	16.5	17.1	18.7	17.1 - 18.9	18.9 - 23.1	22.2 - 31.6
	17.8	18.7	19.6	21.3	19.6 - 21.6	21.8 - 26.2	25.3 - 36
High end of yield range	20	21.1	22	24	22 - 24.2	24.5 - 29.6	28.7 - 40.5
	22.2	23.3	24.5	26.7	24.5 - 27.1	27.1 - 32.9	31.8 - 45.1
	24.5	25.8	27.1	29.3	26.9 - 29.8	29.8 - 36.2	34.9 - 49.6
	26.7	28	29.6	32	29.3 - 32.5	32.5 - 39.6	38 - 54

3.2.1.b. Agricultural residues

The BTS provides detailed estimates of agricultural residue availability in the U.S. from 2012 to 2030 for a range of farm gate price scenarios and agricultural yield assumptions. Residue production rates are calculated for barley, corn, oats, sorghum, and wheat. Production is based on predicted crop yield and on the harvest index. [6]

The total availability of agricultural residues by 2030 in the U.S. is expected to be on the order of 300 million tons for farm gate prices above $50 per ton, though for $40 per ton availability would be greatly reduced to 80 million tons. As with energy crops, the bulk of the resource is available in the eastern states, but availability in the Pacific Coast region is higher than the energy crops case. As shown in Figure 3.8, total availability in the Pacific Coast region could rise to about 3 million dry tons by 2030 at $80 farm gate prices, enough to supply about 300 million gallons of ethanol. The largest Pacific Coast resource by far is wheat straw in Washington, as shown in Figure 3.9.

[6] The harvest index refers to the ratio of total biomass in a crop that is concentrated in the ‘useful’ part vs. the residues, e.g., in the grain vs. the stover in the case of corn. A harvest index of 1 would mean that the biomass fraction in the corn was equal to that in the stover.

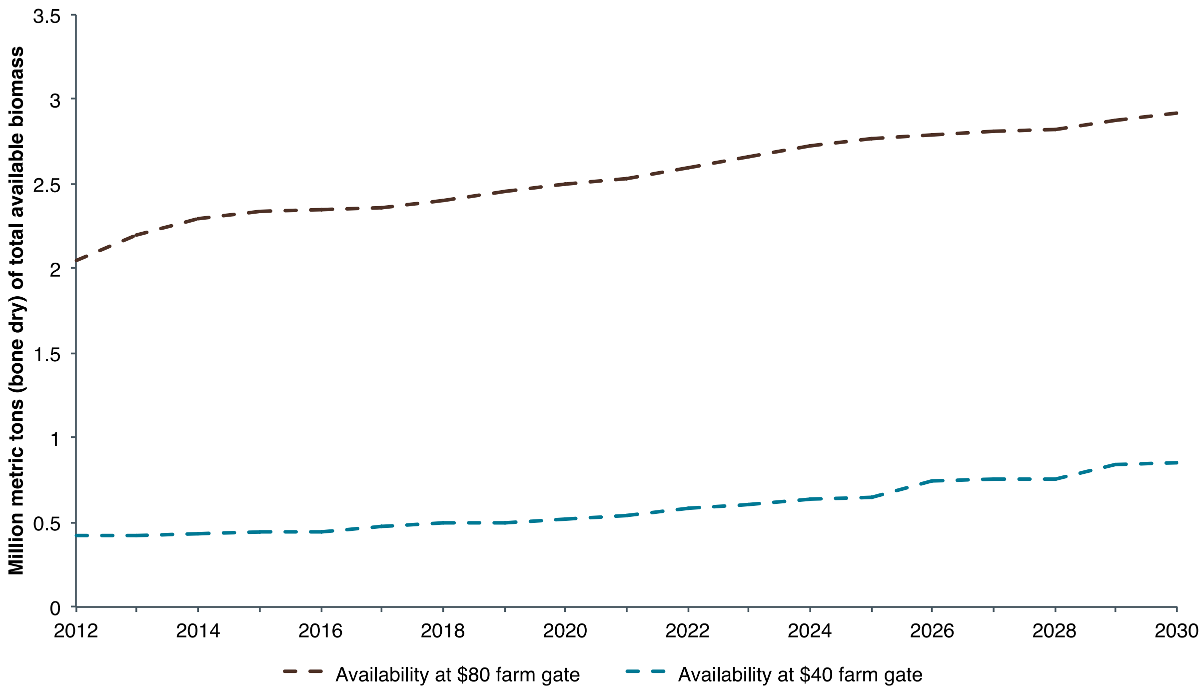


Figure 3.8. BTS-estimated agricultural residue biomass availability in the Pacific States over time

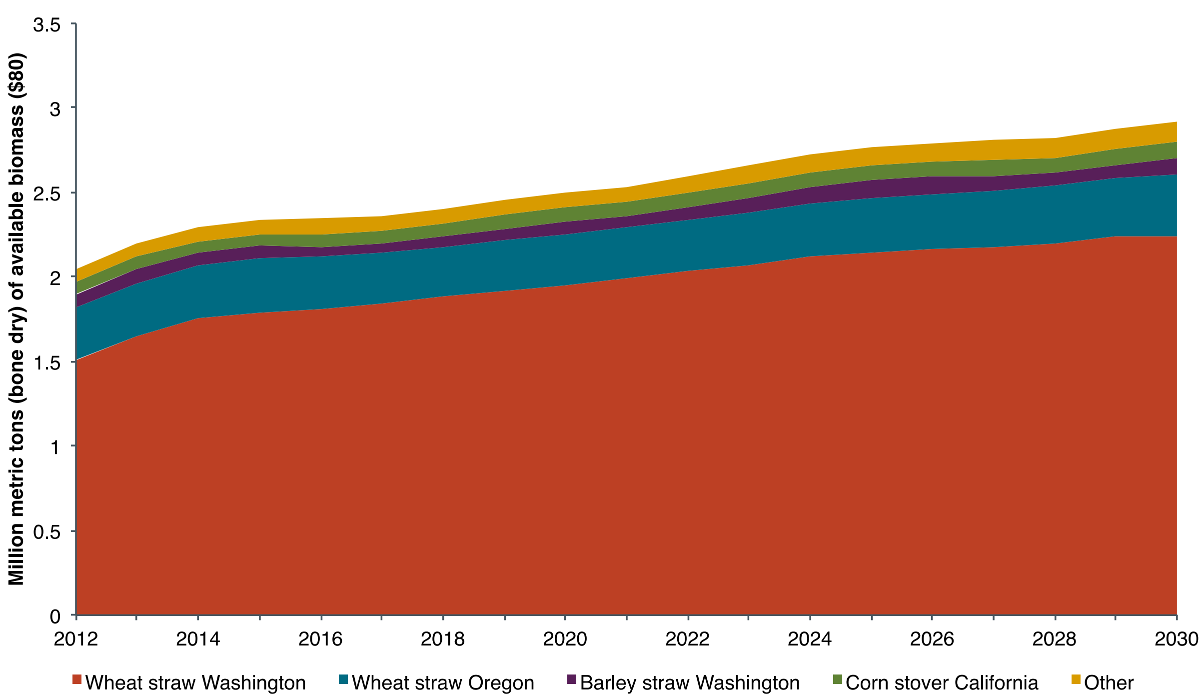


Figure 3.9. Major agricultural residue supply stream on the U.S. Pacific Coast

Availability in the Pacific States is less than a third at $40 per ton than it would be at $80 per ton, but the price sensitivity is very low above about $55 as shown in Figure 3.10.

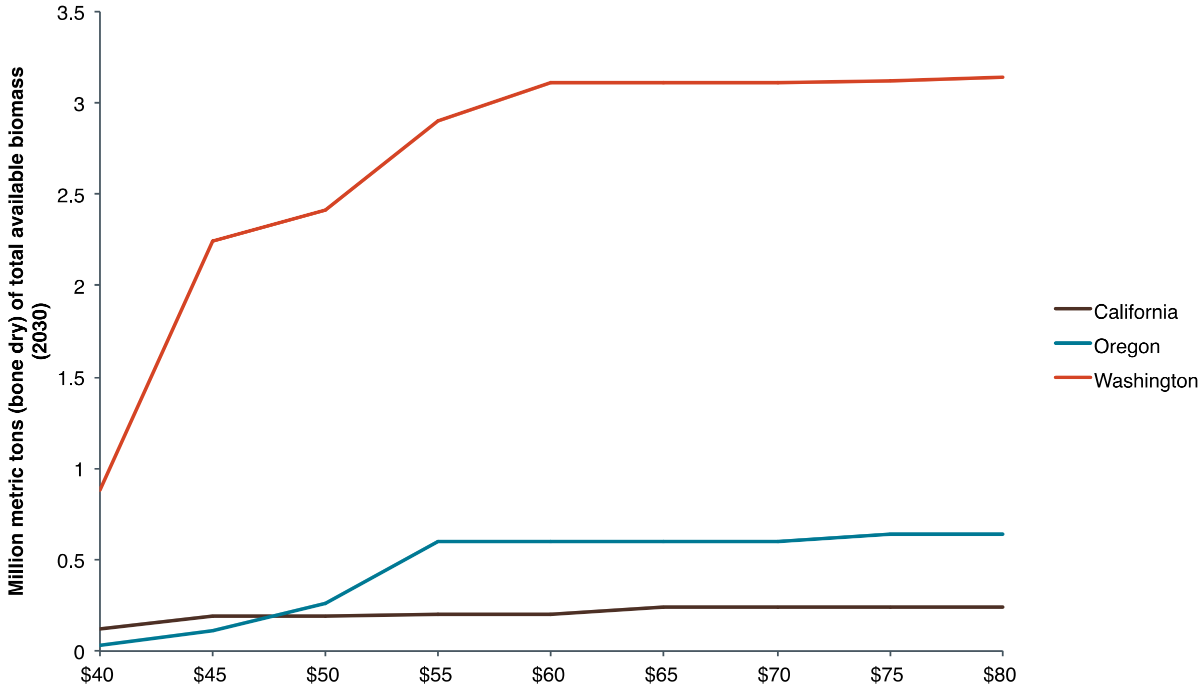


Figure 3.10. Agricultural residue availability by farm gate price and State

3.2.1.b.1. Yields

It is assumed that the harvest index is constant with respect to growing yields. In the baseline scenario, agricultural yields for food crops are set to increase geometrically by 1% per year. There is also a 'high yield' scenario modeled with double the rate of yield increase. The yield assumptions are based on the outcome of an expert workshop held by DOE. Note that it is generally accepted in agronomy that yields tend to increase linearly, not geometrically – i.e., a percentage rate of yield increase may be a good approximation to reality for short time periods, but in the long term exponential behavior is not observed. Over 18 years, this introduces a modest optimism bias to the results for the baseline (1%) case, however the non-linearity becomes more important in the higher yield cases. The modeled rate of 1% yield growth per year is reasonable in the near term. For instance, a 1% increase on 2014 yields is close to the historical trend for corn. Assuming constant harvest index may also be optimistic. This is because yield growth has historically tended to be associated with increased harvest index – that is, yields have been increased in part by 'transferring' biomass from stalks, leaves etc. to the grain (or the seed, fruit, etc. as appropriate).

3.2.1.c. Forestry residues

The BTS assesses the following forestry resources: residues from timberland and other forestland categories such as thinnings and unused mill processing residues; urban wood wastes and conventionally sourced wood. Total U.S. logging residues and other non-roundwood removals amount to about 80 million tons per year, split between 60 million tons of residues and 20 million tons of other removals. Most of this material is not currently collected, but the BTS argues that, “as markets for bioenergy feedstocks develop, a significant fraction of this residue could become economically feasible to remove, most likely in conjunction with conventional harvest operations where the costs of extraction (i.e., felling and skidding) are borne by the conventional forest product.” Removal of woody residues is associated with loss of habitat and loss of nutrient capital from the forest system. Because nutrients are concentrated in residues, whole tree harvesting involves disproportionately more nutrient removal than roundwood harvesting. Nutrient loss can be mitigated by fertilization, and wood ash from biomass burning can be returned to sites to replenish some nutrients. The BTS concludes that 30% of residues should be left in place for stands on slopes less than 30%, and that 50% should be left on steeper slopes.

Overall, about 40 million dry tons of residues are expected to be available at $40 per ton roadside price, along with 18 million tons of forest thinnings. About 10% of this resource is available from federal lands, and therefore would not be eligible as feedstock under the RFS. In the Pacific region, availability is about 1.4 million tons in California, about 2.9 million tons in Oregion, and about 2.5 million tons in Washington, with little variation over time. Feedstock density is greatest on the Pacific coast of Washington and Oregon (see Figure 3.11). Forest thinnings are also identified as a significant source – about 20 million dry tons at $40 roadside price. Forest thinning results in carbon losses from the system, but BTS notes that these may be offset by increased growth rates and reduced risk of wildfires. It is important to note that there is some double counting between the BTS estimates of residue availability and of thinnings. As a conservative estimate, BTS assumes that half of the combined resource is really available, about 30 million tons at $40 per dry ton.

In addition to these forestry resources, there are mill residues and urban wastewood. At $40 a ton, the availability is an additional 28 million tons. The BTS also considers conventional pulpwood. Bioenergy markets will not be competitive at expected prices, but at higher prices (>$60 per ton) availability of pulpwood starts to become significant. Overall, at $40 per ton, the BTS finds about 70 million tons of available woody resource (not including woody energy crops).

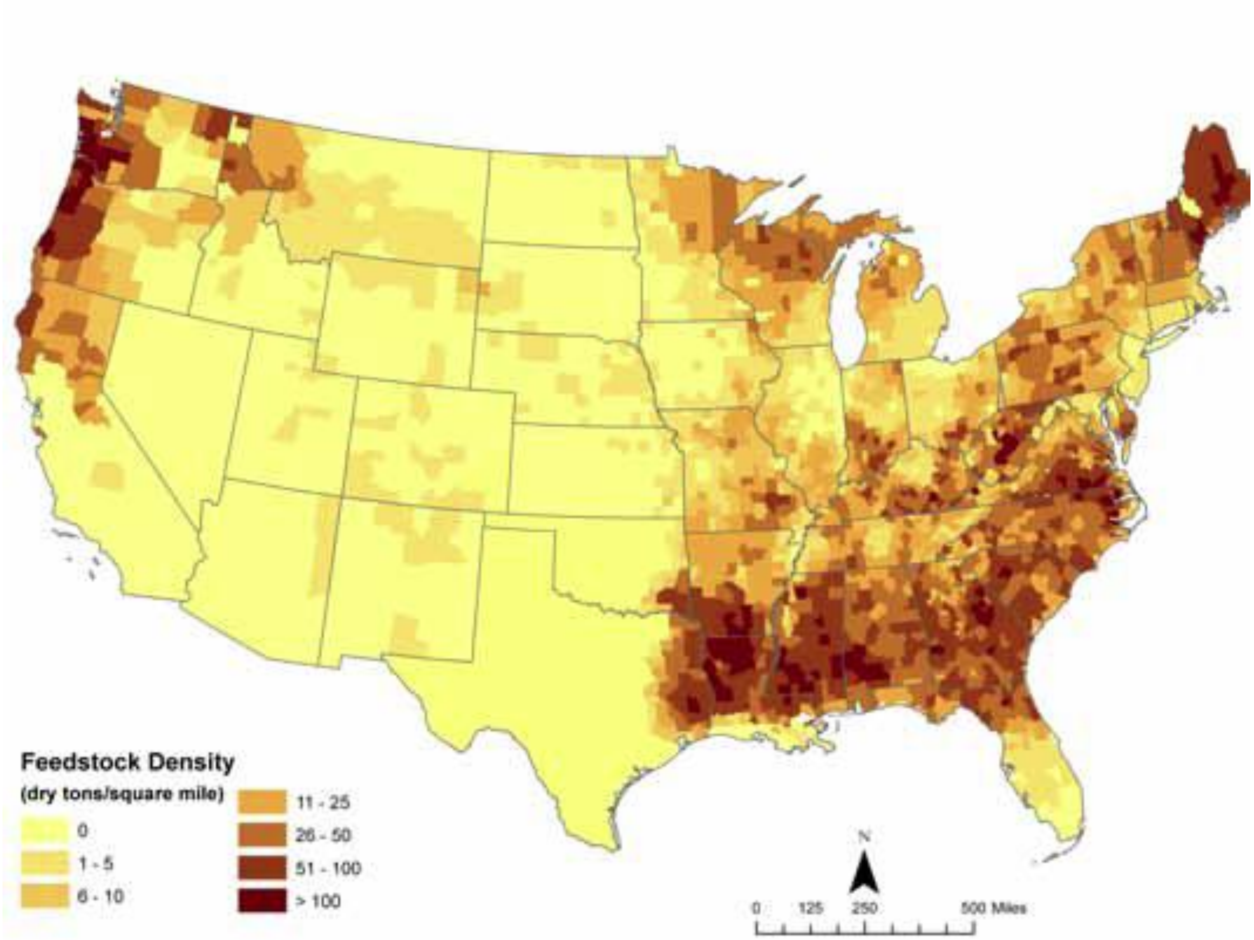


Figure 3.11. Feedstock density of forestry residues at a roadside price of $40 per ton

3.2.2. Parker – Spatially Explicit Projection of Biofuel Supply for Meeting Renewable Fuel Standard

Parker (2012) considers what industrial development would be necessary by 2018 to hit a trajectory to achieve the 2022 U.S. RFS cellulosic ethanol standard (16 billion gallons). Using an integrated supply chain model, Parker found that with $60-140 billion of investment the required fuel volumes could be brought to market at fuel prices between $2.65 and $3.87 per gallon. The resource potential, shown in Table 3.5, is based on analysis in Parker (2011).

Table 3.5. Feedstock availability by 2018 from Parker at up to $50 | up to $75 | up to $100 per dry ton, respectively

RESOURCE	ESTIMATED AVAILABILITY		
	Low	Middle	High
Agricultural residues	0 | 30.2 | 71.2	0 | 122.7 | 128.2	159.2 | 227.5 | 238.8
Orchard and vineyard wastes	8.0 | 8.0 | 8.0	8.0 | 8.0 | 8.0	8.0 | 8.0 | 8.0
Forest residues	47.9 | 52.3 | 52.5	47.9 | 52.3 | 52.5	53.4 | 60.5 | 60.9
Pulpwood	0 | 1.6 | 26.0	0 | 8.7 | 33.2	1.6 | 33.2 | 64.4
Energy crops	0 | 0.4 | 26.0	0 | 0.4 | 52.1	0 | 60.4 | 293.8
MSW*: Total	**24.2**	**67.55**	**135.2**
Construction and demolition wood	15.8	15.8	31.5
Urban wood	8.5	8.5	16.9
Paper and cardboard	0	13.3	26.6
Food wastes	0	3.9	7.8
Yard or green wastes	0	3.3	6.7
Mixed organics	0	22.9	45.7
Total	**80.1 | 116.7 | 207.9**	**123.5 | 259.7 | 341.6**	**357.4 | 524.8 | 801.1**

**It is assumed that all MSW resource is available below $50 per ton*

The largest single resource in the low and middle scenarios is agricultural residues. Parker (2011) determines possible rates of residue removal based on assessing minimum residue retention requirements to prevent unsustainable levels of wind erosion, rain erosion or soil carbon loss. Minimum retention requirements are sensitive to agricultural practice, being lower for conservation or no till agriculture. The base case assumes current practices continue, the optimistic case assumes complete adoption of conservation tillage.

Parker's baseline case for yields is less aggressive than that taken in the BTS. In the more conservative yield case (the 'low' scenario'), historical yields and areas are used based on the past ten years. The second approach (baseline and high scenarios) uses the national yield increase over time from USDA's Long Term Projection (2009). USDA note that, "The growth rate in crop yields has slowed somewhat during the last several decades and is projected to continue to do so." Their yield projections are based on the linear trend. Parker notes evidence (Johnson et al., 2006) that from 1940 to 2000 growth in the grain yield of various key crops far outstripped growth in residue yield – for corn, grain yield has increased three times more than residue yield in that period, while soy yields have increased by almost 100% with hardly any accompanying increase in residue yield (see Table 3.6). Nevertheless, harvest indices are assumed constant in the model, as in the BTS. Parker notes that the results can be quite sensitive to the harvest index assumption. This is because total residue availability is based not on total residue generation but on the availability above the minimum retention level. Reducing the harvest index from 0.53 to 0.5 would increase residue availability by 43%, even though it corresponds to only a 12% in gross residue generation. The final key limitation on residue availability is harvest efficiency. For the baseline and low case, a harvest efficiency of 38% is used, which is limiting on residue harvest in most fields. For the high case, a harvest efficiency of 70% is allowed (which has been reported for a shred, windrow, and bale system).

Table 3.6. Comparative increase in grain vs. residue yields, 1940-2000

CROP	GRAIN INCREASE	RESIDUE INCREASE
Barley	200%	12%
Corn	340%	110%
Oat	92%	20%
Sorghum	330%	150%
Soybean	100%	2%
Wheat	170%	27%

Municipal waste provides the second largest contribution in most of the scenarios. Parker uses the 'State of Garbage" report (Arsova et al., 2008) to estimate volumes of waste production by state, and uses EPA estimation of the breakdown between waste categories (see Table 3.7). In the base case, half of the resource is presumed available. In the low case, only the woody construction and demolition debris is available. Parker notes that future projections of municipal waste generation are speculative and suggests that the projections used in Parker (2011) may give an optimistic picture of MSW availability for biofuel production.

Table 3.7. Summary of MSW landfilled in the U.S.

MSW CATEGORY	FRACTION OF TOTAL MSW (WET WEIGHT BASIS) -FF	RECOVERABLE FRACTION -RF	MOISTURE CONTENT - MCF
Food Waste	19%	50%	70%
Paper/Cardboard	21%	50%	10%
Wood	9%	75%	12%
Yard trimmings	7%	75%	47%
Mixed waste	18%	75%	19%

A third key biomass resource is forestry residues. For harvest residues, Parker (2011) considers 50 and 65% removal rates. Thinnings and other woody harvests (such as urban land clearing) are also considered.

In the high availability case, especially at high biomass prices, energy crops become important. Energy crops are allowed to be grown on idle cropland (including Conservation Reserve Program land) and on cropland pasture. Production cost is based on a switchgrass production study from Iowa (Duffy, 2008) and on land rental data from USDA-NASS. The low scenario allows 25% of eligible land to be used, while the baseline allows 50%, both based on upland switchgrass yields. The high scenario additionally allows for 5% of pasture to be converted and for higher lowland switchgrass yields to be achieved. In Parker's middle and high scenarios, energy crop production becomes significant at prices over $75 per ton. Availability in the U.S. is estimated at 50 million dry tons and 290 million dry tons respectively for those cases. This high end estimate is rather higher than the baseline case at $80 in the Billion-Ton Study (180 million dry tons).

Parker finds price to be more limiting than is the case in the BTS – availability at $100 per ton is much greater than at $75 per ton. In the BTS, most energy crop biomass is available at $60 per ton. Parker's production cost estimates are based on an Iowan study of switchgrass production (Duffy, 2008) and on USDA-NASS data on land rents. The sensitivity of Parker's results to price suggests that production could be highly sensitive to the level of price support available to cellulosic fuel.

3.2.3. Searle and Malins– "Will energy crop yields meet expectations?"

Searle and Malins (2014) provide a review of likely growth in energy crop yields. They note that many studies in the literature are very optimistic about future energy crop yields, but that there are biological and structural reasons to expect that energy crop yield growth will not match historical rates delivered for annual food crops.

For instance, cereal and grain yields have benefitted historically from an increase in the harvest index, or the ratio of grain to the rest of the above-ground plant. This type of increase is not possible for crops grown for cellulosic material. They also note that much of the historical increase in food crop yields has come from increased use of inorganic fertilizers and irrigation. While some irrigation may be available for bioenergy crops in the future, water resources are likely to be increasingly scarce in the future due to population pressures and climate change on a global scale.[7] On the fertilizer side, perennial grass yields do not usually respond to fertilizer application above a modest threshold. A standard route to yield improvement in annual crops is conventional crop breeding. However, while breeding cycles of annual cereal crops are short, on the order of a few months, perennial biomass crops take longer to reach maturity – up to 10 years to maturity for Eucalyptus. Similarly, the effects of genetic modification could take years to fully detect, and so while such yield increases are possible, they cannot be relied upon in the short-medium term. Searle and Malins therefore argue that we should expect yield growth for cellulosic energy crops to be slower than the historic rates achieved for cereals.

As well as discussing yield growth, Searle and Malins note that some studies extrapolate expected commercial scale yields from small test plots, and that this can give a grossly exaggerated expectation of achievable harvests. For instance, one study is reported as predicting yields of over 50 metric tons per hectare per year (t/ha/yr), but this is extrapolated from results for only five plants. Yields will be much lower at scale and for the type of non-prime agricultural land likely to be available for energy crops. They conclude that reasonable estimates for currently achievable commercial energy crop yields should fall in the range 0-15 t/ha/yr depending on crop and climate (see Table 4.9).

Table 3.8. Yields of energy crops that can be expected at commercial scale on land that is marginal for agriculture, by climatic zone (t/ha/yr)

	COLD TEMPERATE	TEMPERATE	WARM TEMPERATE	TROPICAL/ SUBTROPICAL
Miscanthus	3-5	7-15		
Switchgrass		2-7	5-10	
Willow SRC*	0-10	4-13		
Poplar SRC*	3-8	4-10	4-10	4-10
Eucalyptus		5-15	5-15	5-15

**Short rotation coppice*

[7] Note that regional changes in precipitation with climate change vary; precipitation is projected by the Geophysical Fluid Dynamics Laboratory of the U.S. National Oceanic and Atmospheric Administration to decrease in California but increase in British Columbia over the next century.

3.2.4. Statistics Canada (StatCan) Census of Agriculture

Statistics Canada (2011) provides data on a number of topics. Every five years, Statistics Canada conducts the Census of Agriculture, collecting key information from farmers on major agricultural commodities. This includes data on agricultural area and number of farms reporting for major crops (including wheat, oats, barley, corn, rye, canola, and soybeans) for each Canadian province, including British Columbia.

From this source, we can utilize data on agricultural area of major crops in 2011 to estimate residue production. As the Census of Agriculture does not appear to report total production or yields, national yield data for Canada is taken from FAOSTAT. Harvest indices from the Billion-Ton Study are assumed for these crops. The resulting total residue production is shown in Table 3.9.

Agricultural practices in Canada are comparable to those in the U.S. Data on tillage practices from the Census of Agriculture is available from Statistics Canada, with categories included are “tillage incorporating most of the crop residue into the soil,” “tillage retaining most of the crop residue on the surface,” and “no-till or zero-till seeding.” All three practices appear to be common in British Columbia. Given the comparable levels of no till practice, we believe that the typical residue removal rates from the BTS are likely applicable to British Columbia. Figure 3.12 shows the sustainable residue removal rates assuming 20% removals. This may be conservative as British Columbian agriculture may be less susceptible to erosion than U.S. farming, but we have not yet confirmed this with data. The total sustainable residue availability would then be 85 thousand tons, although additional work would be required to determine viable farm gate prices. It seems unlikely that British Columbia would sustain a commercial scale cellulosic ethanol plant on agricultural residues alone. Additional annual agriculture production data is also available from the Statistics Canada database (Statistics Canada, 2014b).

Table 3.9. Estimated residue production for key crops in British Columbia

	2011 AREA (ha)	2011 YIELD (t/ha)	HI (RESIDUE TO GRAIN RATIO)	MOISTURE CONTENT	TOTAL RESIDUE PRODUCTION (DRY t)
Barley	26,500	3.3	2	15%	110,000
Corn (grain and silage)	300	8.9	1	16%	2,500
Oats	35,200	2.9	2	14%	180,000
Spring wheat (including durham)	33,300	3.0	1	14%	110,000
Winter wheat	1,600	3.0	2	14%	7,100

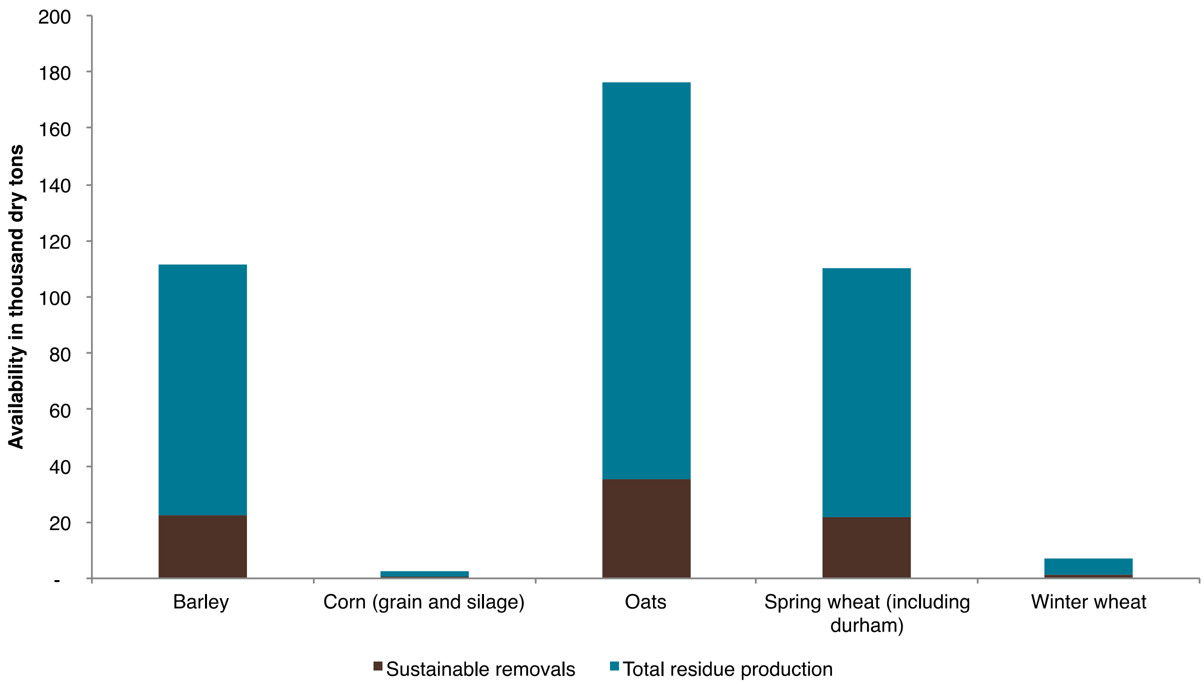


Figure 3.12.Total residue production and sustainable removal rates in British Columbia

3.2.5. LMC International: Current and future supply of RFS2 qualifying and non-qualifying oils and fats for biofuels

The supply of cellulosic biomass is important in the context of cellulosic biofuel production, but for the production of biodiesel and hydrotreated vegetable oil (HVO) the availability of vegetable oils is much more important, and in particular waste and by-product oils that can be used to produce lower carbon intensity fuel. The LMC International (2013) report commissioned by the National Biodiesel Board assesses global production of animal fats, inedible corn oil, and waste grease (used cooking oil or “yellow grease”). U.S. supply of animal fats, which is determined by levels of livestock slaughter, is at about 4 million tons compared to a global total of around 13 million tons by 2018 (Table 3.10) . Inedible corn oil extraction from distillers grains is a relatively new process being increasingly adopted in the corn ethanol industry. By 2018, LMC anticipate a doubling of production from the 2012 level of 800 million tons to over 1.7 million tons. This reflects 93% of all corn ethanol production. Finally, biodiesel can also be produced from yellow grease. The projected 2018 collection of yellow grease in the U.S. is 853 thousand tons. This assumes a slight decline in yellow grease collection rates as a fraction of total cooking oil consumption, in line with historic trends. Adding Europe, China and Canada, LMC estimate a potential yellow grease collection rate of 5 million tons per annum by 2018. There is additional potential for collection of “brown grease” from grease traps in drains, but it is unclear what collection rates might be expected. Finally, LMC also consider the potential availability of camelina oil from camelina grown as a break crop to be grown in rotation with wheat as a fallow alternative. They note that it is exceedingly difficult to predict camelina cultivation with confidence, but believe that an annual supply of 700 thousand tons may be possible by 2020.

Table 3.10. Availability of biodiesel feedstocks from wastes, residues and cover crops

FEEDSTOCK	POTENTIAL U.S. SUPPLY (THOUSAND METRIC TONS)	APPROXIMATE BIOFUEL POTENTIAL (BGAL)
Tallow	4,000	1
Inedible corn oil	1,700	0.5
Yellow grease	853	0.2
Camelina	700	0.2

3.3. Cellulosic biofuel plant deployment rate

3.3.1. Plevin, Mishra and Parker, Comments to the EPA on the 2014 volume rule

Plevin et al. (2014) submitted comments to the EPA relating to the production that might reasonably be expected from new cellulosic biofuel facilities during the year 2014. They hypothesize that as all cellulosic biofuel facilities can currently be treated as “first of a kind”, it is reasonable to assume that they will not be able to run successfully at full nameplate capacity upon completion. Rather, following on from work by the National Renewable Energy Laboratory (NREL, 2013) that in turn refers back to a 1981 RAND Corporation study of performance at new chemical plants, they assume that complicated new processes will take some time to bring to full capacity. RAND (Merrow et al., 1981) developed an equation for capacity in the second six months after completion, based on analysis of 44 chemical process plants using new technologies, and both NREL and Plevin et al. have applied this equation to the case of cellulosic ethanol. Based on this, they expect performance in the range from 5 to 50% of nameplate capacity in the second six months of operation, depending on technology pathway and level of optimism applied. The results are most favorable to Fischer-Tropsch (FT) technologies, then pyrolysis technologies, and then biochemical ethanol.

In addition to considering “process risk”, Plevin et al. propose distributions to represent feedstock risk, and risk of delay in startup. The former term reflects the possibility that a plant may have to rest inactive temporarily for lack of feedstock, while the latter is based on the reasonable observation that new plants do not always become operational on the pre-announced date. Based on this analysis, they conclude that the likely deployment of cellulosic biofuel in 2014 was 10.3 million gallons, although they are careful to point out that their priority is the methodology rather than the outcome, and encouraged EPA to consult additional experts to find the right parameters for the model.

3.3.2. Example of corn ethanol – EIA data

Corn ethanol has been suggested (e.g., UC Davis NextSTEPS biofuel report) as an example of technology deployment and production ramp up that could be used for the case of cellulosic fuels. Figure 3.13 shows the historical level of ethanol production in the U.S. since 1995, and several curve fits approximating the line. Ethanol production increased rapidly, especially from 2000 onwards, but has now leveled off (since about 2010) as the blend wall approaches. The growth in corn ethanol production represents growth in a market with clear and relatively certain policy support through policies like the Volumetric Ethanol Excise Tax Credit (VEETC) and the RFS. It is growth in an industry that uses a technology already developed and demonstrated well before 2001, and where the capital expenditures are significant, but modest compared to those required for the expected cellulosic biofuel technologies. It is important to be aware of these differences when considering the applicability of the experience of the first generation (1G) corn ethanol market for the prospective second generation (2G) cellulosic market.

Four fits to the data are shown on the graph below – two exponential and two quadratic. The fits are shown for the two periods, 1991-2010 and 2001-2010. The fit varies significantly depending on how many and which years of data are used; including the earlier years of production would give a lower expected growth rate by the end of the period. The more recent years since 2010, where growth has been curtailed by the blend wall, were not included in the fit. The exponential fit from 2001-2010 gives an annual growth rate in production of 26%, starting at 1.8 billion gallons. The longer exponential fit from 1990 gives an annual growth rate of 15%. For comparison, the annual average rate of growth implied by the Biofuel Digest data from 2013 to 2018 would be about 33%.

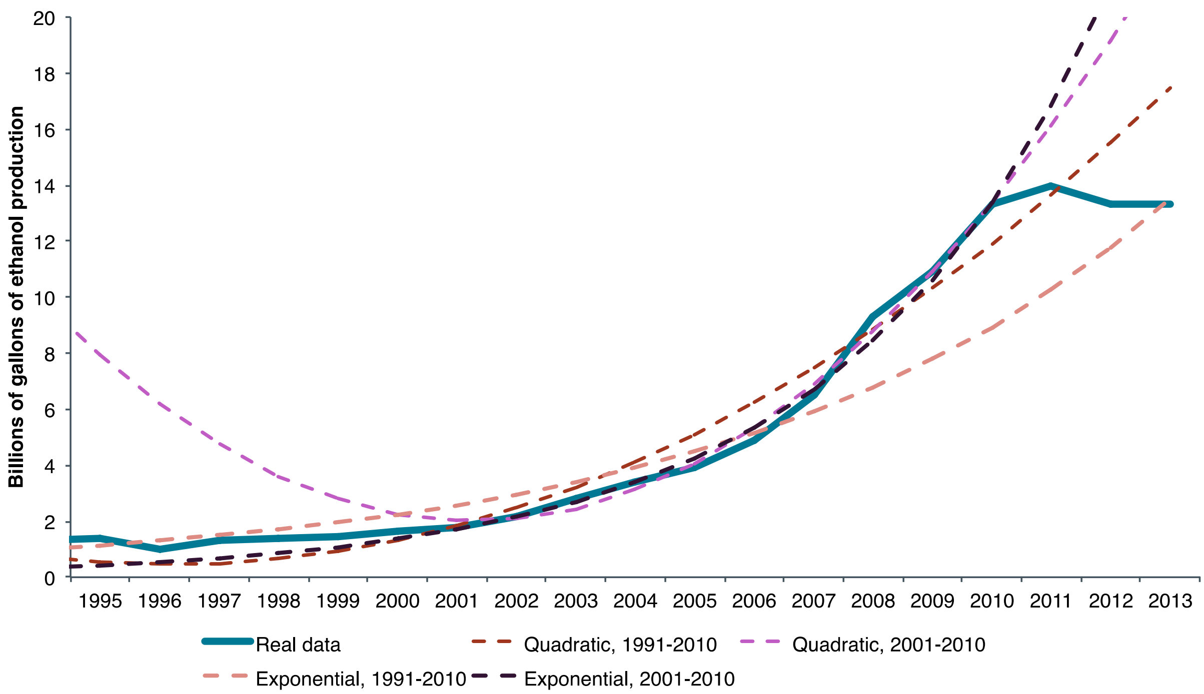


Figure 3.13.Rate of increase in U.S. corn ethanol production, 1995 - 2013

3.4. Consumption of E85 in flex-fuel vehicles

The use of E85 (a blend of 51-83% ethanol in gasoline) in Flex-Fuel Vehicles (FFVs) can increase the capacity of the Pacific region's vehicle fleet to consume biofuels. FFVs have minor technical adjustments compared to conventional gasoline vehicles that allow them to tolerate any concentration of ethanol in gasoline, including metal and elastomeric materials resistant to corrosion, a higher fuel system capacity to offset the lower energy density of ethanol, and a sensor in the fuel line that measures alcohol concentration (Heisner, 2008).

FFVs cost around $100 more per vehicle to manufacture compared to a non-FFV of the same model (Reuters, 2010; Hess, 2007). Through 2016, automakers receive additional credits from selling FFVs to comply with EPA's greenhouse gas standards (U.S. EIA, 2012). Despite the higher cost of manufacture this incentive has effectively driven increased sales of FFVs in recent years; for example, General Motors (GM) has announced that half of its new cars sold in 2015 will be FFVs (Green Car Congress, 2010).

However, to date FFVs in the U.S. have consumed relatively little E85: in the past three years, only 1-3% of the fuel consumed by FFVs has been E85 (Table 3.11; U.S. EIA, 2014a). This is likely in part because many FFV owners are not aware that they drive a FFV (AFDC, 2013).

Table 3.11. Number of Flex-Fuel Vehicles (FFVs), consumption of E85, and use of E85 in FFVs in the U.S. in 2011-2013 (EIA, 2014).

[FILL IN?]	2011	2012	2013
FFV stock (millions)	9.94	11.38	12.82
E85 (million gallons)	25.4	132.0	175.8
% of FFV miles driven on E85	0.6%	2.5%	3.0%

3.4.2. U.S. EIA Annual Energy Outlook 2014

The U.S. Energy Information Administration (EIA) is the main source in our literature review that provides clear projections for E85 consumption and FFV stocks to 2020 and 2030. Other studies that discuss the response of E85 consumption to price and other relevant factors are discussed later.

3.4.2.a. National level EIA projections

Using the National Energy Modeling System (NEMS), EIA's Annual Energy Outlook 2014 projects growing consumption of E85 to 2020 and 2030, but not to a level that would enable the original RFS targets to be met. Interestingly, EIA has dramatically changed its forecast of E85 consumption in its 2012, 2013, and 2014 Annual Energy Outlooks (Figure 3.14) and does not discuss the reasons behind these changes in the report apart from declining projections of total gasoline consumption. Projected E85 demand in 2035, for instance, was far lower in the AEO 2013 compared to the AEO 2012, and the latest AEO 2014 projection is somewhere in the middle.

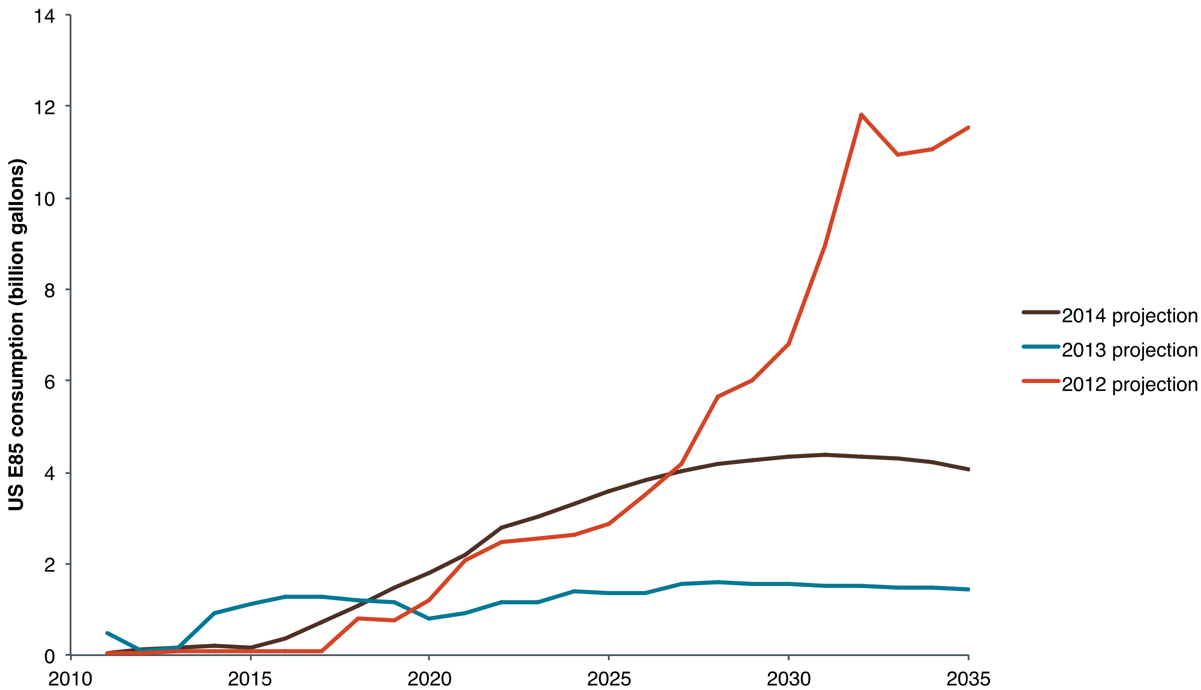


Figure 3.14. Projected E85 consumption in the U.S. from 2011-2040 according to EIA's Annual Energy Outlooks published in 2012, 2013, and 2014

EIA similarly projects increasing FFV stocks in future decades, and has also substantially changed this forecast between its 2012, 2013, and 2014 projections (Figure 3.15). As with E85, projected FFVs stocks decreased from the 2012 AEO to the 2013 AEO, with stocks in the 2014 AEO about halfway in between. EIA projects the fraction of FFV miles driven on E85 to increase sharply after 2015 to a maximum of about 60% around 2030, and to decrease thereafter (Figure 3.16). This expected decrease in E85 miles per FFV is consistent with the projected decrease of E85 consumption overall from 2030 to 2040. FFV stocks do not follow this same decrease (Figure 3.15), perhaps because the average turnover rate of vehicle stock is several years.

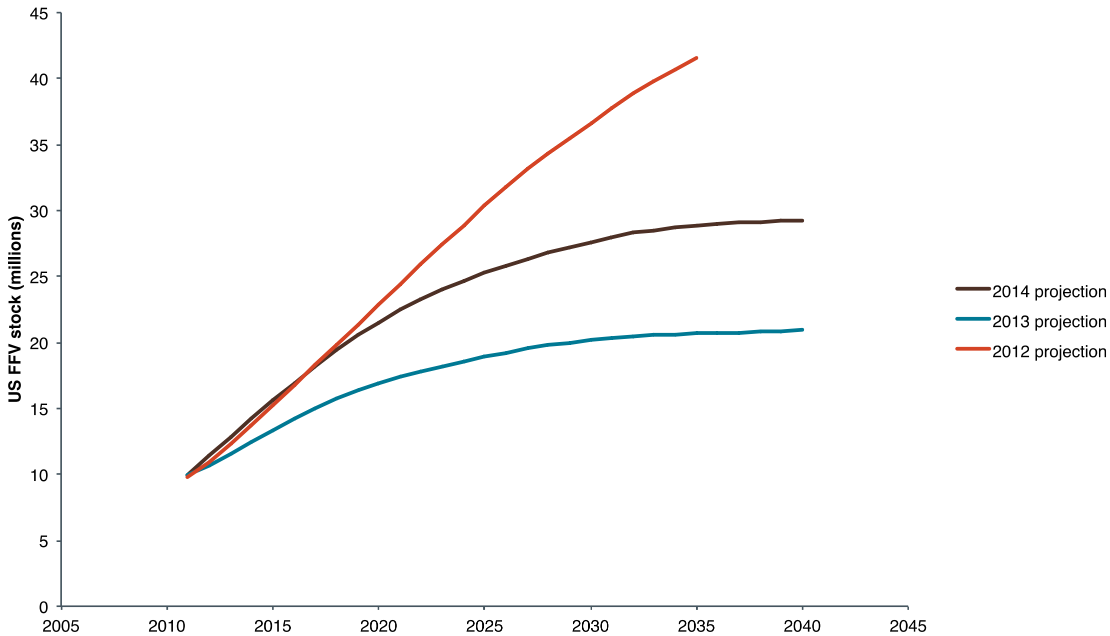


Figure 3.15. Projected FFV stocks in the U.S. from 2011-2040 according to EIA's Annual Energy Outlooks published in 2012, 2013, and 2014

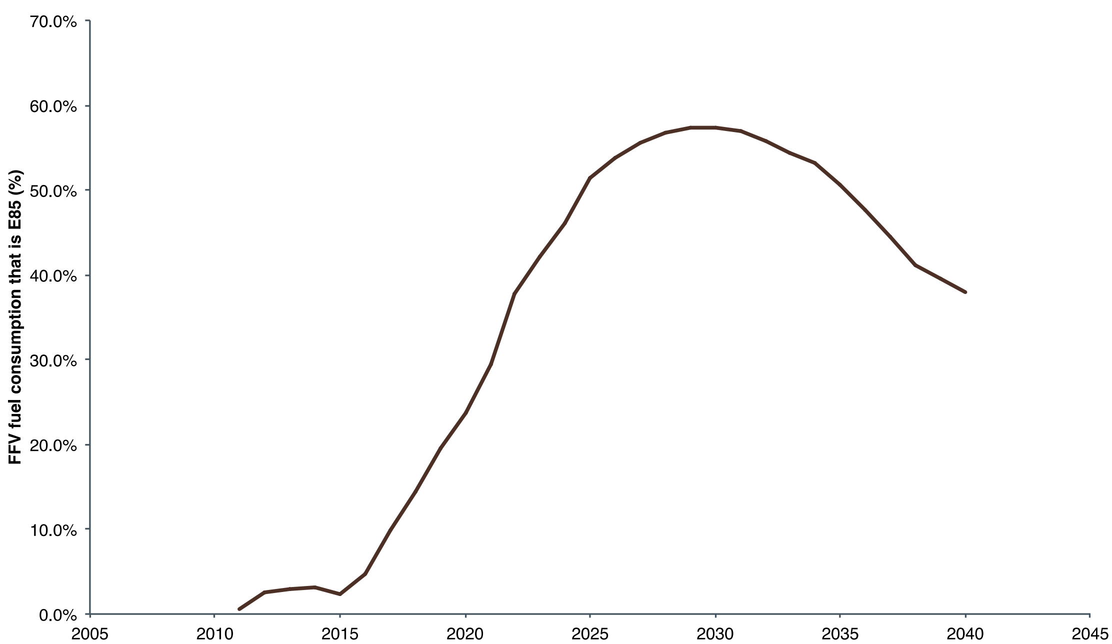


Figure 3.16. Fraction of fuel consumed by FFVs that is E85 (on an energy equivalent basis) in the U.S. from 2011-2014 (EIA, 2014)

3.4.2.b. EIA projections for the Pacific region

For some parameters, EIA offers projections specific to certain U.S. regions. Their Pacific region is defined as California, Oregon, Washington, Hawaii, and Alaska. EIA forecasts slightly different trends in E85 consumption and FFV sales in the Pacific region compared to the nation as a whole. The percentage of national FFV sales expected to occur in this region increase slightly from the present to 2035, and the percentage of national E85 gallons expected to be consumed in the Pacific rises from about 10% in 2012 to over 25% in 2017, and decrease and then level off thereafter (Figure 3.17). Why consumption of E85 is expected to rise faster than FFV sales in the Pacific region in particular is not explained in the report.

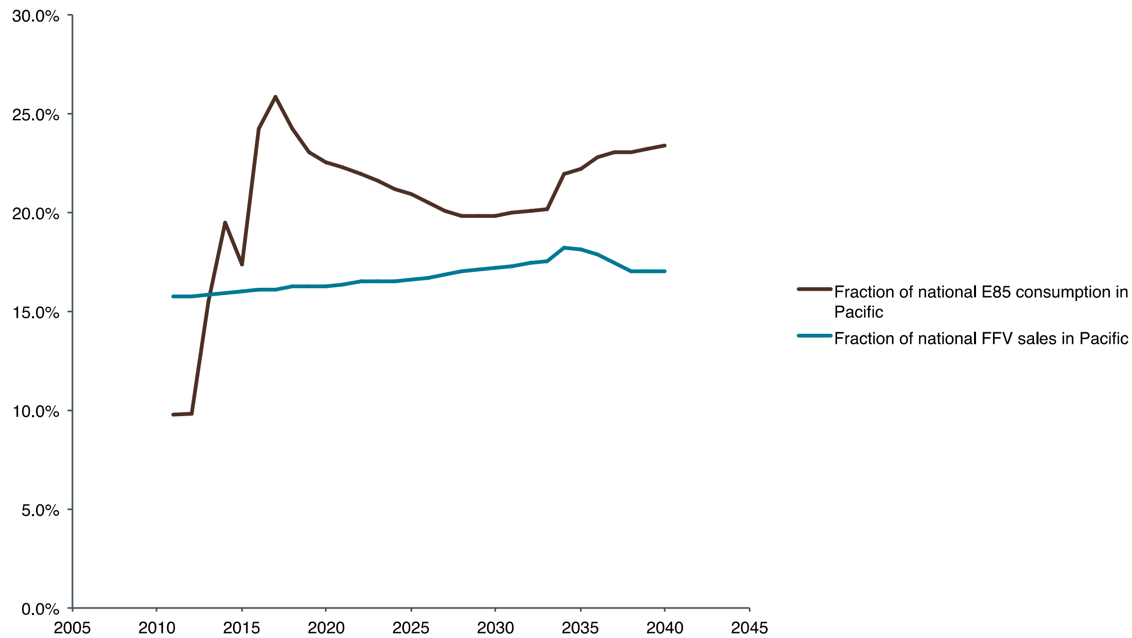


Figure 3.17. The percentage of national E85 consumption and FFV sales that occur in the Pacific region in the 2014 EIA AEO

Regional data that would allow the calculation of total fuel consumption by FFVs in the Pacific region (vehicle miles driven, fuel economy, and FFV stocks) was not available. Assuming each FFV in the Pacific region has the same fuel economy and drives the same number of miles per year as the national average, and that the ratio of FFV sales to stocks is the same in this region as nationally, the percentage of total FFV miles driven on E85 can be estimated for the Pacific (Figure 3.18). EIA expects Pacific FFV drivers to fill up on E85 slightly more frequently than the national average. It should be noted that these results would be different if Pacific vehicle owners drive more or less than the national average or tend to purchase vehicles with lower or greater fuel economy.

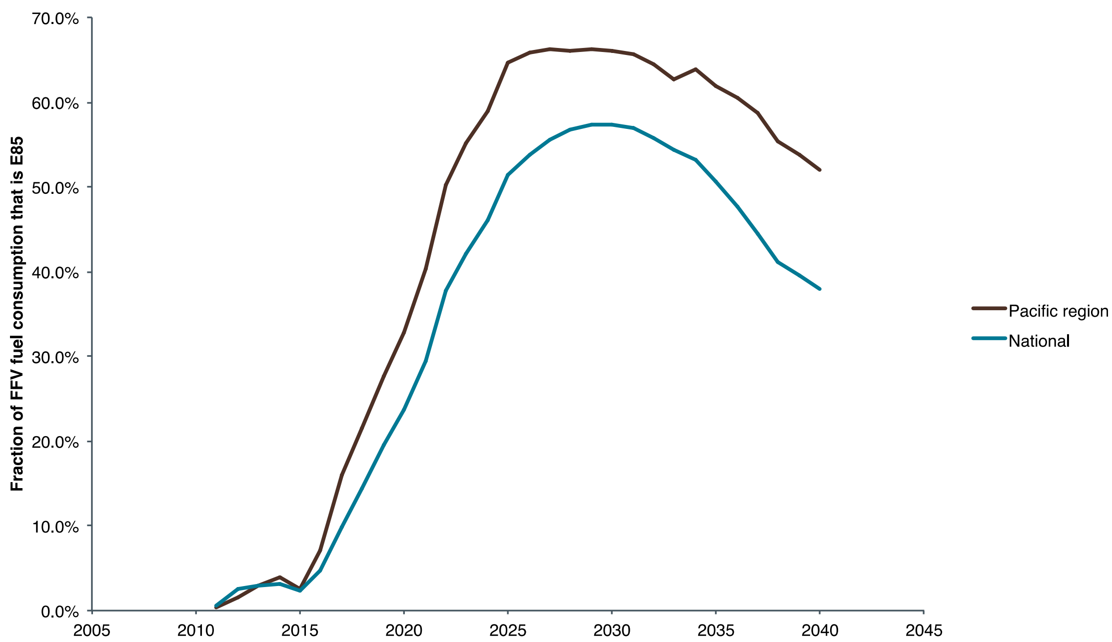


Figure 3.18. Estimated fraction of fuel consumed by FFVs that is E85 (on an energy equivalent basis) in the Pacific region compared to the national U.S. from 2011-2014 (EIA, 2014).

3.4.3. Fuels Institute (2014)

The Fuels Institute report reviews the EIA forecasts detailed above, and then presents a new forecast based on EIA's FFV projections combined with the average of AFDC, Growth Energy, and Renewable Fuels Association projections on the number of fueling stations that will sell E85 to 2023. These sources project on average just under 8,000 E85 stations in 2020, compared to around 3,000 today. The Fuels Institute then applies five different scenarios of E85 sales per station to estimate nationwide E85 sales:

1. NACS-CSX Scenario: a 70% increase in average per-station E85 sales as reported by NACS-CSX by 2023

2. Top 10 Store Scenario: 2023 per-station E85 sales 70% higher than today's top 10 selling stations (about 8 times greater than average sales today)

3. Top Quartile Store Scenario: 2023 per-station E85 sales 70% higher than today's top quartile of E85 stations (about 4 times greater than current average sales)

4. Average Store Scenario: a 70% increase in average per-station E85 sales within the entire Fuels Institute dataset (about double the NACS-CSX scenario)

5. Bottom Quartile Scenario: 2023 per-station E85 sales 70% higher than today's bottom quartile of E85 stations (about 4 times greater than current average sales)

The results of these scenarios are shown for 2020 and 2023 in Table 3.12.

Table 3.12. Projected national E85 consumption in 2020 and 2030 in each of the five scenarios in the Fuels Institute report

SCENARIO	PROJECTED E85 CONSUMPTION IN 2020 (MILLION GALLONS)	PROJECTED E85 CONSUMPTION IN 2023 (MILLION GALLONS)
NACS-CSX Scenario	300	570
Top 10 Store Scenario	2,400	4,400
Top Quartile Store Scenario	1,200	2,200
Average Store Scenario	610	1,100
Bottom Quartile Scenario	260	400

3.4.4. IEA 2013 World Energy Outlook

The International Energy Agency (IEA) is more optimistic than the U.S. EIA in overall ethanol consumption in the U.S. in its 2013 World Energy Outlook (IEA, 2013) the IEA projects 1.2 mboe/d (million barrels of oil equivalent per day) ethanol consumption in the U.S. compared to approximately 0.7 mboe/d projected by the EIA (calculated from a forecast of about 14 billion physical gallons). It is not clear if IEA's higher ethanol projection is due to a higher projection of gasoline consumption in the U.S. or an expectation of increased consumption of higher blends of ethanol such as E85.

3.4.5. Studies on the sensitivity of E85 consumption to price

E85 consumption is widely thought to respond to price: more people should buy E85 more frequently if it is cheaper than E10 on an energy equivalent basis. The response of E85 sales to the price differential between E85 and gasoline has been investigated in a handful of studies. These are briefly reviewed below. It is not possible to use these studies to project future consumption of E85 without making assumptions about future fuel prices.

3.4.5.a. Babcock and Pouliot (2013)

This study was aimed at forecasting the level of price support that would be necessary to incentivize consumers to purchase varying levels of E85 on a national scale in the near term (2014-2015). It uses the national number of FFVs and their driving distance to an E85 station to estimate the FFV fleet that currently has access to E85, and relies on earlier work by Pouliot (2013) that estimates the price sensitivity of E85 consumption in Brazil. Babcock and Pouliot (2013) assume the same price sensitivity exists in the U.S., although it should be noted that Brazilian consumers likely have greater awareness of E85 than U.S. FFV drivers (see section 4.4 "Consumption of E85 in flex-fuel vehicles"). The authors apply this price curve to the current FFV fleet with access to E85 to estimate the price discount compared to E10 necessary for the consumption of up to 4 billion gallons of E85 in 2015. The authors model the production price of ethanol (it should be noted that this is lower than actual ethanol prices in recent years) and then calculate the necessary level of price support (through RFS Renewable Identification Numbers) to close the gap between production cost and retail price.

3.4.5.b. Pei and Parker (2013)

This study models E85 demand at varying E85 price in 2015 and 2020. Like Babock and Pouliot (2013), this study takes into account current spatial availability of E85 in the U.S. It constructs price response curves based on a previous study in which people were interviewed about their willingness to use a cheaper fuel that is less available. This response curve is fairly steep; for instance, in the reference scenario in 2020, this study projects E85 demand would be around 12 billion gallons at $1.80/gallon (price at terminal) with almost no demand at all at $2.40/gallon. The authors note that at some level of price support, E85 consumption would be constrained by FFV numbers.

3.4.5.c. Liu and Greene (2013)

This study describes the price response of E85 consumption using an econometric analysis based on available data on historical E85 prices and sales, mostly from the state of Minnesota. It models a “learning process” whereby consumers initially believe E85 to have the same energy density as E10, but gradually learn through experience that E85 has a lower energy density, and consequently require a greater price discount for E85 over time.

3.5. Electric-drive vehicles

3.5.1. Jin et al., Evaluation of state-level U.S. electric vehicle incentives

Electric vehicle (EV) deployment is being driven by a multitude of factors, including the increased availability of plug-in electric vehicles, financial incentives, increased consumer awareness, increased public infrastructure, and vehicle regulatory programs. In “Evaluation of state-level U.S. electric vehicle incentives,” Jin et al. (2014) quantified the impact of U.S. state-level policy to reduce the effective cost of electric vehicle ownership to increase sales of plug-in hybrid and battery electric vehicle. As shown in Figure 3.19, the study found that the three U.S. states in this study – California, Oregon, and Washington – were among the 2013 leaders in electric vehicle sales deployment with about 2 to 4 times the national U.S. average electric vehicle share.

3.5.2. California ZEV Program

The Zero Emission Vehicle (ZEV) program was introduced by the California Air Resources Board (ARB) with the goal of contributing to aggressive long-term greenhouse gas (GHG) reduction goals for passenger cars and light-trucks. The latest major ZEV program amendments, made in 2012, require wider commercialization and greater deployment of ZEV technology through 2025. The ZEV requirements are estimated by CARB to be met with the deployment of up to 15% of new 2025 sales being some form of ZEV technology, including fuel cell vehicles (FCVs), battery electric vehicles (BEVs), and plug-in hybrid electric vehicles (PHEVs) (CARB, 2012b). The precise sales share, and breakdown of the various ZEV types, is uncertain, based on automaker technology choices and the credits available within the ZEV program per vehicle technology. CARB’s transitional zero emission vehicle (TZEV) category includes PHEVs. Through 2025, California expects to see 1.4 million BEVs, PHEVs, and FCVs cumulatively on California roads. Figure 3.19 shows the projected sales patterns of the various

ZEV types in California from 2018 to 2025. Detailed sales numbers are enumerated in Table 3.13 below.

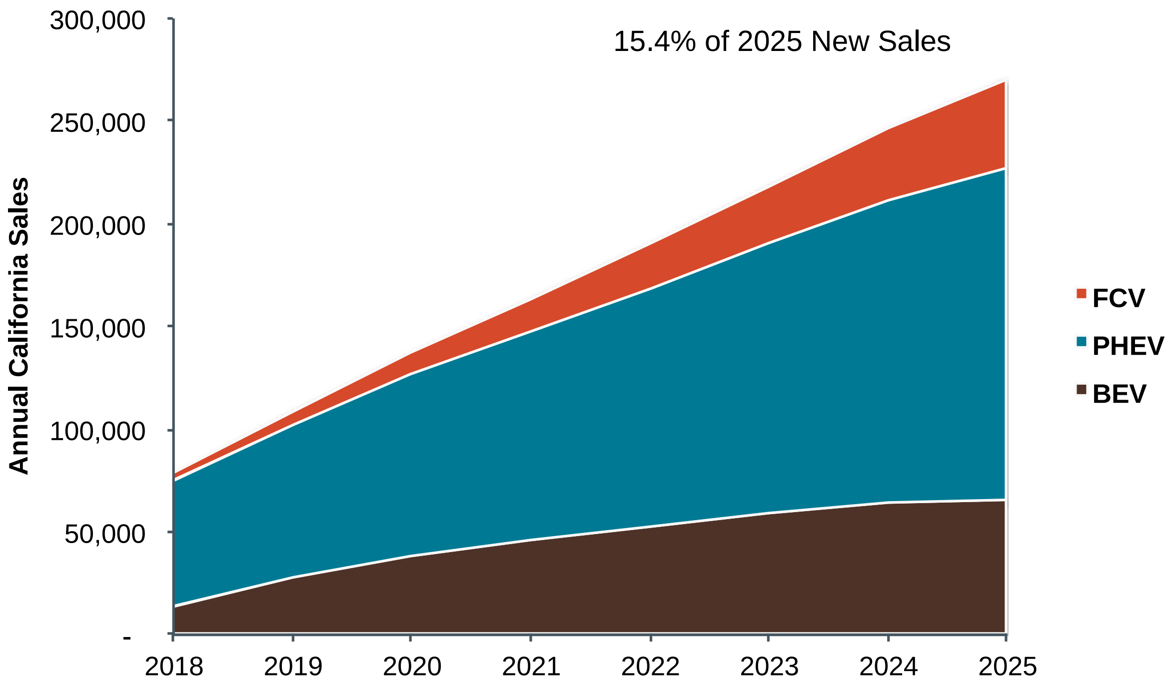


Figure 3.19.Expected ZEV regulation compliance for 2018 through 2025 model years

Table 3.13. Number of ZEV vehicle sales expected annually (rounded to nearest 100)

VEHICLE TYPE	2018	2019	2020	2021	2022	2023	2024	2025	CUMULATIVE TOTAL
FCVs	2,900	6,200	10,600	15,400	21,600	27,800	35,200	43,600	163,300
BEVs	13,900	27,300	37,700	46,300	52,600	59,500	64,200	65,400	366,900
TZEVs	61,300	75,300	89,100	101,900	116,300	131,200	146,900	161,700	883,700
Total Vehicles	**78,100**	**108,800**	**137,400**	**163,600**	**190,500**	**218,500**	**246,300**	**270,700**	**1,413,900**

Oregon is the only other state in the Pacific region that follows California's Zero Emission Vehicle program as part of Section 177 of the Clean Air Act. Oregon is expected to see similar ZEV deployment to California, excluding California's projected increase for hydrogen fuel cell vehicles, due to California's accompanying hydrogen policy and various ZEV program provisions. In addition to the ZEV program, California and Oregon are parties to the complementary eight-state Memorandum of Understanding to implement additional supporting policies (NESCAUM, 2013, 2014)

3.5.3. Greene et al., Transitioning to Electric Drive Vehicles

Greene et al. (2013, 2014) investigated the transition to electric drive (e-drive) vehicles in California and the Section 177 states, as well as in the rest of the U.S., under different assumptions about the potential of alternative vehicle technologies and policy promotions (including the California ZEV program). The study estimated the costs and benefits of this transition under six scenarios using the same model and technology and market assumptions from the recent National Research Council study (2013).

Even under the expected (mid-range) technology development, California and Section 177 states would make a major transition towards electric drive vehicles by 2050, as shown in Figure 3.20. In this scenario, early infrastructure deployment (for PHEVs and HEVs) is assumed along with subsidies or other support policies for ZEVs. When combined with low-carbon electricity, hydrogen and gasoline (4.6 billion gallons or 35% of which is produced thermo-chemically from biomass), both petroleum use and GHG emissions will be reduced significantly. The rest of the U.S. will adopt the similar transition but with a five-year lag, following the success of ZEV program in California and the Section 177 states.

If electric drive technology develops more rapidly (optimistic technology assumptions), the transition to electric drive vehicles will be easier and faster. Figure 3.20 shows the sales projection in California and the Section 177 states under the assumptions of combining both the ZEV program and optimistic technology development. Assuming the rest of the U.S. will not follow the transition policy (with no early hydrogen infrastructure deployment, and no promotion on ZEVs), the underlying optimistic technology assumptions will still successfully drive rapid sales growth of BEVs and PHEVs nationwide. Sales share of BEVs and PHEVs could reach 15 percent of new vehicle sales in both California and the Section 177 states (Figure 3.21), and 8 percent, in the rest of the U.S. (Figure 3.22). In this scenario, it is worth noticing that only California and the Section 177 states will adopt the ZEV programs and deploy the required infrastructure early. Thus, there will be almost no FCVs produced in rest of the U.S. due to lack of hydrogen infrastructure. If instead the rest of the U.S. were to follow the California ZEV program with a five-year lag, FCVs would be expected to take a larger share of the market, especially after 2030.

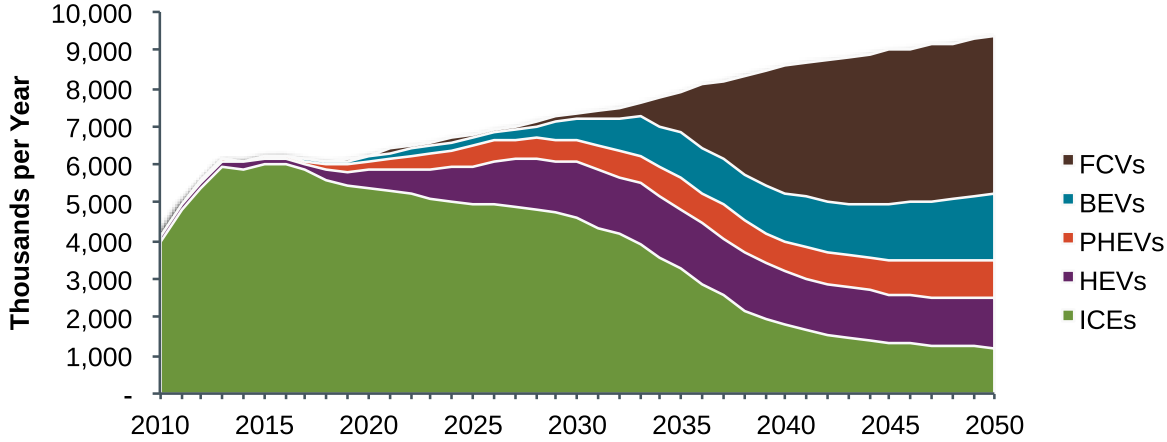


Figure 3.20.Estimated sales by technology in California and the Section 177 States

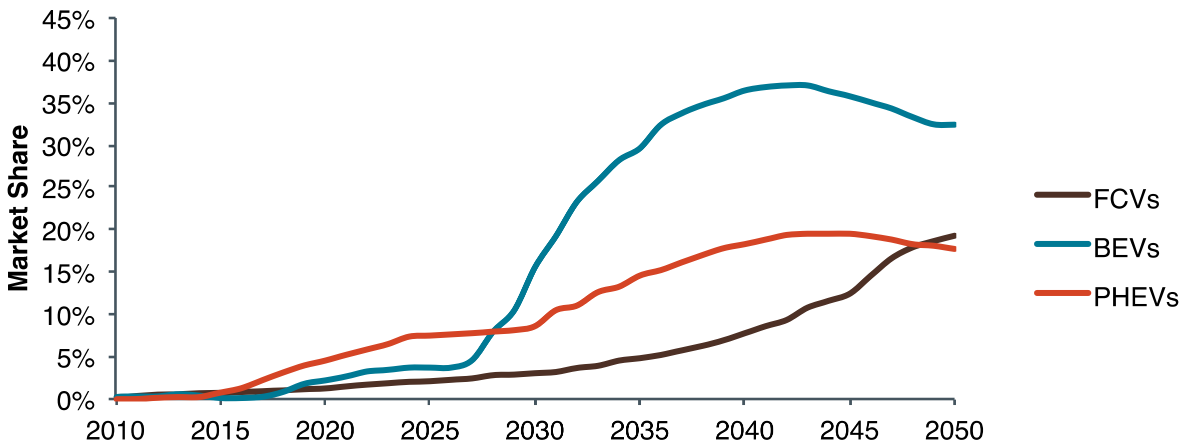


Figure 3.21.Estimated electric drive market in California and the Section 177 States

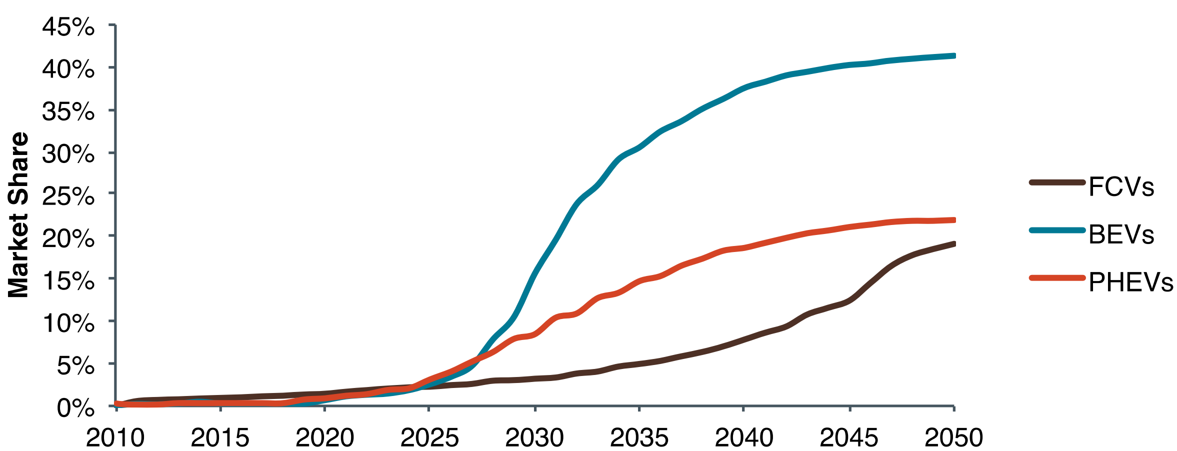
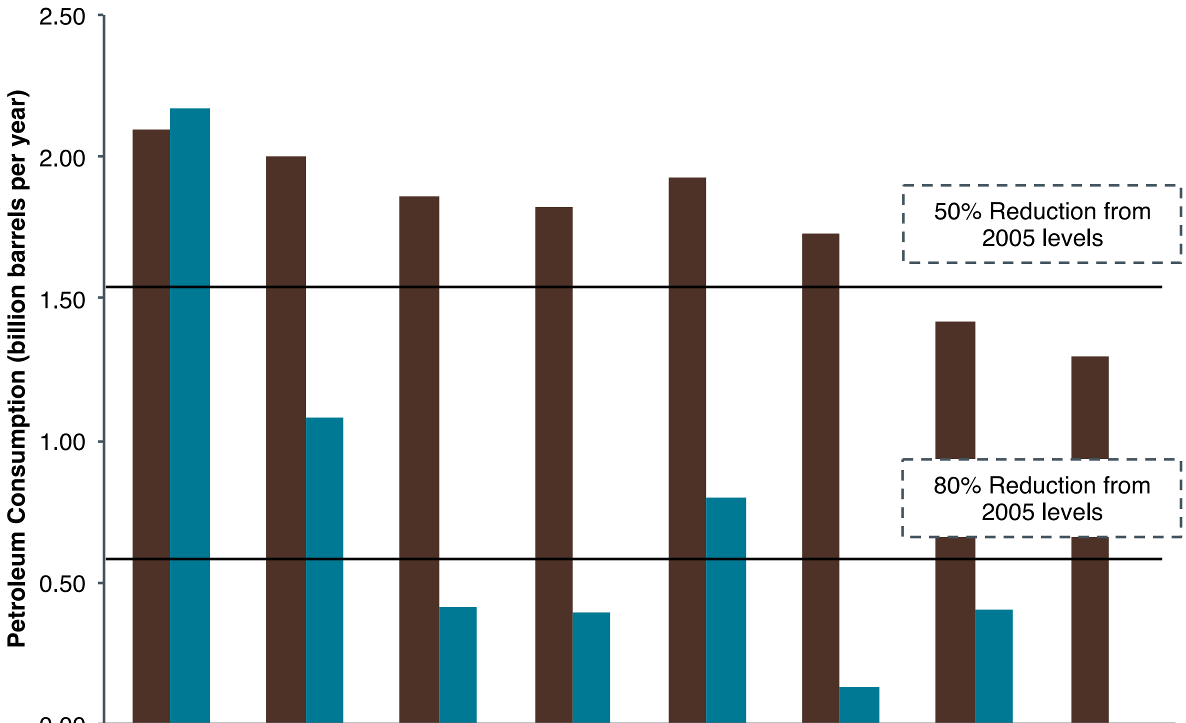


Figure 3.22.Estimated electric drive Market in rest of the U.S.

3.5.4. NRC – Transition to Alternative Vehicles and Fuels

The National Research Council (2013) discusses how the petroleum use of on-road light-duty vehicles (LDVs) in the U.S. could be reduced by 50 percent in 2030, relative to 2005. Four general pathways are discussed: efficient internal combustion engine vehicles (ICEVs), biofuels, electricity (plug-in electric vehicles, PEVs), and hydrogen (FCVs). Projected petroleum usage is shown in Figure 3.23, under the policies emphasizing specific technologies. The study looks into the fuel availability through 2050.

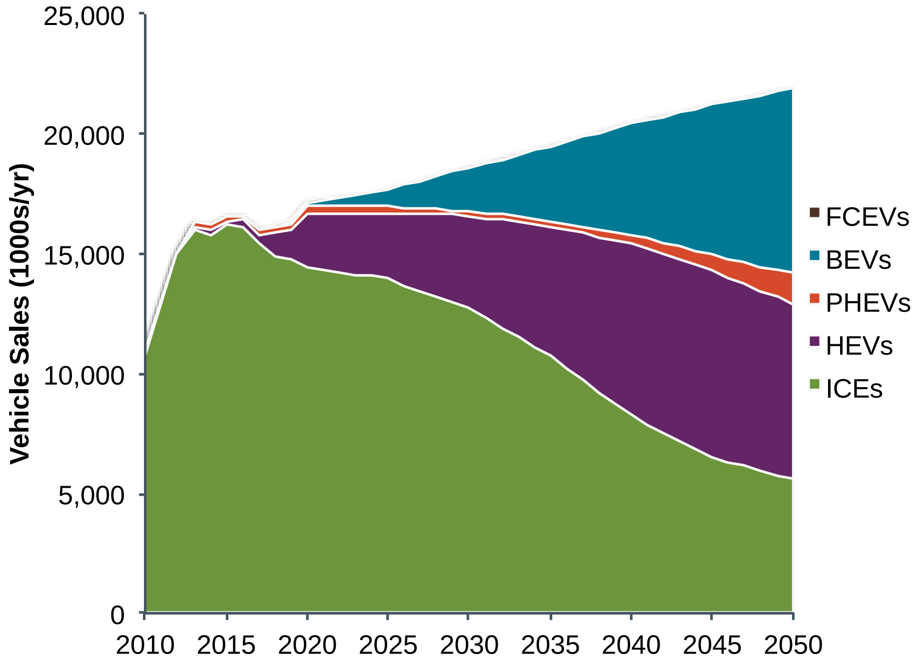
Two of the scenarios achieved the targeted 50% reduction in petroleum use by 2030, the natural gas vehicles ("NGVs") scenario and the combined "PEV+FCV+biofuels" scenario. For the "PEV+FCV+biofuels" scenario, the sales share of FCVs in 2030 is projected to reach 40 percent of total new vehicles, as shown in Figure 3.24. To reach the targeted petroleum consumption reduction, the scenario also assumes subsidies and incentives are available for BEVs, FCVs, and biofuels supplied for ICEVs. Also shown in Figure 3.24, is a case where plug-in electric vehicles are promoted with subsidies, but the BEV share of new vehicles remains at approximately 10 percent in the 2030 timeframe.



	Committee Reference (Current Policies)	Efficiency	Efficiency + Biofuels	Efficiency + Carbon/ Oil Price + Feedbates	Plug-In Electric Vehicles (PEVs)	Fuel Cell Electric Vehicles (FCEVs)	Natural Gas Vehicles	PEVs + FCEVs + Biofuels
2030	2.10	2.00	1.86	1.82	1.93	1.73	1.42	1.30
2050	2.17	1.08	0.41	0.39	0.80	0.13	0.40	0.00

Figure 3.23. Estimated U.S. LDV petroleum use in 2030 and 2050 under policies emphasizing specific technologies

Mid-range technologies and plug-in electric vehicle subsidies



Mid-range technologies and policies promoting BEVs, FCVs, and biofuels

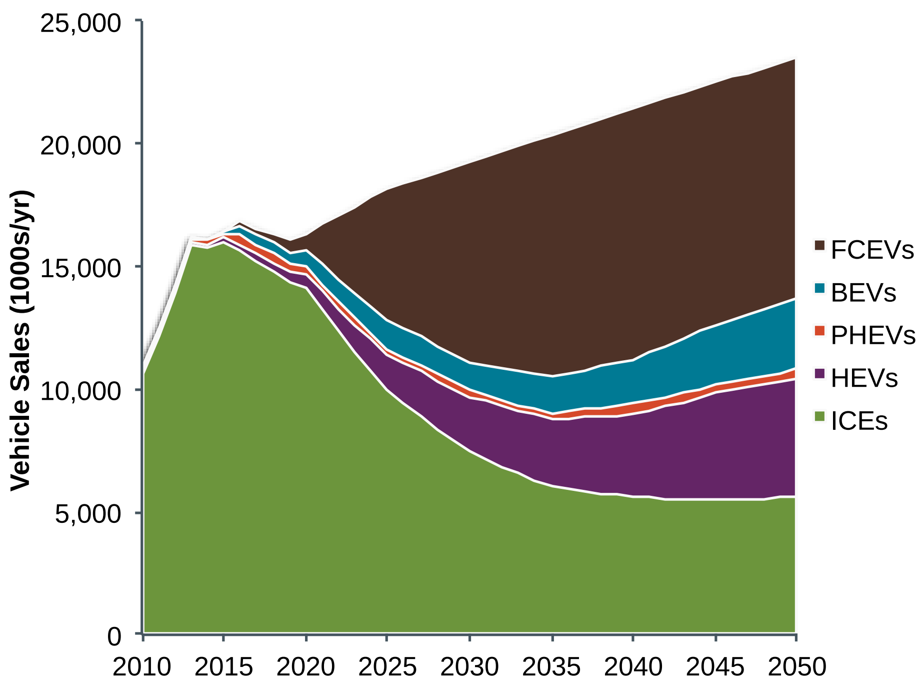


Figure 3.24. Vehicle sales by vehicle technology for midrange technologies and policies, for scenarios that promote the adoption and use of plug-in electric vehicles (top) and all low-carbon vehicle technologies (bottom)

3.5.5. ICF 2013: California's Low-Carbon Fuel Standard – Compliance Outlook for 2020

ICF (2013) analyzes the fuel consumption associated with compliance with the California Low-Carbon Fuel Standard by blending different ethanol, biofuels, and renewable fuels to lower the average fuel carbon intensity. Hydrogen and electricity consumption from minimum vehicle deployment from the ZEV program are estimated from 2013 to 2020, and shown in the Table 3.14. In addition, Table 3.15 shows the ICF results for more aggressive adoption of ZEVs from an enhanced LCFS scenario. Table 3.16 shows the ICF results for LCFS credits that could result from off-road electrification and innovative crude recovery technologies.

Table 3.14. Hydrogen and electricity consumption, minimum ZEV compliance scenario (million gge)

VEHICLE TYPE	2013	2014	2015	2016	2017	2017	2019	2020
FCVs	0	0	1	1	1	2	3	5
BEVs	3	4	7	10	13	19	27	37
PHEVs	7	10	15	20	25	36	51	68
Total	**10**	**14**	**23**	**31**	**39**	**57**	**81**	**110**

Table 3.15. Hydrogen and electricity consumption in ZEVs, enhanced LCFS scenario (million gge)

VEHICLE TYPE	2013	2014	2015	2016	2017	2017	2019	2020
FCVs	1	1	2	5	8	11	15	21
BEVs	5	7	17	26	37	49	67	88
PHEVs	12	19	41	60	82	104	143	184
Total	**18**	**28**	**61**	**92**	**127**	**165**	**225**	**293**

Table 3.16. LCFS credits from off-road electrification and innovative crude recovery technologies

VEHICLE	2013	2014	2015	2016	2017	2017	2019	2020
Off-Road Electrification	609,380	624,368	641,487	677,025	684,570	719,512	726,821	765,276
Recovery credits	-	76,778	153,555	230,333	307,110	409,481	511,851	641,221

3.5.6. Yang (2013): Plug-in vehicles in low-carbon fuel policies

Yang (2013) analyzed several factors related to plug-in electric vehicles and their potential value in low-carbon fuel standards. The report finds that a low-carbon fuel standard is likely to have a limited role in decreasing the carbon intensity of electricity, that the prevailing carbon intensity could result in considerable value for fuel providers and plug-in electric vehicle consumers. Figure 3.25 shows contour lines for the annual value for electricity providers of charging one BEV under the LCFS, as a function of permit price and carbon intensity. As shown in the figure, for the value of carbon permit prices \$100-200 per tonne CO_2e, and for carbon intensities of 20-50 gCO_2e/MJ, the charging of each BEV could represent \$200-500 per year of BEV use. The research also indicates that PHEVs with an electric range of 40 miles could be worth up to $300 per year. This study points out value of BEVs and PHEVs under low-carbon fuel standards. Such value could directly support charging infrastructure, as well as provide an incentive for prospective plug-in electric vehicle consumers.

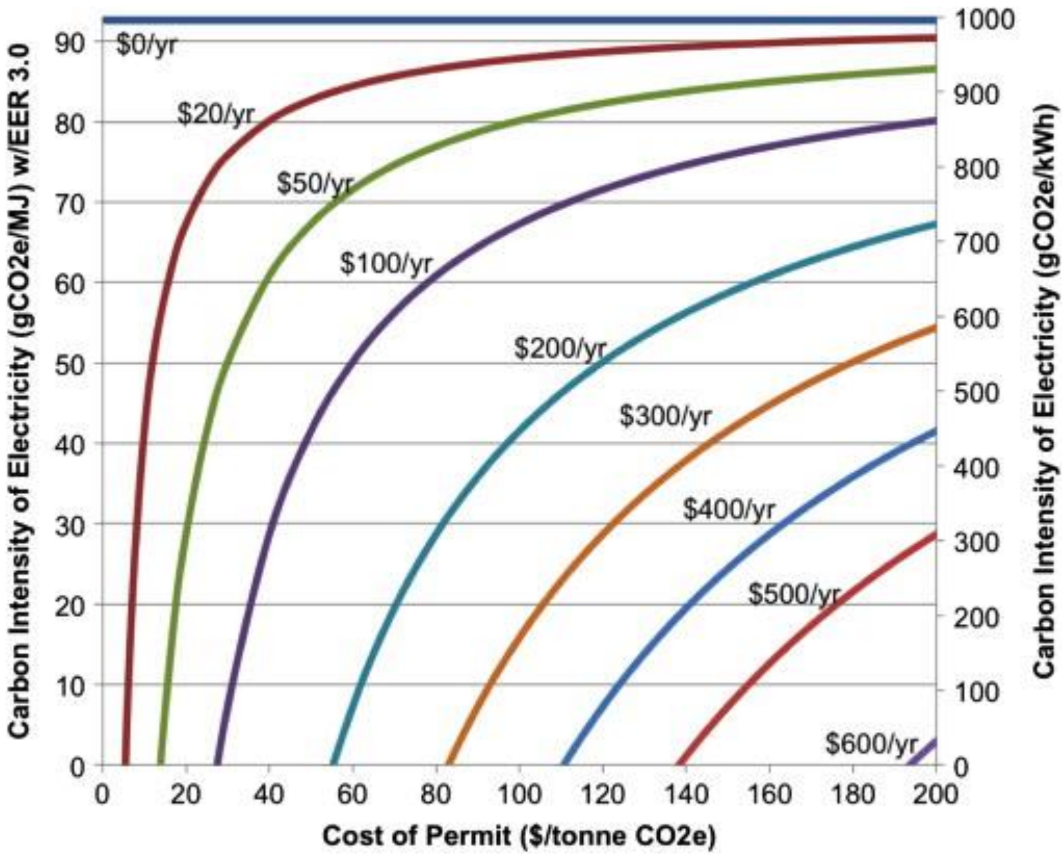


Figure 3.25.Contour lines showing the annual value for electricity providers of charging one BEV under the LCFS, as a function of permit price and carbon intensity

3.6. Natural gas consumption and vehicle deployment

3.6.1. U.S. EIA (2014a): Annual Energy Outlook 2013-2040

The U.S. EIA's Annual Energy Outlook provides the most comprehensive listing of energy production and consumption by transportation fuel that is publically available in the United States. It serves as the basis for many of the studies that have been reviewed for this work. The U.S. EIA AEO (2014) provides data on a large number of energy variables and their trends projected through 2040 for up to 31 different scenarios. These include scenarios for high and low economic growth, high and low oil price, high and low oil and gas resources, among others. Each carries a different set of assumptions that influence projections to 2040, particularly in what concerns deployment of compressed natural gas vehicles (CNGVs). EIA's reference case compares favorably with other agencies projections regarding natural gas. In terms of production, while EIA estimates total production in 2035 to grow to 36.1 trillion cubic feet (tcf), based on internal communications, it also shows that British Petroleum (BP) estimates natural gas production capping off at 35.1 tcf. In terms of natural gas consumption, EIA shows a peak of 30.4 tcf in 2035, which is the lowest projected increase among comparable projections, for example IHS Global Insight (2013) and ICF (2014b) that show domestic consumption growth exceeding net export growth through 2035.

Returning to EIA's scenarios, the main scenario (reference case) assumes that current laws and regulations remain unchanged through 2040. This excludes any future changes in policy directed at carbon emissions or other environmental issues. Other scenarios include such policies and other assumptions. For example, the high oil and gas resource case assumes that the estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the reference case. Similarly, the low oil and gas resource case estimates ultimate recovery per shale gas, tight gas, and tight oil well as 50% lower than in the reference case. Correspondingly, each of these scenarios has different projections in terms of natural gas production. For example, the EIA's estimates all show an increase from 2013 levels – 24.2 trillion cubic feet. The increase to 2040 is 20%, 42%, and 60%, respectively, for the low gas and oil resource case, the reference case and the high gas and oil resource case. Total natural gas supply is not expected to grow as rapidly as production. Even in the high gas and oil resource case, total natural gas supply grows by 25% respective to 2013 levels. Still this compares favorably to oil production figures for the same scenarios and time horizon, confirming expectations of relatively increased natural gas resource availability in the U.S. energy mix over the coming years. Importantly, these figures show production increases primarily concentrated in the years prior to 2025 beginning to slow down.

Other scenarios show a larger range of estimates. To understand the upper bounds of natural gas projections we looked at the high oil price scenario that assumes that growing demand for transportation fuels from non-OECD countries together with slowing oil production will drive Brent crude spot prices to $204.20 (2012 U.S. Dollars) a barrel in 2040. These high oil prices are expected to drive consumption of natural gas and other alternative fuels. Compressed and liquefied natural gas projections to 2030 show a growth of over 6000% from 2013 levels for the high oil price scenario compared to a 520% increase for the reference case – over a 10 fold difference between the two projections. EIA also provides a low oil price scenario that assumes lower demand for oil products from non-OECD countries coupled with increased supply that reduce Brent spot prices at $74.90 (2012 U.S. Dollars) per barrel in 2040. For the same time period, this scenario shows consumption of natural gas (compressed and liquefied) growing by only 17% compared to 2013 levels. Similar trends are visible for total vehicle stock and sales of compressed and liquefied natural gas vehicles.

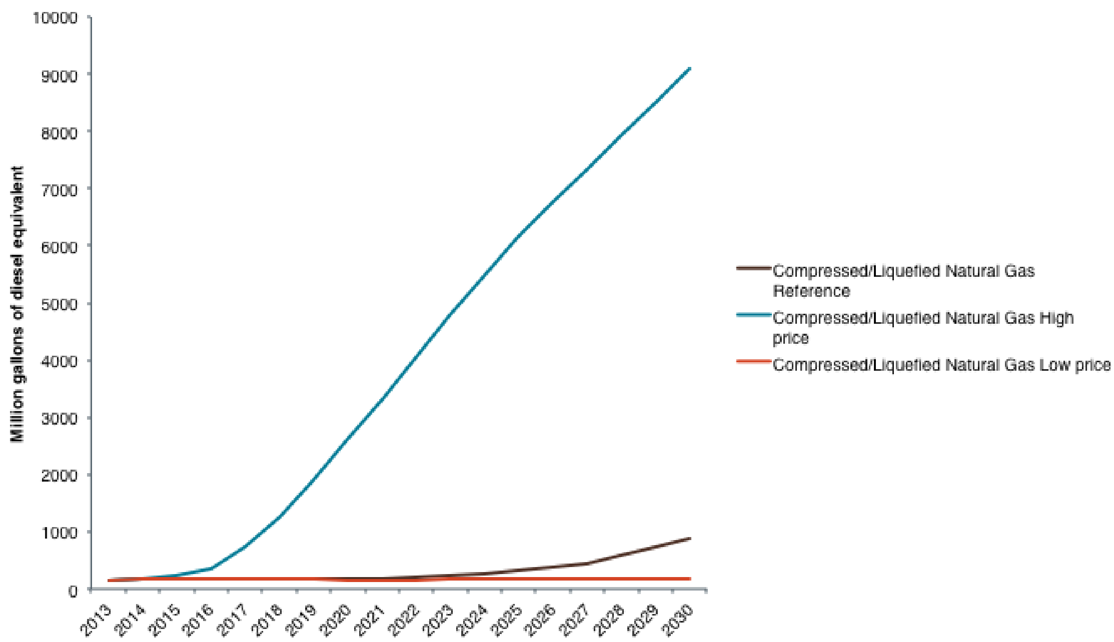


Figure 3.26.Compressed and liquefied natural gas consumption for transportation sector (2013-2030)

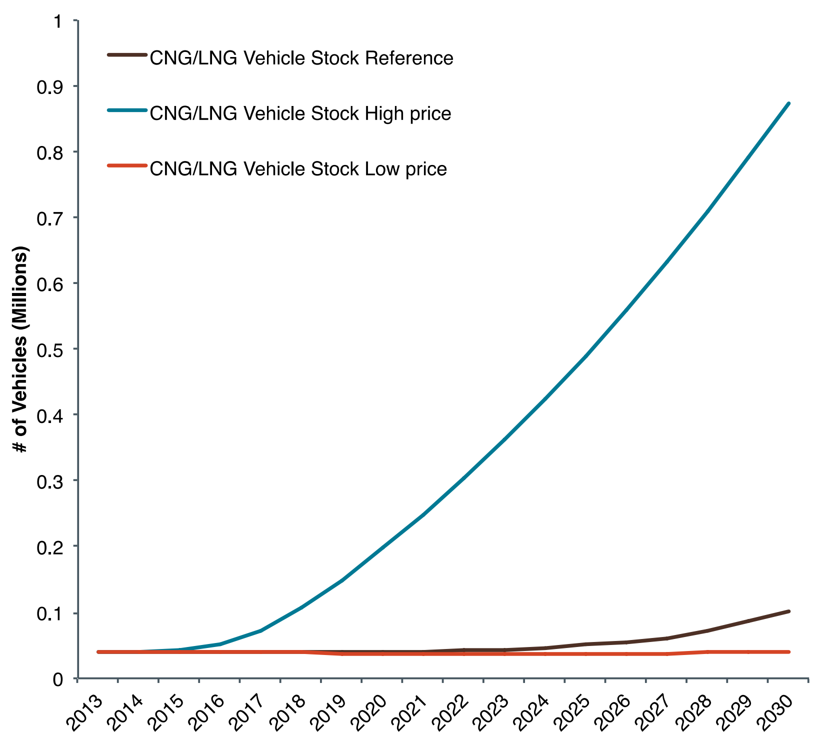


Figure 3.27.Total vehicle stock of compressed and liquefied natural gas vehicles (2013-2030)

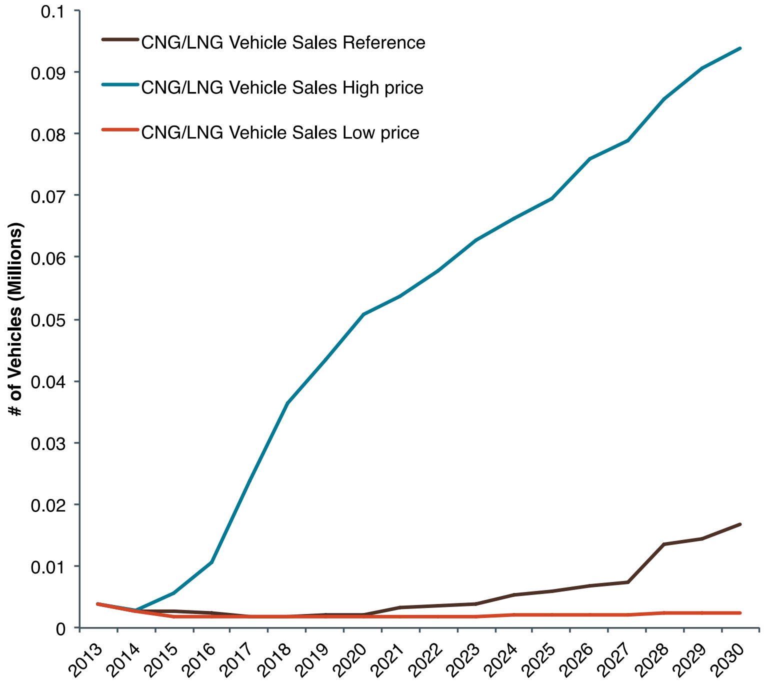


Figure 3.28.Total vehicle sales of compressed and liquefied natural gas vehicles (2013-2030)

In terms of state specific projections, the EIA provides some projections for the Pacific region which includes California, Oregon, Washington, and Alaska. However, this level of aggregation is not available for all scenarios or data points. In this case, and for demonstrative purposes, we can see that for the period 2013-2030, liquefied natural gas is expected to grow from 2013 levels by 214%, 118% and 125% for the reference case, low oil and gas resource, and high oil and gas resource scenarios, respectively. From these projections, it is unclear why energy consumption trends for liquefied natural gas in the transportation sector are intensified for the reference case, even in comparison to the high gas and oil resource scenario. However, the same trend holds true at the national level where liquefied natural gas energy consumption is expected to increase from 2013 levels by 405%, 282%, and 297% for the reference case, low oil and gas, and high oil and gas scenarios respectively.

3.6.2. National Research Council of the National Academies (2013): Transition to Alternative Vehicles and Fuels

As previously mentioned, many studies have based their analysis and projection on the EIA's Annual Energy Outlook. In its 2013 study, the National Research Council (NRC, 2013) looks at the transition to alternative vehicles and fuels in the U.S. with a timeframe extending to 2050. Their projections show different scenarios drafted to meet target reductions of 50% of petroleum use by 2030 and 80% by 2050 and a reduction of GHG emissions of 80% by 2050 for the transportation sector. However, the study is focused on light-duty vehicles that have historically occupied a slow proportion of compressed natural gas consumption in North America. In scenarios looking at gas-to-liquids investment costs in the U.S. to 2030, the study finds initial investments costs on the order of $1,690 per vehicle compared to $810 per vehicle for compressed natural gas. The cost burden for the former is assumed centralized while for compressed natural gas it is distributed to retailers and car owners. Overall, although CNGVs can provide significant reductions in GHG and petroleum use, it is hard to make them cost-competitive. The basis for the CNGV analysis remains the EIA AEO (2011).

3.6.3. TIAX (2014): U.S. and Canadian Natural Gas vehicle Analysis - Comparative Scenario Analysis

Over the last couple of years, TIAX has drafted a number of papers looking at the natural gas industry in the U.S. and Canada for America's Natural Gas Alliance. These studies show estimates of natural gas vehicle use and penetration over the coming years as well as the GHG benefits from increased natural gas use. Similarly, the EIA AEO (2010) is used as the basis for the analysis presented by TIAX. According to their reference case, they expect that by 2035 less than 2% of the total fleet will be Heavy Duty Natural Gas Vehicles (HDNGVs) consuming less than 1% of all fuel consumed by HDNGVs today. In terms of natural gas refueling stations, the reference case predicts an additional 800 units by 2035. However, when using the EIA's 2027 Phaseout Case – which assumes incentives that partially or completely offset incremental vehicle costs, station capital costs, and natural gas costs and expire at the end of 2027 – natural gas vehicle deployment in 2035 is significantly increased. According to this case, by 2035 40% of the HDVs fleet will use natural gas, representing about 15% of all fuel consumed by HDVs. Similarly, over 12,000 compressed natural gas (CNG) stations and 700 liquefied natural gas (LNG) stations are expected to be built by 2035, compared to less than 800 CNG and 61 LNG stations in the reference case. As a marked difference between this and other studies, the TIAX work provides estimates of full time employee (FTE) positions created by additional natural gas stations – 456 FTEs in 2030 for the 2027 Phaseout Case.

3.6.4. National Petroleum Council 2012: Advancing technologies for America's transportation future

The National Petroleum Council (NPC) in response to a request by the Secretary of Energy in 2009, conducted a study on future transportation fuels which would analyze U.S. fuels prospects through 2030 while also providing advice on policy for integrating new fuels and vehicles into the marketplace. In addition, a further request (April 2010) was made to provide insights into ways in which the government could stimulate technology adoption to reduce life cycle greenhouse gas emissions by 50% by 2050 from the US transportation sector. As a result of these requests, the report "Advancing technologies for America's transportation future" was published in 2012. The scope of this study covers a wide range of fossil and biofuels, vehicles modes and technologies, and infrastructure deployment. The timeline for technology adoption was set to 2050 in response to the previously mentioned request. The study also assumes aggressive but not disruptive improvements in advanced fuel-vehicle systems. In order to develop different scenarios for technology adoption, the NPC used the AEO 2010 reference case and includes the use of VISION modeling tools.

For heavy-duty vehicles, the NPC presents results for two scenarios based on high and low oil prices compared against a reference case. Price projections for gasoline and diesel are taken from AEO 2010 low, reference and high oil price projections and extrapolated to 2050. For biofuels, they are assumed to take the price of the fuel they displace. For natural gas prices, these were developed using estimates from AEO 2010 of gas prices and also including provisions for liquefaction, compression, road distribution, dispensing capital and taxes. In turn, the vehicle market share calculation for heavy-duty vehicles is based on three main inputs: (1) vehicle price, (2) vehicle fuel economy and (3) payback decision criteria and payback adoption criteria.

In terms of market share for new vehicles, as shown in Figure 3.29 the NPC results show Class 7&8 combination vehicles reaching 20 percent by 2025 and growing to just over 40 percent by 2050 in the reference case. For the high oil price case, their market share reaches 40 percent by 2025 and leveling out at just under 50 percent by 2050. For Class 7&8 single unit vehicles, as shown in Figure 3.30 the market share is more modest, but still significant. By 2025 it is expected these vehicles reach just under 20 percent of the market share and growing to about 30 percent by 2050. For the high oil case, this market segment grows to about 37 percent by 2025 before leveling off at 40 percent by 2040[8].

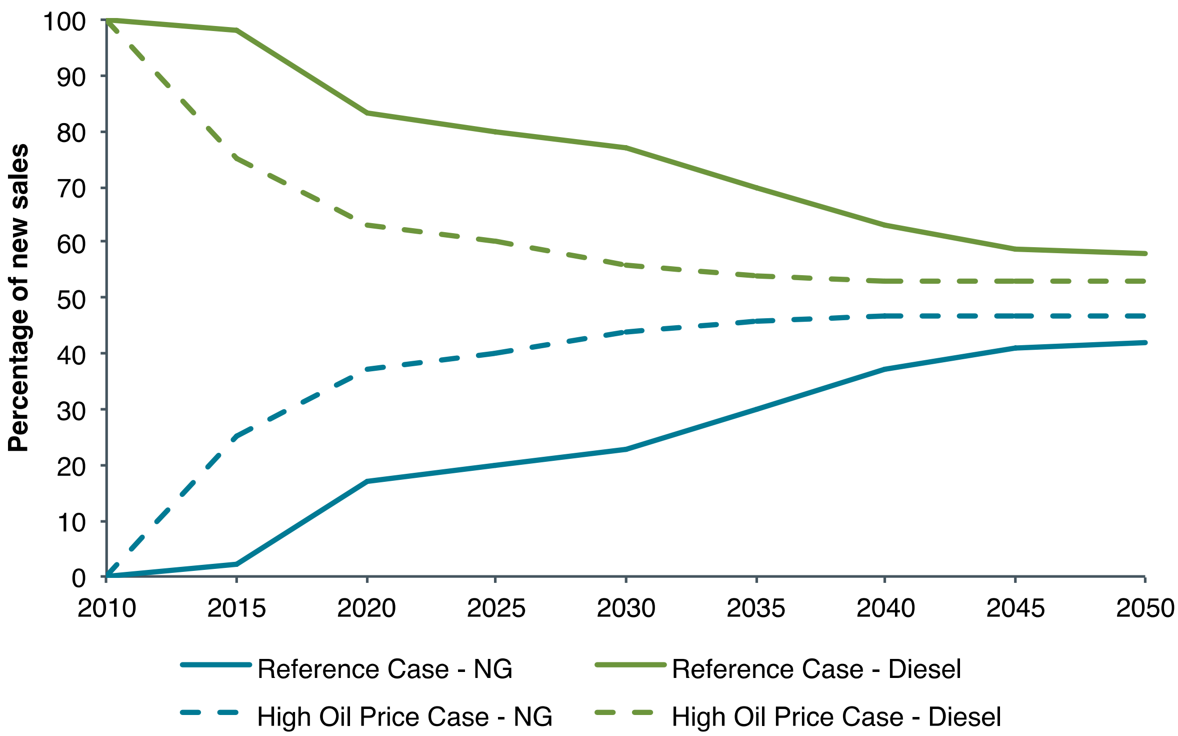


Figure 3.29.Class 7&8 combination market share of new vehicles (2010 - 2050)

[8] Note that for all Class 7&8 vehicles, the NPC study assumes a 50-50 split of spark ignition (SI) and compression ignition (CI) technologies. This can affect market share of natural gas vehicles. For example, a shift towards 100 percent SI engines could increase market share by 10-15 percent while the opposite is true of an equal shift towards CI technologies.

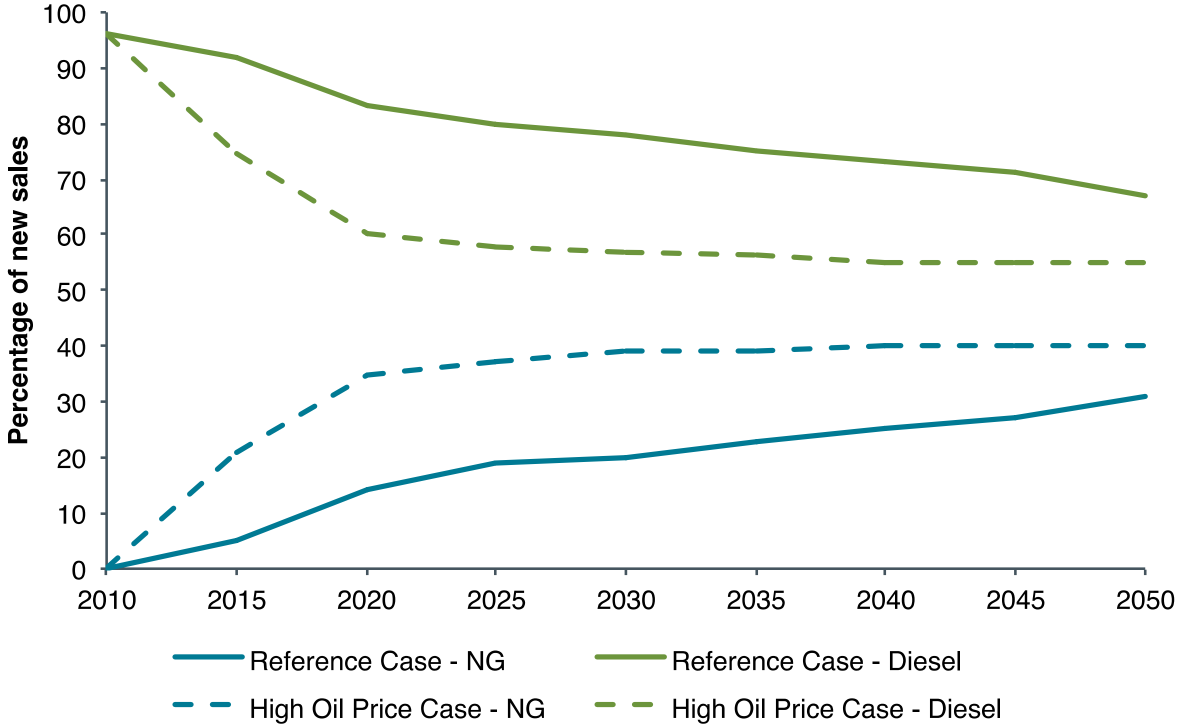


Figure 3.30.Class 7&8 single unit market share of new vehicles (2010 - 2050)

For Class 3-6 vehicles, four different powertrain technologies are included in the NPC market share analysis: (1) gasoline, (2) diesel, (3) diesel hybrids and (4) natural gas vehicles. In the low oil price case, the market share of new Class 3-6 natural gas vehicles remains constant at around 3 percent from 2020 onwards. In the reference case, natural gas vehicles grow to about 17 percent by 2025 before slowing increasing to around 22 percent by 2050. Finally, in the high oil price case, natural gas vehicles reach 27 percent by 2025 before leveling off at around 32 percent by 2050. The reference and high oil price cases are shown in Figure 3.31.

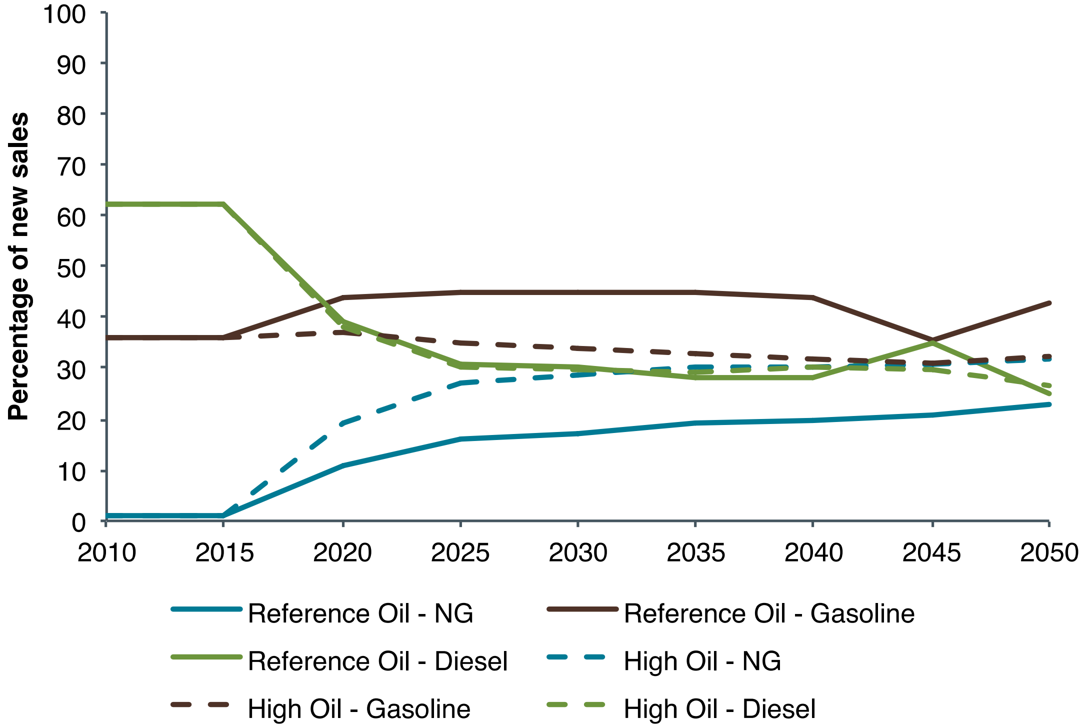


Figure 3.31.Class 3-6 market share of new vehicles – Low oil price case, reference and high oil price case (2013-2030)

Finally, in terms of renewable natural gas (RNG) the NPC estimate that approximately 4.78 trillion cubic feet will be available annually in the 2035 to 2050 timeframe based on analysis of potential organic feedstock inventories from domestic sources. The main source for RNG are energy crops (1.5 tcf) followed by agricultural waste (1.3 tcf) and forestry waste (1.1 tcf). Landfill gas represents around 0.34 tcf and the remaining feedstocks correspond to other gasifiable waste, municipal wastewater and livestock manure.

3.6.5. CARB (2011): Low-Carbon Fuel Standard 2011 Program Review Report

In this LCFS report, the California Air Resources Board (CARB) staff discusses the implementation status of the LCFS and provides insights into different aspects of the program. These include opportunities to further harmonize the LCFS with similar programs within the United States and outside of the country, the ongoing status of LCFS assessments (including technology, lifecycle, economic, and environmental impacts) and most importantly for this exercise, the supply and availability of low-carbon fuels. In estimating the supply of alternative low-carbon fuels, the LCFS report has drafted a number of different scenarios that project the total supply of fuels and vehicle stock to 2020. In terms of natural gas, the CARB includes two different scenarios: the high petroleum demand case (“Natural Gas High”) represents primarily faster economic recovery and low crude prices. The low petroleum demand case (“Natural Gas Low”) represents primarily increases in fuel efficiency and lower alternative fuel prices. In both cases, the California vehicular natural gas consumption is projected to increase due to greater penetration of new vehicles compatible with natural gas or vehicles converted to use natural gas, as well as installation of additional natural gas fueling infrastructure. The baseline provided in this case is 2010 where natural gas consumption from the transportation sector was 125 million gallons of gasoline equivalent. In comparison, the high natural gas scenario shows consumption rising to 207 million gge by 2020 compared to 202 million gge in the low natural gas case.

3.6.6. ICF 2013: California's Low-Carbon Fuel Standard – Compliance Outlook for 2020

In this 2013 report, and in follow up work released in 2014 (ICF, 2014a), ICF present an assessment of the economic and environmental impacts of compliance with California's LCFS out to 2020. The report focuses on the development of compliance scenarios based on market research, consultation with stakeholders, and market forecasts based on best estimates of fuel availability. Their research shows that natural gas consumption will increase rapidly in California. This is due to several factors including the increase in domestic natural gas supply that has helped maintain a favorable price differential between natural gas and diesel. Importantly, the transition to natural gas will also incentivize the use of biogas from landfills and other sources, with a carbon intensity less than 30 gCO_2e/MJ. ICF developed two compliance scenarios in coordination with the Stakeholder Review Panel who developed a third scenario – the LCFS Enhanced scenario. In all cases, there is significant reliance on biofuel blending to achieve compliance. However, Scenario 1 represents a market that is more dependent on advanced vehicle technologies than Scenario 2. In terms of natural gas, Scenario 1 shows a linear increase from 0.3 billion gge of natural gas consumed by the transportation sector in 2012 to 1.2 billion gge in 2020. In Scenario 2, which is more reliant on fuel blending to achieve LCFS compliance, it is expected that natural gas consumption will grow to 0.9 billion gge by 2020. In both cases growth is concentrated in heavy-duty natural gas vehicles that consume up to 10% of renewable biogas. Finally, in the LCFS Enhanced scenario, natural gas consumption grows to over 1.5 billion gge by 2020.

In terms of renewable natural gas potential, the National Renewable Energy Laboratory estimated methane generation potential from landfills (as defined by the EPAs Landfill Methane Outreach Program) to be on the order of 2,454,974 tonnes per year in 2013 (U.S. EPA, 2013a). These resources are obtained from 621 operational landfill gas projects spread throughout the United States. The EPA also estimates that there is large potential to recover landfill gas particularly from those landfills that have gas collection but no associated projects as well as from those that are not mandated to collect and combust liquefied petroleum gas. In the case of California, several of ICFs scenarios for compliance with the LCFS assume that at least 10% of the natural gas used for the transportation sector will be derived from renewable sources.

3.7. Propane

3.7.1. U.S. EIA Annual Energy Outlook (2014a)

Propane has been used as a transportation fuel for over a hundred years in the U.S. as liquefied petroleum gas. It represents a growing proportion of transportation fuel consumption but few studies look into projections for propane usage in the detail available for natural gas and other feedstocks for transportation fuels. That said, the EIA Annual Energy Outlook (2014) provides projections for propane use in the transportation sector. The EIA's projections for propane are less sensitive to high and low oil prices than those for natural gas and maintain a fairly constant rate of growth through 2030. The reference case has propane usage in the transportation sector growing by 55% relative to 2013 levels and reaching a peak of 31.2 trillion Btu (TBtu) in 2030. Relative to 2013 levels, the high oil price scenario grows by 82% to reach 36.7 TBtu in 2030 while the low oil price scenario grows by 22% to reach 24.6 TBtu in the same time period (Figure 3.32). Similar trends are replicated in terms of vehicle stock and sale for propane-powered vehicles, as shown in Figure 3.33 and Figure 3.34.

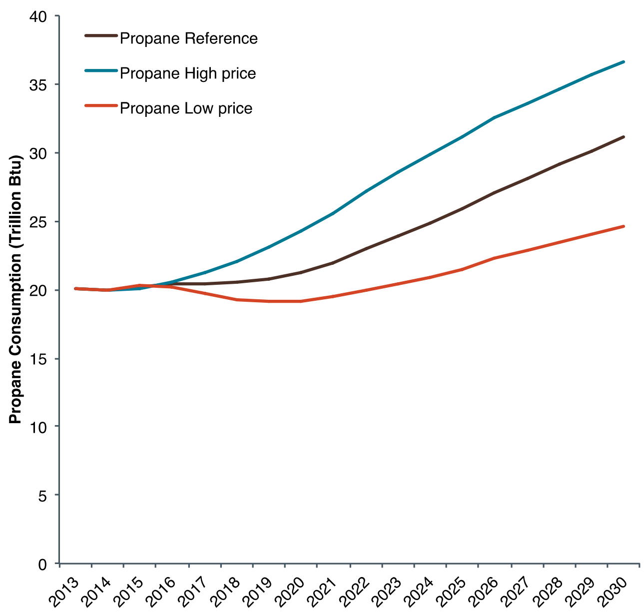


Figure 3.32.Propane consumption for transportation sector (2013-2030)

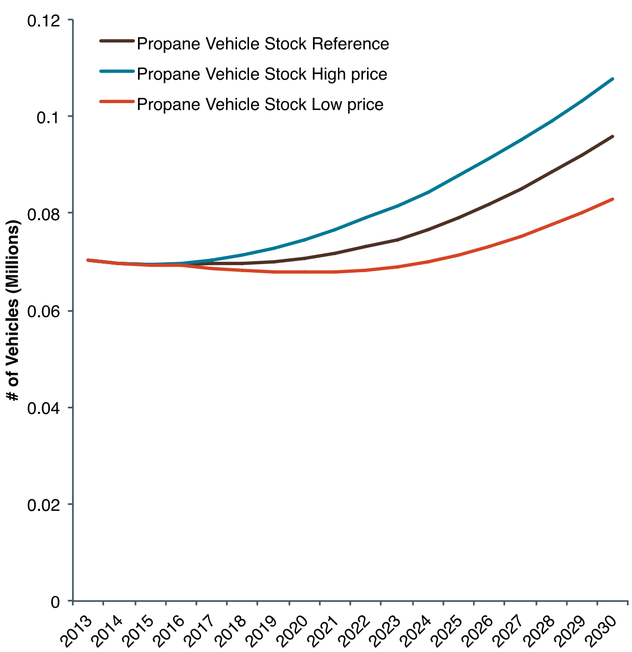


Figure 3.33.Total vehicle stock of propane-powered vehicles (2013-2030)

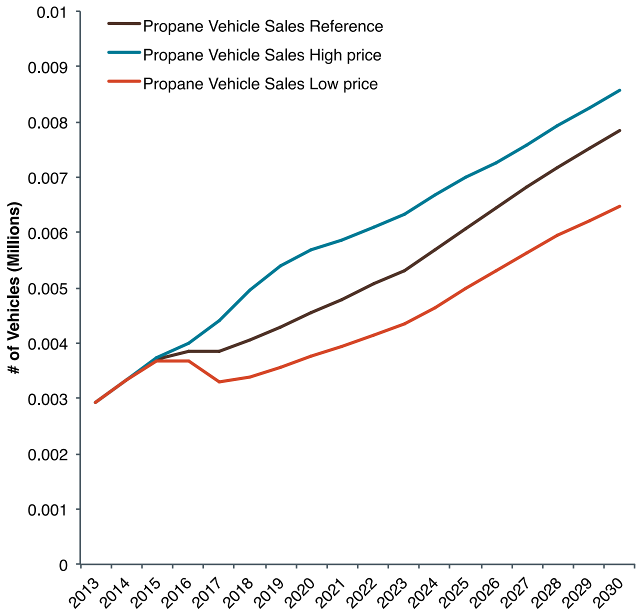


Figure 3.34.Total vehicle sales of propane-powered vehicles (2013-2030)

3.8. Other studies

Beyond the studies above, many other studies have examined the potential deployment of other fuel and vehicle technologies. Many other studies across biofuels, electric drive, and natural gas areas were reviewed as part of this literature review. Generally, the other leading and relevant studies that predated the ones listed above fall within the lower and higher bound that are being assessed in this study. For example, many of the other studies were done in advance of the abovementioned ZEV amendments and were inputs that were considered in that policy process (e.g., CARB, 2009b). Other studies have also examined the full range of electric drive deployment in the context of developing scenarios that are consistent with long-term climate stabilization goals (see, e.g., Yang et al., 2009; Williams et al., 2012).

There are also a number of areas that have potential, but were not considered, due to both the research scope of this study and current prevailing uncertainties. There is some potential for electrification of medium-duty, heavy-duty, and off-road vehicles could contribute toward low-carbon transportation goals. California, in the update to its climate Scoping Plan acknowledges these areas as a potential area for future policy promotion (California, 2014). As indicated above the ICF (2013) study pointed out the potential for non-road electrification. Alternative fuels that have potential in marine and aviation applications were not analyzed within the scope of this work (see, e.g., Lowell et al., 2013; E4tech, 2014).

Another promising carbon reduction area for fuels that is not analyzed here is the potential to reduce the carbon intensity of petroleum-based fuels. Innovations in the petroleum supply chain represent an important source of potential reductions in the lifecycle emissions of fossil fuels. In line with this, CARB has developed and adopted a provision to credit innovative upstream emissions reduction projects in crude oil extraction, and proposed a refinery investment provision to credit downstream carbon intensity reductions in oil refining.

Currently, the provision for innovative upstream reductions includes crediting for carbon capture and sequestration (CCS) and solar thermal steam generation. Under a recently proposed rulemaking, the crude oil provisions would be amended so that credits are accrued revised so that credits would be generated by crude oil producers making those investments rather than refineries. In addition, CARB has shown openness to considering additional innovative methods (e.g., CO_2 flooding) proposed by interested parties subject to technical review. No credits have yet been accrued under this provision.

A recent study conducted by TetraTech for NRDC (2013), describes the reduction potential from a number of these innovative processes based on different adoption scenarios. The technologies that they review include: renewable solar steam generation; steam generation with carbon capture and sequestration; refinery energy efficiency improvements including improved controls, improved heat recovery, hydrogen and fuel gas management, utilities optimization, and advanced process technologies; refinery carbon capture and sequestration; and the use of renewable refinery feedstocks displacing part of the refinery's crude oil use with natural oils. Although this list provides an extensive list of methods to reduce emissions from crude oil lifecycles, it is not exhaustive as other measures, including the adoption of a lower carbon crude slate or reductions in venting and flaring, are excluded from the analysis.

Notwithstanding, if these technologies were adopted across the board in all facilities in California, they would have the potential to reduce more than 20 million metric tons from the petroleum supply chain or over 40 percent of all emissions from California petroleum refining and crude oil production (NRDC, 2013). However, given the low likelihood of across the board adoption by 2020, the authors construct two adoption cases that describe reduction potential from these sources. These result in a GHG emissions reduction range between 2.8 and 6.6 million metric tons annually by 2020 or 17% to 39% of the entire 2020 requirements under California's LCFS program (see Table 3.17 for adoption case assumptions).

Table 3.17. Low and high adoption carbon reduction opportunities in the California oil industry (Adapted from NRDC 2013)

CARBON REDUCTION OPPORTUNITY	LOW ADOPTION CASE	HIGH ADOPTION CASE
Renewable steam generation	5% of once-through steam generators in CA adopt either solar thermal or CCS	20% of once-through steam generators in CA adopt either solar thermal or CCS
Refinery energy efficiency	Average 5% improvement across all refineries	Average 10% improvement across all refineries
Refinery CCS for hydrogen production	15% of refining capacity	30% of refining capacity
Renewable feedstocks	30% of refineries using 2% renewable feedstocks in crude oil stream	60% of refineries use 4% renewable feedstocks in crude oil stream

In 2012, the California Electric Transportation Coalition (CalETC) commissioned a study to explore electric credits in the California LCFS. The study conducted by TIAX LLC (2012), covered potential credits from electricity consumption in on-road applications (light-duty plug-in electric vehicles, such as battery electric vehicles or plug-in hybrid vehicles) and off-road applications (including electric passenger rail, electric forklifts, and E-transport refrigeration units). The former have been covered in other sections of this report so we will focus on their findings for off-road applications, for example electric passenger rail, electric freight, electric transport refrigeration unites. As a reference for this discussion, the illustrative compliance curves presented by CARB (2014c) show that electricity for HDVs and rail is expected to reach 894,000 MWh starting in 2016 and remaining constant through 2020 with a carbon intensity of 34.9 gCO_2e/MJ.

TIAX constructs scenarios for electric passenger rail based on the National Transit Database (2010) and takes into account planned rail expansion by 2020. Electric passenger rail is assumed to displace light-duty auto miles and transit bus miles. The results show that through 2020, electric rail has a potential to generate on average between 730,000 and 770,000 metric tons of credits per year. In addition, displacement of light-duty vehicles can yield somewhere between 910,000 to 950,000 metric tons of credits per year while displacing transit buses yields 540,000 to 57,000 metric tons of credits annually. For electric forklifts and E-transport refrigeration units, TIAX estimates potential credits of 600,000 and 3,000 metric tons per year, respectively.

4. Modeling framework

4.1. Vehicle fleet modeling

To support the analytic modeling of the supply of the various low-carbon fuels in the Pacific Coast region, a comprehensive vehicle fleet stock-turnover is utilized. To match the most commonly used assumptions for sales, vehicle stock, vehicle fleet composition by vehicle technology type and class, vehicle retirement characteristics, and vehicle activity by age, the U.S. DOE VISION Model (ANL, 2014a) is utilized as the initial modeling framework. This approach ensures that the basic assumptions applied here for the vehicle use parameters are consistent with those most typically applied in U.S. policy analyses. The VISION model has been developed by Argonne National Laboratory, and is the basis for many research and government scenario analyses (e.g., see CARB, 2014a).

The VISION model is developed and augmented to provide estimates of the potential energy use, oil use, and carbon emissions impacts of advanced light- and heavy-duty vehicle technologies and alternative fuels through 2050. In particular, the modeling here relies upon the part of VISION that models the vehicle stock turnover to calculate the demand for different types of fuels, including gasoline, diesel, natural gas, electricity, and hydrogen. The VISION model critically allows tracking, analyzing, and modifying key aspects that are central to the demand for the different fuels. The model also ensures consistency between the vehicle and fuel assumptions, and thus provides critical checks on alternative fuel (as well as flex-fuel and fuel blending) vehicle deployment constraints.

4.1.1. Amendments made to VISION

The VISION model is augmented in several ways to meet the objectives of this project. The first major modification to VISION was to accommodate the particular fuel types and their carbon intensities as analyzed in this report. Whereas the VISION model handles the fundamental vehicle fleet activity and associated fuel demand, we externally model how this demand for different fuels is met by a bottom-up analysis of the various alternative fuels. As described in Chapter 5 these alternative fuel supply assumptions are based on a range of cases from “low” to “high”. The remainder of vehicle fleet fuel usage is drawn from conventional gasoline and diesel fuel usage. We also calculate the carbon intensity externally from the VISION model. The carbon intensities in this document are based on low-carbon fuel pathways under the California LCFS (CARB, 2012a; CARB, 2014b) where available, and are otherwise based on estimates from the literature. The fuel carbon intensity values are discussed in the section below and summarized in Annex B.

The VISION model allows a user to input assumptions about the market penetration of different alternative fuelled in the respective vehicle categories (cars, light trucks, medium-duty vehicles, and heavy-duty vehicles). We model the penetration of different technologies in different vehicle categories, depending on the scenarios. As with the fuel supply assumption, this is based on low to high cases for the carbon intensity reductions available from each option. In this manner, all the fuel supply deployments in the scenarios do not exceed any potential fundamental vehicle constraints regarding how quickly advanced vehicle types (e.g., electric and natural gas) phase into the vehicle fleet. For the different assumptions taken regarding the penetration of these different vehicles in the different scenarios, see Chapter 5.

The VISION model also allows a user to input different assumptions about the blend level at which ethanol and biodiesel is used by light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs) over time. The blend levels that we have assumed in the different scenarios are described in Chapter 6. Several input parameters are left unaltered in the model, including total vehicle miles traveled (VMT), elasticity to the cost of driving, light truck share of total LDV market, vehicle activity over age, vehicle retirement characteristics, fuel price, and vehicle costs.

4.1.2. Scaling to the Pacific region

The VISION model is scaled down from the U.S. to the Pacific Coast region. VISION models the fleet turnover and fuel use for the entire U.S. Therefore, based on the scenario inputs we have selected, the VISION model calculates total U.S. demand for different types of fuel, as if the input assumptions held across the whole U.S. Since we are not modeling supply and use of low-carbon fuels across the entire U.S., we scale down the model to make it representative of the Pacific Coast region of California, Oregon, Washington, and British Columbia.

Scaling to the relevant four jurisdictions of the Pacific Coast region has been done based on overall travel activity, after comparing VMT in the Pacific Coast region to that of the entire U.S. as modeled in VISION. The sources for the VMT for the four jurisdictions are taken from 2012 U.S. Federal Highway Administration data and 2009 Statistic Canada data (FHWA, 2013; Statistic Canada, 2009). No adjustment is made in terms of the calendar year difference between the Canadian data and the U.S. data because the VMT in British Columbia over historic years varies only minimally. The scale rate is assumed to be constant from 2010 to 2030 as the change of VMT share across the regions is slight over the years. A scaling factor between the original VISION vehicle fleet, vehicle activity, and energy use of 14.8% is calculated. In making these amendments to the VISION model for the Pacific Coast context, there was not sufficient data to provide a basis for making regional assumptions different to U.S. averages for: vehicle categorization; vehicle fuel efficiency or CO_2 per mile by technology types; vehicle retirement characteristics.

4.1.3. Vehicle efficiency characteristics

Among the more fundamental variables within the VISION framework that impacts overall fuel demand is the vehicle efficiency of new vehicles entering the vehicle fleet in future years. This analysis retains the VISION model’s assumed compliance with existing North American vehicle greenhouse gas and fuel economy regulations. Namely, the adopted regulations for U.S. and Canada include an approximate 4% per year reduction in new light-duty vehicle fuel consumption per mile through model year 2025 (see U.S. EPA and NHTSA, 2010, 2012; Canada, 2014). An approximate 1-2% per year reduction new heavy-duty vehicle fuel consumption per mile through model year 2018 (see U.S. EPA and NHTSA, 2011; Canada 2013). However, consideration of the in-development post-2018 heavy-duty vehicle efficiency and greenhouse gas regulations (White House, 2014) is not included in this analysis. The VISION model incorporates these efficiency trends in new vehicles, and also includes comparable efficiency improvements across combustion vehicles (e.g., gasoline, diesel, and natural gas).

Vehicle efficiency of electric drive vehicles is also modeled within VISION. The VISION model incorporates Energy Economy Ratios (EERs), derived from the miles per gallon achieved by each vehicle category in a given year. These represent the ratio of the fuel economy (miles per MJ fuel) of alternative fuel vehicles, compared with the fuel economy of a comparable base vehicle. These ratios can therefore be used to calculate the fuel economy of the alternative fuel vehicle from the base fuel vehicle, and track and compare various vehicle technology types fuel economy per equivalent energy unit over time.

In the VISION model, the efficiencies of the vehicle types vary over time and are summarized in Annex D. The diesel and gasoline ICE vehicle efficiencies improve in line with the adopted efficiency standards. Electric-drive vehicles are significantly more efficient than vehicles with internal combustion engines, yet there is less potential for increased efficiency over time. As such, electric vehicle efficiency is still modeled as increasing over time due to powertrain improvements, light weighting, aerodynamics, etc. but at a lesser rate than conventional combustion vehicles.

4.2. Fuel carbon intensity assumptions

4.2.1. Biofuels

Where possible, carbon intensities for biofuels are taken from CARB's default pathway analyses, or from approved 2A/2B pathway applications (CARB 2012a, 2014b). In some cases, we have made assumptions about the potential for improvement to the carbon intensity of biofuel pathways over time to 2030. However, a comprehensive assessment of potential for efficiencies in the various pathways is beyond the scope for this report. We have sought to remain conservative in our assumptions about likely future carbon intensities.

For indirect land use change, the results in this report reflect the latest CARB update to proposed indirect land use change (ILUC) values (CARB, 2014e). The new values, though not currently in regulatory effect subject to change, are likely closer to what will be in place over the coming years than the current regulatory values are, and therefore we feel it is most appropriate to use those values in the modeling. The following ILUC values are therefore used (Table 4.1).

Table 4.1. ILUC factors used in model carbon calculation

FEEDSTOCK	ILUC FACTOR (gCO_2e/MJ)
Corn	20
Sugarcane	12
Sorghum	19
Wheat	19
Soy	29
Canola	15

The carbon intensities assumed for conventional ethanol are shown below in Table 4.2. They are all based on ARB pathways. The average corn CI is assumed to drop from a typical 2015 value towards the low end of the existing pathways, with sorghum ethanol production achieving similar efficiencies.

Table 4.2. Conventional ethanol feedstock carbon intensities over time in gCO_2e/MJ

FEEDSTOCK TYPE	2015	2020	2025	2030	REFERENCE
Corn	74	69	64	60	Estimate 2015 CI based on 2014 quarterly credit reports. Assume efficiency improvements allow carbon intensity reduction the best current 2A/2B pathways by 2030.
Sugarcane	32	24	24	24	2015 intensity based on pathway with electricity credit (ETHS003). Assume full mechanization by 2020.(ETHS002)
Sorghum	66	62	57	52	Average of 2A/2B pathways for 2015, dropping to 2030 assuming efficiency savings consistent with those assumed for the corn pathway
Molasses	30	30	30	30	Average of 2A/2B pathways
Wheat	66	62	57	52	Assumed equal to sorghum

The carbon intensities assumed for biodiesel are shown below in Table 4.3. No changes are assumed over time, as there are not a comparable set of examples of lower-carbon biodiesel pathways established through the 2A/2B process as there are for ethanol. This assumption is conservative.

Table 4.3. Biodiesel feedstock carbon intensities in gCO_2e/MJ

FEEDSTOCK TYPE	CI	SOURCE
Soy	51	ARB lookup tables
Canola	74	Lookup tables ARB priority pathway
UCO	14	ARB lookup tables, no cooking
Tallow	34	ARB lookup tables R-Power pathway
Corn oil	4	Lookup tables ARB priority pathway
Camelina	30	Placeholder pathway estimate

The carbon intensities assumed for cellulosic biofuels are shown below in Table 4.4. The same values are used for ethanol, drop-in renewable diesel, and drop-in renewable gasoline, except that bagasse as an ethanol feedstock is replaced by municipal solid waste as a drop-in feedstock. MSW is conservatively assigned a carbon intensity of 0 gCO_2e/MJ. This is conservative because it limits the avoided methane emissions credit assigned to MSW based fuels in many analyses.

Table 4.4. Feedstocks and carbon intensities assumed for cellulosic ethanol

FEEDSTOCK	SUPPLY FRACTION	CARBON INTENSITY (gCO_2e/MJ)				REFERENCE
		2015	2020	2025	2030	
Corn stover	50.0%	30	27	23	20	2020 value from Baral and Malins (2014), assumed to reduce to 20 gCO_2e/MJ by 2030
Bagasse	5.0%	7	7	7	7	GranBio ARB pathway application
Woody residues	5.0%	32	28	24	20	2020 value from Baral and Malins (2014), assumed to reduce to 20 gCO_2e/MJ by 2030
Short rotation coppice	5.0%	6	6	6	6	Baral and Malins (2014)
Annual grasses	10.0%	29	26	23	20	2020 value for switchgrass from Baral and Malins (2014), with 10 gCO_2e/MJ added for lower soil carbon. Assumed to reduce to 20 gCO_2e/MJ by 2030
Perennial grasses	25.0%	19	19	19	19	Baral and Malins (2014)

Carbon intensities for HVO renewable diesel are set at 5 gCO_2e/MJ higher than the biodiesel values for the same feedstock. This reflect the higher energy intensity of the hydrotreating process, including the energy footprint of hydrogen production.

4.2.2. Hydrogen and natural gas

Carbon intensities for hydrogen and natural gas are outlined in Table 4.5.

Table 4.5. Carbon intensities for hydrogen and natural gas in gCO_2e/MJ

FEEDSTOCK TYPE	CI	SOURCE
Hydrogen from steam reforming	118	CARB lookup tables
Renewable hydrogen	76 -> 38	2015 value based on CARB lookup tables, then assume 50% efficiency gains by 2030
Fossil natural gas	73	CARB lookup tables
Renewable natural gas	19	Average of CARB lookup table pathways CNG003, CNG004, LNG006-9

Source: CARB 2012a, 2014b

An important consideration in the carbon intensity of natural gas concerns leakage rates from fugitive emissions. Calculating exactly how much methane fugitive emissions occur during production, processing and distribution of natural gas is difficult. Various estimates are reported and range from 1.5 to 9 percent. Brandt et al. (2014) reviewed a comprehensive set of top-down and bottom-up studies and concluded that leaks of methane from drilling sites were 50 percent (+/-25 percent) higher than EPA previous emissions inventory estimates at 1.4 percent of gross gas withdrawals (U.S. EPA 2013b). The study describes a high-end estimate of 7.1 percent gas leakage (on an end use basis) that can be considered a very unlikely worst-case scenario. According to calculations with CA-GREET 2.0 (CARB 2014g), the methane leakage carbon intensity for conventional natural gas contribution to the total natural gas is estimated 4.28 g CO_2e/MJ or about 5.8 percent of the fossil natural gas carbon intensity. A higher leakage rate would affect the climate benefits available from deploying natural gas vehicles.

4.2.3. Electricity

The greenhouse gas emissions from electricity-powered vehicles are largely from electricity generation, as well as from the associated upstream extraction emissions and the transmission, distribution, and charging losses. In order to approximate potential changes to the electricity grid's carbon intensity over time, we analyze the carbon intensities of various electricity energy sources, the current renewable and non-renewable electricity mix, and information related to the renewable electricity portfolio standards in the jurisdictions.

Upstream emissions associated with electric vehicles are evaluated as the CO_2 emissions per unit electricity produced (i.e., gCO_2e/kWh). In this study, the marginal California electricity carbon emissions of 377 gCO_2e/kWh is adopted to estimate the upstream fossil electricity emissions utilized in electric vehicles (CARB, 2009a). The weighted average electricity carbon intensity of 7.97 gCO_2e/kWh from California, Oregon, and Washington in U.S. EPA's eGRID data (U.S. EPA, 2014) is assumed here for the renewable and nuclear electricity. In order to provide a life cycle analysis, transition and distribution losses, and upstream emissions are considered in the calculation besides the direct emissions.

The renewable, non-hydroelectric electricity generation is expected to increase across the Pacific region due to renewable electricity portfolio standards. Due to these policies, photovoltaic, solar, and other renewable electricity sources are expected to increase to some degree. Based on an approximation of the weighted electricity supply of the regions, renewable (non-hydroelectric) electricity is expected to increase from approximately 11% in 2015 to at least 26% in 2030, or greater depending on increased renewable electricity after reaching the state renewable portfolio standards by 2020 (California Public Utilities Commission, 2011; Anair & Mahmassani, 2012; North Carolina State University, 2014). After 2020, a 1% increase per year in renewable generation share is applied for the Medium case, while no change is assumed for the Low case. For the High case, a 2% annual increase in renewable share is assumed from 2020 to 2025, followed by a 1% annual increase through 2030. The combined hydroelectric and nuclear share, based on eGRID data (U.S. EPA, 2010), is assumed to remain constant in this analysis at 47% from 2015-2030. The fossil electricity share in the Pacific region is expected to decrease in all scenarios because of the increase of renewable energy-derived electricity on the power grid.

4.3. Other compliance options

In addition to the fuel supply options modeled in this study, there are additional opportunities to generate credits within the California LCFS. In particular, it is possible to generate credits through the use of electricity for rail transport, and through innovative emissions reduction projects in the upstream oil sector. It is important that these credit sources should not be ignored when considering the implications of the scenarios modeled in this report for compliance with regional carbon intensity reduction goals, for instance as shown in Figure 6.17. We therefore include an assumed contribution of carbon reductions from these options when comparing carbon intensity of the regional fuel supply with the regional compliance targets. For this purpose, it is assumed that 700,000 tons of CO_2 credits are generated per year in California from electricity for fixed guideway systems (CARB, 2014e), and that oil sector emission reductions increase linearly from nothing in 2015 to 1.5 million tons per year in 2022, and then continue at that level (based on NRDC, 2013).

4.4. Baseline carbon intensity

The baseline carbon intensity for 2010 (against which all emissions reductions are assessed in this study) is based on the California 2010 baseline under the LCFS, adjusted to reflect a proposed reduced indirect land change factor for corn ethanol. The carbon intensity of diesel fuel is set at 102.7 gCO_2e/MJ, and the baseline carbon intensity of gasoline blendstock (based on CARBOB) is set at 100.5 gCO_2e/MJ. Based on this, the baseline carbon intensity of blended E10 gasoline is set at 98.5 gCO_2e/MJ. Carbon savings of diesel substitute fuels are assessed against baseline fossil diesel, while carbon savings from gasoline substitute fuels are assessed against baseline E10 gasoline. Where fuels such as natural gas may substitute for both diesel and gasoline, proportionate savings are assessed to the substitution rates. Because conventional ethanol is included in the baseline, quoted carbon intensity reductions from conventional ethanol are always the savings *over and above the baseline.* Therefore, for instance, a 10% inclusion of baseline corn ethanol would not be reported as delivering any carbon saving, even though the corn ethanol has a lower carbon intensity than the gasoline blendstock. Note however that all ethanol volumes are included when volumes or energy consumption are presented.

5. Alternative fuel supply evaluation

Outlined below are the assumptions that go into each case for each variable from low to high. The scenario modeling is presented in Chapter 6 of this paper. Each scenario is based on the selection of an input case from low to high for each variable listed below. Thus a high case for cellulosic fuel deployment can be paired with a low case for electric drive vehicle deployment or vice versa, and so forth. Note that some cases are included in the model but are not implemented in any of the scenarios presented here (see Table 5.15). This reflects the fact that the model allows enough permutations to produce over 20 billion distinct scenarios.

5.1. Standard ethanol blend

The "standard" ethanol blend is the assumed average fraction of ethanol in the gasoline sold in the Pacific region. There are two cases for evolution of the ethanol blend. Where the blend is set to change by 2030, the assumed ethanol blend is constant (E10) until 2020, and then changes linearly to the new blend level by 2030. Where the blend is set to change by 2020, in contrast, the blend rate changes to the new level by 2020 and then remains constant to 2030. There are two possible eventual blend levels, E10 and E15. None of the scenarios assumes a higher average rate of ethanol use (e.g. E20 or E30). E10 is the current norm, but E15 blends are permitted by the EPA and potential compatibility issues with legacy vehicles will reduce as older vehicles get cycled out of the fleet. As noted by Searle et al. (2014), there is no technical reason from the point of view of engine compatibility not to introduce E15 for new vehicles. Note that the supply and demand for E85 fuel are treated separately (see section 5.12).

The amount of conventional (first generation) ethanol used in each scenario is defined as the difference between the supply of cellulosic ethanol and the amount of ethanol required to meet the standard blend and supply any requirement for E85 for flex-fuel vehicles.

5.2. Standard biodiesel blend

The "standard" biodiesel blend is the assumed average fraction of biodiesel in the diesel. The 2015 average biodiesel blend rate in diesel fuel is set at 1.9%. This is based on a 2% mandate in Oregon, 4% mandate in British Columbia under the RLCFRR, 0.2% current blend rate in Washington (Life Cycle Associates, 2014) and a 73 million gallon supply in 2015 in California (CARB, 2014f).

There are two ways that the biodiesel blend is modeled. For scenarios where the blend is set to change by 2030, for the first five years to 2020 the biodiesel blend is set to change linearly from the 2015 level to a 5% blend. After 2020, the blend is modeled as increasing linearly to the 2030 target blend (allowed to vary from 5 to 30% in the model, but set between 7 and 20% for all scenarios presented here). Where the biodiesel blend is set to change by 2020, in contrast, the blend rate immediately increases linearly to the target rate between 2015 and 2020, and is then frozen until 2030 at that level. It is assumed in all cases that the same standard blends are adopted for diesel used in light- and heavy-duty vehicles. Blends up to 20% are considered technically feasible from the vehicle engine point of view, given adequate attention to issues such as cold flow properties, but actual blend rates will depend on manufacturer and consumer acceptance and on any issues related to compliance with clean air regulations. The amount of biodiesel used in each scenario is defined as the amount required to meet the standard blend.

5.3. Conventional ethanol carbon reductions

The emissions reductions delivered by conventional ethanol are defined by the feedstock mix, and the presumed carbon intensities for each feedstock. The carbon intensities by feedstock are identical in all cases scenarios – only the feedstock mix changes. In the lower scenarios, there is more corn ethanol, which is replaced by sugarcane and sorghum and then by molasses in the higher cases. The assumed mixes are shown in five-year intervals in Table 5.1 below.

Table 5.1. Fraction of first generation ethanol from each feedstock in each case

CASE	FEEDSTOCK TYPE	2015	2020	2025	2030
Low	Corn	89%	89%	90%	90%
	Sugarcane	10%	8%	7%	5%
	Sorghum	0%	0%	0%	0%
	Molasses	0%	0%	0%	0%
	Wheat	1%	2%	4%	5%
Low-med	Corn	89%	75%	62%	48%
	Sugarcane	10%	17%	23%	30%
	Sorghum	0%	3%	7%	10%
	Molasses	0%	3%	7%	10%
	Wheat	1%	1%	2%	2%
Medium	Corn	89%	55%	22%	13%
	Sugarcane	10%	35%	60%	60%
	Sorghum	0%	5%	10%	15%
	Molasses	0%	3%	7%	10%
	Wheat	1%	1%	2%	2%
Med-high	Corn	89%	45%	6%	0%
	Sugarcane	10%	40%	70%	70%
	Sorghum	0%	6%	12%	18%
	Molasses	0%	9%	13%	13%
	Wheat	1%	1%	0%	0%
High	Corn	89%	29%	3%	0%
	Sugarcane	10%	60%	80%	80%
	Sorghum	0%	0%	0%	0%
	Molasses	0%	11%	17%	20%
	Wheat	1%	1%	0%	0%

The carbon intensities for each feedstock are based on pathways published by ARB for the LCFS. For some pathways it is assumed that efficiency improvements will deliver increased savings over time. The carbon intensities for conventional ethanol are shown in Table 4.2. All ILUC emissions are based on the initial statement of reasons for re-adoption of the California LCFS (CARB, 2014e).

5.4. Fatty acid methyl ester biodiesel carbon reductions

The emissions reductions delivered by biodiesel are defined by the feedstock mix, and the presumed carbon intensities for each feedstock. The carbon intensities by feedstock are identical for all scenarios – only the feedstock mix changes. In the lower scenarios, there is more soy biodiesel, which is replaced by used cooking oil (UCO) and corn oil biodiesel in the higher scenarios. The assumed mixes are shown at five-year intervals in Table 5.2 below. The initial feedstock mix is based on soy biodiesel being supplied in WA and OR, canola biodiesel being supplied in BC and the 2015 feedstock mix identified in CARB (2014f) for CA. This likely underestimates the supply of waste grease and tallow biodiesel in OR, WA and BC, and is hence conservative.

Table 5.2. Fraction of first generation biodiesel from each feedstock in each case

CASE	FEEDSTOCK TYPE	2015	2020	2025	2030
Low	Soy	15.3%	23.5%	31.8%	40.0%
	Canola	31%	27%	24%	20%
	UCO	32%	24%	17%	10%
	Tallow	4%	6%	8%	10%
	Corn oil	18%	19%	19%	20%
	Camelina	0%	0%	0%	0%
Low-med	Soy	15%	20%	25%	30%
	Canola	31%	27%	24%	20%
	UCO	32%	26%	21%	15%
	Tallow	4%	8%	11%	15%
	Corn oil	18%	19%	19%	20%
	Camelina	0%	0%	0%	0%
Medium	Soy	15%	21%	16%	10%
	Canola	31%	30%	30%	30%
	UCO	32%	15%	15%	15%
	Tallow	4%	15%	15%	15%
	Corn oil	18%	15%	18%	20%
	Camelina	0%	3%	7%	10%
Med-high	Soy	15%	16%	13%	10%
	Canola	31%	24%	17%	10%
	UCO	32%	20%	20%	20%
	Tallow	4%	15%	15%	15%
	Corn oil	18%	20%	25%	30%
	Camelina	0%	5%	10%	15%
High	Soy	15%	5%	2%	0%
	Canola	31%	24%	17%	10%
	UCO	32%	25%	25%	25%
	Tallow	4%	15%	15%	15%
	Corn oil	18%	25%	28%	30%
	Camelina	0%	7%	13%	20%

5.5. Cellulosic fuel deployment

Cellulosic fuel deployment is calculated in one of two ways. For the “low” case, it is based on assuming that half the rate projected in AEO 2013 is achieved, assuming that a “fair share”' (15%) is imported to the Pacific region.

The low-med to high cases are based on a set of assumptions about the scale up rate of currently planned biofuel projects, and about the subsequent rate of industry growth and fraction of fuel brought to the Pacific region. The initial scale up rate (to 2018) is based on the methodology presented by Plevin, Gurtz, and Parker (2014) in comments to the EPA on the RFS volume mandate. In this methodology, production to 2018 is based on assumptions about the rate at which known projects come to full capacity, and after that further growth is based on some functional form. Figure 5.1 gives an example of results from this methodology when the "baseline" rate of facility production scale-up suggested by Plevin et al. is used through 2018, for three different exponential growth cases (annual growth rates of 10, 15 and 20%) and a Gompertz function. The initial set of plants and expected production start dates assumed for this chart are listed in Table 5.3. It is likely in reality that not all of these plants will be developed, but that there will be plants that we are not aware of that will come online. We assume that these effects cancel each other out so that announced plants are a reasonable basis for modeling.

Where the growth rate is described as "Gompertz", a Gompertz function (a sigmoid function of the mathematical form: $y(t) = ae^{-be^{-ct}}$) has been fitted to the 2018 production value. The asymptote for eventual potential total cellulosic fuel production is set at 40 billion gallons. The annual growth rate given by the Gompertz function is tuned to give around 30% initial growth in 2019, which is broadly consistent with continued capacity build up in the given list of facilities and gradual opening of additional plants, and falls towards 15% by 2030.

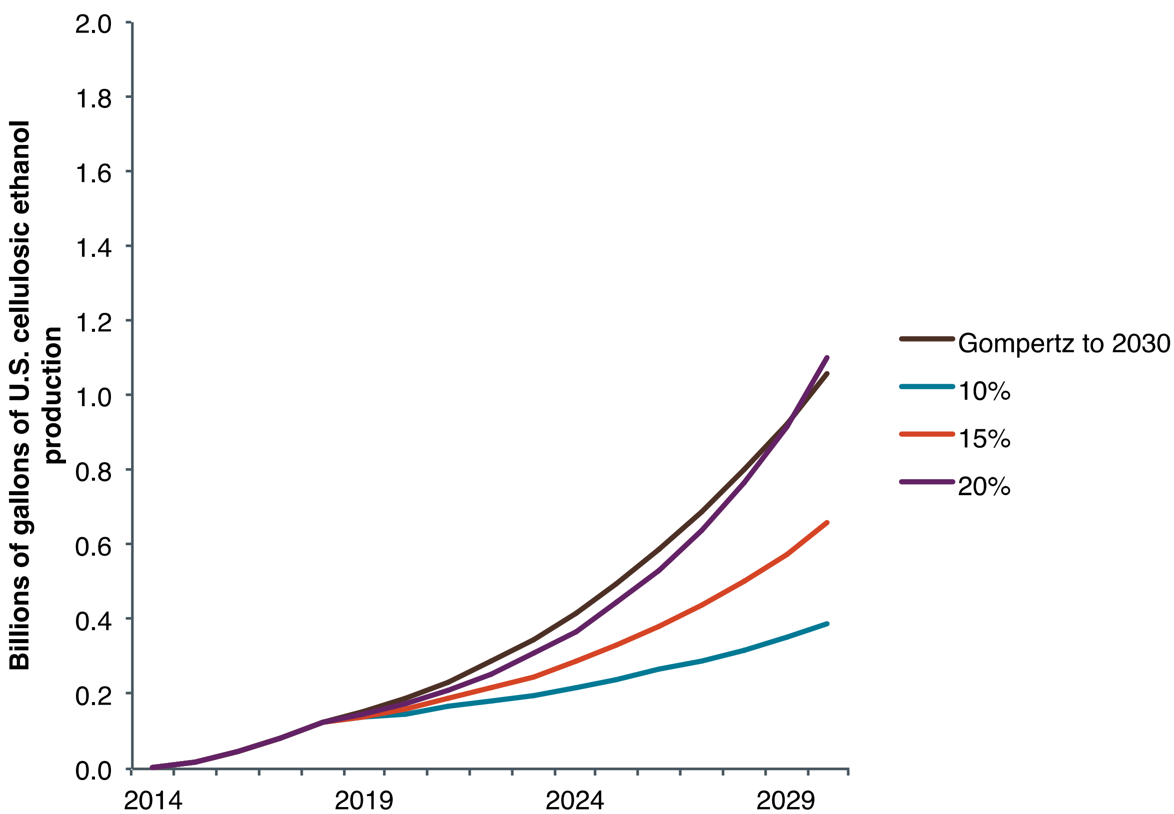


Figure 5.1. Examples of possible growth trajectories* for U.S. total cellulosic ethanol capacity given "baseline" assumptions on initial scale-up rate

** Growth trajectories are based on either 10, 15 or 20% annual growth, or growth in line with a Gompertz function as described in the text.*

The model is applied to two sets of facilities. Facilities in the U.S. are taken from the E2 (2014) report on the state of the advanced biofuel industry. The U.S. facilities, nameplate capacities, and assumed start of production dates are shown in Table 5.3.

Table 5.3. U.S. cellulosic production facilities expected to open by 2018

PLANT	TYPE	NAMEPLATE (MILLION GALLONS)	ASSUMED START OF PRODUCTION
Abengoa	Biochemical ethanol	25	10/1/14
Canergy	Biochemical ethanol	30	6/15/16
Chemtex	Biochemical ethanol	20	6/1/17
Cool Planet	Fast Pyrolysis	10	6/1/15
DuPont	Biochemical ethanol	30	1/1/15
Fiberight	Biochemical ethanol	6	6/1/17
Fulcrum	Gasification F-T	10	6/1/16
INEOS Bio	Biochemical ethanol	8	12/31/14
Red Rock biofuels	Gasification F-T	16	6/1/17
Pacific Ethanol-Sweetwater Energy	Biochemical ethanol	4	9/15/17
POET-DSM	Biochemical ethanol	25	9/1/14
Virent	Biochemical ethanol	1	1/1/14
Sweetwater Energy	Biochemical ethanol	4	6/1/16
Highlands Envirofuels	Biochemical ethanol	30	1/1/16
Quad County Corn	Fast Pyrolysis	4	6/1/16
Cellefuel	Fast Pyrolysis	11	12/1/15
Enerkem	Biochemical ethanol	21	6/1/15

Projects are split into ethanol projects and drop-in renewable gasoline and diesel projects. The Plevin assessment methodology transitions from a plant-based assessment to a functional assessment in 2018, but this may underestimate the length of the initial period of relatively fast plant deployment as the industry develops. In particular, because there are relatively few drop-in fuel plants in Table 5.3, using this methodology limits the potential for drop-in fuel production by 2030. This may be unduly conservative as it is anticipated that the U.S. DOE and military will provide substantial support in the next ten years to support the accelerated development of drop-in fuel production. We have therefore implemented an option that extends the plant-based phase of the Plevin et al. methodology for an additional four years, based not on planned plants but on a set rate of annual plant deployment. For this case we assume that from 2018 to 2022 an additional five plants are opened every year, three cellulosic ethanol plants, one fast-pyrolysis plant and one gasification plant with 25 million gallon nameplate capacity. Figure 5.2 shows the production volumes that would be projected with this methodology for the same set of plant and initial deployment rate assumptions as given in Figure 5.1. By 2030, the 20% growth case delivers 1.6 billion gallons rather than 1.2 without the accelerated deployment to 2022.

We also consider international production capacity based on seven cellulosic ethanol facilities active by 2018, three in Brazil and four in Europe, with growth set using the same model. This implies that U.S. production capacity will be several times larger than that in the rest of the world. This is likely a reasonable assumption for the short to medium term, but may well become invalid in the longer term, especially if additional countries such as China join the market. In that case, the 2030 cases here could substantially underestimate the potential for cellulosic fuel imports to the region. The accelerated roll out to 2022 is only ever applied to the U.S. cellulosic fuel production rate, so the modeled potential for imports remains conservative.

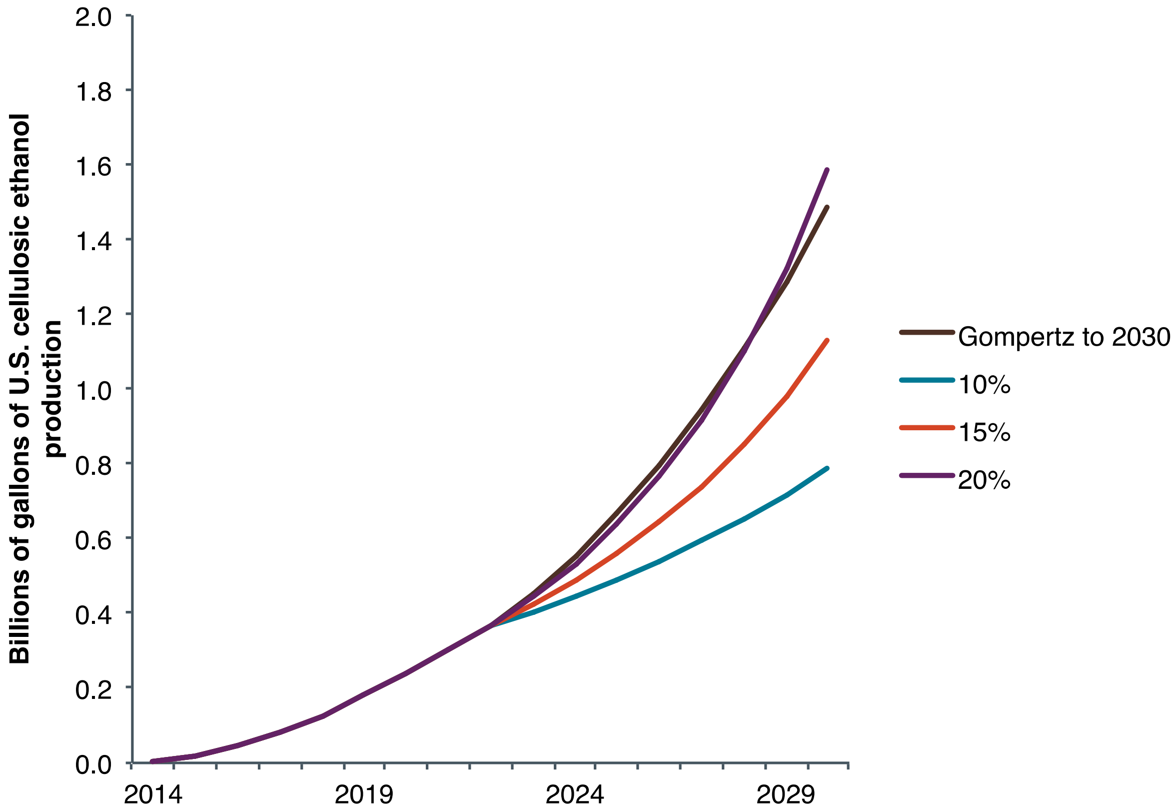


Figure 5.2. Examples of possible growth trajectories for U.S. total cellulosic ethanol capacity given “baseline” assumptions on initial scale-up rate and an extended period of accelerated deployment

The deployment rate assumptions for U.S. cellulosic ethanol production in the medium to high cases are shown in Table 5.4. The deployment rate assumptions for U.S. cellulosic drop-in fuel production in the medium to high cases are shown in Table 5.5.

Table 5.4. Medium to high assumptions on growth rate of cellulosic ethanol production

CASE	POST-2020 GROWTH RATE	PACIFIC SHARE OF PRODUCTION		INITIAL CAPACITY BUILD UP	U.S. DEPLOYMENT RATE 2018-2022
		U.S.	Global		
High	Gompertz	80%	50%	Optimistic	Plant-deployment based
Med-high	Gompertz	80%	50%	Pessimistic	Functional
Medium	15%	60%	30%	Baseline	Plant-deployment based

Table 5.5. Medium to high assumptions on growth rate of cellulosic drop-in production

CASE	POST-2020 GROWTH RATE	PACIFIC SHARE OF PRODUCTION		INITIAL CAPACITY BUILD UP	U.S. DEPLOYMENT RATE 2018-2022
		U.S.	Global		
High	Gompertz	80%	50%	Optimistic	Plant-deployment based
Med-high	15%	60%	30%	Baseline	Plant-deployment based
Medium	Gompertz	80%	50%	Pessimistic	Functional

It is assumed that 75% of the total supply of drop-in fuel is renewable diesel and 25% is renewable gasoline. Changes to this ratio should not have a large impact on the scenario results, as there is no practical limit in the short to medium term on the capacity of the region to use drop-in fuels. Renewable jet production is not considered.

The low-medium scenario is set to match the medium-high scenario for each fuel type but with a five-year delay before production starts to increase. The resulting fuel volumes in each case are shown below in Table 5.6.

Table 5.6. Potential Pacific Region supply of cellulosic fuels (billion gallons) for each case

CASE	FUEL	2015	2020	2025	2030
Low	Cellulosic ethanol	0.02	0.02	0.02	0.02
	Drop-in renewable diesel	0.00	0.01	0.02	0.04
	Drop-in renewable gasoline	0.00	0.00	0.01	0.01
Low-med	Cellulosic ethanol	0.02	0.04	0.17	0.34
	Drop-in renewable diesel	0.00	0.01	0.03	0.07
	Drop-in renewable gasoline	0.00	0.00	0.01	0.02
Medium	Cellulosic ethanol	0.01	0.14	0.29	0.47
	Drop-in renewable diesel	0.00	0.03	0.06	0.12
	Drop-in renewable gasoline	0.00	0.01	0.02	0.04
Med-high	Cellulosic ethanol	0.02	0.15	0.29	0.59
	Drop-in renewable diesel	0.00	0.07	0.20	0.31
	Drop-in renewable gasoline	0.00	0.02	0.07	0.10
High	Cellulosic ethanol	0.02	0.21	0.47	0.95
	Drop-in renewable diesel	0.00	0.11	0.34	0.69
	Drop-in renewable gasoline	0.00	0.04	0.11	0.23

The volumes by case are shown for cellulosic ethanol in Figure 5.3, and for cellulosic renewable diesel in Figure 5.4. Note that AEO 2013 has no growth in cellulosic ethanol, but does have some for drop-in fuels, and so the low case would look quite different for drop-in renewable gasoline or diesel. The feedstock mix for cellulosic fuels is assumed the same for all cases and constant over time, and constant across time. Carbon intensities are in the range 0 – 32 gCO_2e/MJ. The detailed feedstock mix and assumed carbon intensities are shown Table 4.4.

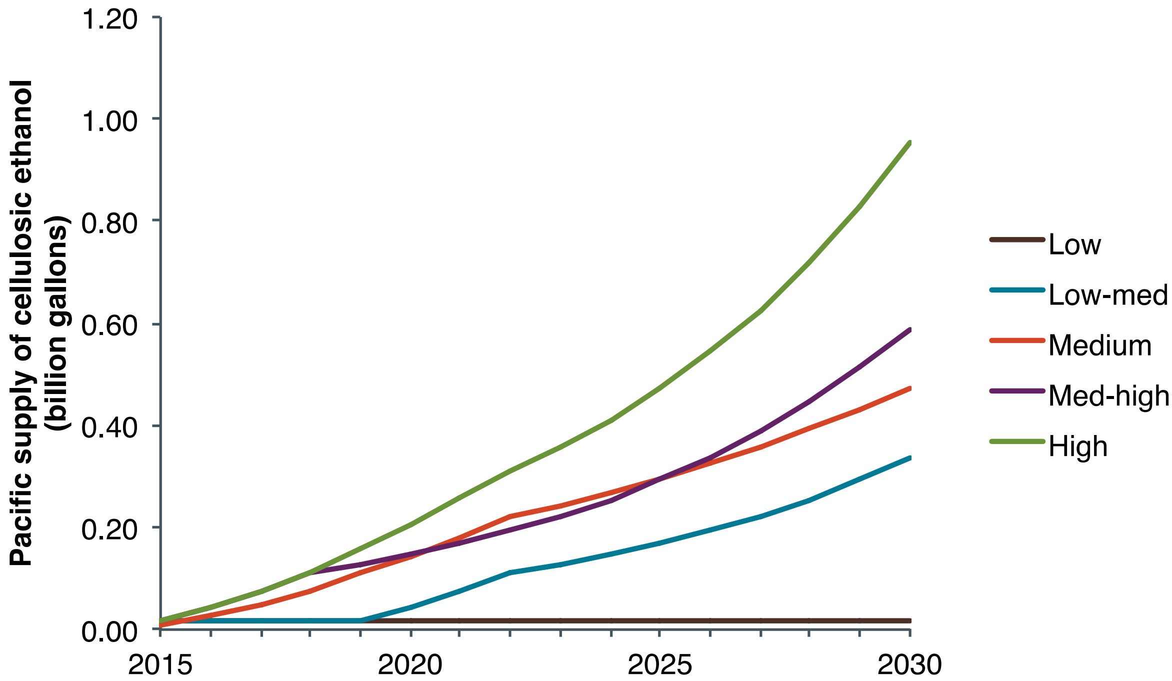


Figure 5.3. Growth rate of cellulosic ethanol production in each case

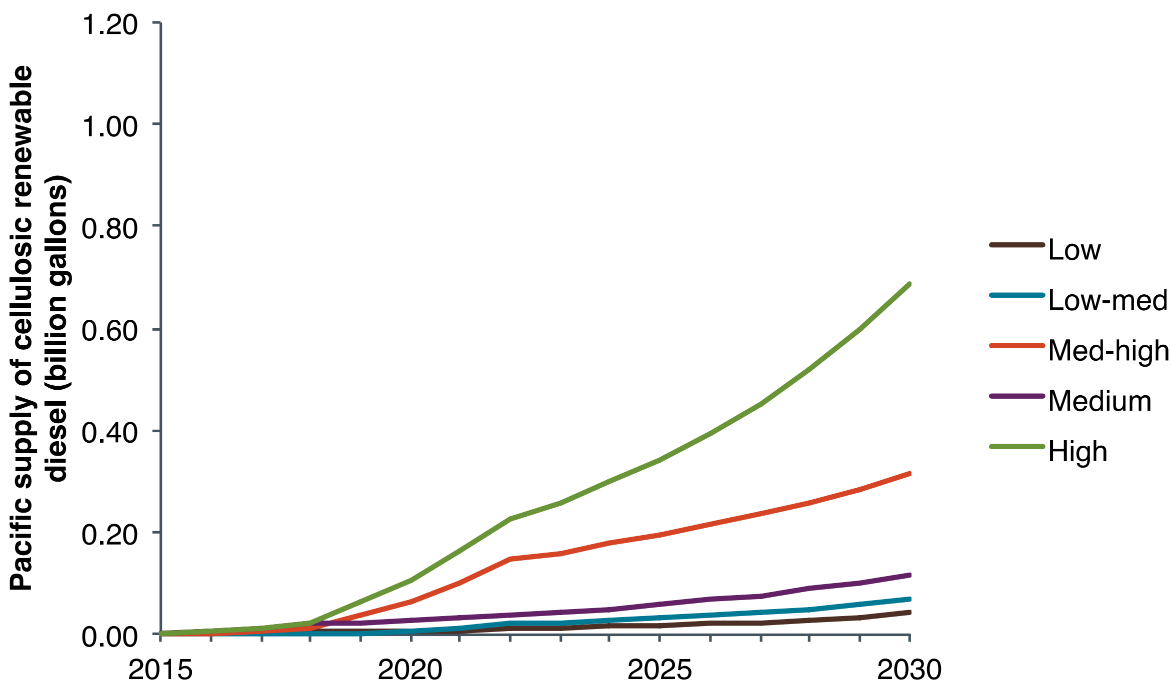


Figure 5.4. Growth rate of cellulosic renewable diesel production in each case

5.6. Natural gas deployment

Approximately one million heavy-duty vehicles are sold in the U.S. every year, and currently less than one percent are powered by natural gas. But as the booming shale gas industry brings prices of natural gas to as low as one quarter the price of diesel, the commercial trucking industry is poised to invest heavily in new natural gas-powered trucks over the coming decade. Furthermore, natural gas engines have historically offered large benefits over diesels in meeting particulate and criteria emissions. In particular, natural gas has replaced some diesel as a result of tightening NO_x standards. Although recent trends have seen this advantage reduced, natural gas engines have the potential to operate at very low lifecycle emission levels over the long term particularly when combined with renewable fuels.

Due to these and other market forces, most projections show strong growth in the segment in the near future. For example, Westport Innovations – a leading natural gas engine developer – estimate that natural gas truck sales for Class 7 and 8 vehicles could represent up to 18 percent of new North American sales in 2020 (Westport Innovations, 2014). Similarly, ACT Research show this segment’s sales growing past 35 percent in the same time period. Estimates by Gladstein, Neandorss & Associates (GNA) have market penetration for natural gas trucks reaching rates of 50 to 60 percent by 2030 (GNA, 2014).

Another study by the National Petroleum Council (2012) developed a methodology to assess the deployment of natural gas medium and heavy-duty vehicles through 2050 as part of a broader request made by the Secretary of Energy to assess the future of transportation fuels in the USA. Their methodology is based on a review of existing literature and the use of previously validated tools including the VISION model used in the current report. Their results are presented as means of scenario outcomes within a broader range of values representing maximum and minimums in the literature and modeling they reviewed. In terms of market share, their results show Class 3-6 natural gas vehicles growing to around 27 percent, Class 7&8 single unit vehicles reaching approximately 37 percent and combination vehicles 40 percent by 2025 for their High Oil Price Case. For their reference case, they show Class 3-6 natural gas vehicles reaching about 17 percent market share while Class 7&8 single unit vehicles grow to just under 20 percent and combination vehicles to 20 percent for the same time period.

The EIA AEO (EIA, 2014a) shows more modest growth in sales. In the reference case, the combined light medium, medium and heavy-duty truck segments powered by compressed/liquefied natural gas account for just under 6 percent of all truck sales (1.2, 0.6 and 4 percent respectively) in 2030, with most of the growth taking place post 2020. The AEO high oil price case has a more aggressive roll out, with 26% sales share in class 7&8 trucks by 2030.

For this study, the cases are defined as shown in Table 5.7.

Table 5.7. Sales shares for natural gas vehicles by type in each case

CASE	VEHICLE TYPE	2015	2020	2025	SOURCE
Low	Class 3-6	0%	0%	1%	AEO 2014 reference case
	Class 7&8	0%	0%	4%	
Low-med	Class 3-6	0%	4%	7%	Halfway between AEO 2014 reference and high oil price case
	Class 7&8	0%	4%	9%	
Medium	Class 3-6	0%	7%	13%	Assume 10% sales in 2025 in both vehicle categories (with linear increase)
	Class 7&8	0%	7%	13%	
Med-high	Class 3-6	0%	13%	27%	Assume 20% sales in 2025 in both vehicle categories (with linear increase)
	Class 7&8	0%	13%	27%	
High	Class 3-6	0%	20%	28%	NPC high oil price case, with class 7&8 natural gas vehicle deployment delayed five years
	Class 7&8	0%	24%	40%	

5.7. Renewable natural gas availability

Renewable natural gas refers to gas methane obtained from biomass that can be produced from urban waste residues (landfills) or from agricultural waste streams. In the transportation sector, this biogas can be used as a drop-in fuel or blended with compressed/liquefied natural gas in order to provide a comparative advantage in terms of its carbon intensity. As shown in the following sections, the carbon intensity of renewable natural gas is substantially lower than other natural gas pathways with lifecycle carbon intensity values as low as 11.26 gCO_2e/MJ (see CARB, 2012a). Hence, renewable natural gas pathways can offer the potential to reduce carbon intensity 70 to 90 percent below levels of comparable petroleum fuel pathways and can be blended with conventional natural gas pathways to maintain a price advantage over diesel and gasoline pathways while having net carbon savings (CEC, 2014). That said, the costs associated with the production of bio-methane remain high and can represent between 30 to 50 percent more than conventional natural gas while access to natural gas pipeline systems remains a barrier to further deployment (Ibid.). In terms of availability, the Bioenergy Association of California (2014) has recently estimated that around 2.1 billion diesel gallon equivalents of renewable natural gas from organic waste can be generated annually in the state. However, given the barriers for natural gas deployment, in particular the costs associated with infrastructure development, it is unlikely that this full potential can be realized in the short term. Our high case assumes that 1.7 billion gallons diesel equivalent could be mobilized for transportation by 2030, either in-state or through imports.

As well as being constrained by the total availability of renewable natural gas, the use for transportation is constrained by the number of natural gas vehicles on the road, and the need to compete with potentially cheaper fossil gas. Therefore, our cases are based on both a maximum possible supply estimate and value for the fraction of all transportation gas supplied from renewable sources. The cases are described in Table 5.8.

Table 5.8. Cases for renewable gas demand (gallons diesel equivalent)

CASE	2015	2020	2025	2030	MAXIMUM FRACTION OF DEMAND
Low	99	99	99	99	25%
Low-med	99	157	215	272	50%
Medium	99	215	330	445	75%
Med-high	99	503	876	1,289	85%
High	99	629	1,158	1,687	90%

5.8. Electric-drive vehicle deployment

The use of electricity and hydrogen in the model is driven by the sales share for electric drive vehicles. There are three scenarios for the increasing sales share of PHEVs, BEVs, and FCVs. The low scenario is based on achieving 50% of the ZEV program. The medium scenario is based on achieving the ZEV program in the manner anticipated by the California Air Resources Board regulatory analysis. The high scenario, based on Greene (2014), assumes that electric vehicle technology development accelerates in the 2020-and-later timeframe so that the projected CARB ZEV compliance rate is exceeded by 2030. Oregon is assumed to match California deployment rates except for fuel cells, while Washington and British Columbia follow the California and Oregon trajectory, with a delay of five years. The overall regional vehicle sales shares for BEV, PHEV, and FCV technologies in each case are shown below.

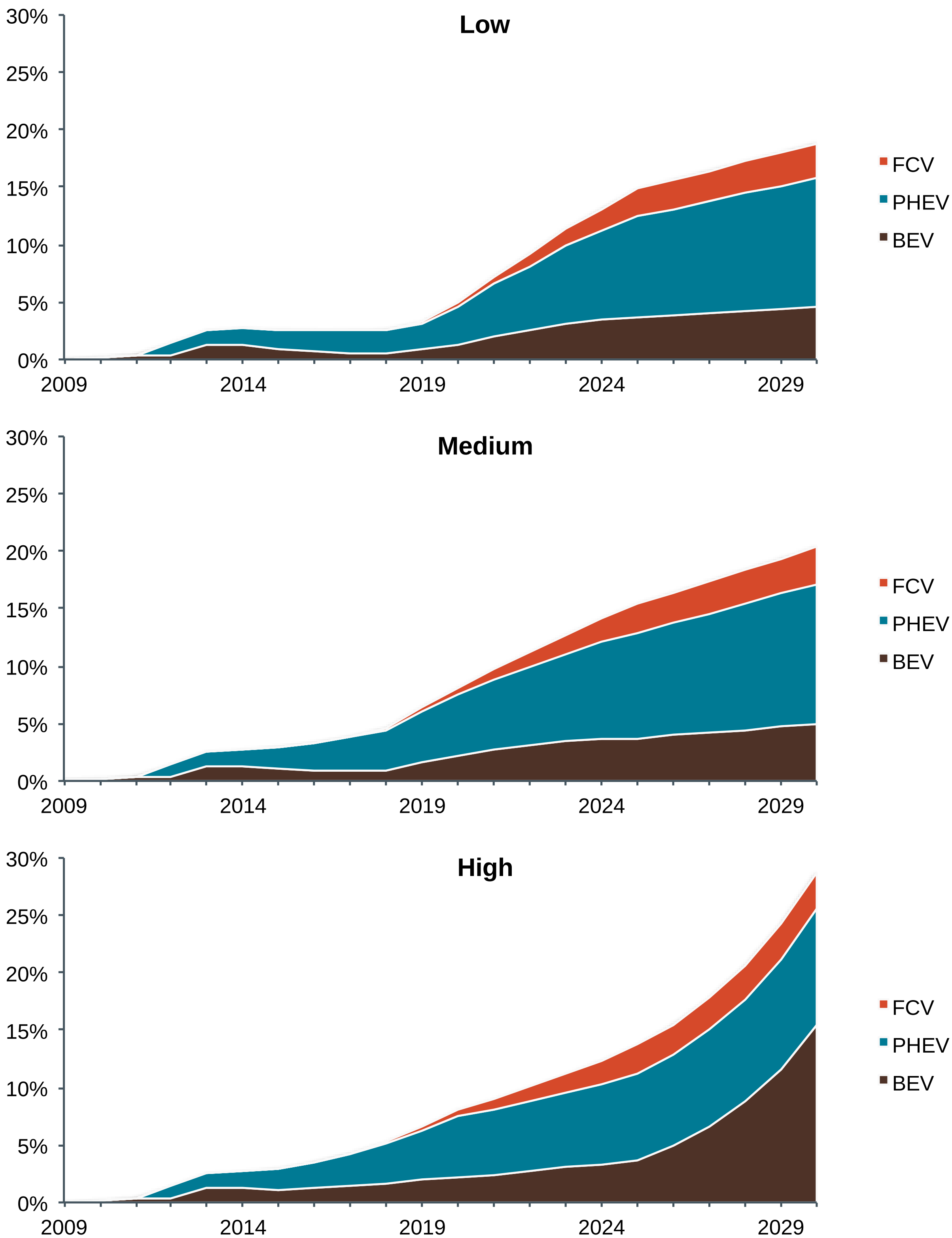


Figure 5.5. Rate of deployment of BEV, PHEV, and FCV new vehicle sales shares for the Low, Medium, and High cases

5.9. Low-carbon electricity availability

As discussed above, the provision of electricity from various energy sources will largely be determined by the four jurisdictions' electricity policy. Based on the increase of low-carbon electricity from renewable sources and sustained use of hydroelectric and nuclear electricity, Table 5.9 summarizes this analysis' assumptions for the supply of low-carbon electricity for the five scenarios.

Table 5.9. Low-carbon electricity generation share and overall electricity carbon intensity

SCENARIO	CHARACTERISTIC	2015	2020	2025	2030
Low	Renewable share	11%	26%	26%	26%
	Hydroelectric and nuclear share	47%	47%	47%	47%
	Fossil share	42%	27%	27%	27%
	Fossil gCO_2e/kWh	391	290	290	290
	Overall gCO_2e/kWh	169	84	84	84
Low-med	Renewable share	11%	26%	28%	31%
	Hydroelectric and nuclear share	47%	47%	47%	47%
	Fossil share	42%	27%	25%	22%
	Fossil gCO_2e/kWh	384	285	285	285
	Overall gCO_2e/kWh	166	83	76	69
Medium	Renewable share	11%	26%	31%	36%
	Hydroelectric and nuclear share	47%	47%	47%	47%
	Fossil share	42%	27%	22%	17%
	Fossil gCO_2e/kWh	377	280	280	280
	Overall gCO_2e/kWh	163	81	68	54
Med-high	Renewable share	11%	26%	33%	38%
	Hydroelectric and nuclear share	47%	47%	47%	47%
	Fossil share	42%	27%	20%	15%
	Fossil gCO_2e/kWh	377	280	273	266
	Overall gCO_2e/kWh	163	81	60	45
High	Renewable share	11%	26%	36%	41%
	Hydroelectric and nuclear share	47%	47%	47%	47%
	Fossil share	42%	27%	17%	12%
	Fossil gCO_2e/kWh	377	280	266	253
	Overall gCO_2e/kWh	163	81	52	37

5.10. Renewable hydrogen availability

The availability of renewable hydrogen for the Pacific region is modeled by varying the assumed carbon intensity of hydrogen. The initial carbon intensity of hydrogen reflects steam reforming of natural gas, taken as the average of hydrogen production pathways HYGN001, HYGN002, HYGN003, HYGN004 listed in the carbon intensity pathways for the California Low-Carbon Fuel Standard (CARB, 2012a). The carbon intensity trajectories to 2030 are shown in Table 5.10. The Low scenario is based on no change and a standards compressed natural gas from central steam reformation of hydrogen over time. The Medium scenario reflects a shift toward 25% renewable hydrogen. The High scenario reflects a shift to 100% renewable hydrogen generation from electrolysis from renewable electricity. The Low-med and Med-high scenarios represent 10% and 50% renewable hydrogen, respectively.

Table 5.10. Average carbon intensity of the hydrogen supply in each case (gCO_2e/MJ)

CASE	2015	2020	2025	2030
Low	118.1	118.1	118.1	118.1
Low-med	118.1	112.1	106.0	100.0
Medium	118.1	105.4	92.7	80.0
Med-high	118.1	98.7	79.4	60.0
High	118.1	92.1	66.0	40.0

5.11. HVO deployment

The illustrative deployment rates for hydrotreated vegetable oil renewable diesel are as shown in Table 5.11. The low case involves a constant fuel deployment of 14.5 PJ in all years, whereas the low-med to high cases are based on increased supply from 29-115.9 PJ/year in 2030, i.e., a maximum supply of 1.5 billion gallons.

Table 5.11. Availability of HVO renewable diesel in each case (PJ/year)

CASE	2015	2020	2025	2030
Low	14.5	14.5	14.5	14.5
Low-med	14.5	19.3	24.2	29.0
Medium	14.5	24.2	33.8	43.5
Med-high	14.5	33.8	53.1	72.5
High	14.5	48.3	82.1	115.9

Current potential HVO production from existing plants (the Diamond Green Diesel and the REG Geismar) in the U.S. is around 30 PJ. There is the potential for imports of HVO from plants outside the U.S. including the UPM plant in Finland (~4.4 PJ), ENI in Italy (13.2 PJ) and current Neste plants in Finland, Singapore, and Rotterdam (totaling ~88PJ). Expected investments in the coming years from these players and others (e.g., Emerald Biofuels and Brasgalp) would increase global capacity by a further 50 PJ. Assuming conservatively that this additional capacity is realized by 2025, the above scenarios for the proportion of this total that the Pacific Region could consume in 2025 would range from between 8-44% of the projected global capacity. This gives a fairly realistic range within which the actual consumption of HVO in the region is likely to fall. The “low” case represents the current imports of HVO to California, and is used as a lower limit for HVO consumption in the Pacific Coast region, out to 2030. The feedstocks assumed in each case are shown in Table 5.12.

Table 5.12. Feedstock assumptions for hydrogenated vegetable oil supply cases

CASE	FEEDSTOCK TYPE	2015	2020	2025	2030
Low	Soy	0.0%	0.0%	0.0%	0.0%
Low	Canola	0.0%	0%	0%	0.0%
Low	UCO	50.0%	42%	33%	25.0%
Low	Tallow	50.0%	50%	50%	50.0%
Low	Corn oil	0.0%	8%	17%	25.0%
Low	Camelina	0.0%	0%	0%	0.0%
Low-med	Soy	0.0%	0.0%	0.0%	0.0%
Low-med	Canola	0.0%	0%	0%	0.0%
Low-med	UCO	50.0%	40%	30%	20.0%
Low-med	Tallow	50.0%	50%	50%	50.0%
Low-med	Corn oil	0.0%	8%	17%	25.0%
Low-med	Camelina	0.0%	2%	3%	5.0%
Medium	Soy	0.0%	0.0%	0.0%	0.0%
Medium	Canola	0.0%	0%	0%	0.0%
Medium	UCO	50.0%	38%	27%	15.0%
Medium	Tallow	50.0%	50%	50%	50.0%
Medium	Corn oil	0.0%	8%	17%	25.0%
Medium	Camelina	0.0%	3%	7%	10.0%
Med-high	Soy	0.0%	0.0%	0.0%	0.0%
Med-high	Canola	0.0%	0%	0%	0.0%
Med-high	UCO	50.0%	38%	27%	15.0%
Med-high	Tallow	50.0%	47%	43%	40.0%
Med-high	Corn oil	0.0%	8%	17%	25.0%
Med-high	Camelina	0.0%	7%	13%	20.0%
High	Soy	0.0%	0.0%	0.0%	0.0%
High	Canola	0.0%	0%	0%	0.0%
High	UCO	50.0%	37%	23%	10.0%
High	Tallow	50.0%	52%	53%	55.0%
High	Corn oil	0.0%	7%	13%	20.0%
High	Camelina	0.0%	5%	10%	15.0%

5.12. E85 deployment

E85 vehicle deployment rates are as shown in Table 5.13.

Table 5.13. Sales fractions for E85 flex-fuel vehicles

CASE	VEHICLE TYPE	2010	2020	2030
Low	Cars	3%	3%	3%
	Light trucks	15%	15%	15%
Low-med	Cars	3%	5%	5%
	Light trucks	15%	18%	18%
Medium	Cars	3%	6%	6%
	Light trucks	15%	22%	22%
Med-high	Cars	3%	7%	7%
	Light trucks	15%	26%	29%
High	Cars	3%	13%	15%
	Light trucks	15%	52%	58%

The volume of ethanol consumed by flex-fuel vehicles depends not only on the number of vehicles in the fleet, but also on the extent to which those vehicles refuel with E85 as opposed to standard gasoline grades. Currently, on average FFVs in the U.S. only use E85 for 1% of total miles traveled, and therefore have a limited contribution to ethanol consumption. However, this fraction is expected to rise in future. The assumed share of vehicle miles traveled on E85 is shown by case in Table 5.14.

Table 5.14. Cases for share of vehicle miles traveled on E85 by flex-fuel vehicles

CASE	2010	2020	2030
Low	1%	4%	8%
Low-Med	1%	6%	12%
Medium	1%	7%	14%
Med-High	1%	9%	18%
High	1%	15%	30%

5.13. Summary of scenarios for low-carbon fuel supply

Eight scenarios are developed for this analysis of potential alternative fuel supplies for the Pacific Coast region in the 2015-2030 timeframe. The scenarios incorporate the above literature review to bound the upper and lower fuel availability and fuel carbon intensities to represent a variety of possibilities for the future Pacific region fuel supply. The scenarios are intended to be reasonable examples of how the regional fuel market could evolve, informed by but not endogenously driven by the existence of the California Low-carbon Fuels Standard, British Columbia Renewable and Low-carbon Fuel Requirement, and Oregon and Washington Clean Fuels Standards. As noted above, although the scenario model is not defined explicitly by the various policies and it does not include all of the precise provisions, below we present a comparison between the carbon intensity reduction delivered in each scenario and the carbon intensity potentially required by regulations.

The scenario assumptions are shown in Table 5.15. As shown in the table there is a wide range of assumptions for the different scenarios, with some being more dependent on alternative vehicle deployment, others more dependent on cellulosic fuel commercialization or on the decarbonization of the first generation biofuel supply. These scenarios, by design, reflect the variation in the possible deployment that could result, depending on industry investment, prevailing policy requirements, and market factors that could push any of the various fuel deployment volumes higher or lower over the next fifteen years. These scenarios are not constraints on the potential for low-carbon fuel development through 2030, but rather plausible scenarios based on emerging technology and market trends. The low and high cases are not intended to represent minimum and maximum possible rates – given the right set of circumstances supply could exceed the high cases modeled here. Descriptions of the eight scenarios are provided in Chapter 7.

Table 5.15. Summary of case assumptions implemented in each scenario

Variable	Cases for each of the eight scenarios							
	1	2	3	4	5	6	7	8
Standard ethanol blend	E15	E10	E15	E15	E15	E15	E15	E10
Standard biodiesel blend	B15	B15	B10	B10	B20	B10	B7	B20
Year of new biofuel blends:	2030	2020	2030	2030	2030	2030	2020	2030
Conventional ethanol	High	Med-high	Med-high	Medium	High	High	Medium	High
Biodiesel	Med-high	Med-high	Low-med	Medium	Med-high	Medium	High	Med-high
Cellulosic ethanol	Low	High	Low-med	High	Medium	Med-high	Medium	Low
Drop in renewable diesel	Low	Med-high	Low-med	High	High	Medium	Low-med	Low
Drop in renewable gasoline	Low	Med-high	Low-med	High	High	Medium	Medium	Low
Natural gas	Medium	Medium	Medium	Med-high	Low-med	Med-high	Med-high	High
Renewable natural gas	Medium	Low	High	High	Med-high	Medium	Medium	Med-high
Electricity	Medium	Low	Medium	Medium	Medium	High	Med-high	High
Renewable Electricity	Medium	Low	Medium	Medium	Medium	Medium	High	High
Hydrogen	Medium	Low	Medium	Medium	Medium	High	Medium	High
Renewable hydrogen	Medium	Low	Medium	Medium	High	Medium	High	Medium
HVO	High	High	Low-med	Medium	Medium	Med-high	Med-high	Medium
E85	Low	High	Medium	Medium	Low-med	Medium	Medium	Low

6. Scenario results

As discussed in Chapter 5 and detailed in Table 5.15, the scenarios are defined in reference to low, low-med, medium, med-high and high cases for the carbon savings available from each key fuel supply variable modeled. Based on these cases, each scenario is modeled with a differing fuel mix and therefore delivering differing carbon emissions reductions.

6.1. Scenario 1

Table 6.1. Supply case assumptions for Scenario 1

	Scenario 1
Standard ethanol blend	E15
Standard biodiesel blend	B15
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	High
Fatty acid methyl ester biodiesel carbon reductions	Med-high
Cellulosic ethanol deployment	Low
Cellulosic renewable diesel deployment	Low
Cellulosic renewable gasoline deployment	Low
Natural gas vehicle deployment	Medium
Renewable natural gas availability	Medium
Electric vehicle deployment	Medium
Renewable Electricity availability	Medium
Hydrogen fuel cell deployment	Medium
Renewable hydrogen availability	Medium
HVO deployment	High
E85 vehicle deployment	Low

Scenario 1 (Table 6.1) represents a case in which the deployment of alternative vehicles is moderate, while the deployment rate of cellulosic biofuel is low. Typical biofuel blend rates increase (with 15% ethanol and biodiesel in gasoline and diesel respectively becoming normative by 2030), production of first generation ethanol and biodiesel shifts to lower carbon feedstocks and there is an increasing supply of low-carbon HVO to the Pacific market. On the vehicles side, this scenario would correspond to the case that the ZEV program is met but not exceeded, and that there is a moderate increase of natural gas use in trucks but that E85 flex-fuel vehicles do not significantly increase market penetration or E85 utilization rates. Renewable natural gas meets 75% of demand for natural gas in transport, with about 125 thousand natural gas vehicles on the road by 2030. This scenario also includes a 1.5 billion gallon supply of HVO, from tallow, corn oil, yellow grease, and camelina.

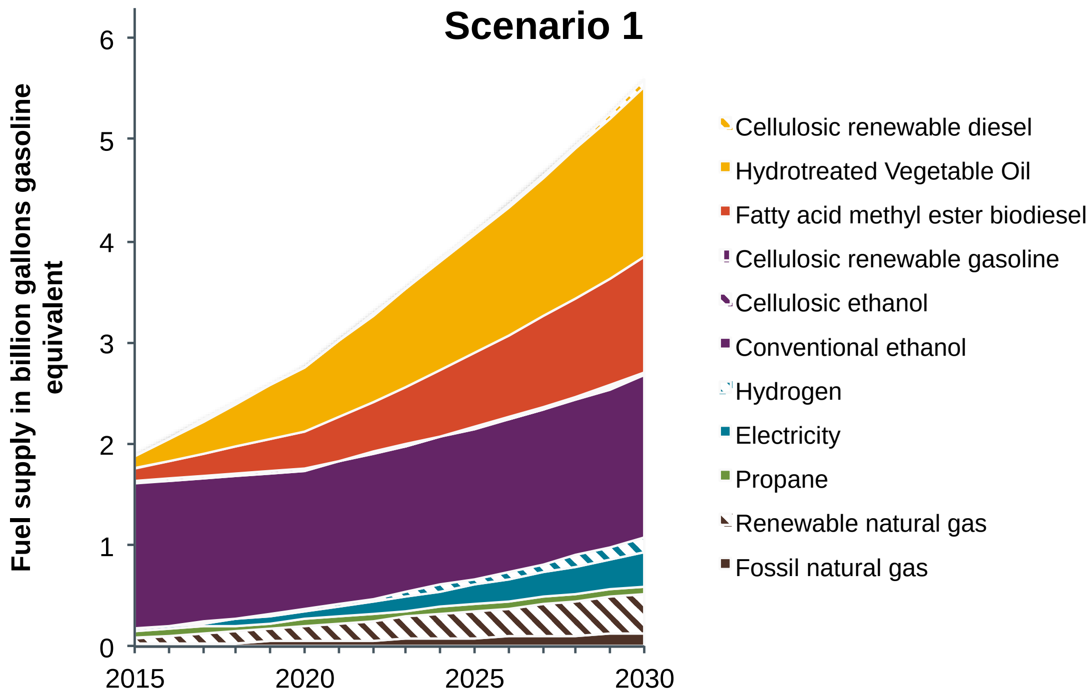


Figure 6.1. Low-carbon fuel supply by fuel type in Scenario 1

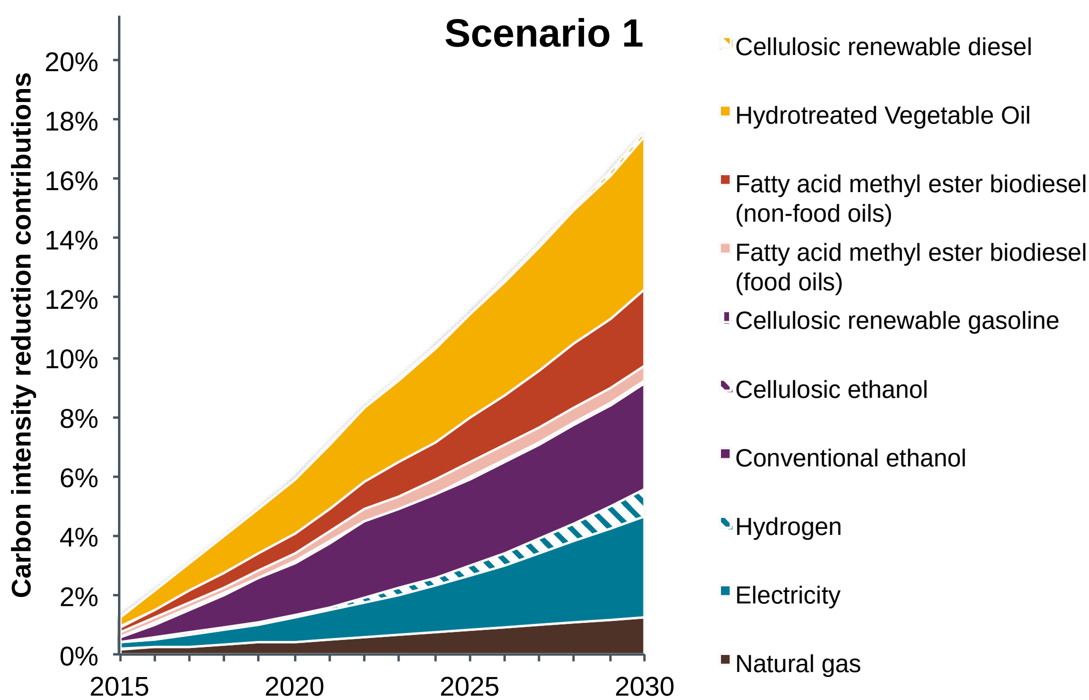


Figure 6.2. Carbon intensity reduction contributions by fuel type in Scenario 1

Figure 6.1 shows the overall supply of low-carbon fuels increasing in energy terms from about two billion gallons of gasoline equivalent in 2015 to over five billion gallons in 2030. The largest source of this increase is hydrotreated vegetable oil used as a drop-in diesel substitute. The supply of biodiesel also increases as the average blend rate increases to B15, and the increased deployment of alternative fueled vehicles creates additional opportunity to increase the low-carbon fuel supply.

Figure 6.2 shows that the largest contributors by 2030 to the carbon intensity reductions achieved in this scenario are first generation ethanol, biodiesel from waste oils, HVO from waste oils, and electricity for transportation.

This scenario does not include rapid cellulosic fuels growth, but it does require gradually increasing volumes of first generation biofuels (ethanol blends increase towards E15 after 2020), and of HVO (1.5 billion gallons), all from increasingly low-carbon feedstocks. This would create demand for sugarcane ethanol and for waste oils. The necessary volumes of sugarcane ethanol (1.2 billion gallons in 2020 and a peak demand of 1.9 billion gallons in 2030) would represent a substantial increase in consumption for the region. However, it would be within Brazil's historical ability to export, and there would be time to improve infrastructure to enable the trade. This level of sugarcane ethanol supply would also fit comfortably within the non-cellulosic, non-diesel portion of the advanced biofuel mandate for 2020 under the Renewable Fuel Standard, suggesting that these imports could have access to valuable advanced Renewable Identification Numbers (RINs). Tallow demand would be high, largely for HVO production, at 350 million gallons in 2020 and rising to a nearly a billion gallons in 2030. This is around total expected 2030 U.S. tallow production. The Pacific region is likely to be a better market for tallow biodiesel/HVO than other states so it is reasonable to believe that a large fraction of tallow supply could be made available to the Pacific market, but this level of consumption would affect other users of tallow. Peak corn oil demand of over 450 million gallons would stretch U.S. production capacity, and again this level of consumption would require that the available resource was monopolized for the Pacific market. 2020 yellow grease demand of 280 million gallons would be above U.S. collection capacity, and this would rise further to 370 million gallons by 2030. Imports of low-carbon feedstock for biodiesel and HVO and/or of processed fuels (such as imports of HVO from yellow grease) would be necessary in this scenario. With an anticipated camelina oil demand of over 300 million gallons, this scenario would also require substantial growth in the production of camelina or alternative low-carbon biodiesel and HVO feedstocks.

In this scenario, compliance with regulatory carbon intensity reduction targets would be possible in all years. In 2020, this would require drawing down stocks of emissions reduction credits. Post-2020, this scenario would allow compliance with the illustrative case of 0.5 percentage point annual increase of targets beyond the published trajectories of the programs.

6.2. Scenario 2

Table 6.2. Supply case assumptions for Scenario 2

	Scenario 2
Standard ethanol blend	E10
Standard biodiesel blend	B15
Biofuel blends increase by year	2020
Conventional ethanol carbon reductions	Med-high
Fatty acid methyl ester biodiesel carbon reductions	Med-high
Cellulosic ethanol deployment	High
Cellulosic renewable diesel deployment	Med-high
Cellulosic renewable gasoline deployment	Med-high
Natural gas vehicle deployment	Medium
Renewable natural gas availability	Low
Electric vehicle deployment	Low
Renewable Electricity availability	Low
Hydrogen fuel cell deployment	Low
Renewable hydrogen availability	Low
HVO deployment	High
E85 vehicle deployment	High

Scenario 2 (Table 6.2) reflects a case where the deployment of electric drive vehicles lags behind the targeted schedule of the ZEV program, but the supply of low-carbon biofuels is strong across the board. In contrast to Scenario 1, the roll-out of cellulosic fuels is relatively aggressive, achieving the medium-high case for each of cellulosic ethanol, cellulosic renewable diesel and cellulosic renewable gasoline. As in Scenario 1, the biodiesel blend increases to 15% on average, but in this scenario the transition happens rapidly by 2020. Unlike Scenario 1, the typical ethanol blend rate remains at E10, however there is some compensating increase in ethanol demand due to robust growth in the demand for ethanol from the E85 fleet. The supply of cellulosic ethanol increases strongly, to about 1.5 billion gallons by 2030, and despite overall ethanol demand growth this results in a reducing market for conventional ethanol, as can be seen in Figure 6.3. As in Scenario 1, there is a 1.5 billion gallons supply of HVO. Corn ethanol supply is reduced to zero by 2030, and natural gas vehicles achieve moderate penetration in the heavy-duty fleet, resulting in 400 million gallons of diesel equivalent consumption by 2030, although only 25% of this is renewable. Figure 6.3 shows that the overall 2030 supply of low-carbon fuels is higher in energetic terms than in Scenario 1, at around 6 billion gallons of gasoline equivalent.

Figure 6.4 shows the contribution to the carbon intensity reductions from each fuel. HVO is again the largest single contributor, with 1.5 billion gallons sourced from tallow, UCO, corn oil, and camelina. Cellulosic fuels, ethanol in particular, make a more significant contribution to carbon intensity reductions than in Scenario 1. Cellulosic fuels deliver over 13 million tons of carbon dioxide emissions reductions per annum by 2030.

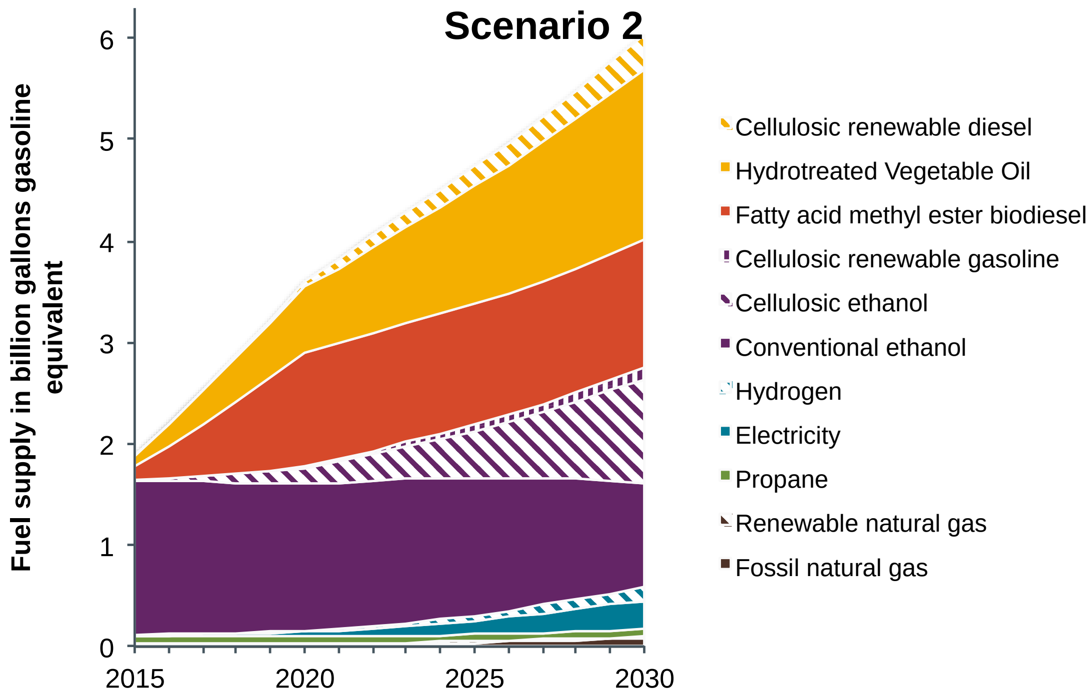


Figure 6.3. Low-carbon fuel supply by fuel type in Scenario 6

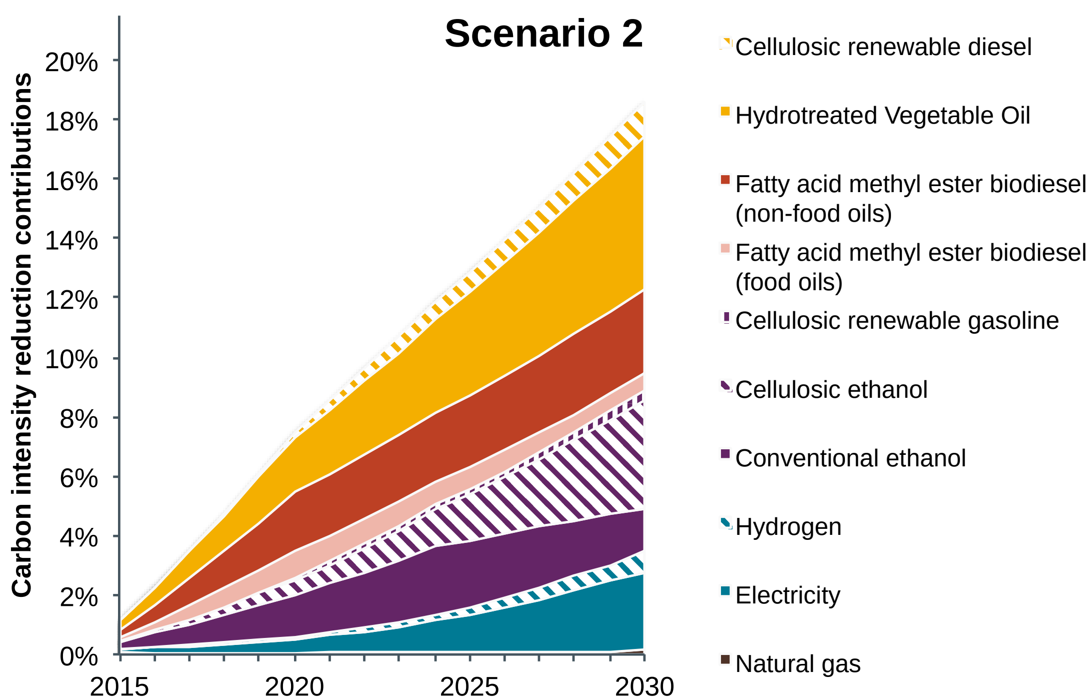


Figure 6.4. Carbon intensity reduction contributions by fuel type in Scenario 2

As in Scenario 1, compliance is achievable with regulatory targets throughout the study period. There would be no year in which suppliers would necessarily need to draw down stocks of banked emissions reduction credits. By 2030, emission reductions would be substantially higher than would be required by the modest illustrative requirement for 2030 considered here. To put it another way, it may be unlikely that the low-carbon fuel supply in this scenario could be achieved without a more ambitious rate of increase of future targets than 0.5 percentage points per year. As in Scenario 1, there would be high demand for waste and residual biodiesel and HVO feedstocks, which would mean that some biodiesel, HVO or feedstock would need to be imported. Sugarcane ethanol demand would rise to about 1.4 billion gallons by 2030. As in Scenario 1, this is within reasonable expectations of Brazilian export potential.

6.3. Scenario 3

Table 6.3. Supply case assumptions for Scenario 3

	Scenario 3
Standard ethanol blend	E15
Standard biodiesel blend	B10
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	Med-high
Fatty acid methyl ester biodiesel carbon reductions	Low-med
Cellulosic ethanol deployment	Low-med
Cellulosic renewable diesel deployment	Low-med
Cellulosic renewable gasoline deployment	Low-med
Natural gas vehicle deployment	Medium
Renewable natural gas availability	Med-high
Electric vehicle deployment	Medium
Renewable Electricity availability	Medium
Hydrogen fuel cell deployment	Medium
Renewable hydrogen availability	Medium
HVO deployment	Low-med
E85 vehicle deployment	Medium

Scenario 3 (Table 6.3) represents a case in which there are tighter limitations across a range of low-carbon fuel supply options. The typical rate of ethanol blending increases to E15 by 2030, but biodiesel blend rates are lower than before, reaching only 10% by 2030. Unlike the first two scenarios, the HVO supply is quite limited in Scenario 3. There is a move away from corn ethanol towards sugarcane and other lower carbon feedstocks by 2030. In this scenario, the commercialization of cellulosic fuel production is severely delayed, with a five-year lag before growth gets started. This makes cellulosic fuel a negligible contributor to emissions reductions in 2020, although supply does pick up somewhat by 2030 (about 400 million gallons of gasoline equivalent).

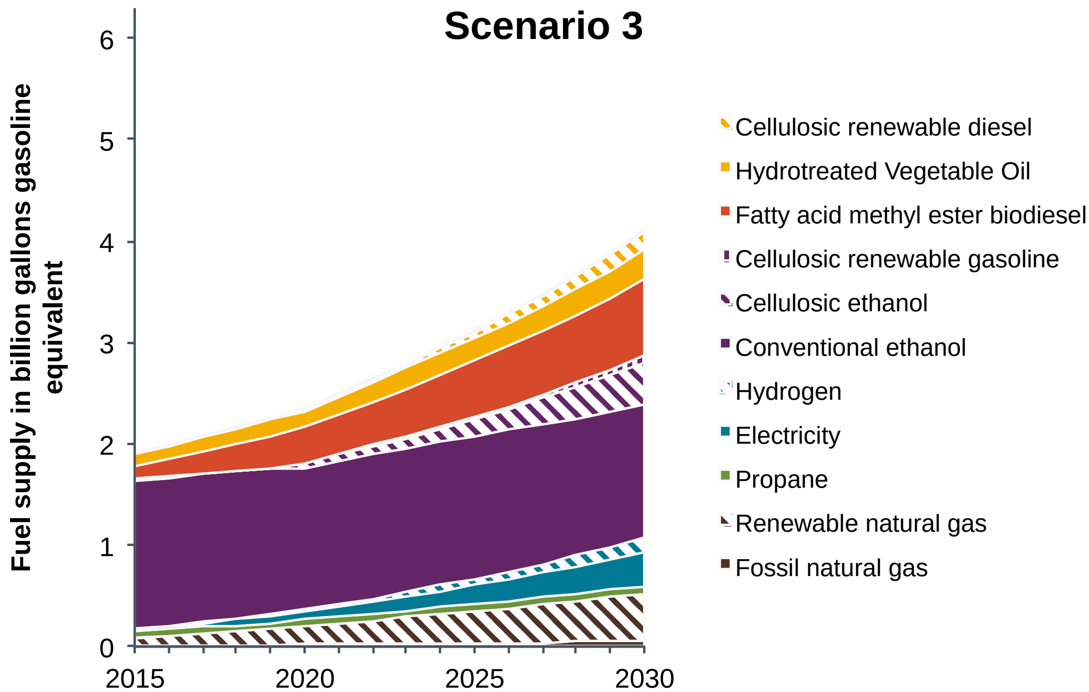


Figure 6.5. Low-carbon fuel supply by fuel type in Scenario 3

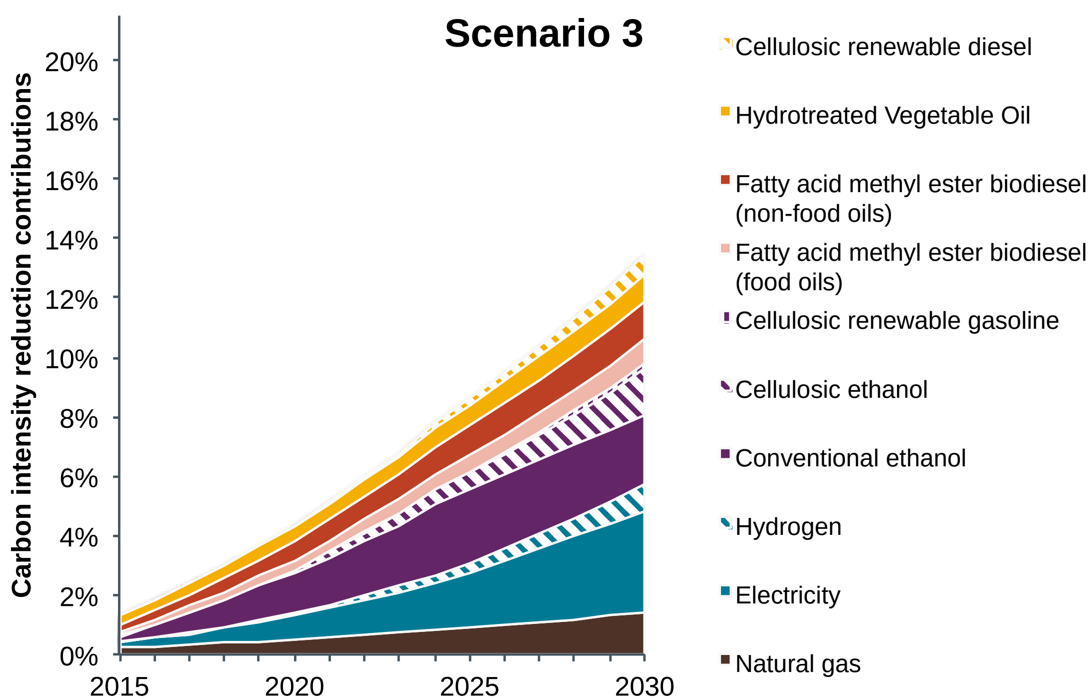


Figure 6.6. Carbon intensity reduction contributions by fuel type in Scenario 3

As seen in Figure 6.6, the largest emissions reduction contributions come from first generation ethanol and electricity for electric vehicles. After about 2025 the contribution of first generation ethanol starts to decline as it is displaced from the market by cellulosic ethanol.

In this scenario, compliance with the regional low-carbon fuel requirements would not be possible without large emissions reductions being delivered from sources outside the scope of this exercise (e.g. innovative upstream emissions reduction in the oil industry). Failing this, we would expect to see at least some suppliers in non-compliance in 2020. It is important to bear in mind that in the real world if the supply of low-carbon fuels is expected to be inadequate to allow compliance with policies in place in the Pacific region, this could be expected to increase the value of emissions reductions on the credit trading market. This value increase should in turn spur increased supply of low-carbon fuels. As discussed in Section 1.1, this study does not make an integrated economic assessment of the implications of potential increases in carbon credit value. Just as the (high) low-carbon fuel supply modeled for Scenario 2 may be unlikely to be actualized without ambitious long-term policy targets to 2030, so it might be expected that the relatively disappointing low-carbon fuel supply in Scenario 3 would only be likely to be actualized in the event of uncertainty in the Pacific Region programs preventing investment, or of some exogenous circumstance impacting on the regional fuel supply.

6.4. Scenario 4

Table 6.4. Supply case assumptions for Scenario 4

	Scenario 4
Standard ethanol blend	E10
Standard biodiesel blend	B10
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	Medium
Fatty acid methyl ester biodiesel carbon reductions	Medium
Cellulosic ethanol deployment	High
Cellulosic renewable diesel deployment	High
Cellulosic renewable gasoline deployment	High
Natural gas vehicle deployment	Med-high
Renewable natural gas availability	High
Electric vehicle deployment	Medium
Renewable Electricity availability	Medium
Hydrogen fuel cell deployment	Medium
Renewable hydrogen availability	Medium
HVO deployment	Medium
E85 vehicle deployment	Medium

In Scenario 4, as in Scenarios 1 and 3, electric vehicle roll out meets the expectations of the ZEV program. However, in this scenario the contribution of first generation ethanol is limited by the standard ethanol blend, which remains at 10%, and the transition away from corn ethanol to lower-carbon feedstocks is slower than in scenarios 1-3. The roll out of cellulosic fuel production is more successful in this than any of the prior scenarios, achieving the high rate with 2.3 billion gallons of gasoline equivalent in the supply by 2030. The emissions reductions from cellulosic ethanol are much greater than those delivered from first generation ethanol by 2030. There is also substantial natural gas vehicle deployment (the med-high rate), with 90% of the 850 million gallons of diesel equivalent consumed in 2030 being renewable (Figure 6.8).

As can be seen in Figure 6.8, electricity, natural gas, and cellulosic ethanol are the major contributors of carbon savings in this scenario. Cellulosic renewable diesel is also a source of considerable savings (10 million tons of CO_2 reductions per annum by 2030). The strong supply of cellulosic fuels would require on the order of 40 million tons of dry biomass feedstock. Even with the high assumptions on all cellulosic fuels and aggressive expansion of the natural gas vehicle fleet, compliance with regional carbon intensity reduction targets may not be possible in 2020 in this scenario – a small deficit of 700 thousand tons of reductions is expected in 2020 without an increased supply of credits from other compliance options. With the illustrative post-2020 trajectory considered here, it would take until 2027 to bring the regional programs back into collective credit under this scenario. As noted in Scenario 3, this modeling does not directly account for the likelihood that a relatively low supply of low-carbon fuels would increase credit value and therefore spur additional investment.

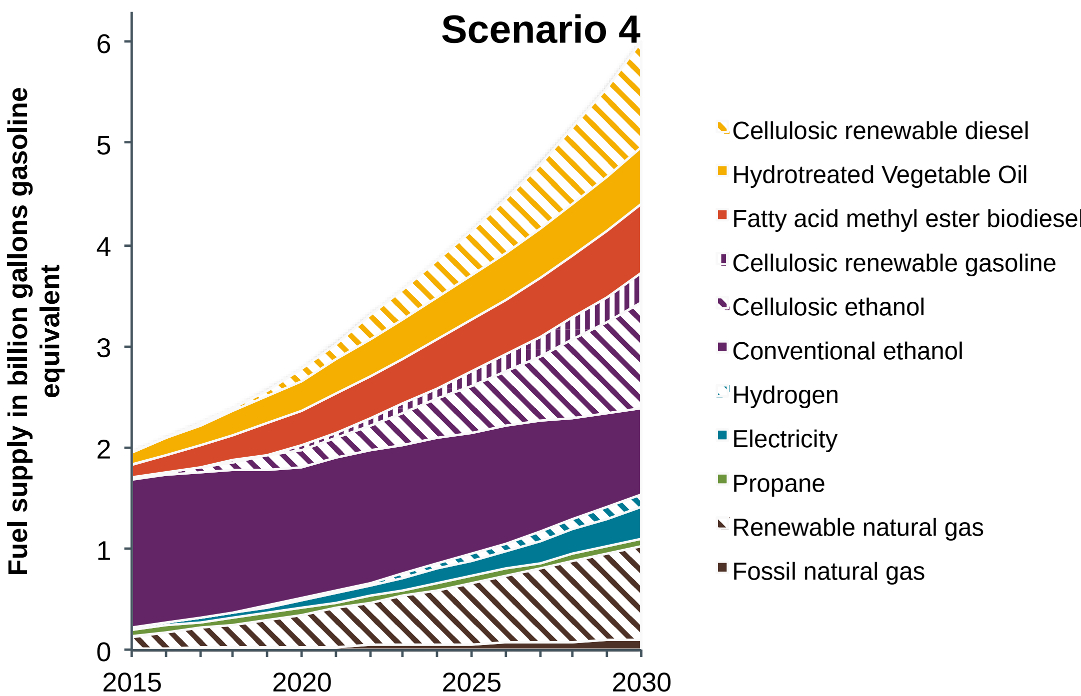


Figure 6.7. Low-carbon fuel supply by fuel type in Scenario 4

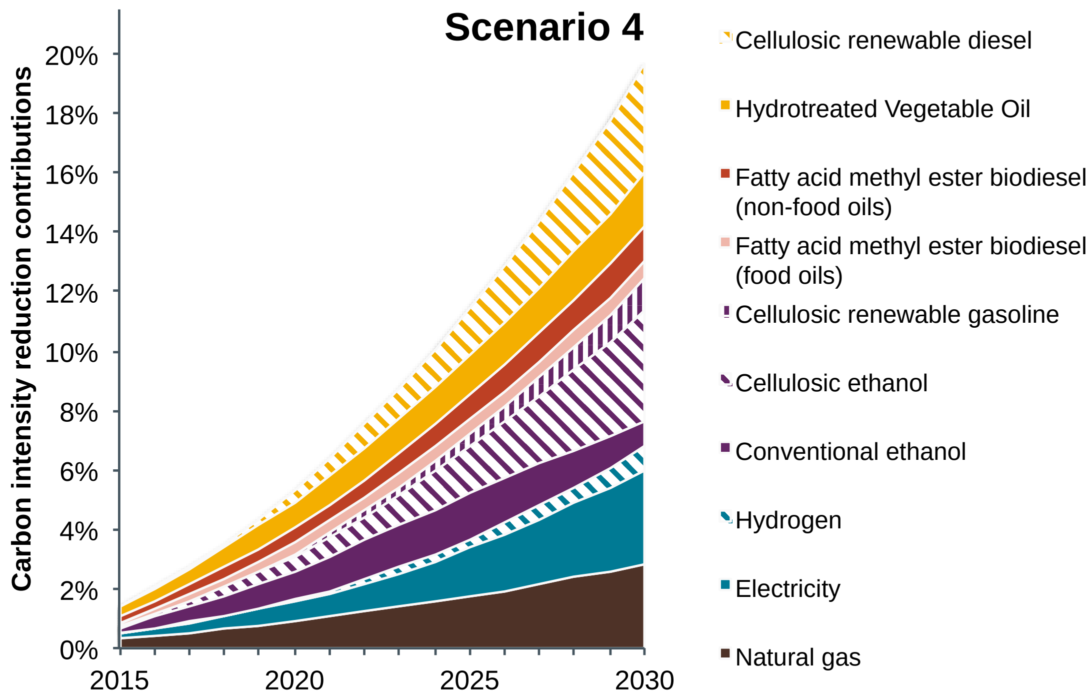


Figure 6.8. Carbon intensity reduction contributions by fuel type in Scenario 4

6.5. Scenario 5

Table 6.5. Supply case assumptions for Scenario 5

	Scenario 5
Standard ethanol blend	E15
Standard biodiesel blend	B15
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	High
Fatty acid methyl ester biodiesel carbon reductions	Med-high
Cellulosic ethanol deployment	Medium
Cellulosic renewable diesel deployment	High
Cellulosic renewable gasoline deployment	High
Natural gas vehicle deployment	Medium
Renewable natural gas availability	Med-high
Electric vehicle deployment	Medium
Renewable Electricity availability	Medium
Hydrogen fuel cell deployment	Medium
Renewable hydrogen availability	High
HVO deployment	Medium
E85 vehicle deployment	Low-med

In Scenario 5 we again consider a transition to higher standard biofuel blends, 15% for both ethanol and biodiesel in 2030. The savings from first generation ethanol are high. Cellulosic ethanol production proceeds at a moderate rate but drop-in cellulosic fuel production proceeds at full pace, with drop-in fuel supply exceeding cellulosic ethanol supply by 2030. The natural gas vehicle fleet reaches over 100 thousand, with 90% of gas being renewable. Total gas demand reaches over 400 million gallons diesel equivalent by 2030. Sugarcane ethanol consumption reaches 1.1 billion gallons by 2020, and rises to 1.6 billion gallons by 2030. Molasses ethanol consumption reaches 390 million gallons by 2030. Again, e-drive vehicle deployment follows the ZEV program.

As can be seen in Figure 6.10, electricity is a major contributor of carbon savings in this scenario. Cellulosic renewable diesel and sugarcane ethanol are also important, as are non-food biodiesel and HVO. The sources of carbon savings are relatively diversified compared to some other scenarios. This scenario would deliver compliance with regulatory targets to 2020, but depending on the post-2020 trajectory compliance may become challenging after that point.

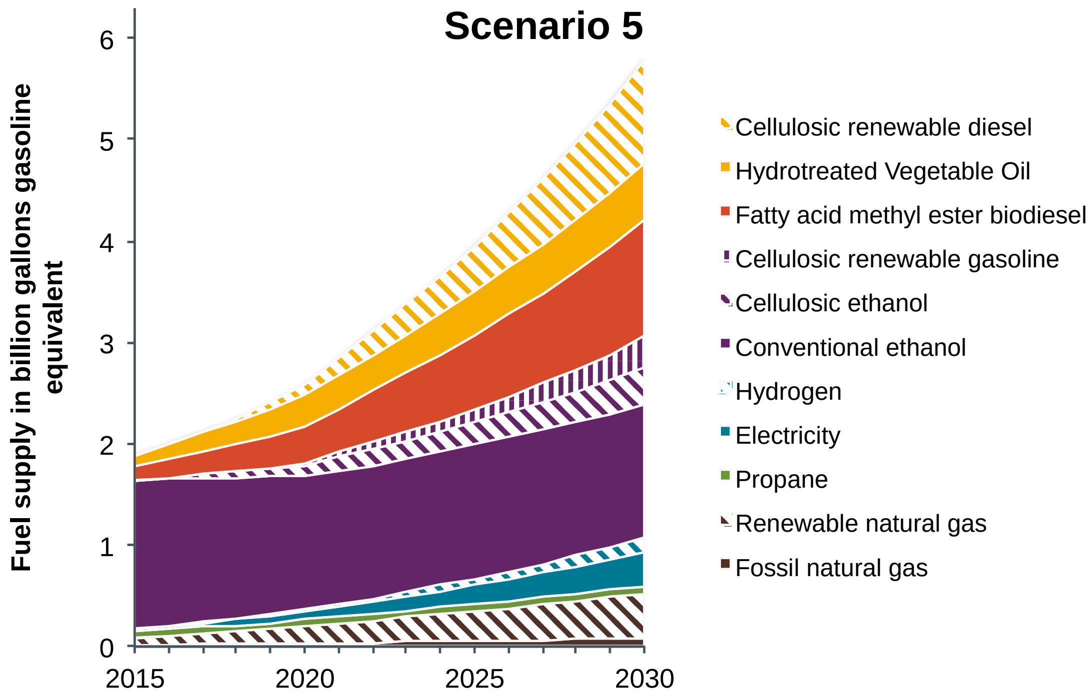


Figure 6.9. Low-carbon fuel supply by fuel type in Scenario 5

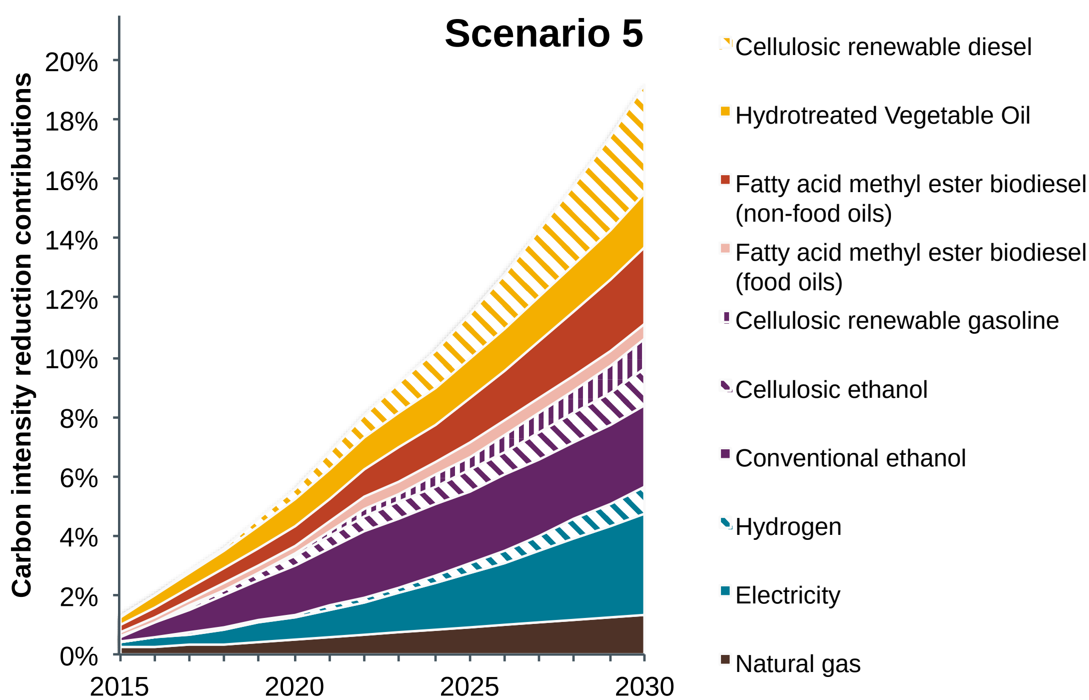


Figure 6.10. Carbon intensity reduction contributions by fuel type in Scenario 5

6.6. Scenario 6

Table 6.6. Supply case assumptions for Scenario 6

	Scenario 6
Standard ethanol blend	E15
Standard biodiesel blend	B10
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	High
Fatty acid methyl ester biodiesel carbon reductions	High
Cellulosic ethanol deployment	Medium
Cellulosic renewable diesel deployment	Medium
Cellulosic renewable gasoline deployment	Medium
Natural gas vehicle deployment	Med-high
Renewable natural gas availability	Med-high
Electric vehicle deployment	High
Renewable Electricity availability	Medium
Hydrogen fuel cell deployment	High
Renewable hydrogen availability	Medium
HVO deployment	Medium
E85 vehicle deployment	Medium

In Scenario 6, carbon emissions reductions from first generation biofuels are strong with medium-high deployment of cellulosic ethanol but slower deployment of drop-in fuels (Figure 6.11). This is the first scenario that includes higher-than-ZEV rates of electric drive sales by 2030. Natural gas vehicle deployment is also medium-high, putting over 130 thousand natural gas vehicles on the road by 2030.

With the high share for electric vehicle sales in this scenario (a combined total of about 5 million PHEVs, BEVs and FCVs by 2030), electric vehicles are the largest single source of emissions reductions (as shown in Figure 6.12), generating 18 million tons of annual savings in 2030. The remaining carbon reductions for Scenario 6 are spread predominantly between conventional and cellulosic ethanol, natural gas and HVO. Demand for waste oils is again significant but is more manageable than in Scenario 1 or 2, about 500 million gallons of tallow, 250 million gallons of yellow grease, and 320 million gallons of corn oil. Sugarcane ethanol demand peaks at about 1.5 billion gallons. Demand for biomass feedstock is on the order of 20 million tons.

The supply of fuel is adequate in this scenario to meet illustrative compliance targets in all years, though some draw-down of banked credits is anticipated for a year or more from 2019.

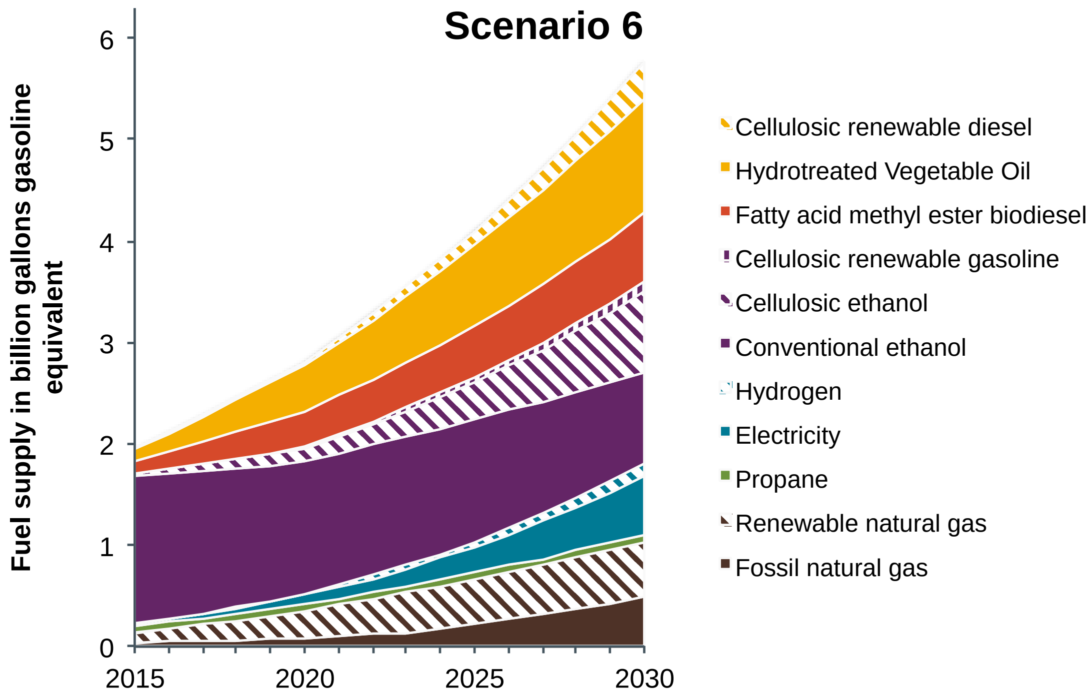


Figure 6.11. Low-carbon fuel supply by fuel type in Scenario 6

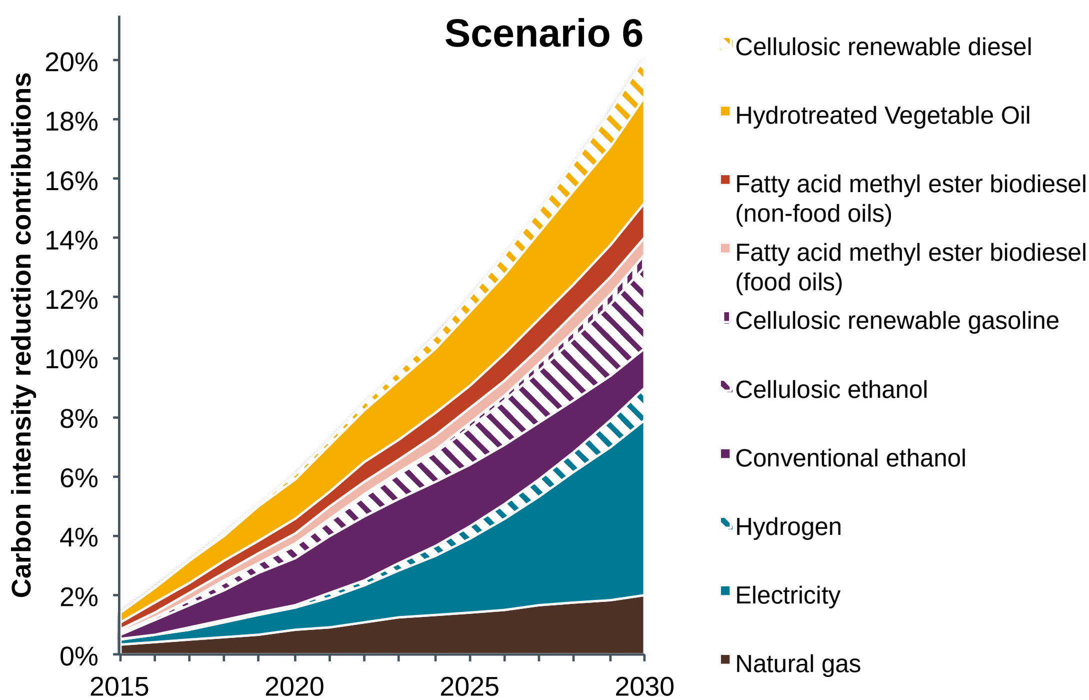


Figure 6.12. Carbon intensity reduction contributions by fuel type in Scenario 6

6.7. Scenario 7

Table 6.7. Supply case assumptions for Scenario 7

	Scenario 7
Standard ethanol blend	E15
Standard biodiesel blend	B7
Biofuel blends increase by year	2020
Conventional ethanol carbon reductions	Medium
Fatty acid methyl ester biodiesel carbon reductions	High
Cellulosic ethanol deployment	Medium
Cellulosic renewable diesel deployment	Low-med
Cellulosic renewable gasoline deployment	Medium
Natural gas vehicle deployment	Med-high
Renewable natural gas availability	Medium
Electric vehicle deployment	Med-high
Renewable Electricity availability	High
Hydrogen fuel cell deployment	Medium
Renewable hydrogen availability	High
HVO deployment	Med-high
E85 vehicle deployment	Medium

Scenario 7 (Table 6.7) couples a positive outlook for electric and flex-fuel vehicles with rapid increase in standard ethanol and biodiesel blends to 15% and 7% respectively by 2020. Rates of cellulosic fuel deployment are moderate (Figure 6.13). Natural gas vehicle deployment is strong and is predominantly renewable, and electricity and hydrogen have a higher renewable fraction than in previous scenarios.

The 2030 picture is positive in Scenario 7, with large carbon savings contributions from electricity, ethanol and HVO, as shown in. The higher ethanol blend in 2020 delivers early savings, giving Scenario 7 the second best 2020 performance behind scenario 2. However, with slower growth in cellulosic fuel availability, by 2030 Scenario 7 is delivering less well, and despite being well in compliance with the illustrative compliance curve in all years, has the second lowest carbon saving recorded for 2030 (16%, Figure 6.14).

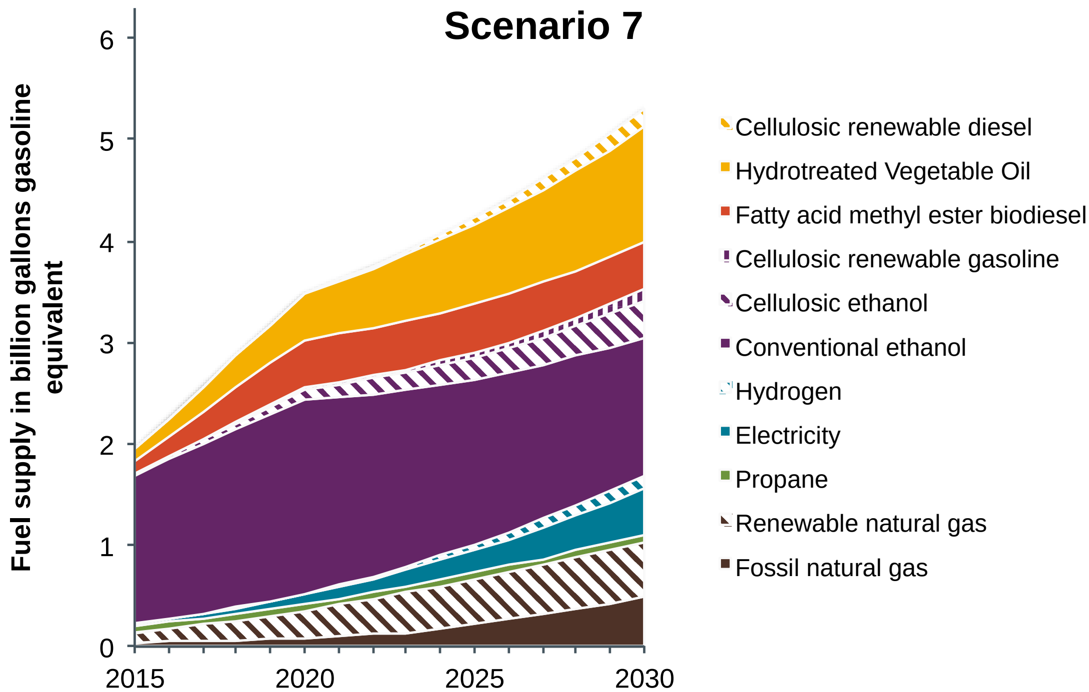


Figure 6.13. Low-carbon fuel supply by fuel type in Scenario 7

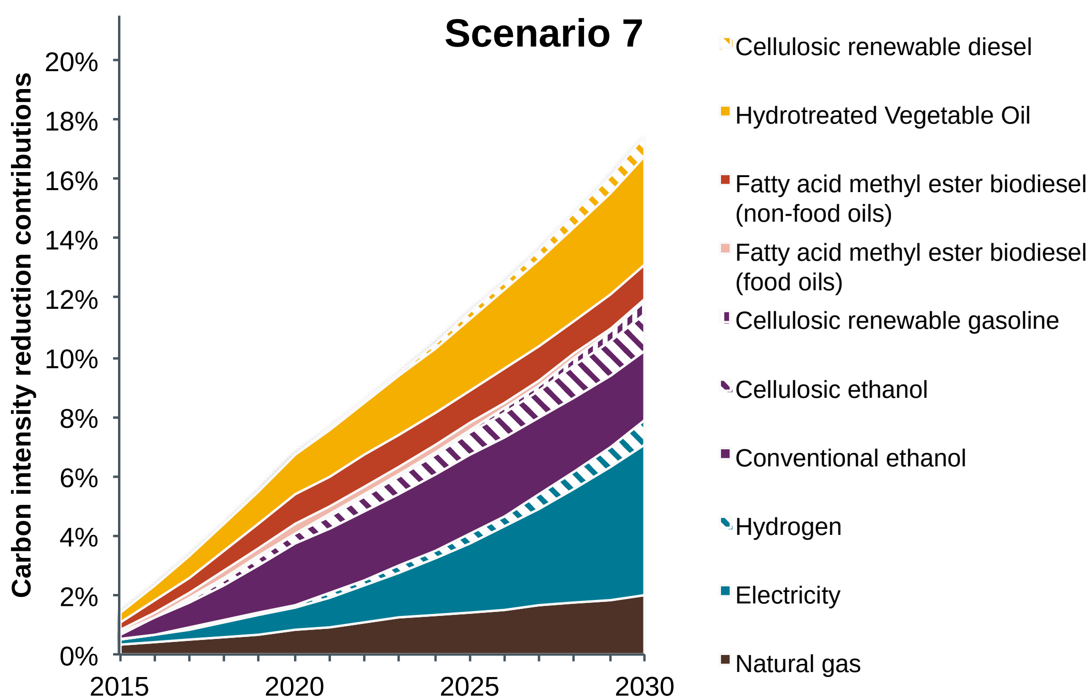


Figure 6.14. Carbon intensity reduction contributions by fuel type in Scenario 7

6.8. Scenario 8

Table 6.8. Supply case assumptions for Scenario 8

	Scenario 8
Standard ethanol blend	E10
Standard biodiesel blend	B20
Biofuel blends increase by year	2030
Conventional ethanol carbon reductions	High
Fatty acid methyl ester biodiesel carbon reductions	Med-high
Cellulosic ethanol deployment	Low
Cellulosic renewable diesel deployment	Low
Cellulosic renewable gasoline deployment	Low
Natural gas vehicle deployment	High
Renewable natural gas availability	High
Electric vehicle deployment	High
Renewable Electricity availability	High
Hydrogen fuel cell deployment	High
Renewable hydrogen availability	High
HVO deployment	Medium
E85 vehicle deployment	High

Scenario 8 (Table 6.8) models the highest biodiesel blend, 20% by 2030, along with high deployment of all types of alternative fuel vehicles. Indeed, by 2030 conventional gasoline vehicles account for less than 10% of sales in the light-duty vehicle pool, with sales consisting of a third hybrid vehicles, a quarter battery electric, a sixth plug-in hybrid, another sixh flex-fuel[9], and the rest being diesel, fuel cells and conventional. High savings are offered by first generation ethanol and biodiesel, but deployment of all cellulosic fuels is low. Renewable natural gas supply reaches 1.1 billion gallons of gasoline equivalent by 2030 (Figure 6.15).

For this scenario alternative fuel vehicles (natural gas and electric) dominate the carbon savings, as shown in Figure 6.16. There are also substantial contributions from biodiesel and HVO. Consumption of tallow, yellow grease and corn oil is substantial, but not so high as in Scenarios 1 or 2. Supply again meets or exceeds illustrative compliance requirements in all years.

[9] Note that the model does not include hybrid electric flex-fuel vehicles.

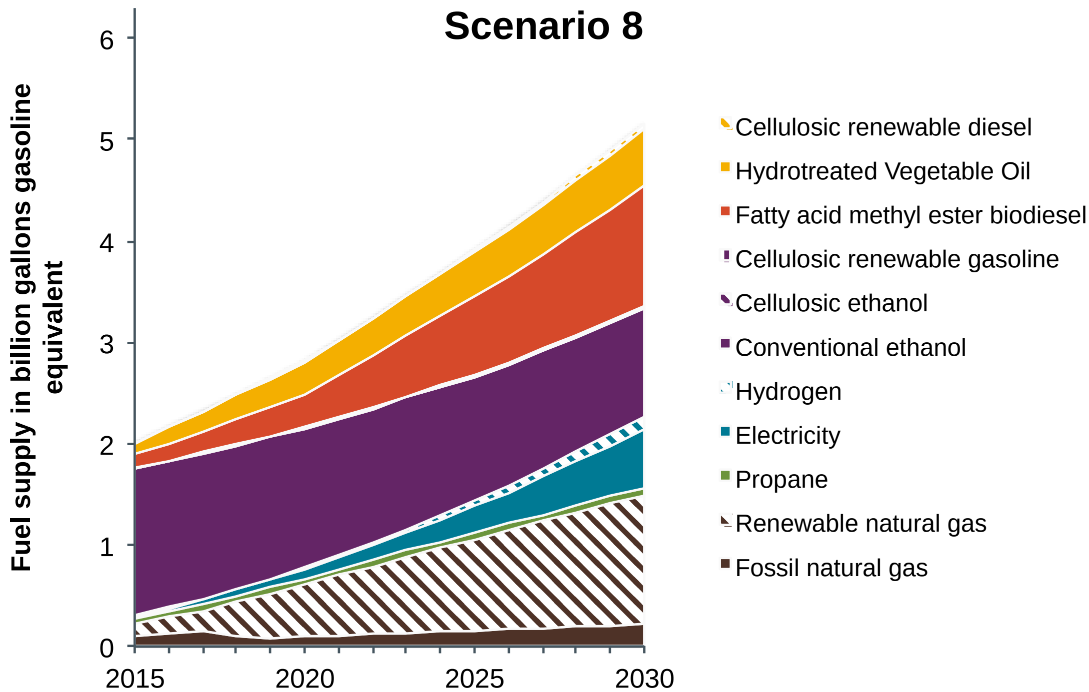


Figure 6.15. Low-carbon fuel supply by fuel type in Scenario 8

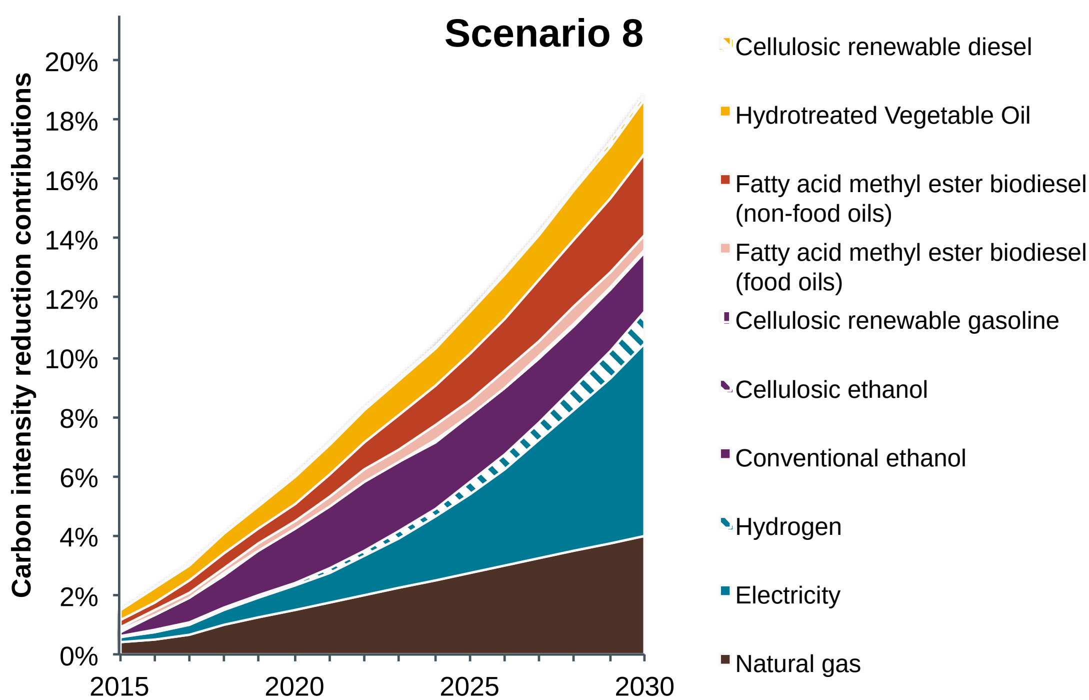


Figure 6.16. Carbon intensity reduction contributions by fuel type in Scenario 8

6.9. Summary of scenario results

Summarizing the results from the above scenarios, Table 6.9 shows the average carbon reduction achieved across the region as a whole in 2020, 2025, and 2030 for each scenario.

Table 6.9. Percentage emissions reductions in 2020 and 2030 against a 98.5 gCO_2e/MJ 2010 baseline for all scenarios*

SCENARIO	2020	2025	2030
1	7%	12%	19%
2	8%	14%	19%
3	5%	9%	14%
4	6%	12%	21%
5	6%	12%	20%
6	7%	13%	21%
7	8%	13%	18%
8	7%	13%	21%

**Including assumed savings from electric rail and innovative upstream emissions reductions, see section 4.3.*

Figure 6.17 and Figure 6.18 show the average fuel carbon intensity reductions from all road transportation fuels in the four Pacific Coast jurisdictions in 2020 and 2030, respectively, across the eight scenarios. As discussed in Section 4.3, additional savings are shown from electric rail and potential emissions savings in the fossil fuel supply chain. As illustrated the mix of contributing fuels varies substantially between the scenarios. The regional carbon intensity reduction ranges from 5 to 8% reduction in the 2020 timeframe, and 14-21% in the 2030 timeframe. Because these results are for the entire region of British Columbia, California, Oregon, and Washington, they are not to be taken as directly defining or limiting the potential for any one jurisdiction in any of the years of the study. For example, within any of the four individual jurisdictions, there is the potential for greater emission reductions – such as an above 10% carbon intensity reduction by 2020 – in the event that the policy and market factors were uneven across the jurisdictions. Indeed, it is likely that whichever jurisdictions have the more aggressive carbon intensity reduction targets in a given year will be more attractive markets for the lowest carbon fuels. The mix of low-carbon fuel options used to deliver these emissions reductions varies considerably over time and between scenarios. As shown in the figure, the 2020 scenarios generally rely much more upon first generation biofuels – with over 50% of the total carbon reduction typically resulting from first generation ethanol and biodiesel. After these two fuels, the most consistent alternative fuels in the 2020 timeframe are hydrotreated vegetable oil and electricity use in plug-in electric vehicles.

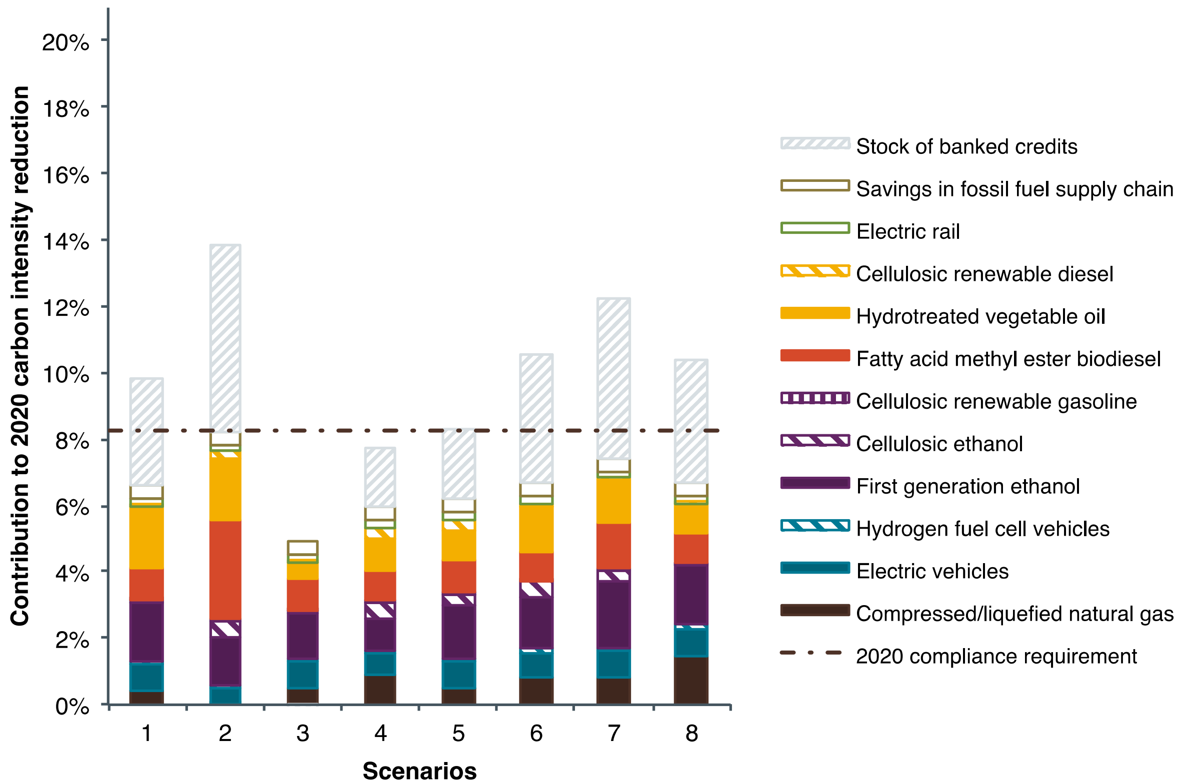


Figure 6.17. Carbon savings contributions of fuel types by scenario in 2020

Figure 6.18 shows the potential for increased carbon reductions from greater deployment of the various alternative fuels in the 2030 timeframe for all of the scenarios. Compared to 2020, the scenarios achieve at least double the overall carbon reduction compared to the 2020 results. There are significant differences in the amount of carbon reduction that come from the various fuel areas. In the 2030 results, the overall carbon reductions are less dependent on first-generation biofuels and generally more dependent upon electric drive, HVO and cellulosic ethanol and renewable diesel. In addition, Scenarios 4 and 5 see significant contributions from cellulosic renewable gasoline. Also, several scenarios, like 4 and 8, see more substantial contributions to region-wide carbon reductions from natural gas. Because these results are region-wide, the associated results within each of the four jurisdictions or by particular fuel providers with proportionally large investments could exceed these levels of emission reduction.

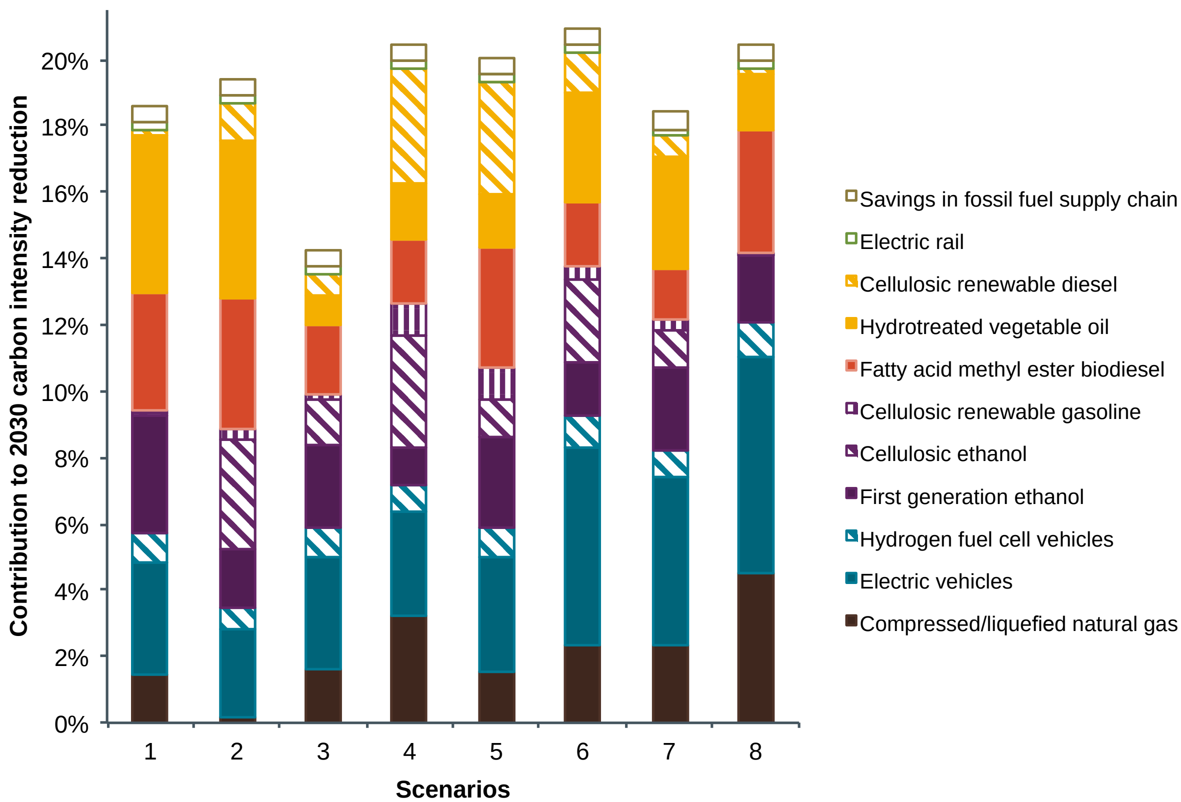


Figure 6.18. Carbon savings contributions of fuel types by scenario in 2030

The above figure illustrates how diverse fuel mixes can each deliver significant fuel carbon reductions in the 2030 timeframe. Scenarios with relatively strong deployments of advanced biofuels (e.g., Scenarios 4 and 5), electricity and hydrogen (Scenarios 6 and 8), and first-generation biofuels (Scenarios 1 and 2) each deliver comparable and substantial reductions in greenhouse gas emissions of 14-21% from road transportation in British Columbia, California, Oregon, and Washington by 2030. If breakthroughs occur in all the fuel areas simultaneously, or if deployment of a single technology were to greatly exceed the high case presented here, then greater carbon reductions would be possible. As the results shown are region-wide, there is the potential for greater or fewer emission reductions than shown within any of the four jurisdictions.

The alternative fuel deployment from the scenarios analyzed here are associated with increasing amounts of avoided use of gasoline and diesel fuel use in the Pacific Coast region. As illustrated in Figure 6.19, the low-carbon fuels replace 200-300 thousand barrels of oil equivalent per day of gasoline and diesel use in 2025 and 290-410 thousand barrels per day in 2030. Note that this analysis does not consider potential changes in overall fuel consumption due to economic responses to increased low-carbon fuel supply.

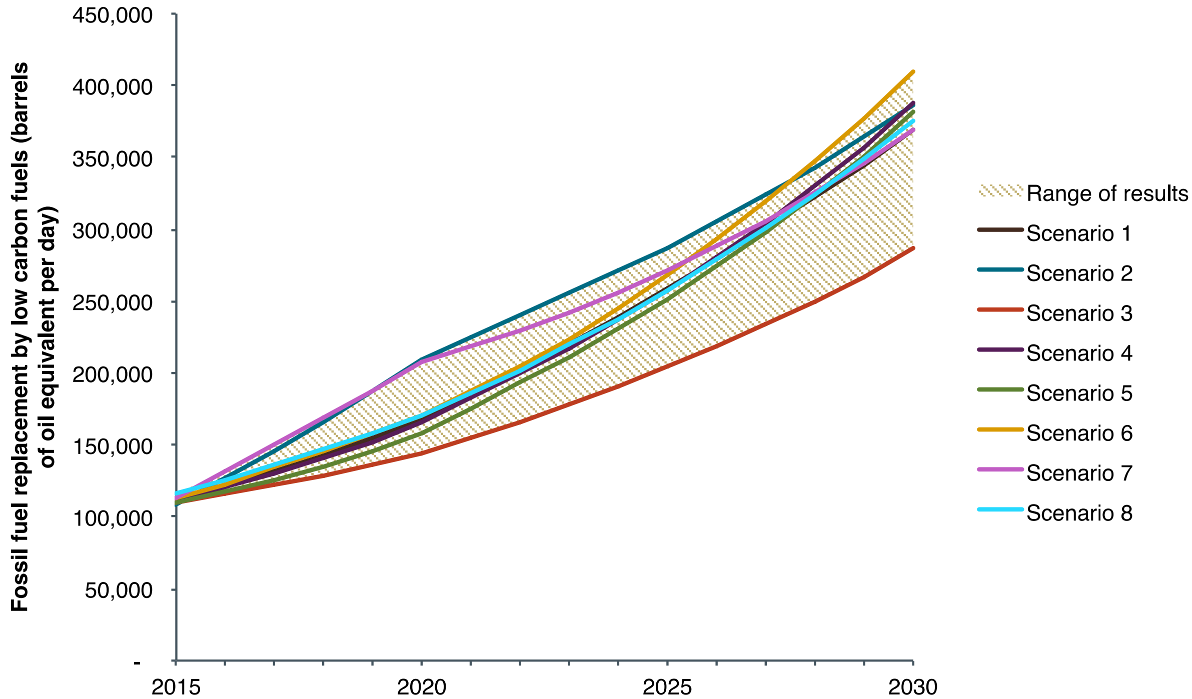


Figure 6.19. Reduction in gasoline and diesel use from 2015-2030 from fuel deployment scenarios for the Pacific Coast region (British Columbia, California, Oregon, and Washington)

7. Discussion of scenario results

7.1. Constraints on low-carbon fuel supply

7.1.1. Feedstock/imports for conventional ethanol

The high case for first-generation ethanol requires a large-scale move from corn ethanol to imported sugarcane ethanol, and some molasses. For Scenario 8, which couples this high case to a standard ethanol blend at E10, limited use of E85 and low deployment of cellulosic fuels, sugarcane ethanol demand peaks at 1.6 billion gallons. Adjusting the standard ethanol blend in Scenario 8 to 15% by 2030 as a sensitivity case, we would increases sugarcane ethanol deployment to 1.9 billion gallons per year (more than the peak level of sugarcane imports required in any of the modeled scenarios). These levels of sugarcane imports to the Pacific Coast region are comparable to total Brazilian sugarcane exports in recent years, and small compared to total production. In the short term, although the full infrastructure is not fully in place to bring such large quantities of ethanol into the Pacific Coast region, such volumes are roughly at the same scale as total California ethanol imports and therefore could likely be accommodated given several years to build the necessary supply chain infrastructure them. An alternative to sugarcane imports would be to develop local ethanol production pathways with comparably low-carbon intensities. Such developments are not included in this modeling, but insofar as comparably low-carbon ethanol pathways reduce the need for sugarcane imports it could deliver program goals while supporting regional agriculture.

7.1.2. Feedstock for cellulosic biofuel production

For the highest rate of cellulosic fuel deployment, with around 2.3 billion gallons of gasoline equivalent cellulosic fuel, we anticipate that of the order of 40 million tons of dry biomass would be required to supply the Pacific region, depending on achieved process yields. This level of feedstock supply is well within even most low-end biomass resource assessments for the U.S. (e.g., the lowest farm gate price estimates from the U.S. DOE 2011 Billion-Ton Study). While the sustainability of biomass supply cannot be assumed automatically, these levels of supply are certainly well within the known sustainable biomass potential for the U.S. In short, for the short and medium term, the consumption of cellulosic fuels in the Pacific region will not be constrained by the availability of biomass, but by the rate at which investment can be attracted to build new cellulosic biofuel plants.

7.1.3. Investment for cellulosic biofuel production

The development of a new cellulosic biofuel industry will require considerable investment. EIA (2014a) identify overnight capital[10] costs of around $10 per physical gallon of installed capacity for cellulosic ethanol, and $21 per physical gallon of installed capacity for drop-in fuel (for the first few facilities). Beyond the initial higher-cost phase, these overnight costs fall to around $8 and $18 respectively. Based on these capital costs, the high case for cellulosic fuel deployment considered in this study would imply capital investment rising to at least $2 billion per year by 2021, and then rising further towards $4 billion per year on to 2030. Total investment to 2030 (based on overnight capital costs) would be of the order of $30 billion. Real investment costs can be expected to be somewhat higher again, and to be inflated by the ongoing costs of research and development in addition to plant construction. Even so, while these are substantial sums of money to mobilize, it is worth noting that they are moderate compared to historical rates of investment in the conventional biofuels industry. Bloomberg New Energy Finance reported nearly $30 billion of investment in conventional ethanol facilities at the peak in 2007, and peak historical investment in what BNEF count as ‘next generation’ fuels of nearly $3 billion in 2011. Given the substantial value potential from the various policy supports available to the growing cellulosic fuel industry, we consider the investment requirements associated with the high case for deployment to be realistic.

7.1.4. Feedstock for biodiesel and HVO

For the highest scenarios of biodiesel and HVO deployment, we would expect to see some stress on the supply of waste and residual oils – namely, yellow grease, corn oil, and tallow. As noted in Section 3.2.5, the potential U.S. supply of these three oils is believed to be around 200 million gallons, 500 million gallons, and 1 billion gallons, respectively. As discussed in Section 5.11, expected HVO production capacity in the U.S. in 2025 could require about 400 million gallons oil feedstock. Currently expected U.S. production is therefore compatible with expected available feedstocks in the U.S. Scenario 2, which is the most reliant on carbon intensity reductions from HVO and biodiesel, would require about 1.9 billion gallons of these resources in aggregate by 2030. This would be greater than the total U.S. supply of these three feedstocks, and would require a more rapid development of HVO processing capacity than is currently forecast, so in this case it is likely that U.S. production of HVO and biodiesel from these feedstocks would be supplemented by imports. For instance, the Pacific Coast region is already receiving substantial deliveries of HVO from Neste Oil’s plant in Singapore. Perhaps a more important question than overall supply potential is the competition that could be experienced for these resources from other regions and sectors. The biofuel industry will experience competition for some of these resources from the oleochemicals industry, and there is potential competition for yellow grease supplies in particular from the European Union under the Renewable Energy Directive. The Pacific region could therefore face significant competition especially for fuel production with good access to East Coast U.S. shipping hubs, for which Europe could be an appealing market. The balance of distribution will be determined by the comparative value propositions provided by regulatory value of yellow grease biodiesel production and supply in the EU and the Pacific Coast jurisdictions.

[10] The overnight capital cost is the cost to build a facility if it could be done immediately, i.e. without financing costs etc., and therefore will generally underestimate the true cost of building real facilities.

7.1.5. Effect of uncertain oil prices

As has been seen over the period during which this study has been undertaken, the world oil price is subject to variation. In particular, the oil price is lower at the start of 2015 than it has been for several years. This is not an economic analysis, and there is no specific oil price that is assumed for any one of the scenarios presented here, or for the cases included in those scenarios. That said, many of the studies considered in the literature review and which inform the cases used in the modeling *do* include some assumption about oil price. The U.S. EIA's Annual Energy Outlook, for instance, explicitly considers both a high and a low oil price scenario in addition to the reference scenario. All things being equal, a reduction in the oil price will tend to make investment in low-carbon alternative fuels less appealing. The deployment of natural gas fuelled vehicles, for instance, is likely to be sensitive to the difference between the retail price of gasoline and diesel (which are highly influence by the oil price) and the retail price of natural gas, which is less directly influenced. While low oil prices may have the effect of reducing the appetite for investment, it is important to recognize that several policy frameworks to support alternative fuel and vehicle deployment are designed to operate despite oil price fluctuations. A good example is the Renewable Fuel Standard, which is designed in such a way that the value of RINs can be expected to rise to compensate for falling oil prices. Similarly, policies such as the California LCFS provide a guarantee of a market for low carbon fuels regardless of oil prices. The value of the cellulosic waiver credit (and thus the potential value of cellulosic fuel) is intentionally counter-correlated to retail gasoline prices. Other policy instruments such as the ZEV program are also insensitive to oil price.

While there is a growing body of research supporting the idea that the fuels identified in this report could become cost competitive with petroleum-based fuels, there is considerable uncertainty about when and under what conditions that will happen. The oil price for the next decade will be one of the factors that influences whether the low, medium or high cases for achievable emissions reductions described in this report are achieved for each fuel, but it is not the only factor. In conclusion, the scenarios described in this study span a range of possible real outcomes for low-carbon fuels between now and 2030.

7.2. Comparison to existing policy

This study assesses the viability for fuel providers to supply increasing amounts of low-carbon transportation fuels to British Columbia, California, Oregon, and Washington through 2030. Although the study is based in the science and the research literature, summarizing the scenario results against existing and planned fuel carbon intensity policy in the four jurisdictions helps to provide some additional context for the research findings.

The findings from the analytical scenarios for increased alternative fuel deployment, summarized in Figure 7.1, indicate that there is the potential for alternative low-carbon transportation fuels to significantly contribute to greenhouse gas reductions through 2030. Although the various fuel pathways each have unique deployment constraints that affect the near-term fuel deployment as described above, all eight scenarios analyzed deliver 14-21% carbon intensity reduction by 2030, from 2010 levels. For context, the scenarios are compared against an estimated Pacific Coast region-wide composite policy target for the four jurisdictions' fuel carbon intensity policies (as introduced above in Figure 2.1). The results shown are region-wide, so greater or lesser emission reduction would be possible in any of the four jurisdictions depending on the varying mix of policy, market, and fiscal incentives within each area.

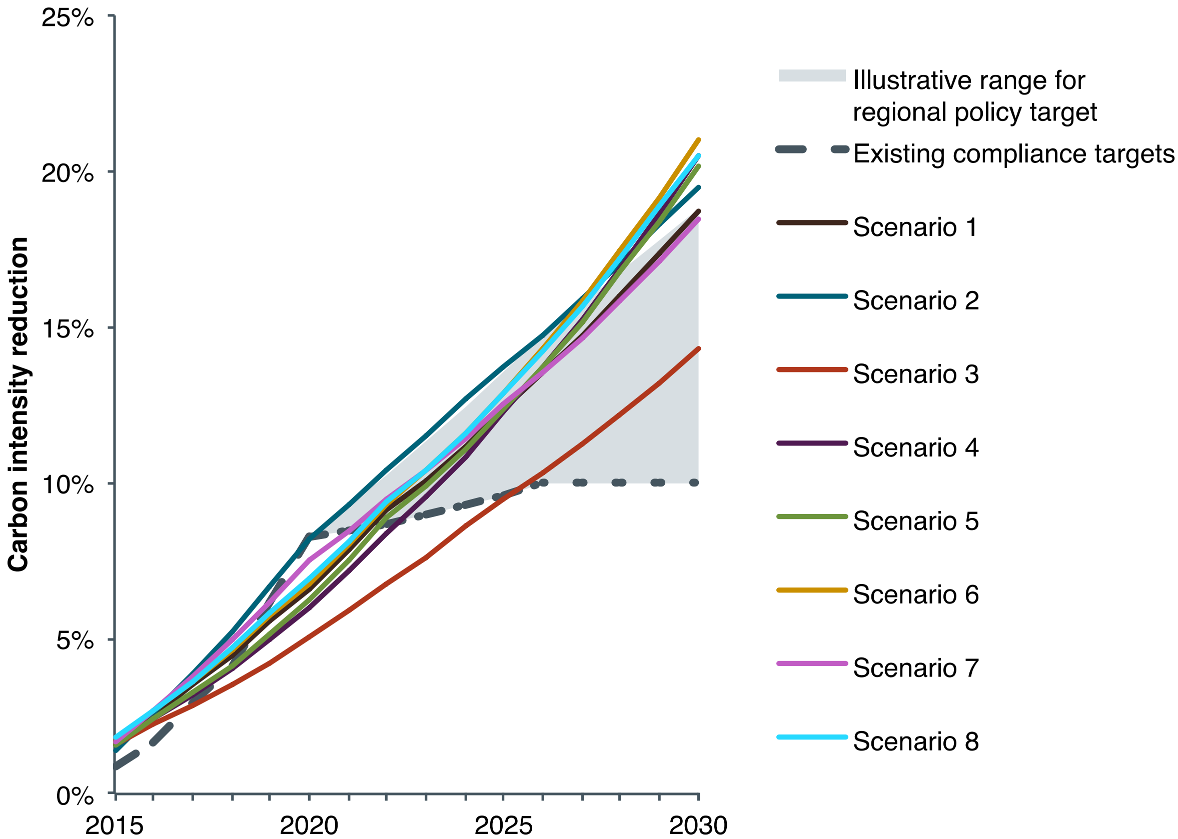


Figure 7.1. Fuel carbon intensity reduction from 2015-2030 from fuel deployment scenarios for the Pacific Coast region (British Columbia, California, Oregon, and Washington)

7.3. Role of other compliance options

There are potentially additional routes to reduce the carbon intensity of the fuel supply beyond those analyzed in this study. Other fuel carbon intensity alternatives include electricity used in rail, credits for innovative emissions reduction in the upstream oil industry, and the carry-over of excess credits from emissions reductions delivered in earlier years of the program. These could also make an important contribution to overall fuel carbon emission reductions. For instance, consider Scenario 8. Figure 7.2 shows credit generation in Scenario 8 (including assumed credits from electric rail and upstream oil emissions reductions) compared to an illustrative compliance schedule in which all targets increase by 0.5 percentage points per year beyond published trajectories. There is a shortfall between credits generated from included low-carbon fuels and the illustrative 2020 to 2022 compliance requirements. However, this shortfall could be met using excess credits generated earlier in the programs, as shown in Figure 7.3, where the blue line (total cumulative credit availability) never drops below zero. Figure 7.3 also demonstrates the importance of other credit generation mechanisms in the program. The lower brown line shows what the cumulative credit stock would be without the availability of options to generate credits from electric rail or upstream emissions reductions in the fossil sector. Without those extra savings, compliance with the illustrative targets would not be achieved for several years following 2020. However, with the combination of flexibility from credit banking and from additional compliance routes, suppliers would be able to meet these illustrative targets in all years.

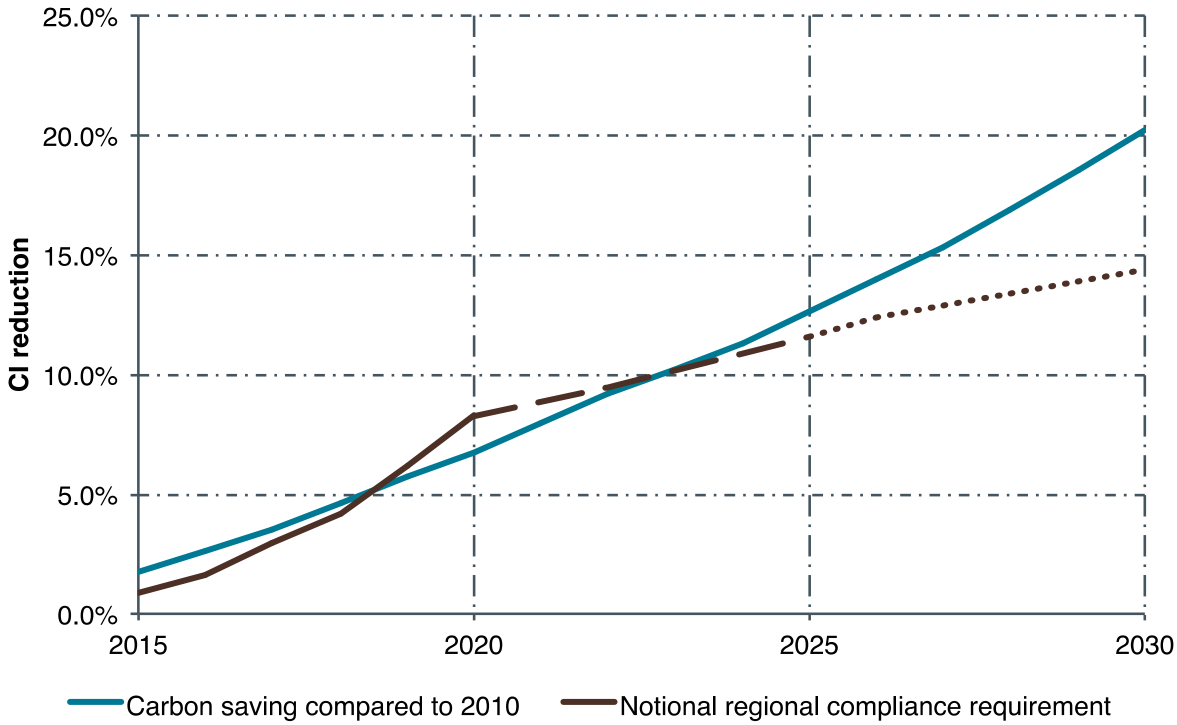


Figure 7.2. Credit generation against compliance schedule for Scenario 8

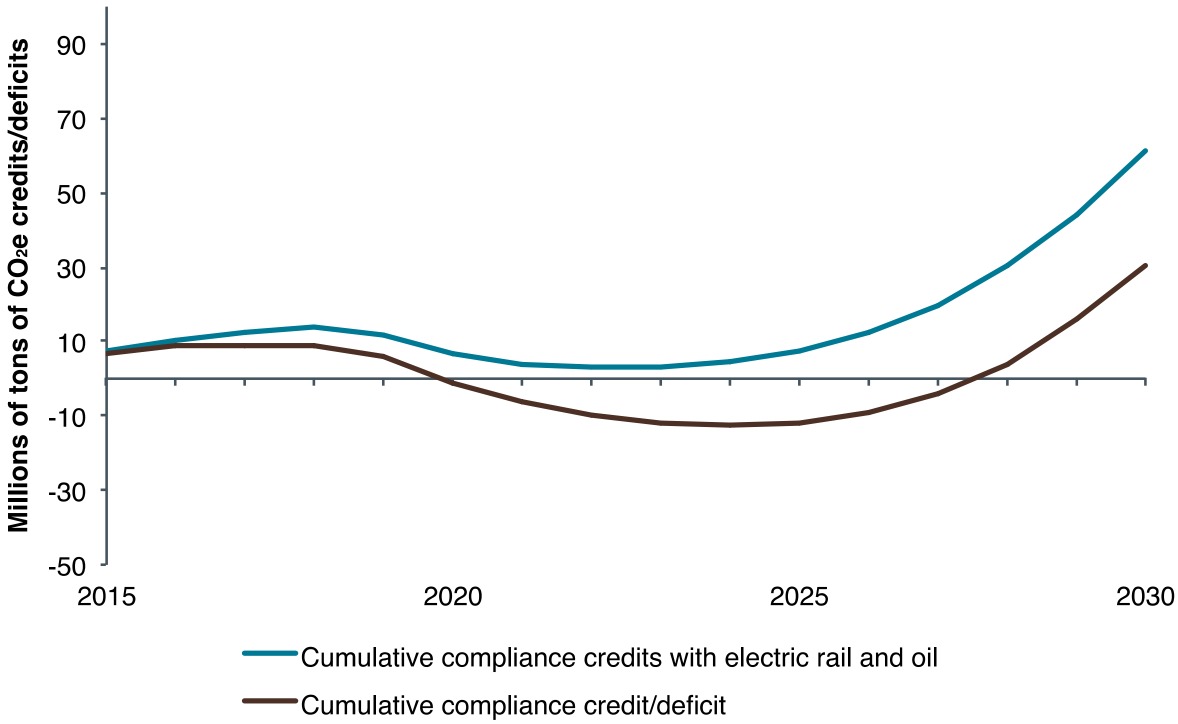


Figure 7.3. Net credit balance for program in Scenario 8

7.4. Role of electric drive vehicles

As illustrated in many of the scenarios above, the use of electricity in plug-in electric vehicles in the Pacific Coast region becomes an increasingly important driver in reducing the average fuel carbon intensity in 2020, and especially in 2030. This is because electric vehicles use a fraction of the energy of combustion vehicles per mile and because the supply of electricity in the region is abundant, is generally low-carbon, and is expected to have increasingly lower carbon intensity. The deployment of electric vehicle that is considered in this analysis, at its maximum, is approximately 2.5 million cumulative plug-in electric vehicles in the four-jurisdiction region by 2025, and 5 million by 2030 (in Scenarios 6 and 8). For the medium electric vehicle deployment scenario, vehicle stocks are around 2 and 4 million in 2025 and 2030, respectively.

Low-carbon fuel standards are but one of a number of actions to support plug-in electric vehicle deployment and use. Aligned actions by many government actors, the auto industry, consumers, and other stakeholders are also important. Federal support for public charging infrastructure is a key part. As indicated above, Yang (2013) indicates that low-carbon fuel standards could create $200-500 per year per plug-in electric vehicle in value that could be useful for infrastructure investments or as an incentive for prospective plug-in electric vehicle purchases. The California (and other states') Zero Emission Vehicle program is an important driver to promote automaker developments and sales, as are the many state and local action plans to help drive further state, consumer, fleet, and public-private partnership actions (e.g., see California, 2013; NESCAUM, 2014). Continued fiscal and non-fiscal policy support in the near-term are also part of the equation. As currently seen with rebates, carpool lane access, and home charger incentives, consumers in California, Oregon, and Washington are responding with relatively high demand for the early electric vehicle models (Jin et al., 2014). The work used to define the electric drive scenarios here are regulatory requirements (CARB, 2011) and based on state-of-the-art vehicle modeling of the interplay of these above factors (e.g., Greene et al., 2013, 2014).

7.5. Supply in the Pacific region

The analysis in this report is largely based on national and international studies about energy sources and low-carbon fuel technologies that are being developed by national and global companies. While any of the fuel supply chains discussed in this report could be developed within the Pacific region, there is also the potential for many low-carbon fuels or feedstocks to be produced elsewhere and imported. With the in-region adoption of low-carbon fuel standards, infrastructure developments, and complementary incentives for fuel production facilities, it becomes more likely that a higher fraction of each fuel will eventually be produced within the region. While transport costs are not always a dominant factor in siting low-carbon fuels facilities, proximity to market remains an advantage and it is possible to draw some broad conclusions about the potential for fuels to be produced on the Pacific Coast. Low-carbon biofuels from most of the various fuel pathways investigated have the ability to largely be supplied from facilities within the region, even though much of the volume of these fuels currently is produced outside the region. It is likely that progressive alternative fuel policies could shift investments toward within-region biomass distribution, processing, and biofuel production facilities.

7.5.1. First generation ethanol

In most of the scenarios discussed here, a transition is seen from corn ethanol towards sugarcane-based ethanol. Sugarcane ethanol is seen as a key low-carbon fuel supply primarily because of the large supply potential and existing export infrastructure in Brazil, and we would anticipate that most of this fuel would be imported to the region. There are opportunities for ethanol production within the region from corn, wheat, sorghum, and potentially other feedstocks, but these would be expected to occupy a smaller place in the supply than Brazilian imports.

7.5.2. First generation biodiesel and HVO

Most of the biodiesel and HVO included in the scenarios in this report is presumed to be produced from waste and residual feedstocks, or cover crops such as camelina, and as noted above the demand for these feedstocks is expected to be larger than in state production capacity. Given that feedstocks will be distributed throughout the U.S., and that there is currently overcapacity for biodiesel production nationally, it is likely that production facilities will remain distributed and that much of the material will be imported from outside the region. Some material such as HVO is likely to be imported from foreign plants such as Neste’s facility in Singapore.

7.5.3. Cellulosic fuel

While the first cellulosic ethanol plants to open in the U.S. have not been sited in the Pacific region, there is interest among investors (for instance Canergy[11]) to develop plants in the Pacific region. As shown in the literature review, the Pacific region is not the most feedstock-dense region of the U.S., but biorefinery location studies still identify promising locations for plants in the region. In the high scenarios for cellulosic fuel deployment, on the order of 40 million tons of dry biomass feedstock would be required. Much of this could in principle be supplied within the Pacific region. Plant siting decisions are likely to be informed by support offered by state governments.

7.5.4. Electricity, natural gas, and hydrogen

Electricity, and hydrogen are primarily produced within the four jurisdictions already and are likely to be predominantly produced, distributed, and sold within the region. Although electricity transmission lines are geographically wide, their production is abundant within the region and hence the majority of electricity generation will continue to be relatively close to the vehicle demand. Similarly, hydrogen production is likely to be sourced from natural gas and occur relatively close to vehicle demand in the near-term due to transportation costs and infrastructure limitations. Further impetus for in-region supply of these fuels would come from the four jurisdictions' low-carbon fuel policies and from complementary infrastructure and incentive support policies. Natural gas supplies come substantially from out of state.

7.5.5. Renewable natural gas

As noted in the literature review, the Bioenergy Association of California (2014) has estimated that around 2.1 billion diesel gallon equivalents of renewable natural gas from organic waste could be generated in California alone. This would more than cover the highest demand levels in any of the scenarios here, but there may be cost barriers to exploiting much of that potential. Local production will need to compete with out-of-state supplies that have access to pipeline infrastructure in order to demonstrate mass balance chain of custody for delivery to the Pacific Coast market.

7.6. Sensitivity of results to carbon intensity assumptions on cellulosic ethanol

Inevitably, the results in terms of carbon savings potential from the fuel mix in each scenario are sensitive to assumptions about the carbon intensity of those fuels, and therefore the carbon savings delivered by increasing the supply. As an example of the sensitivity of results to CI assumptions, we have investigated the impact of using alternative sources for assumptions about the carbon intensity of cellulosic ethanol pathways. On the more-optimistic side, the carbon intensity values for cellulosic ethanol in the latest version of GREET (ANL, 2014) are lower than the values used as the central case in this study. On the less optimistic side, Murphy (2013) gives higher carbon intensity values for corn stover and switchgrass based cellulosic ethanol production. We have rerun Scenario 4 (which is a high cellulosic ethanol scenario) using

[11] http://www.canergyus.com/project/

these alternate assumptions. The 2020 carbon intensity values are based directly on the references in question. For the optimistic case, we allowed a further 30% carbon intensity reduction by 2030. For the less optimistic case we assumed constant carbon intensities. Where no value was available for a feedstock pathway, the central values were kept. The three cases are shown in Table 7.1.

Table 7.1. Cellulosic ethanol carbon intensities for sensitivity analysis**

FEEDSTOCK	OPTIMISTIC (GREET)		CENTRAL		LESS OPTIMISTIC (MURPHY)	
	2020	2030	2020	2030	2020	2030
Corn stover	30	20	10	7	35	35
Bagasse	7	7	7	5	7	7
Woody residues	32	20	-3	-3	32	20
Short rotation coppice	6	6	5	4	6	6
Annual grasses*	29	20	26	18	47	47
Perennial grasses	19	19	7	5	37	37

**As in the central case, we assume that the carbon intensity for annual grasses would be 10 gCO_2e/MJ higher than that for switchgrass.*
***In other cases where there is no value explicit within the alternate sources, the 2020 values are based on the central case (e.g. for bagasse based ethanol production).*

Table 7.2 shows the implications of these differences in carbon intensity assumption for the carbon savings delivered by Scenario 4. The more-optimistic assumptions deliver about an additional million tons CO_2e of carbon savings in 2030, whereas the less optimistic assumptions reduce the carbon savings by about one and a half million tons. The range from less to more optimistic spans a difference of about one percentage point in the overall carbon saving achieved. In 2020, the more optimistic assumptions deliver a small increase in carbon savings but this would not be enough to make Scenario 4 fully compliant with the regional targets, but it would approximately halve the shortfall. This emphasizes that reducing the carbon intensities of fuels delivered below the level modeled in this study is one of the ways that fuel suppliers may be able to improve performance and meet targets in the real world.

Table 7.2. Carbon reductions delivered by cellulosic ethanol in Scenario 4 for different CI assumptions

YEAR	OPTIMISTIC (GREET)		CENTRAL		LESS OPTIMISTIC (MURPHY)	
	Carbon savings ($MtCO_2e$)	Fractional CI reduction (%)	Carbon savings ($MtCO_2e$)	Fractional CI reduction (%)	Carbon savings ($MtCO_2E$)	Fractional CI reduction (%)
2020	1.8	0.5%	1.5	0.5%	1.3	0.4%
2030	11.4	3.8%	10.2	3.4%	8.6	2.9%

7.7. Comparison with recent related studies

This analysis is found to be broadly consistent with two recent works of immediate relevance to the Pacific Coast regions consideration of low-carbon fuel policies. The Life Cycle Associates (i.e., Pont et al, 2014) study was conducted and the final report was released in December 2014 to inform Washington State policy. In addition, the California Air Resources Board released its Initial Statement of Reasons in December 2014 for the LCFS program through 2020 (CARB, 2014e).

Although this study differs in its overall scope, region-wide context, and details regarding some scenarios we note many commonalities between the studies. The consideration of the various fuel pathways of lower carbon conventional biofuels, advanced cellulosic and drop-in biofuels, electric-drive vehicles, and natural gas vehicles is largely consistent. Many of the same expert studies are referenced and used as data sources. The average carbon intensities for the fuels across the various fuel pathways are nearly identical. The fuel volumes of this studies' eight scenarios offer low and high values that are below and above CARB's "illustrative scenario" for 2020 LCFS compliance across the major fuel categories. Based on comparing the studies, the state-level studies' findings on low-carbon fuels fit broadly within the regional supply capabilities investigated in this report.

8. Conclusions

This work has sought to answer key questions regarding what the available supplies of low-carbon alternative energy sources are, and how quickly they can be deployed. In particular, this study assesses the viability for fuel providers to supply increasing amounts of low-carbon transportation fuels within the four Pacific Coast jurisdictions of British Columbia, California, Oregon, and Washington through 2030. The work includes a review of the scientific literature on the extent to which available and emerging low-carbon biofuels, natural gas, electricity, and hydrogen have the potential to replace gasoline and diesel usage in road transportation. The analysis evaluates alternative fuel availability across the four jurisdictions simultaneously, as well as considers potential resource and industry constraints that impact fuel deployment timing. Finally the work quantifies the resulting fuel carbon intensity impact from a range of alternative fuel deployment scenarios to reflect varying technology advancement, policy promotion, and industry investment.

The findings from the analysis on scenarios for increased alternative fuel deployment indicate that there is the potential for alternative low-carbon transportation fuels to significantly contribute to greenhouse gas reductions through 2030. Although the various fuel pathways each have unique deployment constraints that affect the near-term fuel deployment, all eight scenarios analyzed delivered between 14% and 20% carbon intensity reduction in the region by 2030, from 2010 levels. This corresponds to between 43 and 64 million tons of carbon emissions reduction per year in 2030. This compares to current regional transport carbon dioxide emissions of 280 million tons per annum, and total regional emissions from all energy use of 510 million tons.[12] This analysis also provides greater resolution into the relative contributions of various fuel pathways and technologies – including advanced biofuel, electricity and hydrogen, first-generation biofuels, and natural gas – toward reducing greenhouse gas emissions by 2030 in the Pacific Coast region. If more profound breakthroughs occur than implied within these scenarios, or in more fuel areas simultaneously, then even greater carbon reductions would be possible. Among the four jurisdictions, greater or lesser emission reduction would be possible depending on the varying mix of policy, market, and fiscal incentives at play within each of the four areas. For context, the scenarios here are compared against an estimated region-wide composite policy target for the four jurisdictions' fuel carbon intensity policies.

The low-carbon fuel programs that are active in California and British Columbia, and proposed in Oregon and Washington, are not designed to be achieved by business-as-usual behavior. These regulations are intended to have a transformative effect on the fuel supply in the Pacific region, and to work in concert with other programs regionally and nationally to form part of a transition to a decarbonized U.S. economy. As a result of prevailing market and policy activities within and beyond the four Pacific Coast jurisdictions, some of the low-carbon fuels needed to meet targets under these programs are already available. Fuels such as waste oil based biodiesel, renewable natural gas, and sugarcane ethanol offer significant carbon savings and can be used for compliance immediately. There is also a place, especially in the early years of the programs, for some carbon savings to be delivered by less high-performing fuels like biodiesel and corn ethanol. However, headed towards 2030, compliance with increasing carbon

[12] Based on 2011 GHG emissions data for California, Oregon and Washington (EIA, 2014b), and 2012 GHG emissions data for British Columbia (BC MoE, 2012). Total regional transport emissions data includes fuel combustion only.

intensity reduction targets will require some combination of new fuel production technologies and changes in the vehicle pool.

Based on the findings here, one technology development that could be a substantial contributor to meeting low-carbon fuel targets is the shift toward increasing vehicle electrification. As the fleet of electric drive vehicles expands, the higher energy efficiency of, and general availability of low-carbon electricity for, those vehicles will contribute to a reduction in carbon intensity for the transportation fuel pool as a whole. Similarly, the findings here indicate that if low natural gas prices drive an increase in the heavy-duty natural gas vehicle fleet, this can help to enable significant emissions reductions. The value proposition provided by a combination of low-carbon fuel standard and cellulosic Renewable Identification Number credits could make it likely that much of this natural gas supply will use renewable sources, offering a much greater emission reduction potential.

The scenarios analyzed here, although not targeted precisely as "compliance scenarios", are broadly consistent with achieving the four jurisdictions' low-carbon fuel goals. This study presents a range of fuel combinations that are achievable by 2030 and, in most cases, would be consistent with meeting low-carbon fuel program compliance schedules for the region. Where the scenarios show brief periods of potential non-compliance, various low-carbon fuel options (e.g., from electricity for rail and emissions reductions in the oil industry) and other regulatory program provisions are highly likely to be more than sufficient in allowing compliance.

Based on the findings from this assessment, we close with the following four conclusions:

Available low-carbon fuels could grow to replace over 400,000 barrels worth of gasoline and diesel use per day by 2030, representing a factor of three increase from today and 24% of the Pacific Coast region's road transportation energy demand.[13] First-generation biofuels (e.g., sugarcane ethanol), second-generation biofuels, advanced cellulosic and drop-in biofuels, renewable and fossil natural gas, electricity in plug-in electric vehicles, and hydrogen in fuel cell vehicles are viable alternative fuels with the potential for substantially increased deployment in the 2020-2030 timeframe. The findings from this analysis indicate that the deployment of these alternative fuels could result in the replacement of 290-410 thousand barrels of oil equivalent per day of petroleum-based fuels in 2030.

Substantial greenhouse gas emission savings are available across the four jurisdictions from the deployment of emerging low-carbon fuels. Pacific Coast region-wide fuel carbon intensity reductions of 14-21% are achievable from increased deployment in new fuels, while accounting for lifecycle carbon emission effects, known resource and supply chain constraints, vehicle technology, and increased travel demand. The scenarios analyzed in this report would amount to reducing road transportation's climate emissions by 43-64 million tons of carbon dioxide equivalent reduction per year, by 2030.

The Pacific Coast region's regulatory targets for reducing the carbon intensity of transport fuel can be met in a variety of ways. The results show a variety of possible low-carbon fuel mixes that would successfully meet the carbon intensity reduction goals for 2020 as described within in California's Low Carbon Fuel Standard, Oregon and Washington's Clean Fuel Standards, and British Columbia's Low Carbon Fuel Requirements. Six of the eight scenarios analyzed would be consistent with full compliance with regulatory targets

[13] The fractional displacement is calculated based on the total fuel demand in 2030 anticipated in the modified VISION model

between 2015 and 2020. These scenarios also demonstrate a wide variety of potential fuels that could be used for compliance. For example, in 2020, the compliance-consistent scenarios include between 100 and 1,200 million gallons (diesel equivalent) of natural gas, between 600 and 1,200 million gallons of ethanol from sugarcane, between 550,000 and 860,000 plug-in electric vehicles using grid electricity, between 300 and 600 million gallons of renewable diesel and between 20 and 300 million gallons gasoline equivalent of cellulosic fuel.

Fuel providers and regions could pursue a diversity of low-carbon fuel strategies. The scenarios in this analysis reveal that many different fuel and vehicle strategies could deliver substantial climate and oil-reduction benefits. The diversity provides a large degree of flexibility and optionality for achieving carbon intensity reductions that are broadly consistent with the jurisdictions' policy goals. For example, substantial aggregate fuel carbon intensity reductions could be achieved with many combinations of electric-drive vehicles, renewable and natural gas vehicles, advanced cellulosic biofuels, lower carbon first generation biofuels, and increased supply of renewable diesel. This suggests that delivering on decarbonization goals does not require a dramatic breakthrough in any one particular technology. This also suggests that different fuel providers in the jurisdictions could focus more heavily on different alternative fuels and achieve similar climate and petroleum-reduction benefits.

Strong regulatory signals will be a key driver for low-carbon fuel investments. Recognizing the prevailing market and technology uncertainties, the adoption of clear regulatory policy signals across British Columbia, California, Oregon, and Washington through 2025, or even 2030, would greatly promote the types of investments that are inherent in the alternative fuel deployment scenarios analyzed in this study. The scenarios in this study are broadly consistent with the analyses that have been conducted by and for government agencies in their consideration of low-carbon fuel policies (i.e., Pont et al, 2014; CARB, 2014e). These scenarios go well beyond business-as-usual industry and market activity and would likely be dependent upon some mix of direct regulatory and fiscal policy support.

Several key factors are beyond the scope of this analysis and warrant further investigation. Issues beyond this report's analytical scope include the role of non-road carbon reduction in the transportation sector, including liquefied natural gas in marine applications, biofuel use in the aviation sector, electrification for transit and other off-highway applications, fossil refinery upgrades, and upstream fossil fuel carbon reductions. In addition, further study would be necessary to better understand questions about the potential implications of the scenarios in this study on carbon credit prices, and vice versa. Further study would be necessary to match the particular, and yet evolving, provisions of the four jurisdictions' fuel policies. In reviewing the biomass supply potential, it is noted that this study does not attempt to systematically apply sustainability screenings on specific feedstocks. However, we note that the referenced studies apply varying levels of consideration of sustainability. Comparing the various studies using consistent sustainability assumptions is an area of potential further study. Potential future shifts in business-as-usual travel activity have not been analyzed. Finally, analyses like this could be increasingly important in understanding the potential for low-carbon fuels beyond the Pacific Coast region, as other governments become similarly motivated.

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The conclusions expressed in this report represent the views of the researchers only, and are not necessarily shared by individuals or organizations that are represented above.

Annex B Case tables

Table A VISION case inputs for auto market sales share

AUTO (CAR) MARKET SALES SHARES	CASE PARAMETER	LOW			LOW-MED			MEDIUM			MED-HIGH			HIGH		
Technology		2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
EV A	Electricity	0%	2%	7%	0%	3%	8%	0%	3%	8%	0%	3%	17%	0%	3%	27%
EV B	Electricity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
E-85 FFV	E85	3%	3%	3%	3%	5%	5%	3%	6%	6%	3%	7%	7%	3%	13%	13%
CNG	Natural gas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI PHEV A	Electricity	0%	2%	6%	0%	2%	6%	0%	2%	6%	0%	2%	6%	0%	2%	5%
SI PHEV B	Electricity	0%	3%	13%	0%	4%	13%	0%	5%	14%	0%	5%	12%	0%	5%	11%
Fuel Cell	Hydrogen	0%	1%	5%	0%	1%	5%	0%	1%	5%	0%	1%	5%	0%	1%	4%

Table B VISION inputs for auto market sales shares that do not correspond to a case parameter

AUTO (CAR) MARKET SALES SHARES	YEAR		
Technology	2010	2020	2030
Diesel	1%	4%	6%
SI HEV on Gasoline	6%	22%	33%
SI HEV on E85/H2	0%	0%	0%
Diesel HEV	0%	0%	0%
Diesel PHEV	0%	0%	0%

Table C VISION case inputs for light truck market sales share

LIGHT TRUCK MARKET SALES SHARES	CASE PARAMETER	LOW			LOW-MED			MEDIUM			MED-HIGH			HIGH		
Technology		2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
EV A	Electricity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%
EV B	Electricity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
E-85 FFV	E85	15%	15%	15%	15%	18%	18%	15%	22%	22%	15%	26%	29%	15%	52%	59%
CNG	Natural gas	0%	0%	0%	0%	5%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI PHEV A	Electricity	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%	0%	0%	0%
Fuel Cell	Hydrogen	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table D VISION inputs for light truck market sales shares that do not correspond to a case parameter

LIGHT TRUCK MARKET SALES SHARES	YEAR		
Technology	2010	2020	2030
Diesel	0.4%	1.6%	1.5%
SI HEV on Gasoline	0.7%	0.5%	0.9%
SI HEV on E85/H2	0.0%	0.0%	0.0%
Diesel HEV	0.0%	0.5%	0.7%
SI PHEV B	0.0%	0.0%	0.0%
Diesel PHEV	0.0%	0.0%	0.0%

Table E VISION case inputs for heavy truck market sales share

HEAVY TRUCK MARKET SALES SHARES	CASE PARAMETER	LOW			LOW-MED			MEDIUM			MED-HIGH			HIGH		
Technology		2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Class 7&8: SU Natural Gas	Natural gas	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Class 7&8 Combination LNG	Natural gas	0%	0%	4%	0%	4%	9%	0%	7%	13%	0%	17%	26%	0%	13%	27%

Table F VISION inputs for heavy truck market sales shares that do not correspond to a case parameter

AUTO (CAR) MARKET SALES SHARES	YEAR		
Technology	2010	2020	2030
Class 7&8: Conv. Single Unit (SU)	0%	0%	0%
Class 7&8: Single Unit HEV	0%	0%	0%

Table G VISION case inputs for medium truck market sales share

MEDIUM TRUCK MARKET SALES SHARES	LOW			LOW-MED			MEDIUM			MED-HIGH			HIGH		
Technology	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Class 3-6: Natural Gas	0%	0%	1%	0%	4%	7%	0%	7%	13%	0%	2%	4%	0%	13%	27%

Table H VISION inputs for medium truck market sales shares that do not correspond to a case parameter

AUTO (CAR) MARKET SALES SHARES	YEAR		
Technology	2010	2020	2030
Class 3-6: Conventional Gasoline	37%	37%	37%
Class 3-6: HEV Diesel	0%	0%	0%

Table I VISION case inputs for fuel supply (values in petajoules)

SCENARIO	FUEL TYPE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low	Cellulosic ethanol	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Low	Drop-in renewable diesel	0	1	1	1	1	1	1	2	2	2	3	3	4	4	5	6
Low	Drop-in renewable gasoline	0	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2
Low	Renewable natural gas	3	3	4	5	5	6	7	8	9	10	10	11	12	13	14	14
Low	HVO	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Low-med	Cellulosic ethanol	2	2	2	2	2	4	8	12	15	18	23	28	34	40	48	57
Low-med	Drop-in renewable diesel	0	0	0	0	0	1	2	3	5	6	8	10	13	16	20	25
Low-med	Drop-in renewable gasoline	0	0	0	0	0	0	1	1	1	2	2	3	4	5	6	7
Low-med	Renewable natural gas	5	6	8	9	11	12	14	16	17	19	21	23	25	27	29	31
Low-med	HVO	14	16	17	19	20	22	23	25	26	28	29	30	32	33	35	36
Medium	Cellulosic ethanol	1	2	4	7	10	14	17	21	23	26	28	31	35	39	43	47
Medium	Drop-in renewable diesel	0	1	2	3	4	6	8	10	12	15	19	23	28	33	40	47
Medium	Drop-in renewable gasoline	0	0	1	1	1	2	2	3	4	5	6	7	8	10	12	14
Medium	Renewable natural gas	8	10	12	14	16	18	21	23	26	29	31	34	37	40	43	46
Medium	HVO	14	20	25	30	35	40	43	46	50	53	56	59	63	66	69	72
Med-high	Cellulosic ethanol	2	4	8	12	15	18	23	28	34	40	48	57	67	78	91	105
Med-high	Drop-in renewable diesel	0	0	1	2	4	8	12	18	20	23	25	28	32	35	40	44
Med-high	Drop-in renewable gasoline	0	0	0	1	1	2	4	6	6	7	8	9	10	11	12	13
Med-high	Renewable natural gas	9	11	13	15	18	21	23	26	29	32	36	39	42	45	49	53
Med-high	HVO	14	23	32	41	49	58	67	75	84	93	101	110	119	128	136	145
High	Cellulosic ethanol	2	4	8	12	17	22	27	33	41	50	60	72	85	100	117	135
High	Drop-in renewable diesel	0	1	1	3	8	14	21	31	38	47	57	69	82	97	114	133
High	Drop-in renewable gasoline	0	0	0	1	2	4	6	9	11	14	17	21	25	29	34	40
High	Renewable natural gas	10	12	14	16	19	22	25	28	31	34	38	41	45	48	52	56
High	HVO	14	28	42	55	69	82	96	109	123	136	150	163	177	190	204	217

Annex C Carbon intensity tables

Table J Carbon intensities for biofuels

FUEL TYPE	FEEDSTOCK TYPE	ILUC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional ethanol	Corn	*74*	74	73	72	71	70	69	68	67	66	65	64	64	63	62	61	60
	Sugarcane	*32*	32	30	29	27	26	24	24	24	24	24	24	24	24	24	24	24
	Sorghum	*66*	66	65	64	64	63	62	61	60	59	58	57	56	55	54	53	52
	Molasses	*30*	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	Wheat	*66*	66	65	64	64	63	62	61	60	59	58	57	56	55	54	53	52
Cellulosic ethanol	Corn stover	*0*	30	29	29	28	27	27	26	25	25	24	23	23	22	21	21	20
	Bagasse	*0*	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Woody residues	*0*	32	31	30	30	29	28	27	26	26	25	24	23	22	22	21	20
	Short rotation coppice	*0*	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Annual grasses	*12.8**	29	28	27	27	26	26	25	25	24	23	23	22	22	21	21	20
	Perennial grasses	*2.8**	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Biodiesel	Soy	*29.1*	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Canola	*14.5*	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
	UCO	*0.0*	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	Tallow	*0.0*	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
	Corn oil	*0.0*	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Camelina	*0.0*	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
HVO	Soy	*29.1*	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
	Canola	*14.5*	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	UCO	*0.0*	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
	Tallow	*0.0*	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
	Corn oil	*0.0*	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Camelina	*0.0*	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34

Drop-in renewable diesel	Corn stover	*0*	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	MSW	*0*	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Woody residues	*0*	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
	Short rotation coppice	*0*	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Annual grasses	*12.8**	29	28	27	27	26	26	25	25	24	23	23	22	22	21	21	20
	Perennial grasses	*2.8**	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Drop-in renewable gasoline	Corn stover	*0*	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
	MSW	*0*	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Woody residues	*0*	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
	Short rotation coppice	*0*	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Annual grasses	*12.8**	29	28	27	27	26	26	25	25	24	23	23	22	22	21	21	20
	Perennial grasses	*2.8**	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19

**ILUC of 2.8 gCO_2e/MJ is assigned to switchgrass by Baral and Malins (2014), which includes benefits from soil carbon sequestration. This value is used for perennial grasses. For annual grasses, it is assumed that soil carbon sequestration is less, increasing the iLUC by 10 gCO_2e/MJ.*

Table K Carbon intensity for electricity, natural gas, and hydrogen

CASE	INPUT	UNIT	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low	Renewables share of electricity	%	1%	2%	2%	3%	3%	4%	5%	5%	6%	6%	7%	8%	8%	9%	9%	10%
Low	Fossil share	%	99%	98%	98%	97%	97%	96%	95%	95%	94%	94%	93%	92%	92%	91%	91%	90%
Low	Renewable electricity	gCO_2e/kWh	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Low	Fossil electricity	gCO_2e/kWh	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Low	Natural gas	gCO_2e/MJ	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Low	Hydrogen	gCO_2e/MJ	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118	118
Low-med	Renewables share of electricity	%	1%	2%	4%	5%	6%	7%	9%	10%	11%	12%	14%	15%	16%	17%	19%	20%
Low-med	Fossil share	%	99%	98%	96%	95%	94%	93%	91%	90%	89%	88%	86%	85%	84%	83%	81%	80%
Low-med	Renewable electricity	gCO_2e/kWh	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Low-med	Fossil electricity	gCO_2e/kWh	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Low-med	Natural gas	gCO_2e/MJ	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Low-med	Hydrogen	gCO_2e/MJ	118	118	117	116	116	115	115	114	114	113	113	112	112	111	111	110
Medium	Renewables share of electricity	%	1%	3%	5%	7%	9%	11%	13%	15%	16%	18%	20%	22%	24%	26%	28%	30%
Medium	Fossil share	%	99%	97%	95%	93%	91%	89%	87%	85%	84%	82%	80%	78%	76%	74%	72%	70%
Medium	Renewable electricity	gCO_2e/kWh	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Medium	Fossil electricity	gCO_2e/kWh	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Medium	Natural gas	gCO_2e/MJ	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Medium	Hydrogen	gCO_2e/MJ	118	117	115	114	113	111	110	109	107	106	105	103	102	101	99	98

Med-high	Renewables share of electricity	%	1%	4%	6%	9%	11%	14%	17%	19%	22%	24%	27%	30%	32%	35%	37%	40%
Med-high	Fossil share	%	99%	96%	94%	91%	89%	86%	83%	81%	78%	76%	73%	70%	68%	65%	63%	60%
Med-high	Renewable electricity	*gCO_2e/kWh*	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Med-high	Fossil electricity	*gCO_2e/kWh*	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
Med-high	Natural gas	*gCO_2e/MJ*	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Med-high	Hydrogen	*gCO_2e/MJ*	118	115	113	110	107	105	102	99	97	94	91	89	86	83	81	78
High	Renewables share of electricity	%	1%	4%	8%	11%	14%	17%	21%	24%	27%	30%	34%	37%	40%	43%	47%	50%
High	Fossil share	%	99%	96%	92%	89%	86%	83%	79%	76%	73%	70%	66%	63%	60%	57%	53%	50%
High	Renewable electricity	*gCO_2e/kWh*	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
High	Fossil electricity	*gCO_2e/kWh*	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377	377
High	Natural gas	*gCO_2e/MJ*	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
High	Hydrogen	*gCO_2e/MJ*	118	113	107	102	97	91	86	81	75	70	65	59	54	49	43	38

Annex D Vehicle energy efficiencies

Table L New passenger car miles per gallon*

YEAR	GASOLINE	EV100	EV200	ETOH	DIESEL	CNG	GASOLN SI HEV	E85/H2 SI HEV	DIESEL HEV	SI PHEV 10	SI PHEV 40	DIESEL PHEV	FCV
2015	36.01	132.11	125.64	36.18	44.75	35.02	51.44	51.44	60.67	60.84	73.14	68.45	47.23
2016	36.25	131.77	125.82	36.42	44.95	35.32	51.61	51.61	61.21	61.26	73.38	69.07	47.31
2017	38.01	132.34	127.14	38.24	46.02	37.42	54.21	54.21	59.53	63.36	74.98	67.17	52.83
2018	38.93	132.90	130.95	39.17	46.45	38.23	55.40	55.40	60.01	64.45	76.44	67.71	53.02
2019	40.82	133.59	132.56	41.12	47.34	40.73	56.63	56.63	60.59	66.33	77.88	68.37	53.16
2020	42.84	134.61	134.53	43.25	48.58	43.27	59.74	59.74	61.70	68.44	79.87	71.02	53.53
2021	44.73	135.44	135.89	45.17	49.93	45.19	61.77	61.77	65.69	70.67	81.35	76.50	53.84
2022	46.88	136.58	137.46	47.35	51.34	47.34	64.45	64.45	68.92	73.38	83.34	81.16	54.34
2023	49.19	137.13	139.07	49.75	53.08	50.05	66.99	66.99	70.60	76.14	85.05	84.04	54.58
2024	50.44	137.10	139.36	51.01	53.98	51.21	68.39	68.39	71.61	77.55	85.81	86.14	54.61
2025	52.95	137.21	140.78	53.67	55.82	54.41	71.12	71.12	73.28	82.08	87.41	89.26	54.71
2026	53.01	137.15	140.78	53.73	55.82	54.61	71.17	71.17	73.50	82.16	87.47	89.01	54.70
2027	53.03	137.17	140.90	53.77	55.83	54.71	71.15	71.15	73.63	82.23	87.57	89.69	54.71
2028	53.03	137.13	140.97	53.77	55.78	54.70	71.14	71.14	73.66	82.25	87.59	89.94	54.71
2029	53.01	137.17	141.05	53.75	55.76	54.68	71.11	71.11	73.63	82.26	87.62	90.28	54.71
2030	52.98	137.19	141.10	53.73	55.74	54.66	71.07	71.07	73.60	82.25	87.63	89.14	54.72

** Miles per gallon gasoline equivalent for vehicles not exclusively fueled by gasoline or diesel*

Table M New light truck miles per gallon*

YEAR	GASOLINE	EV100	EV200	ETOH	DIESEL	CNG	GASOLN SI HEV	E85/H2 SI HEV	DIESEL HEV	SI PHEV 10	SI PHEV 40	DIESEL PHEV	FCV
2015	28.11	123.91	111.52	28.50	35.17	27.76	40.80	40.80	43.60	48.51	58.33	49.19	44.51
2016	28.57	128.44	115.60	28.97	35.55	28.13	41.44	41.44	43.66	51.86	62.13	49.27	44.86
2017	29.15	130.63	117.57	29.55	35.88	28.66	41.74	41.74	42.68	52.69	62.35	48.16	45.03
2018	29.90	130.59	120.98	30.29	36.31	29.35	42.13	42.13	42.93	53.69	63.89	48.45	45.40
2019	32.59	140.05	125.17	33.01	37.71	31.72	44.68	44.68	43.18	58.26	67.87	48.72	46.97
2020	33.23	142.87	126.47	33.65	38.22	32.44	45.12	45.12	51.41	59.36	69.19	58.01	47.46
2021	34.28	145.19	128.19	34.69	38.93	33.47	46.15	46.15	51.94	60.76	70.45	58.61	48.10
2022	35.24	146.62	129.84	35.62	39.63	34.47	47.11	47.11	53.52	62.00	71.60	60.39	48.72
2023	36.24	148.20	131.51	36.63	40.35	35.54	48.15	48.15	54.79	63.31	72.78	61.82	49.34
2024	38.02	150.39	134.01	38.41	41.72	37.41	51.15	51.15	55.99	65.97	74.90	63.18	50.28
2025	39.90	150.76	135.60	40.29	43.11	39.26	53.72	53.72	57.57	68.29	76.60	64.95	50.16
2026	40.08	148.54	135.67	40.45	43.23	39.46	53.86	53.86	57.55	68.39	76.68	64.94	50.11
2027	40.25	146.49	135.75	40.62	43.40	39.65	54.11	54.11	57.55	68.55	76.79	64.94	50.06
2028	40.26	144.63	135.73	40.62	43.40	39.64	54.09	54.09	57.57	68.58	76.79	64.96	49.98
2029	40.32	143.22	135.76	40.67	43.43	39.72	54.05	54.05	57.61	68.59	76.81	65.00	49.94
2030	40.38	142.21	135.78	40.72	43.49	39.79	54.06	54.06	57.50	68.62	76.83	64.88	49.92

** Miles per gallon gasoline equivalent for vehicles not exclusively fueled by gasoline or diesel*

Table N New heavy-duty vehicle mile per gallon

YEAR	3-6 GASOLINE	3-6 DIESEL	3-6 NG/ LPG	7&8 GASOLINE	7&8 DIESEL	7&8 NG/ LPG	7&8 SU GASOLINE	7&8 SU DIESEL	7&8 SU NG/ LPG	7&8 COMB NG/LPG	7&8 COMB DIESEL	7&8 SU	7&8 COMB
2015	7.83	10.84	7.97	5.31	6.70	5.71	5.31	7.09	5.98	5.38	6.62	6.80	6.62
2016	7.96	11.14	8.03	5.32	6.74	5.72	5.32	7.13	6.01	5.41	6.66	6.84	6.66
2017	8.11	11.48	8.18	5.33	7.09	5.71	5.33	7.50	6.01	5.41	7.00	7.14	7.00
2018	8.17	11.58	8.24	5.34	7.08	5.71	5.34	7.49	6.03	5.42	7.00	7.13	6.99
2019	8.01	11.28	8.12	5.32	7.04	5.68	5.32	7.45	6.01	5.41	6.96	7.09	6.96
2020	8.12	11.43	8.25	5.33	7.07	5.69	5.33	7.48	6.03	5.43	6.99	7.11	6.98
2021	8.21	11.57	8.51	5.33	7.09	5.77	5.33	7.50	6.14	5.53	7.01	7.12	7.00
2022	8.29	11.65	8.65	5.33	7.10	5.79	5.33	7.51	6.18	5.56	7.02	7.12	7.02
2023	8.36	11.72	8.73	5.33	7.12	5.79	5.33	7.53	6.20	5.58	7.04	7.12	7.03
2024	8.45	11.79	8.83	5.33	7.13	5.86	5.33	7.54	6.30	5.67	7.05	7.13	7.04
2025	8.54	11.82	8.90	5.33	7.14	5.87	5.33	7.56	6.34	5.71	7.07	7.13	7.05
2026	8.64	11.85	8.98	5.33	7.16	5.89	5.33	7.57	6.38	5.74	7.08	7.13	7.06
2027	8.75	11.86	9.10	5.33	7.17	5.90	5.33	7.59	6.40	5.76	7.09	7.14	7.08
2028	8.87	11.86	9.19	5.33	7.18	5.95	5.33	7.60	6.50	5.85	7.11	7.14	7.06
2029	8.99	11.85	9.35	5.33	7.19	5.95	5.33	7.61	6.52	5.86	7.12	7.14	7.07
2030	9.11	11.84	9.43	5.33	7.20	5.96	5.33	7.62	6.54	5.89	7.13	7.14	7.08

Notes: 3-6=Class 3-6 medium duty vehicles (i.e., from 10,000-26,000 lb gross vehicle weight rating); 7-8=Class 7-8 medium duty vehicles (i.e., 26,001 lb and greater gross vehicle weight rating); NG=natural gas; LPG=liquefied petroleum gas; SU=single unit; Comb=Combination tractor-trailer