A Clean Fuel Standard in Washington State

Revised Analysis with Updated Assumptions

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Terms and Abbreviations

ARB	California Air Resources Board
BAU	Business-as-Usual
Btu	British thermal unit

More to come….

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Executive Summary

TO BE COMPLETED

1. Introduction

Transportation produces the largest share of Washington's greenhouse gas emissions, typically close to half of the state's emissions (about 45 percent in recent years). Addressing this source of emissions is a key to achieving Washington's statutory greenhouse gas reduction goals (RCW 70.235.020).

One way to reduce greenhouse gas emissions from transportation is to implement a Clean Fuel Standard (CFS) for transportation fuels. Carbon intensity of a fuel is defined as the well-to–wheel carbon emissions of a fuel pathway per unit of energy produced. Well-to -Wheel (WTW) emissions include the emissions produced during: feedstock recovery, feedstock transport to the fuel production plant, fuel production, fuel transport to the refueling stations and vehicle emissions.

In 2009-2011, Washington Department of Ecology's (Ecology) Air Quality Program commissioned an analysis of the implications of launching a Clean Fuel Standard program to reduce these emissions.[1] In 2013 a review of the original analysis was conducted to consider the degree to which updated assumptions might alter the original conclusions.[2]

As a next step, Governor Inslee has directed, by Executive Order 14-04, the Office of Financial Management (OFM) with other agencies, and advice from subject matter experts, affected industries, and public interests, to evaluate the technical feasibility, costs and benefits, and job implications of requiring the use of cleaner transportation fuels through standards that reduce the carbon intensity of these fuels over time. In June 2014, OFM entered into contract with Life Cycle Associates, LLC, to carry out the analysis, building on the original work and subsequent review. Specifically Life Cycle Associates was commissioned to*:*

- Re-evaluate the availability of low carbon fuels and update carbon intensity values for previously analyzed fuel pathways.
- Using current version of the VISION model, update Washington baseline and business as usual (BAU) cases, as appropriate, and adjust and model compliance scenarios; create REMI PI+ model inputs for economic analysis, based on the VISION model outputs.
- Using REMI PI+ and supporting analysis, estimate the economic affects within the state of Washington of implementing a Washington CFS.
- Identify and assess various policy mechanisms to avoid escalating fuel costs.

This draft report presents the results of the analysis of availability of low carbon fuels, carbon intensity estimates for several fuels, and the business as usual case and scenario analysis results.

[1] *A Low Carbon Fuel Standard in Washington: Informing the Decision"*, TIAX LLC, 2011
[2] *WA LCFS Analysis: Implication of Updated Assumptions*, Life Cycle Associates, 2013

This draft report does not cover at this time the economic analysis results and the cost containment mechanisms. It is anticipated that a complete draft report will be available on October 6, 2014 for review. The final report will be available on October 17, 2014.

2. Availability of Low Carbon Fuels

Like many energy and environmental policies that have been implemented in the past, clean fuel standards require industry to innovate and supply products that are either currently not available or not available in sufficient quantity. The intent of the regulation is to provide signals to spur the market to respond with the desirable outcome. In the first few years of California's existing LCFS, the market has seen a tremendous response with new low carbon fuels emerging that were not anticipated five years ago (e.g. corn oil biodiesel, high solids anaerobic digestion CNG, tallow based renewable diesel).

This analysis of low carbon fuels availability consists of evaluating compliance scenarios that bound the range of possible low carbon fuel supply. The exercise requires us to estimate volumes of low CI fuels that might be available in the future. It is important to recognize that, consistent with the recent California experience, additional low CI fuel pathways will emerge over the next five to ten years that will not be captured in the analysis. Future volumes of known low CI fuels, particularly cellulosic fuels, are difficult to predict with certainty since they require strong signals from regulators to provide sufficient stability to encourage investment. We have attempted to quantify volumes produced today and potential volumes that could be produced in the future, and consider these two bounds in the definition of the compliance scenarios.

The following section provides current and projected availability of a variety of low carbon intensity fuels that could be utilized for compliance with a Washington State CFS. For each fuel and feedstock we note how much if any is produced in-state. Clearly Washington is able to source transportation fuels from around the globe; this information is utilized later in the macro-economic modeling since consumption of goods produced in-state has a different economic activity than consumption of imported goods.

Recognizing that if Washington and Oregon both implement a CFS, three states and British Columbia would require low CI compliance fuels. In several instances, estimates of Washington's share of projected available fuel volumes are required. Because Washington consumes 14 percent of the gasoline and diesel consumed in California, Oregon, Washington and British Columbia[3], and because these four regions would be the main competitors for low CI fuels, it is assumed in a number of instances that 14 percent of projected low CI fuel volumes could come to Washington State. Even if these fuels are produced outside of California, if they are needed for compliance, they will be pulled into the Washington.

Table 2-1 summarizes the low CI fuel availability assumptions utilized for the scenario analysis exercise. More detailed discussion for each fuel type follows in the paragraphs below.

[3] 2012 Motor gasoline (EIA State Energy Data System), On-road distillate (EIA Adjusted Sales of Distillate Fuel Oil by End Use), http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/trade37c-eng.htm (for BC fuel use).

Table 2-1 Summary of Potential Fuel Supply in 2026

Fuel Pathway	2026 Potential Supply	Notes
Ethanol[a]		
Conventional	Abundant	13 BGY consumed in 2013
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[b]		
Fossil	As needed	Limited by vehicle sales and refueling station capacity
Renewable	170 MGY	16 MGY existing capacity
Hydrogen	As needed	Limited by vehicle sales and refueling station capacity
Electricity	As needed	Limited by vehicle sales and charging infrastructure
Biodiesel[c]	108	Limit total use to in-state production capcity (B15)
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

a. As gallons of ethanol
b. As diesel gallon equivalenat
c. As gallons of biodiesel

2.1 Conventional Ethanol

Washington currently consumes corn ethanol imported from the Midwest in its motor gasoline. Estimated ethanol blend levels for the past several years, obtained through the Washington State Department of Agriculture's (WSDA's) Fuel Testing program[4] are provided in Table 2-2. Note that in 2013, WSDA completed rulemaking allowing E15 to be sold in-state. E15 is a blend of 15% ethanol by volume in motor gasoline. It is assumed that sufficient Midwest corn ethanol will be available for use through the analysis period. In response to California's LCFS, ARB has registered 80 lower carbon corn ethanol pathways. We assume that these volumes are available for use in Washington.

Table 2-2. Recent Washington State Blend Levels in Motor Gasoline

[4] Jerry Buendel, Washington State Department of Agriculture, Weights and Measures Program

Year	Motor Gasoline Average Ethanol Content (% vol)
2011	9.81%
2012	9.72%
2013	9.64%
2014 (Jan-June)	9.47%

Ethanol can also be produced from sorghum and wheat. California has labeled this category of ethanol "Corn+" and has imported over 200 MGY of this grain ethanol[5]. For this analysis, we assume that this volume grows by 3 percent per year and that 14% of it would be available to Washington State (40 MGY by 2026).

There are currently four molasses to ethanol pathways registered in California's LCFS program. We assume here that these four plants produce a total of 100 MGY in 2016 and that these volumes grow by 3 percent per year and that Washington could receive up to 14 percent of it. This corresponds to 20 MGY of ethanol from molasses.

Ethanol produced in Brazil from sugarcane has an attractive CI value. California has imported up to 190 MGY, but has recently imported only half of that amount. Figure 2-1 provides DOE's Energy Information Administration projection of U.S. sugarcane ethanol imports[6]. The AEO projection dips after 2022, likely due to uncertainty about continuation of EPA's RFS2. We have smoothed the projection here and assume for a lower bound, 14 percent is available for use in Washington State (146 MGY by 2026).

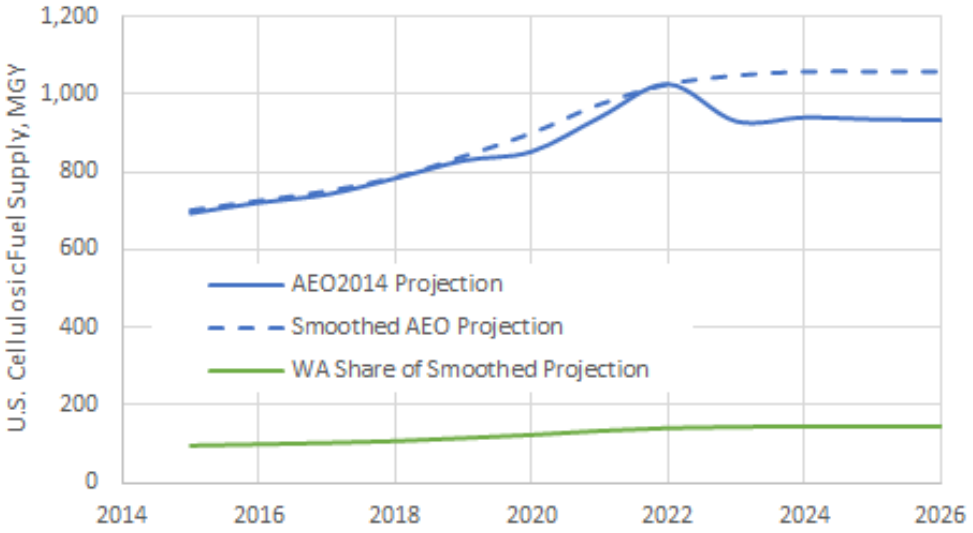

Figure 2-1. Projected sugarcane ethanol imports.

[5] Low Carbon Fuel Standard Reporting Tool Quarterly Summaries
[6] Annual Energy Outlook 2014 (AEO2014)

2.2 Biodiesel

Biodiesel is produced from waste oils (used cooking oil and tallow) and a variety of vegetable oils (soybean, canola, corn). Although there is significant biodiesel production capacity in-state, there has been relatively little biodiesel consumption to date. Estimated on-road biodiesel use is 2 MGY for 2013, which corresponds to a blend level of 0.22% in 2013[7]. Washington's installed production capacity is provided in Table 2-3.

Table 2-3. In-State Biodiesel Production Capacity

Plant	Feedstocks	Capacity (MGY)
Imperium Renewables	Vegetable oils, planning to add used cooking oil and tallow capability	100
General Biodiesel	Used Cooking Oil	10
Transmessis	Canola oil (crushing capacity too)	4

Because of the macro-economic modeling exercise, it is important to determine whether the feedstocks utilized to produce biodiesel are also produced in-state or are imported. Table 2-4 provides the estimated quantities of in-state feedstock potential. Canola oilseed production in 2013 was 30,600 tons[8], which corresponds to approximately 3.3 MGY of biodiesel. In-state canola oilseed crushing capacity is significantly higher than in-state oilseed production; Transmessis Colombia Plateau and Pacific Coast Canola have a combined crushing capacity of 43 MGY biodiesel equivalent. The oilseeds come from the Pacific Northwest. For this analysis we assume that up to 43 MGY of canola oil biodiesel is available for use.

Imperium Renewables has identified 6 to 8 MGY of collectible used cooking oil in-state and 10 to 12 MGY of tallow from Tyson Foods located in Pasco and Agri Beef Company located in Toppenish. For this analysis we have assumed up to 10 MGY of used cooking oil biodiesel and 12 MGY of tallow biodiesel are available for use.

Table 2-4. Biodiesel Feedstock Supplies

Feedstock	Biodiesel Potential (MGY)
Canola oilseeds (2013 WA production = 30,600 tons)	3.3
Canola oilseed crushing capacity	
Transmessis	4
Pacific Coast Canola	39
Used cooking oil (in-state potential supply)	6-8
Tallow (in-state potential supply)	10-12
Corn oil (Oregon and Idaho)	3
Oregon and Idaho	3
U.S.	140*
Midwest soybean oil	700*

* 2013 production, EIA Monthly Biodiesel Production Report

[7] Washington State agencies utilized 0.35 MGY on-road, estimate an additional 1.65 MGY non-public vehicles for a total statewide consumption of 2 MGY.

[8] NASS, Crop Production Annual Summary, January 10, 2014, assumes 18.6 wet lbs canola/gal biodiesel

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Local corn oil supplies are available from the Pacific Ethanol plants in Burley, Idaho and Boardman, Oregon (beginning in 2015). Significantly more corn oil for biodiesel production is available from the Midwest. Corn oil extraction is growing rapidly and we have assumed that by 2026 up to 40 MGY of corn oil biodiesel will be available for use in Washington. Washington currently imports some soybean oil for production of biodiesel. We assume that an unlimited supply (100 MGY) of soybean oil is available for use in the state.

2.3 Renewable Diesel

Renewable diesel is comparable to petroleum diesel and can be utilized in existing engines either on its own or as a blending component. It is also compatible with existing fuel storage and dispensing equipment. Renewable diesel is produced through hydro-treating vegetable oils or waste oils. California has had significant imports of waste oil based renewable diesel in the last several years for compliance with its LCFS, and RD is an important compliance fuel for regions with standards that limit the carbon intensity of transportation fuels.

In California there is concern that biodiesel blended with CARB diesel causes increased tailpipe NOx emissions; this effect does not occur with the diesel fuel formulation utilized in Washington State. ARB is currently working on a rule to address the issue of elevated NOx emissions from biodiesel use. The NOx reduction remedies considered include use of approved NOx control additives, use of approved biodiesel formulation, or blending with a “B20-ready” diesel fuel formulation. Because renewable diesel does not cause an increase in NOx emissions, California will preferentially utilize renewable diesel over biodiesel for compliance with the LCFS. Because of this preference and because Washington already has significant existing biodiesel production capacity, we have assumed that no renewable diesel will be utilized for compliance with a CFS in Washington State.

2.4 Cellulosic Fuels

Of the low CI fuels, it is the most difficult to predict future volumes of cellulosic fuels that could be available to Washington for compliance with a possible CFS. Future production capacity will only be available if durable regulations are in place to generate a need for it. Therefore, to a certain extent, predicting future capacity based on projections that do not take into account a need for future cellulosic fuel supply is unrealistic. In a rational market, if cellulosic fuels are required for compliance, plants will be built and the fuel will be supplied.

2.4.1 Cellulosic Fuel Availability

EIA provides annual projections (Annual Energy Outlook, AEO) of fuel supply based on regulations in place. Over the past several years, projections for cellulosic fuel supply have decreased as EPA has signaled softening future regulatory requirements. Figure 2-2 provides the AEO2013 and AEO2014 projections for U.S. cellulosic ethanol consumption. Note that EIA projects no increase in cellulosic ethanol use beginning in 2021. This is not a reflection of EIA’s opinion on whether cellulosic fuels are producible, rather it is a result of modeling assumptions about future RFS2 cellulosic volume requirements[9]. It is reasonable to assume that with consistent regulatory signals, the volumes produced and consumed could increase. We have

[9] Telephone conversation with Michael Cole, EIA. In their modeling, the cost of credits was set below the cost of cellulosic ethanol so that regulated parties opted to purchase credits rather than purchase cellulosic fuels.

assumed here that the shape of the increase is similar to the AEO2013 "liquids from biomass" projection (in yellow). This extension results in 450 MGY of cellulosic ethanol in 2026.

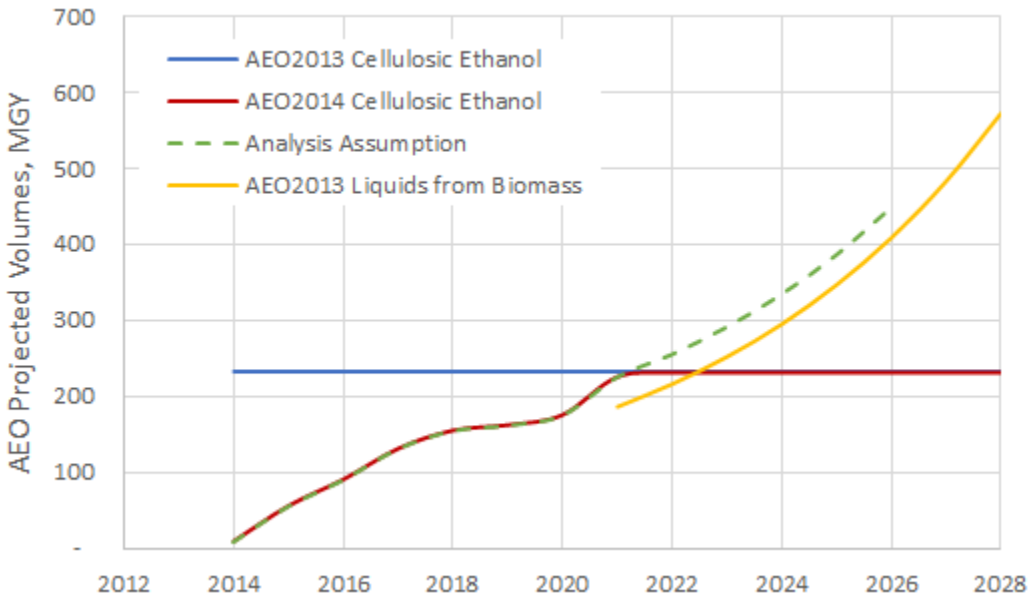

Figure 2-2. EIA cellulosic ethanol consumption projections.

EIA's category "liquids from biomass" category includes Fischer-Tropsch fuels from biomass feedstocks as well as pyrolysis based gasoline and diesel[10]. Figure 2-3 provides the AEO2013 and AEO2014 "liquids from biomass" projections. Again we have assumed that supply grows along the AEO2013 projection rather than the AEO2014 flat line due to anticipated softening of the RFS2 volume requirements.

In addition to EIA projections, other organizations have projected U.S. cellulosic fuel volumes. For example, E2[11] tracks cellulosic biofuel capacity and predicts that in 2016 there will be 750 MGY of cellulosic ethanol production in the U.S. This corresponds to 500 MGY on a gasoline equivalent basis. Researchers at UC Davis[12] recently found that up to 2.8 BGY (gasoline equivalent basis) of cellulosic fuels could be produced by 2025 if the "Leapfrog" approach were adopted. The Leapfrog approach assumes major breakthroughs in cellulosic technology at standalone refineries. This provides an upper bound on the amount of cellulosic fuel that could be available to regulated entities in a Washington CFS. Figure 2-4 compares the EIA projection to the E2 and UC Davis optimist projections.

Applying the 14% factor discussed above to the EIA (lower bound) and E2/UC Davis (upper bound) projections results in a range of 2026 cellulosic volumes available to Washington State of 100 to 400 MGY in gasoline equivalent gallons.

[10] Telephone conversation with Michael Cole, EIA.
[11] "Advanced Biofuel Market Report 2013", Mary Solecki, Bob Epstein Environmental Entrepreneurs and Anna Scodel, Goldman School of Public Policy
[12] "Three Routes Forward for Biofuels: Incremental, Transitional, and Leapfrog", Lew Fulton, Geoff Morrison, Nathan Parker, Julie Witcover, Dan Sperling, UC Davis, July 2014.

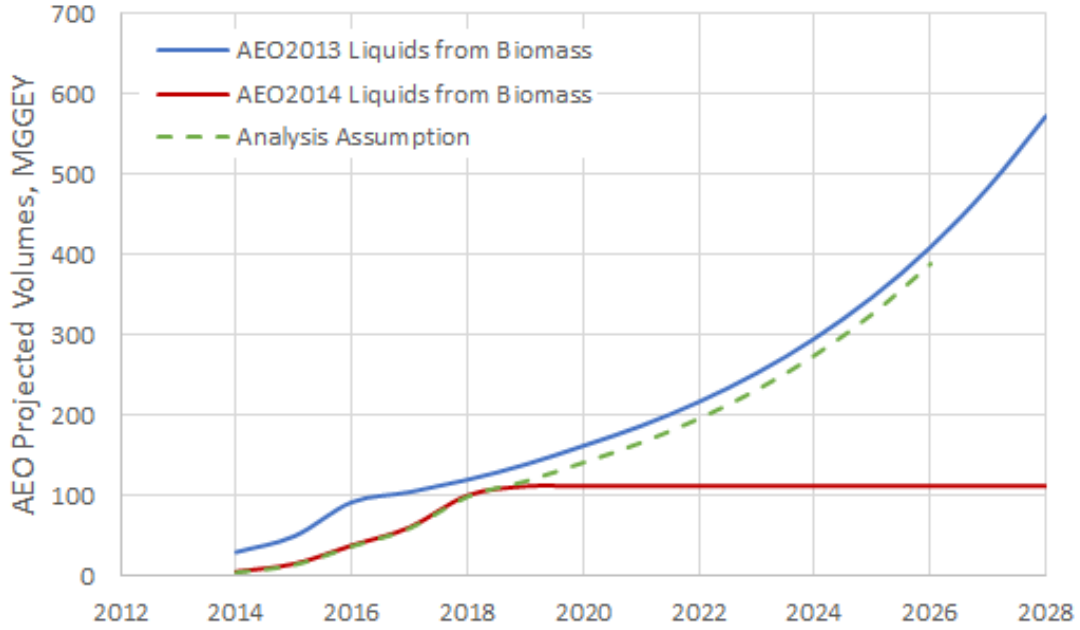

Figure 2-3. EIA cellulosic gasoline and diesel consumption projections.

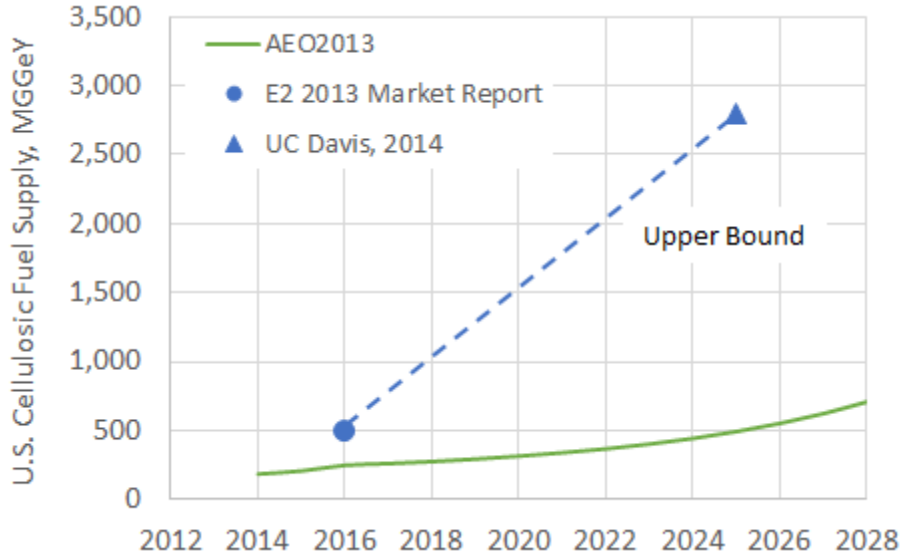

Figure 2-4. Range of predicted cellulosic biofuel availability.

2.4.2 Washington State Cellulosic Fuel Feedstock Potential

Washington State has two main cellulosic biofuel feedstocks of interest: wheat straw and forest residue. Wheat straw is amenable to cellulosic ethanol production while forest residue is better suited to cellulosic gasoline and diesel production through pyrolysis.

To assess the quantity of sustainably removed field residues (wheat and barley straw), several studies are utilized. Muth et al[13] have projected that by 2030, 2.24 million tonnes of sustainably removed straw would be available for use as a biofuel feedstock. Assuming a 70 gal/ton conversion rate, this corresponds to 170 MGY of cellulosic ethanol potential. Similarly, DOE's updated billion-ton study[14] estimates 163 MGY of cellulosic ethanol potential in 2024 assuming 70 gal/ton yield and over $65 per ton for feedstock.

In terms of woody biomass, the Billion-Ton Update estimates that 2.5 million bone dry tons of woody biomass are available ($60 per bone dry ton) on an annual basis in Washington State. The Washington Department of Natural Resources[15] estimates that by 2025 between 1.2 and 2 million bone dry tons of woody biomass would be available for use as a biofuel feedstock. Using this more conservative estimate and an assumed yield of 50 gal per bone dry ton results in 60 to 100 MGY of cellulosic gasoline potential.

In summary, Washington State has the potential to supply feedstock for approximately 165 MGY of cellulosic ethanol from agricultural residues and 60 to 100 MGY of cellulosic gasoline from waste wood. In our scenario analysis exercise we assume that up to three plants with a capacity of 30 MGY each are built in Washington. This represents approximately one third of available agricultural and forest residue potential.

2.5 CNG

The quantity of compressed natural gas (CNG) consumed is dictated by the number of CNG vehicles on the road and the number of CNG refueling locations available. We assume for this analysis that sufficient CNG will be available either from fossil or renewable natural gas (RNG) to fuel all of the CNG vehicles in the inventory.

RNG from landfill gas (LFG), wastewater treatment (WWT) anaerobic digestion, and high solids anaerobic digestion (HSAD) that is cleaned, injected into the pipeline and compressed at a CNG station is a very low carbon intensity fuel. Washington State already has RNG to CNG pathways registered with the California LCFS. **Error! Reference source not found.** summarizes the current and potential RNG production in equivalent diesel gallons. There is significantly more potential than ability for vehicles to consume it, and current supplies of LFG and WWT RNG are sufficient for projected 2026 consumption.

[13] "Sustainable agricultural residue removal for bioenergy: A spatially comprehensive US national assessment", D.J. Muth Jr., K.M. Bryden, R.G. Nelson, October 2012.
[14] U.S. Department of Energy. 2011. U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry. R.D. Perlack and B.J. Stokes (Leads), ORNL/TM-2011/224. Oak Ridge National Laboratory, Oak Ridge, TN.
[15] Washington Forest Biomass Supply Assessment, Washington Department of Natural Resources March 2012.

Table 2-5. Pipeline Quality RNG Current Supply and Potential

Feedstock	Current Capacity MGY diesel equivalent	Potential Capacity MGY diesel equivalent
Landfill Gas[1,2]	15	136
Wastewater Treatment[1,3]	1.4	12
Municipal Solid Waste (HSAD)[1,4]	0	20-24

1. *Roadmap for Biogas Development in Washington State*, supplied by Peter Moulton
2. 15 MGY current production at Cedar Hills Landfill, ongoing project for 7 MGY additional supply at LRI 34th Street Landfill.
3. http://www.kingcounty.gov/environment/wastewater/ResourceRecovery/Energy/Renewable.aspx
4. *2009 Washington Statewide Waste Characterization Study*, ECY 10-07-023, July 2010

2.6 Electricity and Hydrogen

Similar to CNG, the quantity of electricity and hydrogen consumed is dictated by the number of plug-in electric vehicles (PEVs) and hydrogen fuel cell vehicles (FCVs), respectively. In both cases we assume that sufficient fuel will be supplied (with investment in infrastructure) to fuel the projected vehicle population.

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3. Carbon Intensity Estimates

When comparing alternative fuel GHG emissions, the entire fuel cycle needs to be considered, not just vehicle emissions. Fuel cycle emissions are also referred to as well-to-wheel (WTW) emissions and can be broken down into two parts: well-to-tank (WTT) and tank-to-wheel (TTW). The WTT portion of the fuel cycle includes all emissions associated with fuel production while TTW emissions are essentially vehicle tailpipe emissions. The relative significance of the WTT portion of the fuel cycle varies with fuel type. For electricity, all of the WTW GHG emissions are in the WTT portion while for petroleum fuels, most of the GHG emissions come from combustion of the fuel in the vehicle (TTW portion). Fuel cycle GHG emissions are typically expressed in terms of carbon intensity – the WTW grams of equivalent CO_2 emitted per energy unit of finished fuel produced (e.g. gCO_2e/MJ).

To estimate WTW carbon intensity, the most recent version of Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model was utilized[16]. GREET is a widely used, publicly available, Microsoft Excel based model. EPA and ARB have used GREET to support transportation policy. Because the default inputs are average values for the U.S., we have made modifications to reflect Washington state conditions. The following sections describe the carbon intensity values utilized in the scenario analysis exercise.

3.1 Petroleum

There are five petroleum refineries located on Washington's west coast (Table 3-1) and approximately half of the gasoline and diesel refined is exported. These refineries produce most of the finished gasoline and diesel consumed in the state, though some is imported by pipeline from Montana and Utah for use in eastern Washington.

Table 3-1. Refineries in Washington State

Company	Location	Operable Capacity bbl per calendar day
BP West Coast Products	Ferndale	225,000
Phillips 66	Ferndale	101,000
Tesoro West Coast	Anacortes	120,000
Shell Oil Products U.S.	Anacortes	145,000
U.S. Oil and Refining Company	Tacoma	40,700

U.S. EIA State Energy Data System

The methodology employed to quantify gasoline and diesel carbon intensity values consisted of the following steps:

1. Determine refining location for finished petroleum fuels consumed
2. Determine sources of crude oil for each refining location
3. Quantify crude oil recovery and transport emissions
4. Quantify refining and finished fuel transport emissions

Each of these steps is discussed in detail below.

[16] GREET1_2013 released on October 25, 2013.

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3.1.1 Refining Locations

The first step in quantifying the carbon intensity values for gasoline and diesel is to determine where these fuels are refined. Table 3-2 indicates total gasoline and diesel consumption for 2011 and 2012. Fuel consumption for 2013 was not available at the time of the analysis so the baseline carbon intensity values are developed for 2012. The pipeline deliveries from Montana and Utah for gasoline and diesel are also shown; Washington refined gasoline and diesel are determined by difference. As shown, 79 percent of the gasoline and 73 percent of the diesel consumed in Washington was refined in Washington in 2012. Therefore, carbon emissions must be quantified for three distinct pathways: crude recovery and transport to Washington for refining and distribution in Washington; crude recovery and transport to Montana for refining in Montana and transport/distribution to Washington; crude recovery and transport to Utah for refining in Utah and transport/distribution to Washington.

Table 3-2. Consumption and sources of gasoline and diesel in Washington.

Washington State Consumption & Supply Million Gallons	Gasoline Blendstock			On-Road Diesel		
	2011	**2012**	2013	2011	**2012**	2013
Consumption[a]	2,417	**2,405**	n/a	599	**613**	n/a
Supply[b]						
Tesoro pipeline	224	**222**	171	186	**94**	112
Yellowstone pipeline	303	**290**	322	65	**74**	71
Total pipeline supply	527	**513**	493	251	**168**	183
In-State refiners (difference)	1,890	**1,892**		348	**445**	
Supply Shares						
Tesoro pipeline (UT)	9%	**9%**		31%	**15%**	
Yellowstone pipeline (MT)	13%	**12%**		11%	**12%**	
Washington state refineries	78%	**79%**		58%	**73%**	

a. EIA State Energy Data System (SEDS) "WA State Historic Fuel Consumption - Transportation"

b. Pipeline imports supplied by Tony Usibelli (Washington State Department of Commerce)

3.1.2 Sources of Crude Oil

The carbon intensity of crude oil extraction and transport depends on the source of the crude oil. In this step of the analysis, the sources of the crude oils refined in each of the three refining locations were determined.

Crudes Refined in Washington

Foreign imports of crude oil were determined for 2012 from EIA databases[17]. In 2012 there were no imports from other PADDs[18] into Washington, however there were shipments from Alaska to PADD 5. PADD 5 is composed of Washington, Oregon, California, Arizona, Nevada, and Hawaii. Since there is no refining capacity in Oregon, Arizona, Nevada and only a small amount in Hawaii, we assume that Washington receives all of the shipments to PADD 5 less the shipments to California. California receipts from Alaska are provided by the California Energy Commission[19]. Table 3-3 provides the sources of crude utilized in Washington in 2012 while Figure 3-1 provides the same data with individual countries grouped into regions.

[17] EIA Company Level Imports http://www.eia.gov/petroleum/imports/companylevel
[18] PADD = Petroleum Administration Defense District; the U.S. is divided into 5 PADDs.
[19] http://energyalmanac.ca.gov/petroleum/statistics/2012_monthly_oil_sources.html

Table 3-3. Sources of crude supplied to Washington Refineries in 2012.

Source	Share	Source	Share
Algeria	0.5%	Eq. Guinea	0.3%
Angola	3.3%	Nigeria	1.4%
Argentina	1.1%	Oman	0.9%
Brazil	0.3%	Russia	5.4%
Canada	26.1%	Saudi Arabia	2.9%
Colombia	0.3%	Alaska	57.3%
Congo	0.3%		

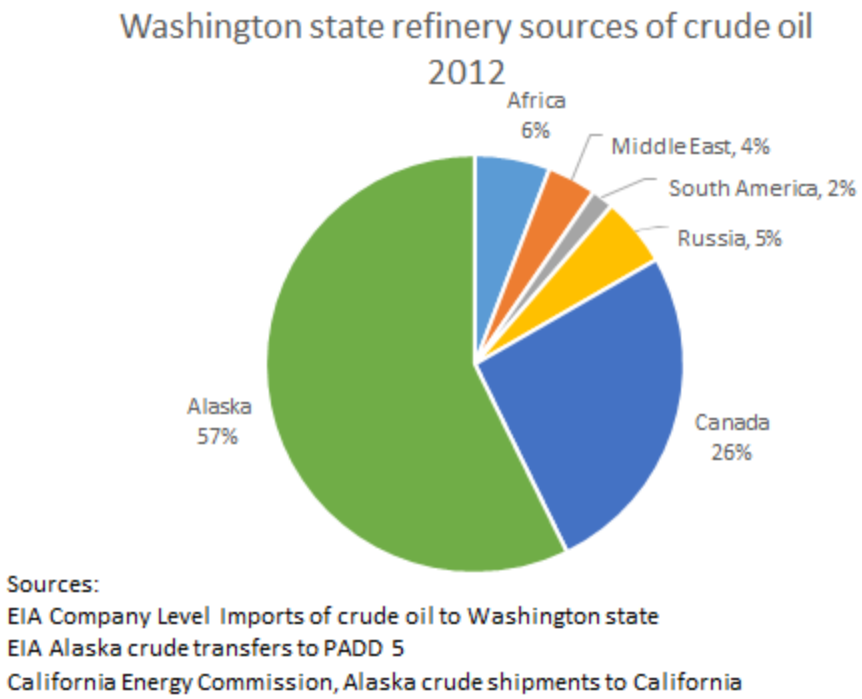

Figure 3-1. Sources of Crude Oil Supplied to Washington State in 2012 by Region.

It is also important to determine how much of the crude oil sourced from Canada is conventional and how much is oil sands crude. Canada's National Energy Board posts amounts of each type of crude oil that is exported by PADD. Figure 3-2 provides the exports to PADD 5 in 2012. Almost no Canadian crude went to California in 2012[20], so this mix is representative of the Canadian crude in Washington. Approximately half of the crude is conventional, half is from oil sands.

[20] http://energyalmanac.ca.gov/petroleum/statistics/2012_crude_by_rail.html

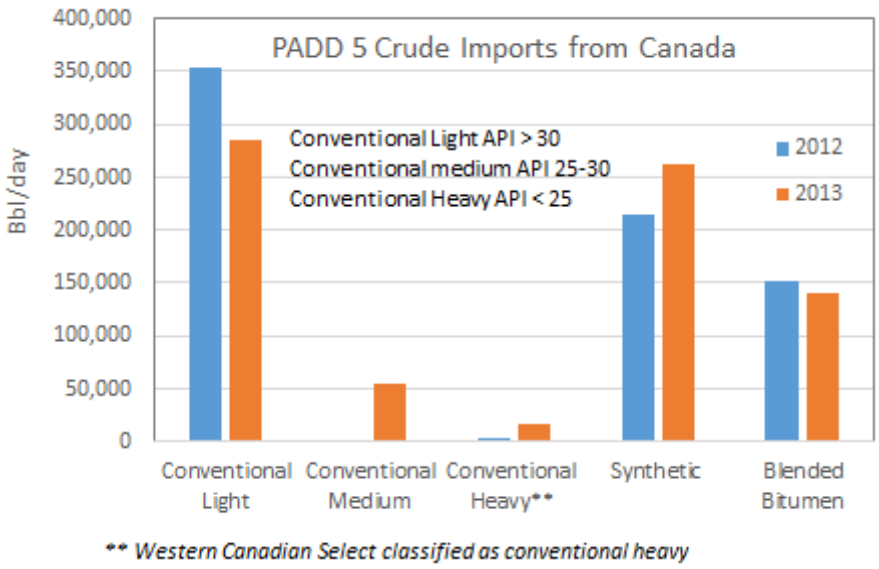

Figure 3-2. PADD 5 crude imports from Canada by type.

Crudes Refined in Montana

Refineries in Montana refine crude oil produced in Montana, Wyoming, and Canada. Table 3-4 provides the sources of crude oil refined in Montana during 2012[21]. The types of crude oil imported from Canada into PADD 4[22] are shown in Figure 3-3. We assume that Montana receives the average mix of imports into PADD 4. Most of the crude imported from Canada is heavy conventional crude.

Table 3-4. Sources of crude oil refined in Montana in 2012

2012 BBLs	Crude Source		
	Montana	Wyoming	Canada
CHS inc	1,467,560	1,737,442	17,273,372
Phillips 66	192,053	103,164	19,238,377
ExxonMobil		5,565,743	12,004,809
Calumet			3,674,548
Total	1,659,613	7,406,349	52,191,106
%	3%	12%	85%

[21] Annual Review 2012, Oil and Gas Conservation Division, Department of Natural Resources and Conservation of the State of Montana
[22] PADD 4 consists of Montana, Idaho, Utah, Wyoming, and Colorado

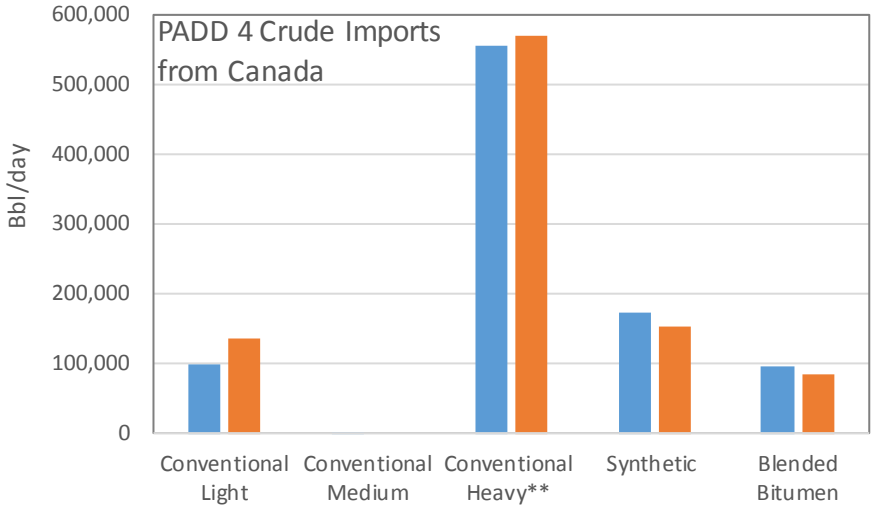

Figure 3-3. Types of crude oil imported from Canada to PADD 4.

Crudes Refined in Utah

Table 3-5 provides pipeline crude oil receipts by source[23]. Most of the crude comes from Utah and Wyoming. A small amount comes from Canada; the Canadian crudes are assumed to have the same mix as in Montana (Figure 3-3). The crude data available does not include any receipts by truck, but this is assumed to be a small share of the total crude oil.

Table 3-5. Sources of Utah refinery crude oil receipts

Year	Colorado Pipeline Imports	Wyoming Pipeline Imports	Canada Pipeline Imports	Utah	Refinery Receipts Total
2010	6,525	20,144	4,278	20,690	51,637
2011	6,997	20,536	3,894	24,473	55,900
2012	7,805	20,769	4,394	26,185	59,153
2012	13%	35%	7%	44%	

3.1.3 Crude Recovery and Transport Emissions

Crude oil recovery emissions can vary widely depending on many factors including amount and type of artificial lift utilized, fluid injection quantities, and whether gas flooding or steam injection is required. In addition, fugitive emissions can significantly impact crude recovery carbon intensity values. Researchers at Stanford University have developed the Oil Production Greenhouse Gas Emission Estimator (OPGEE) model[24] to quantify carbon intensity for crude oil recovery and transport by oil field.

[23] Utah Geological Survey, http://geology.utah.gov/emp/energydata/oildata.htm#refinery
[24] https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator

We utilized Version 1.1 Draft C of the OPGEE model to estimate carbon intensity for the crude oils utilized in Washington, Montana, and Utah. In cases where OPGEE estimates CI for multiple fields in a given location, we employ an average. Only transport distance inputs have been adjusted from default values. Figure 3-4 through Figure 3-6 provide the weighted average carbon intensities for crude oil recovery and transport for each of the three refining locations (Washington, Montana, and Utah).

The OPGEE model does not yet calculate CI for crude oils that are recovered with hydraulic fracturing. However, since only 3% of the crude oil refined in Montana in 2012 was from Montana, and since most of the carbon emissions come from the vehicle rather than the crude oil recovery, this is likely a small effect.

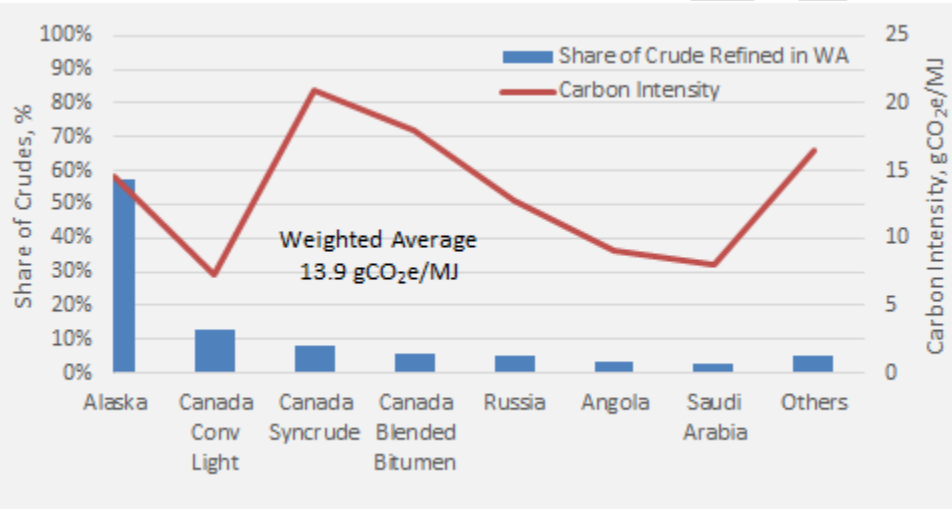

Figure 3-4. Average CI for crude oils refined in Washington.

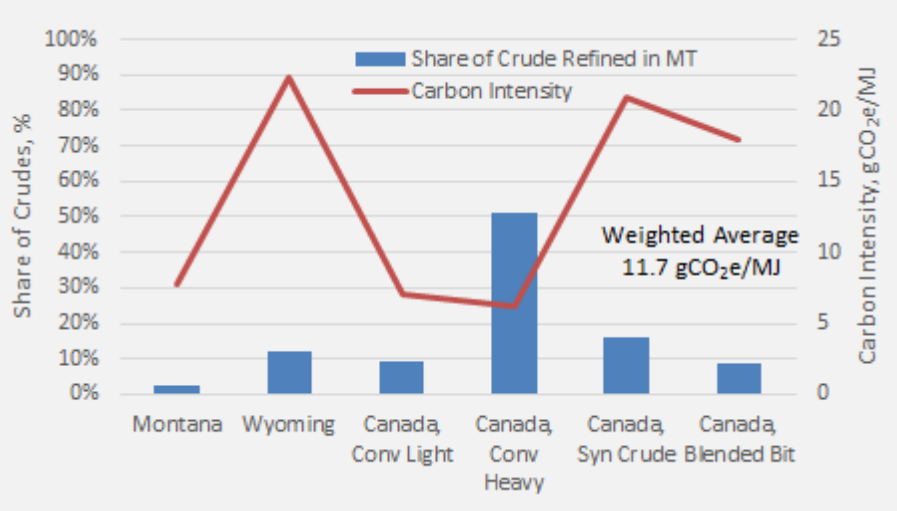

Figure 3-5. Average CI for crude oils refined in Montana

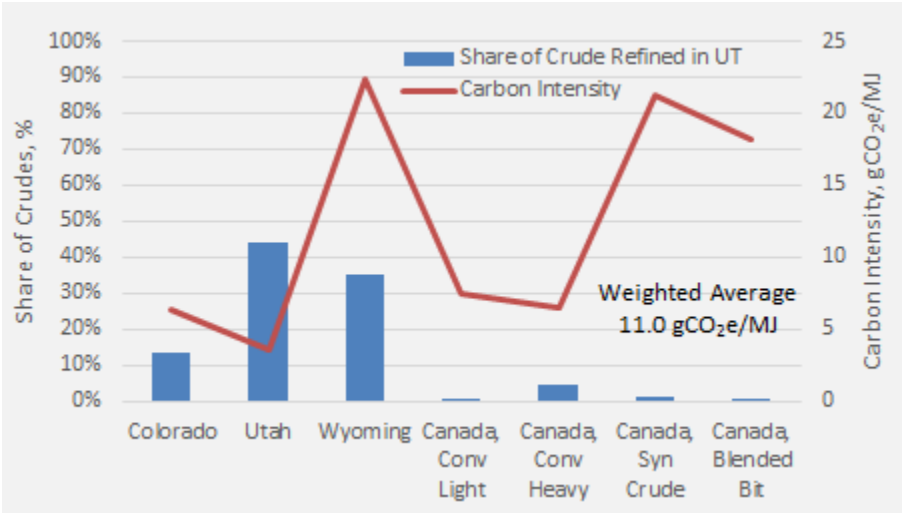

Figure 3-6. Average CI for crude oils refined in Utah.

3.1.4 Refining and Finished Fuel Transport Emissions

The WA-GREET1 model was utilized to calculate crude refining and transport emissions. This updated version of the GREET model now calculates refining efficiency based on crude API and sulfur content. If these values are unknown, GREET supplies average values depending on crude oil source. The GREET calculated refining efficiencies are presented in Table 3-6. It is interesting to note that the gasoline refining efficiency was lower than the diesel refining efficiency in earlier versions of GREET.

Table 3-6. GREET calculated refining efficiencies.

Refinery Location	Gasoline	Ultra Low Sulfur Diesel
Washington	89.2%	89.2%
Montana	88.4%	88.4%
Utah	89.4%	89.4%

The refining efficiency dictates the amount of fuel consumed per unit of fuel produced. The total fuel consumed is divided between a number of different process fuel types including natural gas and electricity. The natural gas and electricity carbon intensity values were modified for each refining location. The natural gas utilized in the western half of the state comes from Alberta and connects to the northwest pipeline system in Sumas. The pipeline distance is estimated at 700 miles. No commercial hydraulic fracturing in Canada yet[25], so assumed to be conventional natural gas. Although Montana is a net exporter of natural gas, because of infrastructure limitations all natural gas consumed is from Alberta[26]. The pipeline transmission distance from Alberta to Butte and then Billings is 700 miles; the natural gas is recovered conventionally. Finally natural gas utilized in Utah refineries is from the Uinta basin[27] and is all recovered through hydraulic fracturing. The assumed pipeline transport distance is 100 miles.

[25] http://www.capp.ca/canadaIndustry/naturalGas/ShaleGas/Pages/default.aspx
[26] http://deq.mt.gov/ClimateChange/Energy/EnergySupply/OilGasProduction.mcpx
[27] Phone conversation with Carolyn Williams, State of Utah, Department of Natural Resources, 6-20-14

The electricity grid mix for Washington State is described in Section 3.5. The 2012 mix is shown in Table 3-7 along with the resource mixes for Montana and Utah. The Montana and Utah mixes are taken from EIA databases[28].

Table 3-7. Refinery electricity grid mixes

Resource	Washington	Montana	Utah
Residual Oil		2%	
Natural Gas	8%	2%	17%
Coal	13%	50%	78%
Nuclear	5%		
Biomass	1%		
Other non-combustion	73%	46%	5%
Total	100%	100%	100%

The transport assumptions for finished fuel from the refinery to the petroleum terminal and refueling station are presented in Table 3-8. Table 3-9 provides the GREET estimated refining and transport carbon intensity estimates.

Table 3-8. Finished fuel transport assumptions.

Refinery Location	Terminal Location	WA Share %	Pipeline Miles	Barge Miles	Truck Miles
Western Washington	Seattle	88%	75	0	75
Western Washington	Pasco-Spokane	11%	150	200	75
Western Washington	Spokane	1%			150
Billings	Spokane		540		75
Salt Lake City	Pasco-Spokane		670		75

Table 3-9. GREET calculated refining and transport carbon intensity

Refinery Location gCO_2e/MJ	Gasoline	Ultra Low Sulfur Diesel
Washington	12.3	12.2
Montana	14.8	14.6
Utah	15.1	14.9

[28] http://www.eia.gov/electricity/data/state/

3.1.5 Vehicle Emissions

Tailpipe emissions consist of CO_2, N_2O and CH_4. The tailpipe emissions for gasoline and diesel are provided in Table 3-11.

Table 3-10. Assumed tailpipe emission factors

Pollutant	Units	Gasoline	Diesel	Source
CO_2	g/MJ	72.8	74.9	GREET Fuel Properties
CH_4	gCO_2e/MJ	0.06	0.01	EPA RFS2
N_2O	gCO_2e/MJ	1.6	0.7	EPA RFS2
CO_2e	gCO_2e/MJ	74.5	75.6	

EPA RFS2 Docket File: EPA-HQ-OAR-2005-0161-0925.1.xls

3.1.6 Summary of Gasoline and Diesel Carbon Intensity Estimates

Table 3-11 summarizes the 2012 carbon intensity estimates for 2012, the year utilized to develop the CFS baseline carbon intensity values. The crude recovery values shown in the table have refining and transport loss factors applied, so are slightly higher than the values shown above. The weighted averages for gasoline and diesel are 100.7 and 101.7 gCO_2e/MJ, respectively.

Table 3-11. Summary of estimated gasoline and diesel 2012 carbon intensity, gCO_2e/MJ

Refinery Location gCO_2e/MJ	Refining Location			Weighted Average
	Washington	Montana	Utah	
Gasoline				
Crude Recovery & Transport	14.0	11.7	11.0	
Refining & Transport	12.3	14.8	15.1	
Vehicle	74.5	74.5	74.5	
Total	100.7	100.9	100.6	
% Consumed in Washington	79%	12%	9%	
Weighted Average				100.7
Diesel				
Crude Recovery & Transport	13.9	11.7	11.0	
Refining & Transport	12.1	14.6	14.9	
Vehicle	75.6	75.6	75.6	
Total	101.7	101.9	101.5	
% Consumed in Washington	73%	12%	15%	
Weighted Average				101.7

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3.2 Ethanol

For the scenario analysis exercise, several different types of ethanol were utilized. The quantification methodology and resulting denatured CI value for each type are provided in Table 3-12. For the analysis it was assumed that denatured ethanol consists of neat ethanol blended with gasoline at 2% volume blend. The GREET model defaults were utilized to estimate the carbon intensity of average Midwest corn and Brazil sugarcane ethanol. Transportation modes and distances were modified to reflect transport to Washington. The GREET model forecasts that the average corn ethanol pathway decreases by 2.8 gCO_2e/MJ in 2020 while the sugarcane pathway decreases by 6.4 gCO_2e/MJ. We have assumed a linear decrease from the 2015 value to the 2020 value, holding constant thereafter.

The carbon intensity values for low carbon corn and corn+ pathway are based on reported average values for fuels sold in California[29]. Because this is an approximation and because the transportation portion of the pathway is small, we have not adjusted the transport distances for these pathways to reflect transport to Washington instead of California. We assume these values remain constant over the analysis period.

The molasses ethanol pathway is an average of four Method 2B applications received by ARB for the California LCFS. We have assumed that this value remains constant over time. At the time of the analysis ARB had not posted any cellulosic fuel pathways, so we utilize the GREET1 default values for corn stover and forest residue ethanol. ARB has recently posted a cellulosic ethanol pathway at 7 gCO_2e/MJ, so 15 gCO_2e/MJ assumed for the analysis is slightly high, but reasonable. We have conservatively assumed that this value remains constant throughout the analysis period. Neither of these feedstock have ILUC emissions associated with them.

Table 3-12. Summary of denatured ethanol carbon intensity values utilized in analysis

Feedstock	Calculation Methodology	2015 CI gCO_2e/MJ
Avg MW Corn	WA-GREET1 with preliminary ARB ILUC[a]	89.0
Low Carbon Corn	Average of corn ethanol used in California in 2013[b]	85.2
Corn+	Average of corn+ ethanol used in California in 2013[c]	58.0
Avg Brazil Sugarcane	WA-GREET1 with preliminary ARB ILUC[a]	43.6
Brazil Molasses	Average of ARB Method 2B applications	30.0
Cellulosic	Average of GREET1 default for corn stover and forest residue	15.0

a. ARBILUC Workshop on March 10, 2013
b. Subtract out previous ILUC value (30 g/MJ) and add preliminary value (23.2 g/MJ)
c. Subtract out previous ILUC value (30 g/MJ) and add preliminary sorghum ILUC (17.5 g/MJ)

3.3 Cellulosic Gasoline

Consistent with the cellulosic ethanol pathway, we have utilized the average GREET1 default value for production of cellulosic gasoline from corn stover and forest residue via pyrolysis. This value is 17 gCO_2e/MJ and we have conservatively assumed that it stays constant over the analysis period.

[29] Status Review of California's Low Carbon Fuel Standard, January 2013, UC Davis ITS

3.4 Biodiesel

The biodiesel fuel pathways included in the scenario analysis consist of biodiesel produced in Washington from a range of feedstocks indicated in Table 3-13. For the canola and soybean pathways, feedstock and crushing energy and emissions were allocated between the oil and the meal on a mass basis. For all pathways, esterification energy and emissions were allocated between the biodiesel and glycerin on an energy basis. All electricity and natural gas use utilize Washington specific inputs. All transport modes and distances were modified to reflect transport of feedstocks to and within Washington state and transport of biodiesel within the state.

For the canola pathway, the rapeseed pathway GREET1 defaults for energy use and yield were utilized, resulting in WTT emissions of 31.7 gCO_2e/MJ. This is lower than ARB's newly posted value of 41.7 gCO_2e/MJ, but higher than the result if inputs provided by S&T2[30] are utilized (26.4 gCO2e/MJ). Given the spread, we have chosen the GREET1 fuel use and yields with transport inputs modified to reflect Washington transport modes and distances.

For the soybean oil and tallow biodiesel pathways, the GREET1 defaults for energy use and yield were utilized. For the used cooking oil (UCO) pathway the ARB energy use and fuel shares for the "cooking" case were utilized. For the corn oil pathway, the carbon intensity value was taken from the Method 2B corn oil pathway posted on the ARB website.

Table 3-13. Summary of biodiesel carbon intensity values utilized in analysis

Feedstock	Calculation Methodology	2015 CI gCO_2e/MJ
Canola Seed	WA-GREET1 rapeseed pathway with preliminary ARB ILUC value[a]. All seeds from Pacific Northwest and crushed in Washington. All fuel produced in Washington.	77.3
Soybean Oil	WA-GREET1 soybean pathway with preliminary ARB ILUC value[b]. All oil from Midwest, all fuel produced in Washington	60.7
Used Cooking Oil	WA-GREET1 UCO pathway, feedstock collected from Washington state and fuel produced in-state.	18.3
Tallow	WA-GREET1 Tallow pathway, feedstock collected from Washington state and fuel produced in-state	29.7
Corn Oil	Carbon intensity value taken from ARB LCFS posted pathway	4.0

a. ARB preliminary ILUC value for canola biodiesel is 41.6 gCO2e/MJ, March 2014 workshop
b. ARB preliminary ILUC value for soybean biodiesel is 30.2 gCO2e/MJ, March 2014 workshop

The CI values for all pathways calculated with the WA-GREET1 model decrease from the 2015 value shown above by 0.2 g/MJ in 2020. We assume a linear decrease between 2015 and 2020, with the CI constant thereafter.

Vehicle emissions consist of tailpipe CO_2, CH_4 and N_2O. Most of the carbon content of the fuel is biogenic and therefore not counted, however in esterification, fossil methanol is consumed as a feedstock (46 Btu/MJ biodiesel). Therefore, the carbon content of the fossil methanol is included in vehicle CO_2 emissions. The N_2O and CH_4 emission factors are taken from EPA.

[30] Inputs provided by email from Don O'Conner.

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Table 3-14. Assumed tailpipe emission factors

Pollutant	Units	Biodiesel	Source
CO_2	g/MJ	3.3	GREET Fuel Properties
$N_2O + CH_4$	gCO_2e/MJ	0.7	EPA RFS2
CO_2e	gCO_2e/MJ	4.0	

EPA RFS2 Docket File: EPA-HQ-OAR-2005-0161-0938.1.xls

3.5 CNG

The CNG pathways included in the scenario analysis utilize fossil natural gas and a variety of pipeline quality renewable natural gas (RNG). The RNG feedstocks are landfill gas (LFG), wastewater treatment (WWT) anaerobic digestion gas, and food and green waste high solids anaerobic digestion (HSAD) gas. These renewable gases are recovered, cleaned to pipeline quality and injected into natural gas pipelines for use to compress to CNG. The WA-GREET1 model with Washington fossil natural gas inputs (discussed above in gasoline and diesel section) and electricity generation resource mix was utilized to quantify the CI for all pathways except the HSAD pathway. Table 3-15 summarizes the calculation methodology and estimated CI values.

For fossil CNG, the GREET defaults for recovery, processing, and compression efficiency were utilized. For LFG, the ARB inputs for LFG recovery energy use and fuel shares was utilized. For WWT, the GREET defaults for energy use were utilized. For HSAD, the value developed by ARB[31] was utilized.

Table 3-15. Summary of biodiesel carbon intensity values utilized in analysis

Feedstock	Calculation Methodology	2015 CI gCO_2e/MJ
Fossil	WA-GREET1 Model default inputs	77.6
Landfill Gas	WA-GREET1 Model with ARB inputs for LFG recovery energy use and fuel shares	7.7
Wastewater Plant	WA-GREET1 Model default inputs	9.6
High Solids AD	ARB LCFS Pathway	-15.3

a. ARB preliminary ILUC value for canola biodiesel is 41.6 gCO2e/MJ, March 2014 workshop
b. ARB preliminary ILUC value for soybean biodiesel is 30.2 gCO2e/MJ, March 2014 workshop

ARB estimates of tailpipe N_2O and CH_4 emissions were utilized (2.5 gCO_2e/MJ). These values are based on old Climate Action Registry g/mi emission factors; re-evaluating these values would be a worthwhile exercise.

[31] Proposed Low Carbon Fuel Standard (LCFS) Pathway for the Production of Biomethane from High Solids Anaerobic Digestion (HSAD) of Organic (Food and Green) Wastes

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3.6 Electricity

Due to large amounts of hydro, Washington enjoys some of the lowest carbon electricity in the country. Figure 3-7provides the 2012 resource mix. Despite the low carbon grid mix, Washington has a renewable portfolio standard which requires 15 percent of the load to be serviced by new renewables by 2020. Figure 3-8 illustrates the RPS requirement through 2020. The CI value (without EER applied) for 2015 is 50.1 gCO2/MJ in 2015 and 44.0 gCO2e/MJ in 2020. With the assumed EER of 3.4[32], this corresponds to a CI of 14.7 gCO_2e/MJ and 13.0 gCO_2e/MJ for 2015 and 2020, respectively.

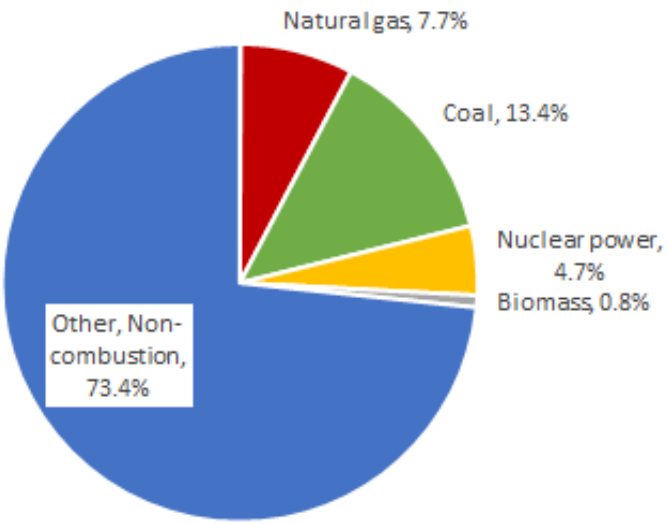

Figure 3-7. Washington State 2012 electricity resource mix.

[32] Consistent with ARB's LCFS assumption

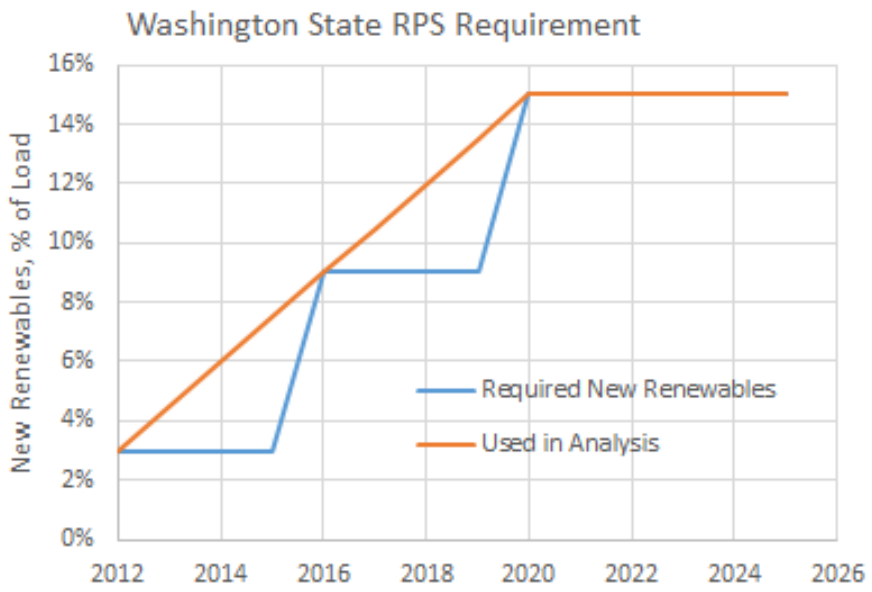

Figure 3-8. Renewable Portfolio Standard requirement.

3.7 Hydrogen

We have assumed on-site natural gas reforming as the hydrogen pathway for the scenario analysis. We utilized WA-GREET1 with the Washington specific natural gas transmission distance and electricity grid mix. All default process efficiency values were utilized. The estimated carbon intensities are 102.4 gCO_2e/MJ and 101.6 gCO_2e/MJ in 2015 and 2020, respectively. With the assumed EER of 2.5, this corresponds to 40.9 gCO_2e/MJ and 40.6 gCO_2e/MJ for 2015 and 2020, respectively.

3.8 Summary of Carbon Intensity Values Utilized in Scenario Analysis

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Table 3-16. Summary of Carbon Intensity Values Utilized in Scenario Analysis

Fuel Pathway	2015				
	WTT	TTW	WTW	ILUC	Total
Petroleum					
Gasoline Blendstock	26.2	74.5	100.7	0.0	100.7
Low Sulfur Diesel	26.0	75.6	101.7	0.0	101.7
Denatured Ethanol					
Average MW Corn	63.4	3.1	66.5	22.5	89.0
Low Carbon Corn			62.7	22.5	85.2
Corn+			40.5	17.5	58.0
Brazil Sugarcane	14.9	3.1	17.9	25.7	43.6
Molasses			30.0	0.0	30.0
Cellulosic			15.0	0.0	15.0
Cellulosic Gasoline			17.0	0.0	17.0
CNG					
Fossil	14.8	58.8	73.6	0.0	73.6
LFG	-51.1	58.8	7.7	0.0	7.7
WWT	-49.3	58.8	9.6	0.0	9.6
HSAD			-15.3	0.0	-15.3
Electricity (w/o EER)	50.1	0.0	50.1	0.0	50.1
Hydrogen (w/o EER)	102.4	0.0	102.4	0.0	102.4
Biodiesel					
MW Soybean	26.6	4.0	30.5	30.2	60.7
Canola	31.7	4.0	35.7	41.6	77.3
UCO	14.3	4.0	18.3	0.0	18.3
Tallow	25.7	4.0	29.7	0.0	29.7
Corn Oil (dry DGS)			4.0	0.0	4.0

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4. BAU and Scenario Definition

To better understand the range of possible economic effects if a CFS was adopted in Washington State, a scenario analysis was conducted. The scenarios were designed to be technologically feasible and to bound the range of possible compliance strategies. A number of scenarios in addition to a business as usual (BAU) case were considered. The VISION model was utilized to estimate fuel volumes, vehicle populations, and corresponding expenditures on fuels and vehicles for each scenario relative to the BAU. These data were subsequently utilized in the REMI macro-economic model to determine the macro-economic impact of each scenario on the State's economy.

4.1 Assumed Structure of CFS

For the purposes of this analysis, we assume that the Washington CFS would be an eleven year program, beginning in 2016 and would result in a 10 percent reduction in carbon intensity by 2026. Year 1 (2016) would be a reporting year only, with no carbon intensity reduction required. Fuels would be divided into two pools: a gasoline pool and a diesel pool. The gasoline pool consists of all gasoline utilized as well as compliance fuels consumed by light and medium duty vehicles (electricity, hydrogen, and CNG). The diesel pool consists of all diesel fuel utilized as well as compliance fuels consumed by heavy duty vehicles (CNG).

Although the baseline year is 2016, the most recent complete set of data to establish baseline CI values is 2012. Therefore 2012 is the data year for the baseline; this may be updated with 2016 data at a later date if desired. The baseline CI values include ethanol blended into gasoline and biodiesel blended into diesel. Table 4-1 provides the baseline CI values for gasoline and diesel. In 2012, motor gasoline contained average of 9.72% ethanol on a volume basis[33]. It is assumed that this ethanol was average Midwest corn ethanol with a carbon intensity of 89 gCO_2e/MJ. This results in a baseline gasoline value of 99.9 gCO_2e/MJ, and a 2026 target of 89.9 gCO_2e/MJ.

Table 4-1. Baseline carbon intensity values

	Baseline CI gCO_2e/MJ	Target CI gCO_2e/MJ
Motor Gasoline		
Gasoline Blendstock	100.7	
Denatured Ethanol	89.0	
Motor Gasoline[1]	**99.9**	**89.9**
Diesel		
Diesel	101.7	
Biodiesel	53.3	
On-Road Diesel Blend[2]	**101.6**	**91.4**

1. Motor gasoline in 2012 contained 9.72% denatured ethanol by volume (6.68% by energy)
2. On-road diesel in 2012 contained 0.22% biodiesel by volume (0.20% by energy)

[33] Jerry Buendel, Washington State Department of Agriculture, Weights and Measures Program

The diesel carbon intensity value for 2012 is 101.7 gCO_2e/MJ. It is estimated that diesel contained 0.22% biodiesel in 2012[34] and that the biodiesel was 505 soybean, and 25% used cooking oil, and 25% canola[35]. The resulting average biodiesel CI is 53.3 gCO2e/MJ. When blended with gasoline the on-road diesel baseline value is 101.6 gCO2e/MJ. Figure 4-1 provides the assumed shape of the compliance curve.

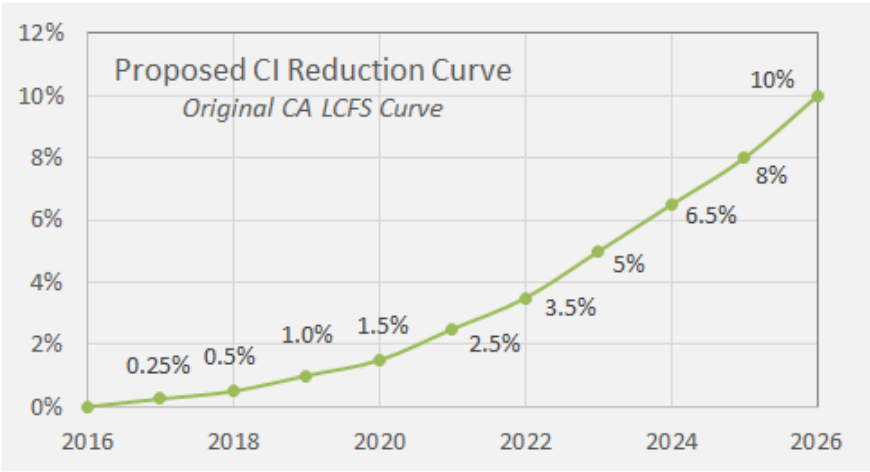

Figure 4-1. Assumed shape of the CFS compliance curve.

For the main set of scenarios, it is assumed that the gasoline and diesel pool will comply with the standard each year separately. This results in very conservative low CI fuel supply estimates. Because Washington State representatives have indicated that if a CFS was adopted, the standard would allow credit trading between the gasoline and diesel pools and would also allow regulated parties to bank credits generated through over-compliance for use at a later date.

4.2 Business-as-Usual Forecast

The VISION[36] model was utilized to forecast fuel consumption and vehicle purchases for the Business-as-Usual (BAU) and each of the compliance scenarios. The VISION model was modified to reflect transportation in Washington State. Please refer to Appendix A for a detailed discussion of the assumptions on vehicle technology market shares, vehicle miles traveled (VMT), fuel economy, and fuel price projections.

To project fuel consumption for the BAU we have made several key assumptions. We assume that gasoline ethanol will remain at the 2013/2014 estimated blend level of 9.6 percent volume and that all ethanol consumed is average Midwest corn ethanol. We further assume that no E85 is consumed. For biodiesel, we assume that the current blend (estimated at 0.22 percent volume) is maintained. The feedstocks used to produce biodiesel are based on the CLEW mix cited earlier which is half soybean oil with the other half split between canola oil and UCO. By 2020 this mix shifts to 35 percent soybean oil, 30 percent UCO, 30 percent canola, and 5 percent corn oil. We assume all CNG use is fossil based; all developed pipeline RNG is sold into other CFS markets.

[34] Washington State agencies utilized 0.35 MGY on-road, estimate an additional 1.65 MGY non-public vehicles for a total statewide consumption of 2 MGY.
[35] Biodiesel Shares from Leidos CLEW Report, Oct 2013.
[36] Argonne National Laboratory model for on-road transportation

These assumptions result in slight carbon intensity declines due to increased sales of EVs and CNG (Figure 4-2). The figure also provides WTW GHG emission reductions. Gasoline pool emissions decrease, but diesel pool emissions increase. This is due to projected decreases in gasoline consumption and increases in diesel consumption (please refer to Appendix A for fuel consumption projections).

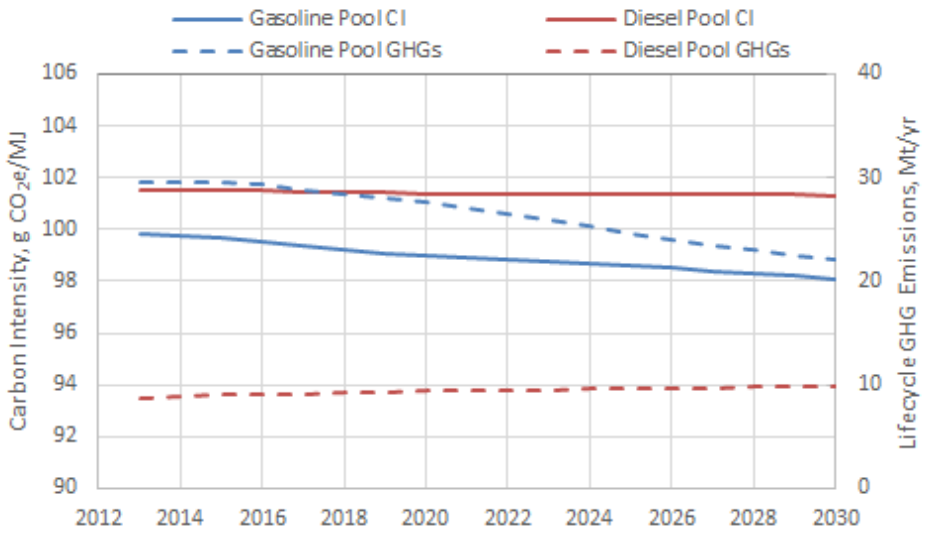

Figure 4-2. BAU Carbon Intensity and Lifecycle GHG Emission Forecasts.

4.3 Compliance Scenario Definition

Because the CFS is a flexible market based standard, there are many possible combinations of advanced vehicles and low carbon fuels that result in compliance each year. Because the compliance scenarios are mainly intended to give an idea of maximum compliance volumes required and the macro-economic impacts to the state, it is most effective to evaluate combinations of fuels and vehicles that bound the possible range of compliance. We have therefore selected three main compliance themes:

Scenario A – Advanced Vehicles
Scenario B – Cellulosic Biofuels
Scenario C – Non-Cellulosic Biofuels

We have added an additional non-cellulosic biofuel scenario, Scenario D, which allows up to 15 percent ethanol blended into gasoline for model year 2001 and newer vehicles. This is modeled by reducing the overall ethanol blend by the percent of older vehicles still in the fleet. In reality, since older vehicles have lower VMT than newer vehicles, this is a conservative assumption.

We have evaluated these four scenarios in two different ways: strict compliance with the separate gasoline and diesel standards each year, and compliance that allows banking and trading of credits. In the bank and trade versions of the scenarios, unlimited trading of excess credits between the gasoline and diesel pools is allowed. Because the ARB LCFS has experienced significant trading from the diesel pool to the gasoline pool and because there more volumes of

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low CI fuels for the diesel pool are available at present than for the gasoline pool, all of our trading scenarios have traded excess credits from the diesel pool to the gasoline pool.
In addition, credits accumulated from over-compliance with the standard in early years may be banked for use in future years. Because the program would not end at the end of the analysis period (2026), we have required that a credit balance equal to 25 percent of the total number of compliance credits required in 2026 remain in the bank at the end of 2026 for use in future years.

Table 4-2 summarizes the vehicle populations and biofuel blend levels for each of these scenarios. The table also provides available quantities of low CI fuel; not all of these volumes will be required for each of the scenarios.

Table 4-2. Compliance Scenario Bounds

	Scenario A	**Scenario B**	**Scenario C**	**Scenario D**
	Advanced Vehicles	Max Cellulosic	Min Cellulosic	Min Cellulosic with E15
Max Gasoline Ethanol %	10%	10%	10%	15%
FFV E85 Consumption	Up to 85%	0%	Up to 85%	Up to 85%
Max Biodiesel Blend %	Up to 15%	Up to 15%	Up to 15%	Up to 15%
Ethanol Volumes				
MW Corn	Balance	Balance	Balance	Balance
Corn+	Up to 40 MGY	Up to 40 MGY	Up to 40 MGY	Up to 40 MGY
Sugarcane	Up to 146 MGY	Up to 146 MGY	Up to 200 MGY	Up to 200 MGY
Molasses	Up to 20 MGY	Up to 20 MGY	Up to 20 MGY	Up to 20 MGY
Cellulosic	63 to 300 MGY	63 to 300 MGY	63 to 300 MGY	63 to 300 MGY
Cell Gasoline and Diesel	55 to 200 MGY (gasoline equiv)	55 to 200 MGY (gasoline equiv)	55 to 200 MGY (gasoline equiv)	55 to 200 MGY (gasoline equiv)
Biodiesel				
Soybean	As needed	As needed	As needed	As needed
Canola	Up to 42 MGY	Up to 42 MGY	Up to 42 MGY	Up to 42 MGY
UCO	Up to 10 MGY	Up to 10 MGY	Up to 10 MGY	Up to 10 MGY
Tallow	Up to 12 MGY	Up to 12 MGY	Up to 12 MGY	Up to 12 MGY
Corn Oil	Up to 40 MGY	Up to 40 MGY	Up to 40 MGY	Up to 40 MGY
RNG	Up to 16 MGY (diesel equiv)	Up to 12 MGY (diesel equiv)	Up to 12 MGY (diesel equiv)	Up to 12 MGY (diesel equiv)
Vehicle Populations				
CNG	1.5 X BAU	BAU	BAU	BAU
EV/PHEV	CA ZEV	BAU	BAU	BAU
H2 FCV	CA ZEV	BAU	BAU	BAU

Scenario A and Scenario A with Banking and Trading (B&T) have different assumptions relative to advanced vehicle market shares. For these scenarios we have utilized the California Zero Emission Vehicle (ZEV) "Likely Compliance Scenario" market shares[37]. Figure 4-3 provides the market shares for the three affected ZEV types. In addition, we have assumed for these scenarios that CNG market shares are 50 percent higher than BAU levels.

[37] ZEV Initial Statement of Reasons, Likely Compliance Scenario Table 3-6, December 2011.

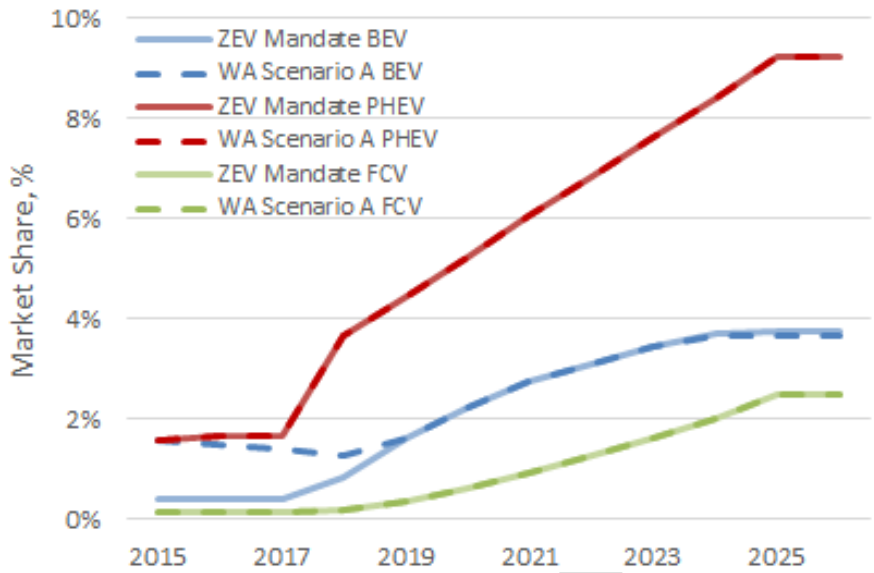

Figure 4-3. Scenario A and Scenario A with B&T light vehicle market shares.

4.4 Opt-in Volumes

Because only parties that sell gasoline and diesel are regulated parties in a CFS, low CI fuel suppliers must "opt-in" to the program to make the credits generated by use of their fuels available for compliance. The opt-in fuels are electricity, CNG, and hydrogen. According to ARB,[38] all of the utilities have opted into the California LCFS, so all residential charging is captured. Companies that provide commercial charging are still negotiating metering arrangements, but will soon be able to opt into the program. The EV Project reports that 80 percent of charging events occur at home; since home charging events are longer, we assume here that 90 percent of the electricity comes from home charging. We therefore assume that 90 percent of electricity opts in by 2017, ramping up to 94 percent in 2018, and 98 percent for 2019 and beyond.

Based on ARB's experience, 100 percent of the RNG sold as transportation fuel would opt into a Washington CFS program. Large fleets utilizing fossil natural gas have now opted into California's LCFS program, but smaller fleets have not. We therefore assume 100 percent of RNG opts in and 50 percent of fossil natural gas opts in.

Finally, there has been very little hydrogen fuel use to date. We assume that 50 percent opts in by 2017, increasing to 90 percent by 2021 and 95 percent for 2022 and beyond.

[38] Conversation with Manisha Singh, ARB

4.5 Credit and Deficit Calculation

The overall carbon intensity of each compliance pool is determined by summing the product of fuel consumption and carbon intensity for each fuel and dividing by total fuel consumption. The total fuel consumption in the denominator is multiplied by the EER, which is the ratio of the alternative fuel vehicle's energy consumption per mile to the gasoline vehicle's energy consumption per mile. The following two equations provide the calculations for overall carbon intensity in gCO_2e/MJ. The values labeled "MJ" are shorthand for total energy consumed in MJ.

$$Gasoline\ Pool\ CI = \frac{CI_{gas}\times MJ_{gas}+CI_{eth}\times MJ_{eth}+CI_{CNG}\times MJ_{CNG}+CI_{Elec}\times MJ_{Elec}+CI_{Cell\ Gas}\times MJ_{Cell\ Gas}+CI_{H}\times MJ_{H}}{MJ_{gas}+MJ_{eth}+MJ_{CNG}+MJ_{Elec}\times EER_{Elec}+MJ_{Cell\ Gas}+MJ_{H}\times EER_{H}}$$

$$Diesel\ Pool\ CI = \frac{CI_{dsl}\times MJ_{dsl}+CI_{BD}\times MJ_{BD}+CI_{CNG}\times MJ_{CNG}+CI_{Cell\ Dsl}\times MJ_{Cell\ Dsl}}{MJ_{dsl}+MJ_{BD}+MJ_{CNG}\times EER_{CNG}+MJ_{Cell\ Dsl}}$$

To calculate number of deficits created by gasoline or diesel (gasoline in this example):

$$Deficits = MJ_{gasoline}\times CI_{Standard} - MJ_{gasoline}\times CI_{gasoline}$$

To calculate the number of credits created by low CI fuels (electricity in this example):

$$Electricity\ Credits = \left(CI_{std} - \frac{CI_{elec}}{EER_{elec}}\right)\times MJ_{elec}\times EER_{elec}$$

4.6 Effect of CFS Credit Prices

In a CFS, regulated parties will need to acquire credits to offset the deficits generated by sale of gasoline and diesel. Regulated parties may directly purchase credits from credit holders and submit them for compliance. Alternatively, regulated parties may generate credits by purchasing low carbon fuels to blend with gasoline and diesel. In this case, the price paid by the regulated party for the low carbon fuel has an implicit credit price built in, so the price of the fuel would increase proportionally with the number of credits the fuel generates. The lower the CI, the more the regulated parties would pay for the fuel.

For this analysis we have assumed a credit price profile that starts at $15 per tonne of CO_2e and increases over time as the CFS becomes more stringent. Figure 4-4 provides the assumed credit price profile. We have further assumed that the total cost to the regulated parties for credit purchases each year (total credits required multiplied by credit price) is divided by the total amount of gasoline and diesel (energy basis) sold and added to the price of gasoline and diesel. In reality, not all of the costs would translate to a commensurate increase in gasoline and diesel price, but without a detailed economic analysis of petroleum pricing, it is a conservative estimate.

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Figure 4-5 and Figure 4-6 provide the effect of the assumed LCFS credit price on gasoline and diesel prices, respectively. For our assumed CFS credit price profile, gasoline prices increase by 10 to 13 cents per gallon in 2026 while diesel prices increase by 11 to 14 cents per gallon. The credit and banking scenarios have higher price increases in the middle years of the standard and lower prices at the end of the analysis period because more credits are generated earlier in the standard and fewer are generated at the end of the analysis period.

The dampening effect of higher gasoline and diesel prices on fuel purchases is taken into account by applying an elasticity to vehicle miles travelled. We have selected an elasticity of -0.17[39], which results in a decrease in gasoline and diesel use of 0.17 percent for each percent increase in fuel price. This resulted in slightly lower volumes of low CI fuel required for compliance.

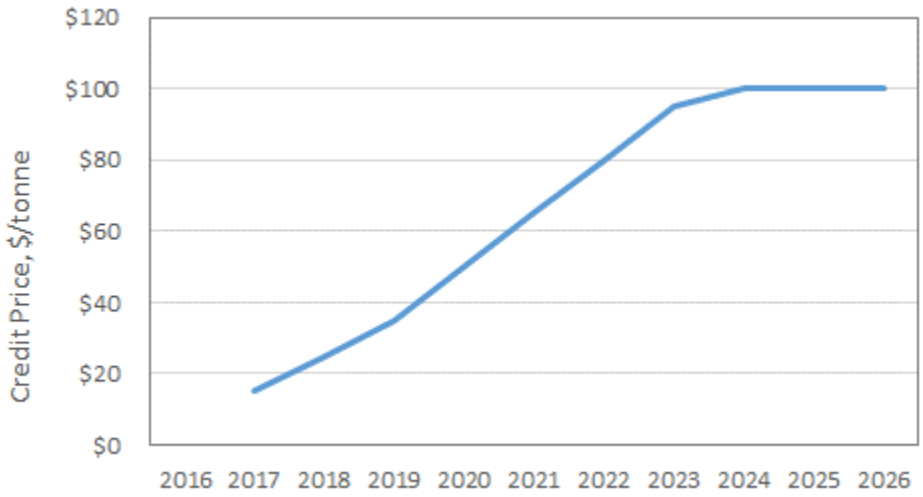

Figure 4-4. Assumed CFS credit price profile.

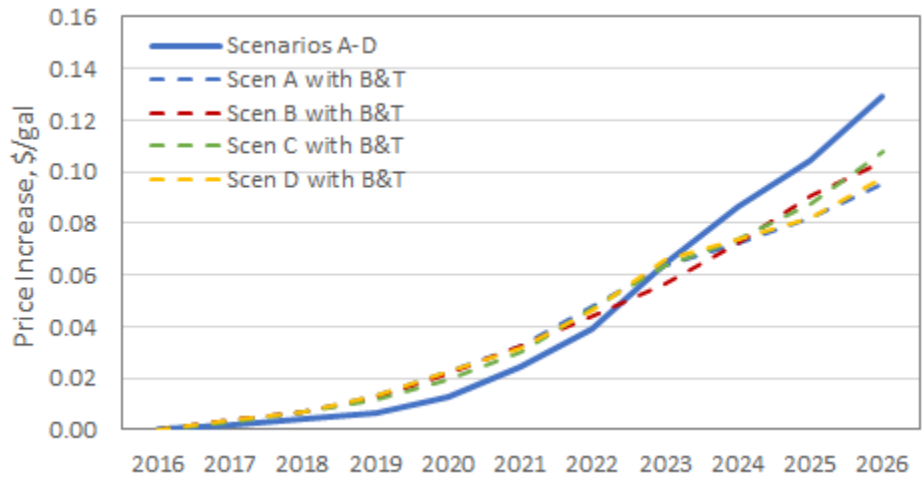

Figure 4-5. Gasoline price increase due to CFS credit price.

[39] "Understanding Transport Demands and Elasticities", Victoria Transport Policy Institute, March 2013

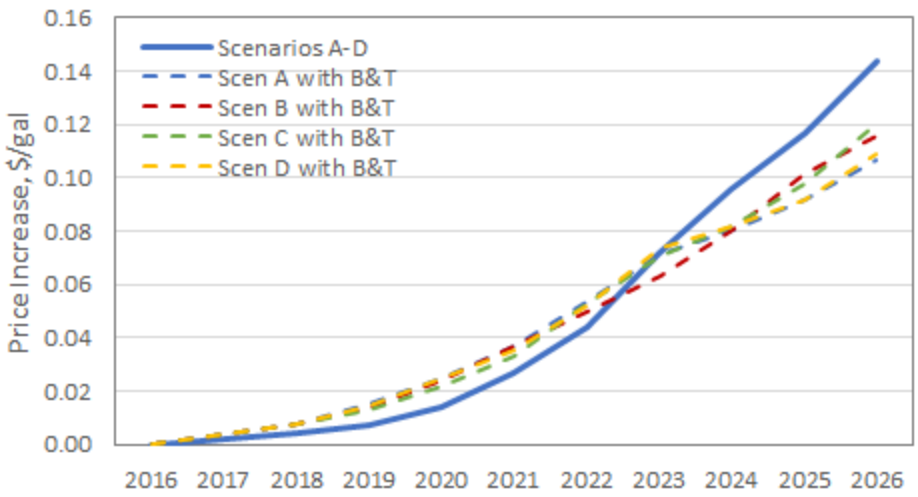

Figure 4-6. Diesel price increase due to CFS credit price.

To evaluate the impact of higher credit prices on macro-economics, sensitivity runs with credit prices of $50, $150, and $250 per tonne CO_2e were performed for Scenario C (low cellulosic) with banking and trading. Figure 4-7 and Figure 4-8 provide the impact of the range of credit prices on gasoline and diesel prices, respectively.

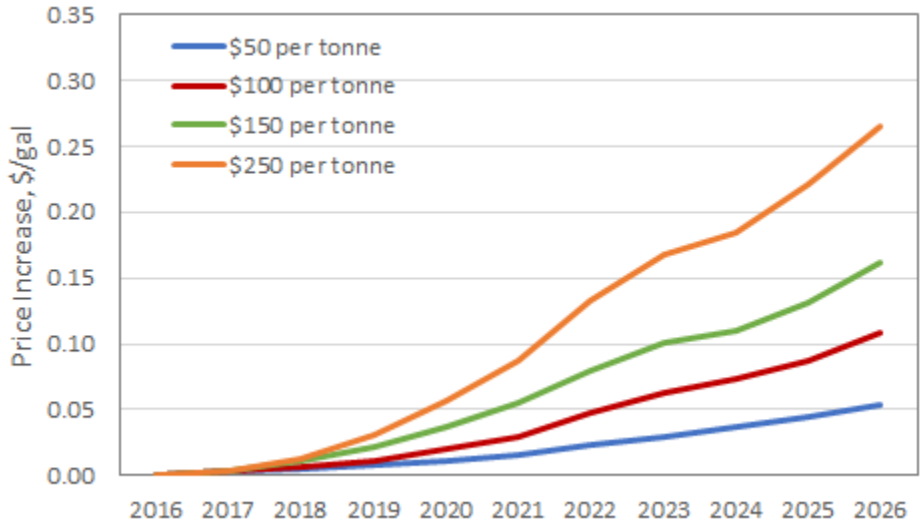

Figure 4-7. Impact of credit price on gasoline prices for Scenario C with banking and trading.

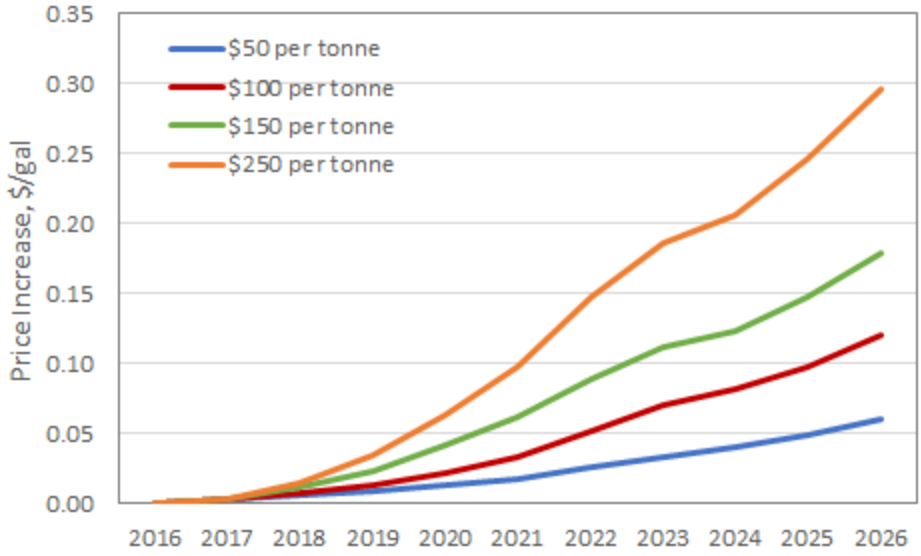

Figure 4-8. Impact of credit price on diesel prices for Scenario C with banking and trading.

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5. Scenario Analysis Results

5.1 Biofuel Blend Levels and E85 Use

All compliance scenarios have a 9.6% volume ethanol blend level in gasoline in 2016, ramping to 10% by 2019 and remaining constant at 10% throughout the analysis period. Scenario D, the low cellulosic E15 scenario ramps to E14 by 2021 and then slowly increases to E15 by 2024. The banking and trading variant of Scenario D has an earlier transition to E14 and a similar ramp to E15. It is assumed that in a banking and trading scenarios, regulated parties would increase blend levels as rapidly as possible to bank early credits. Figure 5-1 provides the ethanol blend levels for the two Scenario D cases.

Figure 5-2 provides the assumed biodiesel blend levels for each of the scenarios. All scenarios except Scenario B (cellulosic) without banking and trading increase blend levels to 15 percent. Scenario B increases the blend level to 10 percent because cellulosic diesel is available for use, and without banking or trading there is no incentive for additional reductions. Note that all banking and trading scenarios ramp to 15% blend earlier than the base scenarios to take advantage of credit trading/banking provisions.

Four of the eight scenarios assume that some level of E85 is utilized by the flex fuel vehicle (FFV) fleet. Note that none of the scenarios has increased FFV populations over the BAU case. It was assumed that E85 is a 75 percent blend of ethanol in gasoline. Figure 5-3 provides the shares of FFV E85 use. Scenario A without banking and trading required up to 15 percent of FFVs to use E85 by 2026. Scenario C (low cellulosic) required up to 85 percent of FFV fuel use to be E85. Scenario D, the low cellulosic case with E15 required E85 use for the base case, but did not require any with banking and trading.

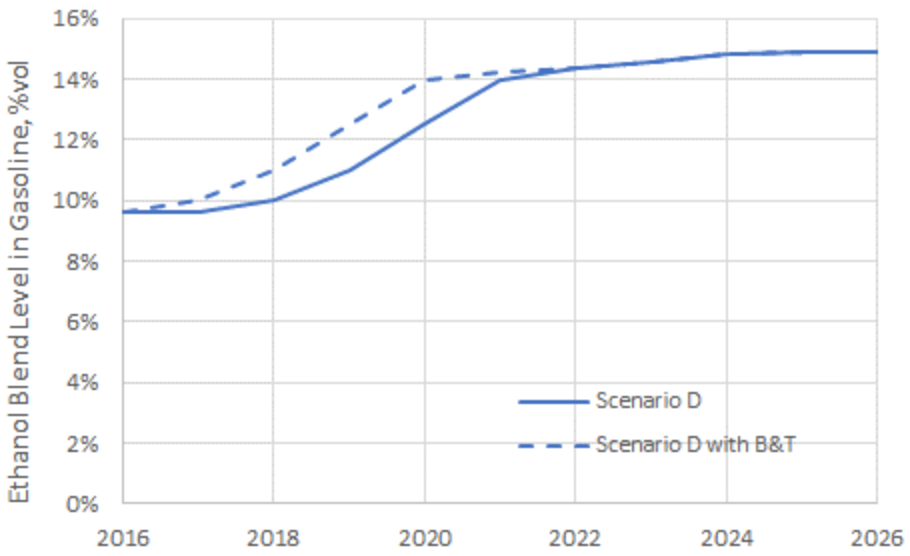

Figure 5-1. Ethanol blend levels in gasoline for Scenario D.

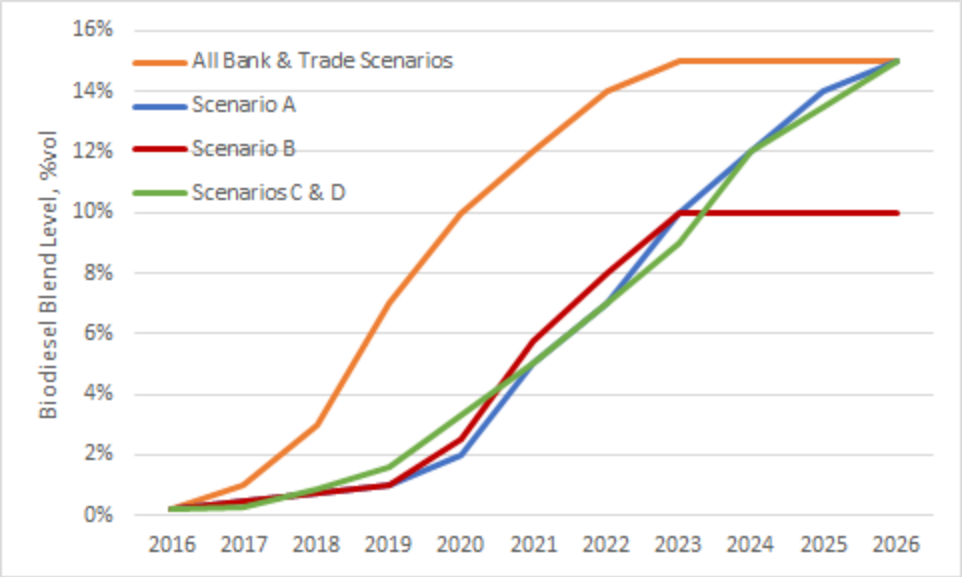

Figure 5-2. Assumed biodiesel blend levels.

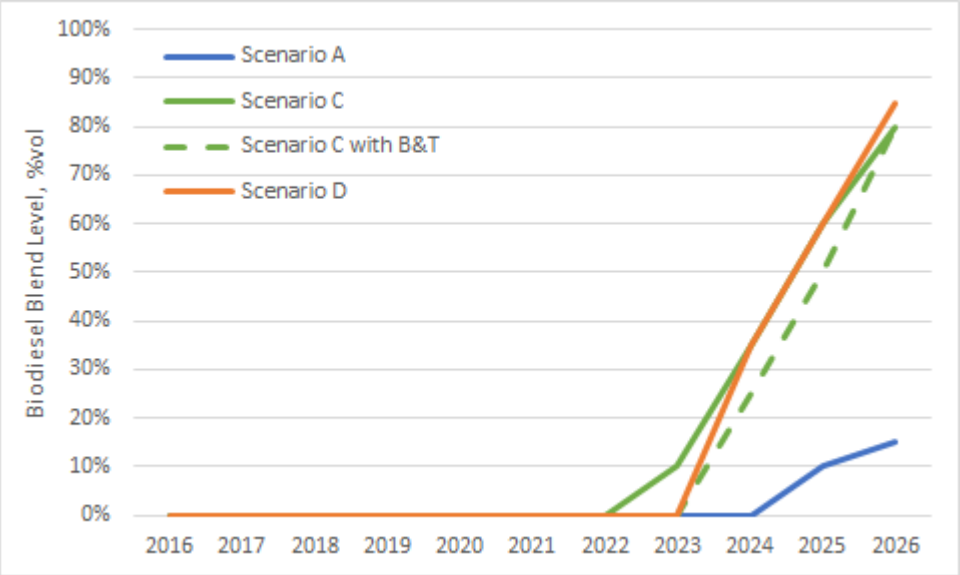

Figure 5-3. Assumed FFV E85 use.

5.2 Low CI Fuel Volumes

Recall from Section 2 that total cellulosic fuel volumes anticipated to be available in Washington State by 2026 ranged from 100 to 400 MGY (gasoline equivalent gallons). The lower end is based on EIA AEO2013/2014 projections and the upper bound was based on recent UC Davis estimates. Figure 5-4 provides the total cellulosic fuel volumes required in the compliance scenarios evaluated. Note that for all scenarios except Scenario B (cellulosic fuels) without banking and trading, that total cellulosic fuel consumption ranges from 40 to 90 MGY (gasoline equiv).

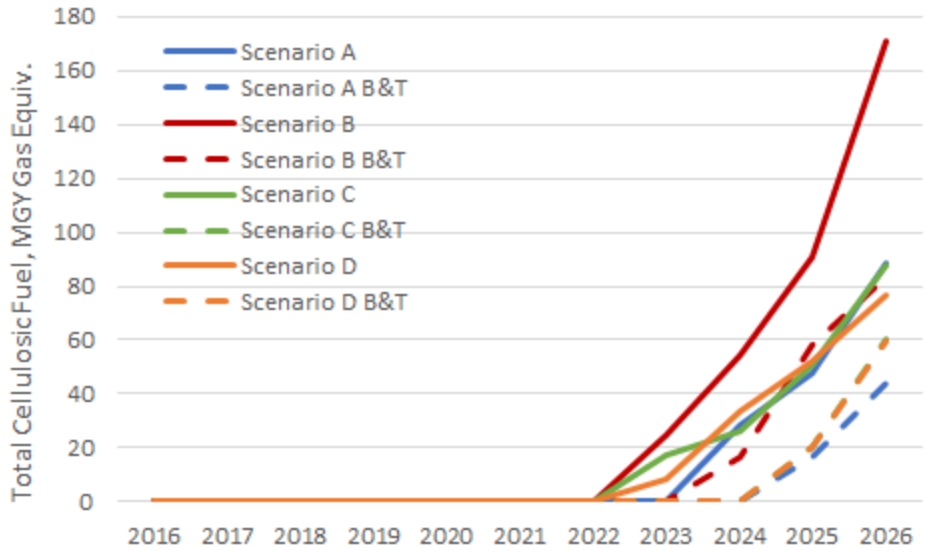

Figure 5-4. Total cellulosic fuel volumes required, MGY (gas equiv).

Consumption of sugarcane ethanol is provided in Figure 5-5. Washington's share of the EIA projection for RFS2 is estimated at 146 MGY. All scenarios except the two low cellulosic scenarios without banking and trading utilize less than 146 MGY of sugarcane ethanol. Since the EIA projection for sugarcane ethanol falls off after 2022 (end of RFS2) and since Brazil generates more than 6 billion gallons per year, it is assumed that up to 200 MGY of this ethanol would be available to Washington if needed.

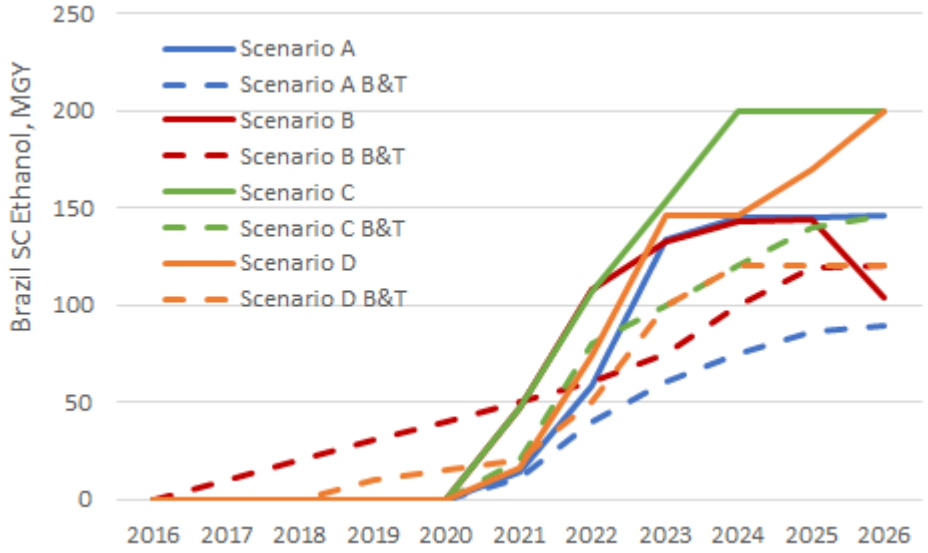

Figure 5-5. Brazil Sugarcane Ethanol Consumption.

Figure 5-6 provides the opt-in electricity volumes. Electricity consumption under the ZEV vehicle market shares scenarios (Scenario A and A with banking & trading) is approximately twice the electricity consumption in the BAU and other compliance scenarios.

Volumes of waste oil biodiesel and not shown, but in each scenario, waste oil biodiesel volumes increase to a total of 20 MGY. Finally, RNG consumption is provided in Figure 5-7. Up to 16 MGY are utilized by the CNG fleet in the Advanced Vehicles scenarios, with total volumes less than 12 MGY in the other cases. The bank and trade versions of the scenarios switch to RNG from CNG earlier than the base scenarios to take advantage of banking provisions.

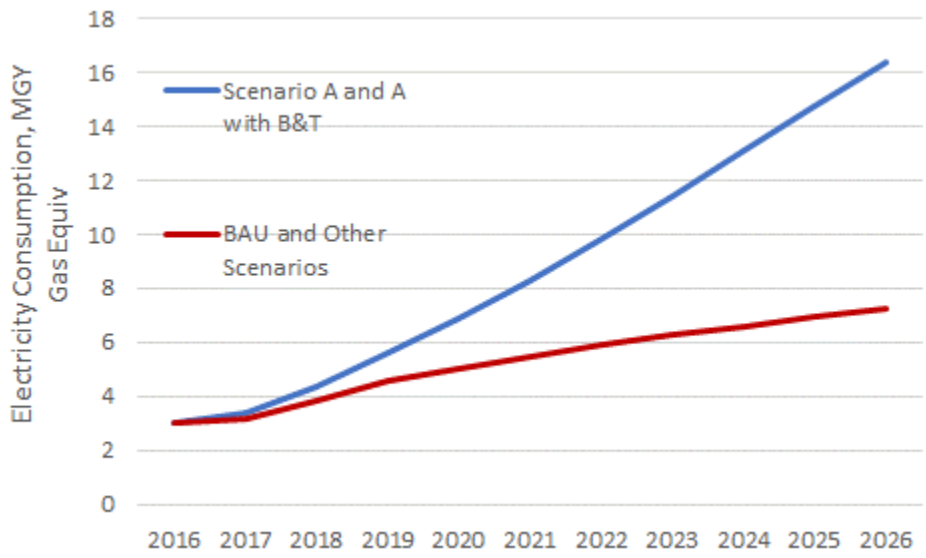

Figure 5-6. Electricity consumption, MGY (gas equiv).

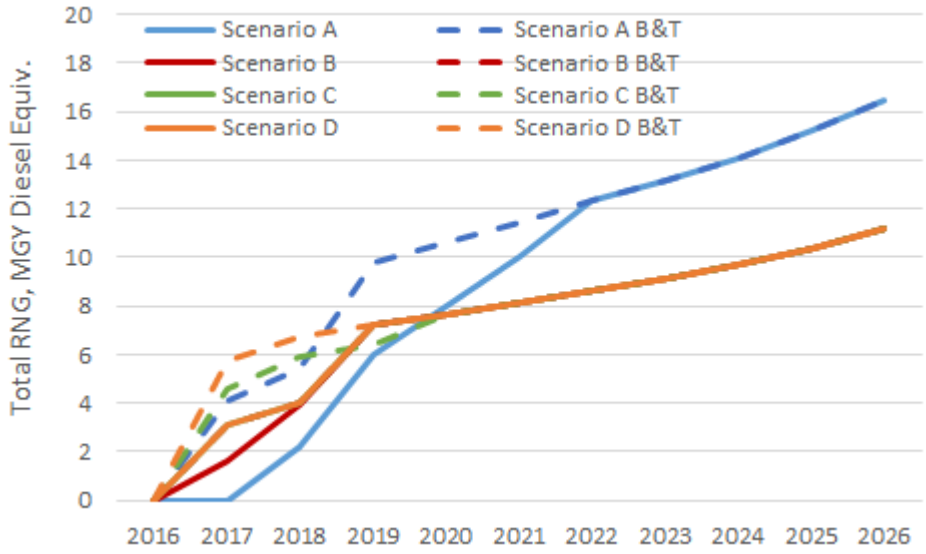

Figure 5-7. Total RNG Consumption, MGY Diesel Equivalent.

5.3 CFS Credits

Figure 5-8 through Figure 5-19 summarize the contribution made by each fuel type to 2026 compliance. For the banking and trading version of each scenario a chart indicating annual deficits and credits along with the cumulative credits is provided. Note that the credit bank at the end of the analysis period (2026) is not drawn down to zero; cumulative credits in 2026 are set to 25 percent of the total credits required in 2026.

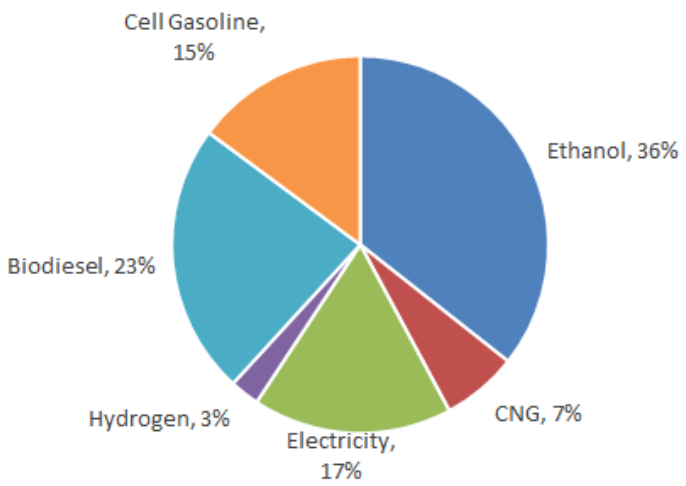

Figure 5-8. Relative contributions to compliance in 2026, Scenario A.

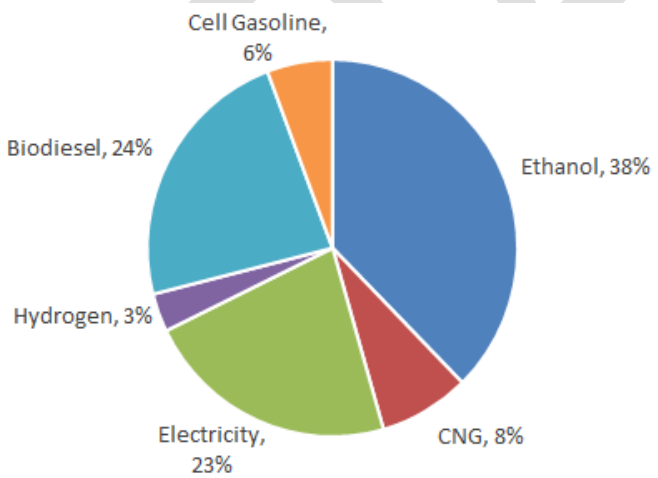

Figure 5-9. Relative contribution to compliance in 2026, Scenario A with banking & trading

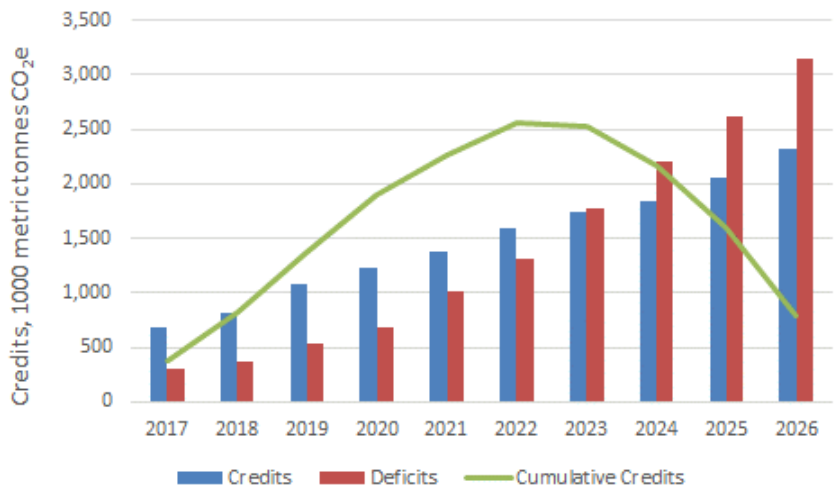

Figure 5-10. Credits, debits, and cumulative credits for Scenario A with banking & trading.

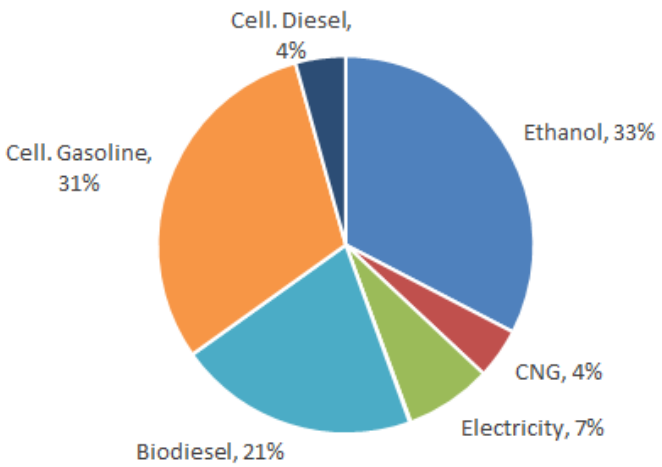

Figure 5-11. Relative contribution to compliance in 2026, Scenario B.

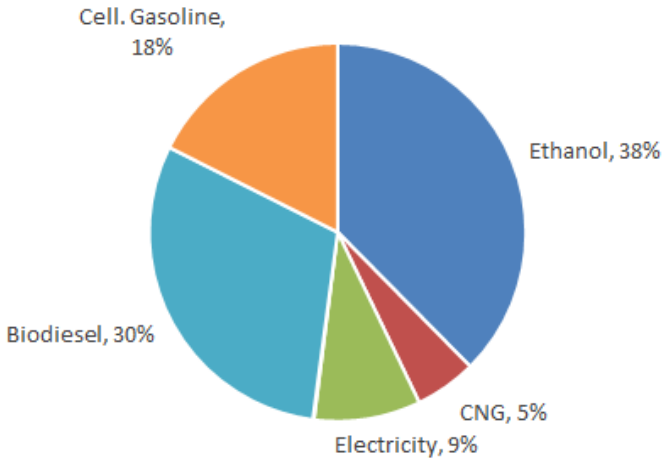

Figure 5-12. Relative contribution to compliance in 2026, Scenario B with banking & trading

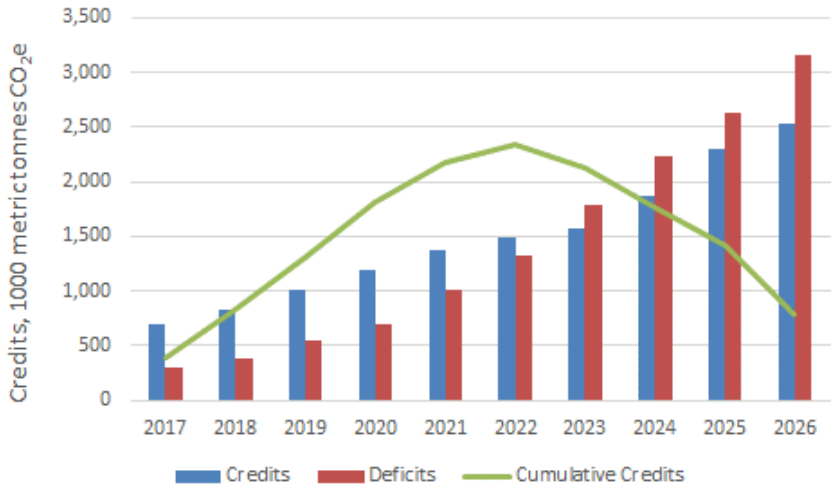

Figure 5-13. Credits, debits, and cumulative credits for Scenario B with banking & trading

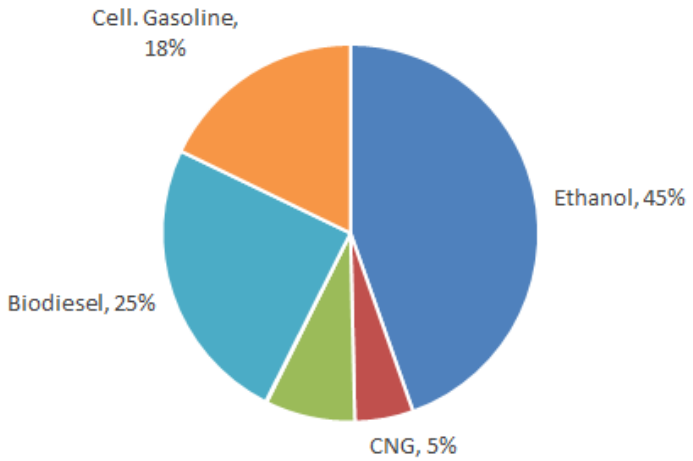

Figure 5-14. Relative contribution to compliance in 2026, Scenario C

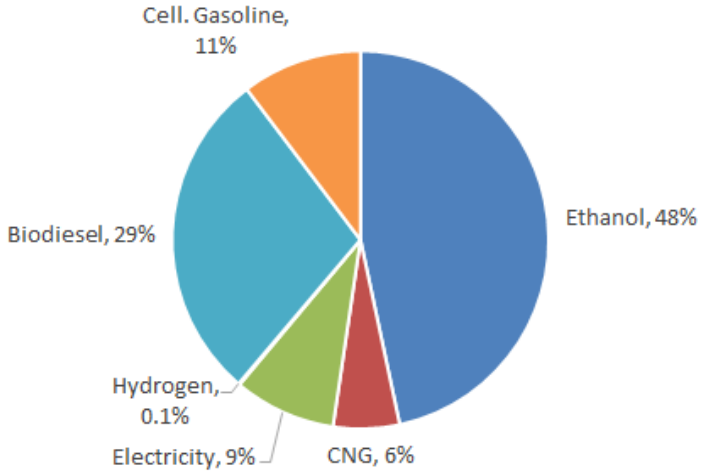

Figure 5-15. Relative contribution to compliance in 2026, Scenario C with banking & trading

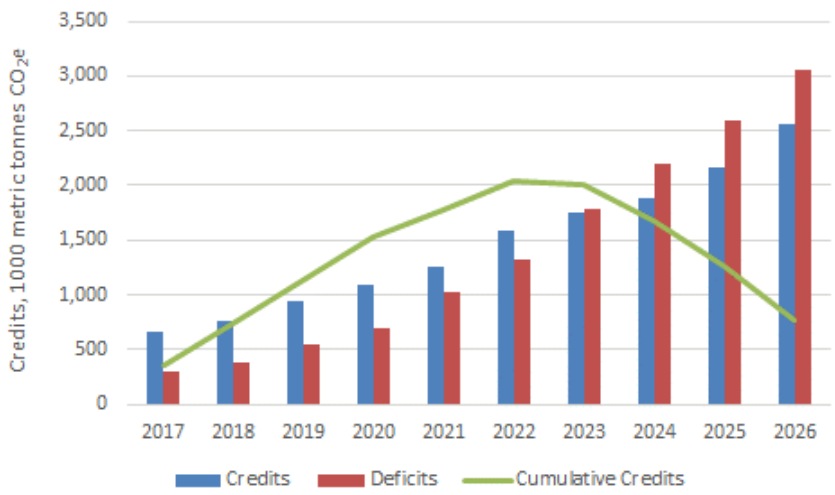

Figure 5-16. Credits, debits, and cumulative credits for Scenario C with banking & trading

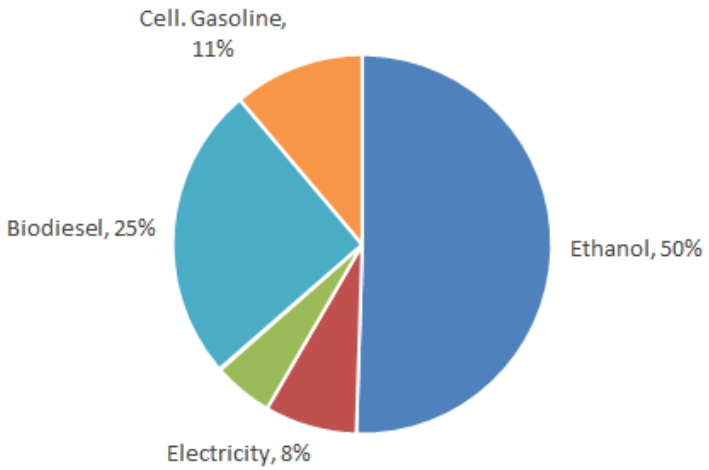

Figure 5-17. Relative contribution to compliance in 2026, Scenario D

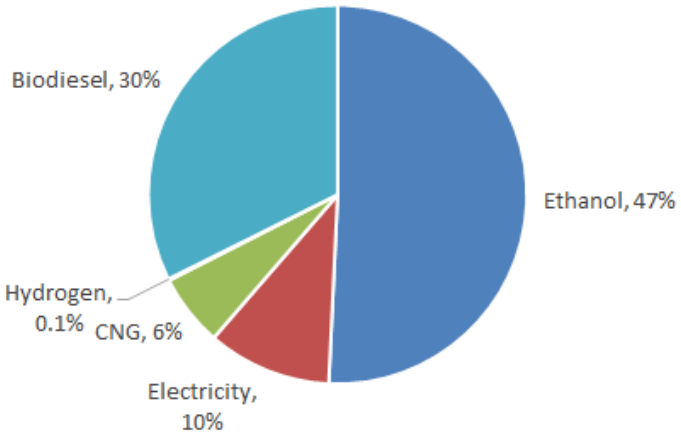

Figure 5-18. Relative contribution to compliance in 2026, Scenario D with banking & trading

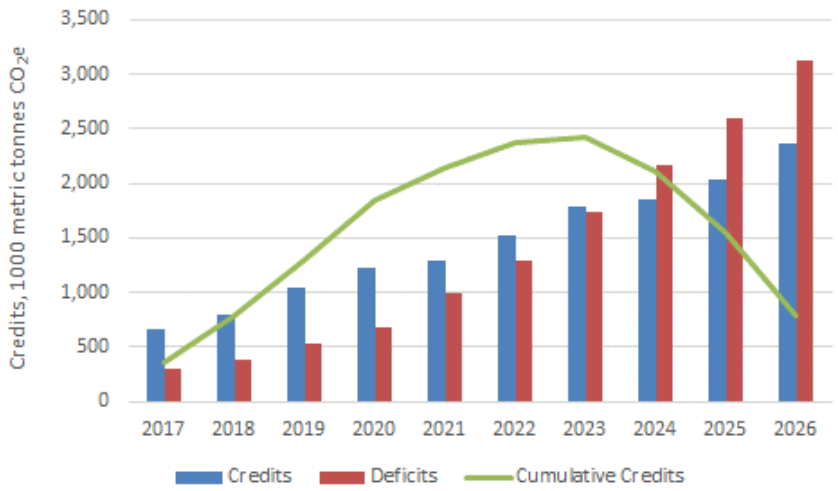

Figure 5-19. Credits, debits, and cumulative credits for Scenario D with banking & trading

5.4 Vehicle Expenditures

Appendix A provides the vehicle market share assumptions for the BAU and compliance scenarios; all compliance scenarios have the same vehicle populations as the BAU except for Scenario A and Scenario A with banking and trading. In Scenario A, the market share of advanced vehicles is assumed to be the same as California's ZEV "Likely Compliance Scenario"; please refer to Section 4.3 for the market share estimates of EVs, PHEVs, and hydrogen FCVs.

Appendix A provides projected incremental vehicle prices for each vehicle technology relative to the base vehicle price. For light duty vehicles, the increments are relative to gasoline internal combustion engines (ICEs). For medium and heavy duty vehicles, the increment is relative to diesel vehicles. Each year, vehicle sales are multiplied by the incremental price above the base vehicle price to determine incremental consumer spending on vehicles. Vehicle expenditures for all scenarios except the two advanced vehicle scenarios are the same as the BAU expenditures. Figure 5-20 provides incremental consumer spending relative to the BAU on vehicles for both Scenario A cases. Up to $250 million is spent on vehicles by 2026 with most spent on PHEVs.

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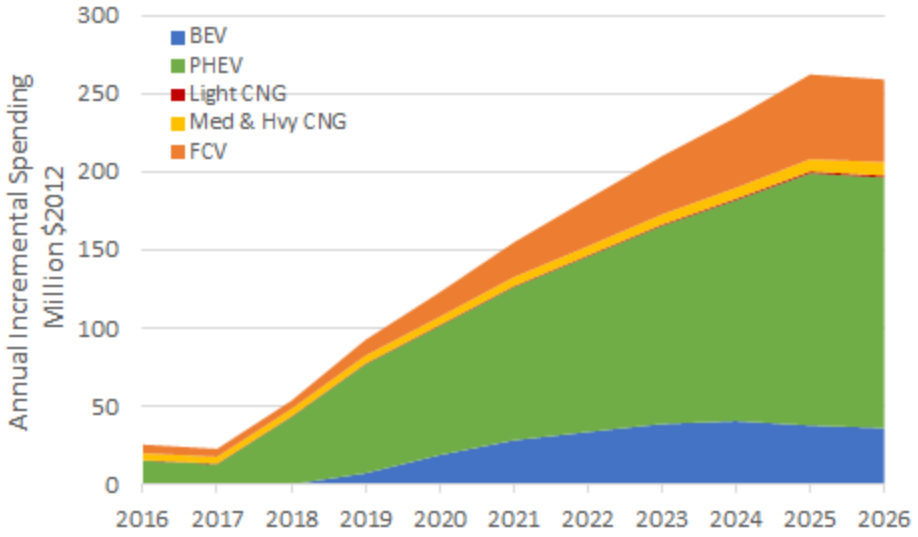

Figure 5-20. Incremental consumer spending on vehicles relative to BAU for Scenario A

5.5 Fuel Expenditures

The fuel consumption for each scenario (please refer to Section 5.2) above was combined with the assumed fuel price projections provided in Appendix A to arrive at annual consumer fuel expenditures. Spending increases relative to BAU spending is provided in Figure 5-21. Scenario A has the lowest fuel expenditures because of the increased electricity and CNG use. Scenario D (E15) has the highest costs because ethanol sold as a gasoline blend component is more expensive than ethanol sold as E85. The cases with banking and trading have higher costs earlier in the program and lower costs later because more credits are generated earlier in the program and added to gasoline and diesel prices. Scenario B (cellulosic) and Scenario C (low cellulosic) have similar costs; the diesel pool costs are approximately the same and Scenario C's higher ethanol costs are offset by Scenario B's higher cellulosic gasoline costs.

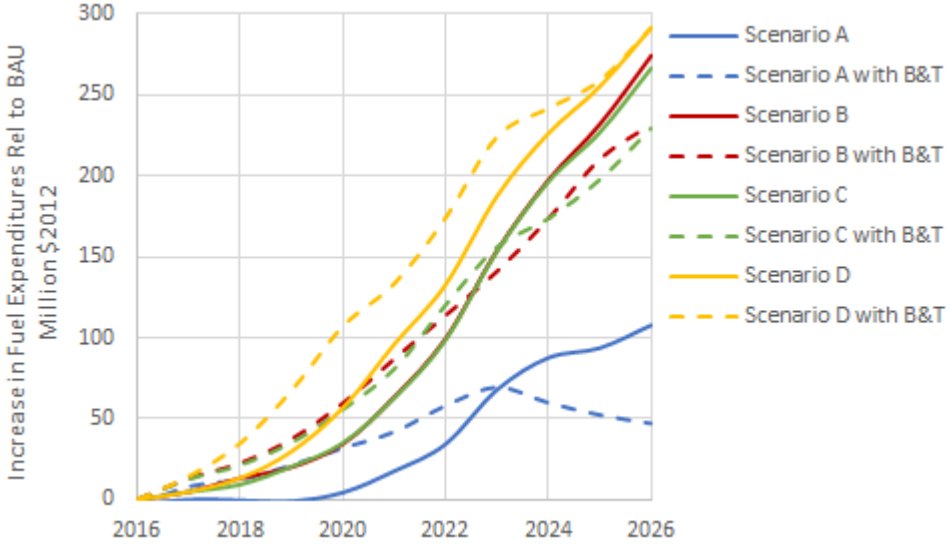

Figure 5-21. Increases in consumer spending on fuel relative to BAU.

5.6 Infrastructure Costs

To support alternative fuel use, a significant amount of infrastructure investment is required. Appendix A provides the assumptions underlying the results presented below. The following paragraphs step through estimated infrastructure expenditures to support Scenario A's advanced vehicle refueling, pipeline quality RNG production plant costs, cellulosic biofuel plant costs, and infrastructure costs to support increased biodiesel and ethanol consumption.

EV Charging Infrastructure

Table 5-1 provides a summary of the estimated EV charging infrastructure costs for Scenario A (advanced vehicles) and BAU (and all other compliance scenarios) in current dollars.

Table 5-1. Summary of Charging Infrastructure Costs for the BAU and Scenario A

	Residential		Non-Residential		DC Fast Charge		Total	
	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A
	$Million	$Million	$Million	$Million	$Million	$Million	$Million	$Million
2017	5.2	5.9	2.7	3.5	0.2	0.4	8.1	9.8
2018	5.0	7.9	2.6	5.3	0.2	0.5	7.9	13.7
2019	5.1	9.8	2.6	6.4	0.2	0.4	7.9	16.6
2020	5.1	12.3	2.5	7.6	0.2	0.4	7.9	20.3
2021	5.1	14.6	2.4	8.7	0.2	0.5	7.7	23.8
2022	5.1	16.5	2.3	9.7	0.2	0.4	7.7	26.6
2023	5.3	18.4	2.2	10.7	0.2	0.4	7.7	29.5
2024	5.4	20.0	2.2	11.4	0.2	0.4	7.8	31.9
2025	5.9	21.3	2.3	12.1	0.2	0.5	8.4	33.9
2026	6.2	21.6	2.3	12.0	0.2	0.4	8.7	34.0

Figure 5-22. Scenario A EV charging costs relative to BAU

Hydrogen Refueling Infrastructure

Scenario A with and without banking and trading are the only scenarios with more hydrogen fuel cell vehicles than the BAU. For the analysis we have assumed on-site natural gas steam reforming. Please refer to Appendix A for details on the number of stations required and assumed cost per station. Figure 5-23 provides the BAU and Scenario A annual expenses for hydrogen refueling stations.

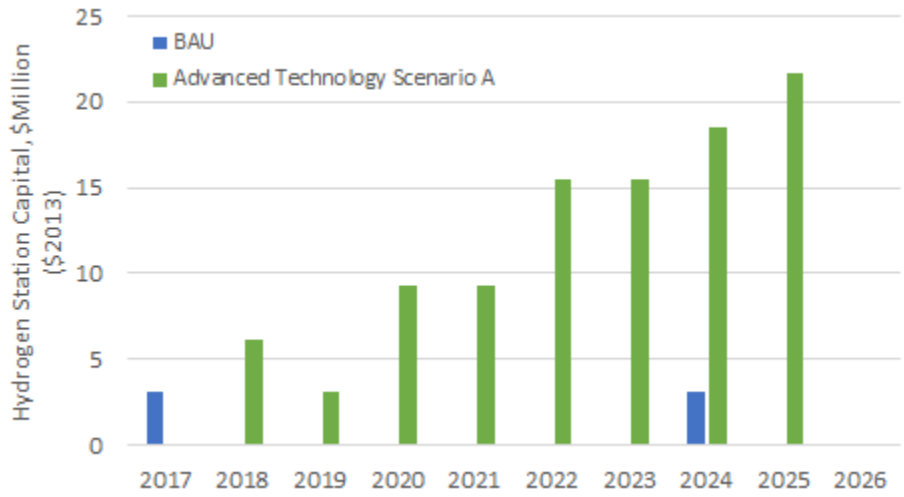

Figure 5-23. Estimated hydrogen refueling station costs for BAU and Scenario A

CNG Refueling Infrastructure

Scenario A with and without banking and trading is the only scenario with increased CNG utilization relative to the BAU. Appendix A provides assumptions on number of CNG refueling stations and cost. Figure 5-24 summarizes cumulative expenditures on refueling stations

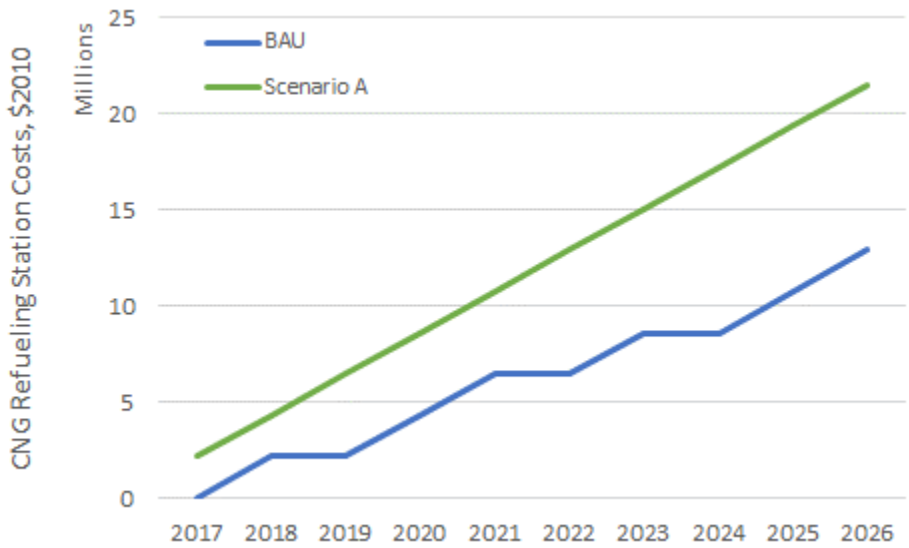

Figure 5-24. Projected cumulative CNG refueling infrastructure spending.

Pipeline RNG Plant Costs

All compliance scenarios assume some level of renewable natural gas utilized as a feedstock for CNG. RNG is recovered, cleaned and injected into the local natural gas distribution pipeline. There is already slightly more LFG to RNG capacity in Washington than is utilized in the compliance scenarios. However, additional capacity for RNG produced from WWT and HSAD gas is needed. For estimates of numbers of plants and plant cost, please refer to Appendix A. Table 5-2 provides the capital spending schedule in for each compliance scenario. These costs are incremental to BAU costs as there is no spending required in the BAU for RNG.

Table 5-2. RNG plant capital spending schedule.

$Million	Scenario A		Scenario A B&T		Scenario B		Scenario B B&T		Scenario C		Scenario C B&T		Scenario D		Scenario D B&T	
($2012)	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD
Capacity	5.5	8.9	5.5	4.5	3.2	5.6	4.9	5.6	4.9	11.2	4.2	11.2	4.9	11.2	4.9	5.6
Cost	27.3	44.6	27.3	22.3	16.2	27.9	24.5	27.9	24.5	55.8	21.2	55.8	24.5	55.8	24.5	27.9
2017	13.7		13.7		16.2		12.3		12.3		21.2		12.3		12.3	
2018			13.7				12.3		12.3				12.3		12.3	
2019	13.7															
2020																
2021																
2022		22.3		11.2		13.9		13.9		13.9		27.9		13.9		
2023										13.9		13.9		13.9		
2024				11.2		13.9		13.9		13.9		13.9		13.9		
2025		22.3								13.9				13.9		
2026																

Cellulosic Biofuel Plant Costs

Each compliance scenario utilizes some volume of cellulosic biofuel, and it has been assumed that all of these volumes will be produced in newly built production plants. For this analysis we have assumed that up to three cellulosic biofuel plants will be built in Washington State and if additional volumes are required, they would be imported. To evaluate the impact of this assumption on macro-economics, we are running a sensitivity case for Scenario C with banking and trading which considers all three plants built out of state. For assumptions on the number of plants required for each scenario and the associated capital cost, please refer to Appendix A. Figure 5-25 provides the cumulative capital costs for building cellulosic biofuel plants.

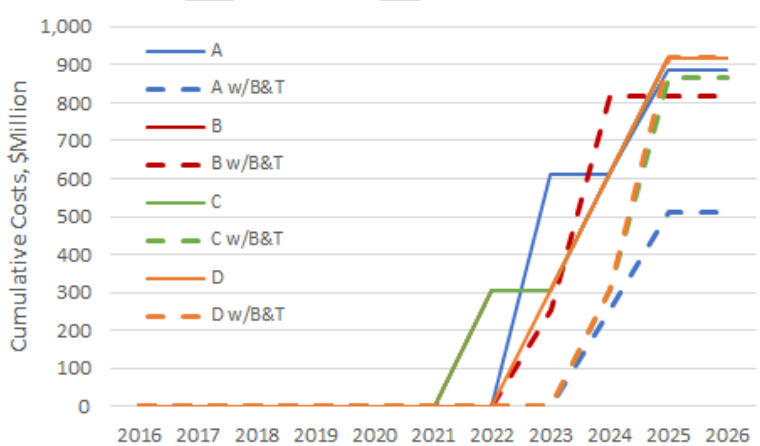

Figure 5-25. Cumulative costs for cellulosic biofuel plant construction in Washington State.

Infrastructure to Support Ethanol Use
There are six different cost categories considered for the change in ethanol consumption for the compliance scenarios relative to the BAU:

- Marine terminal
- Rail terminal
- Petroleum terminal
- Trucks for transport from blending terminal to refueling
- E15 infrastructure
- E85 infrastructure

The underlying assumptions for costs in each of these categories are provided in Appendix A. Figure 5-26 provides cumulative costs for ethanol related infrastructure relative to the BAU case.

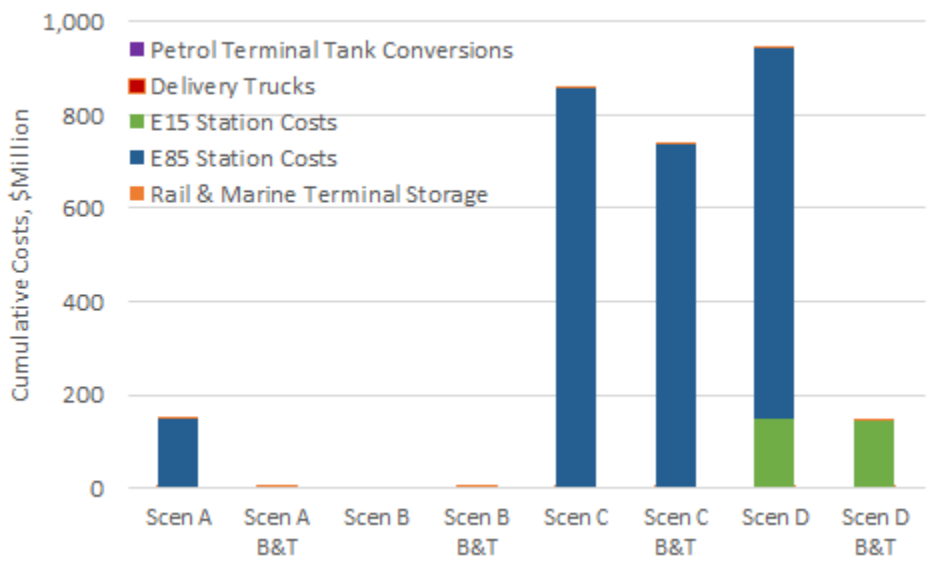

Figure 5-26. Cumulative ethanol infrastructure costs relative to BAU.

Infrastructure to Support Increased Biodiesel Use
Additional infrastructure required to support increased biodiesel use consists of more trucks to transport biodiesel to the petroleum terminals, upgrades at petroleum terminals, and refueling station upgrades. Appendix A provides the assumptions utilized to calculate these infrastructure costs. Figure 5-27 provides cumulative spending on biodiesel infrastructure relative to the BAU.

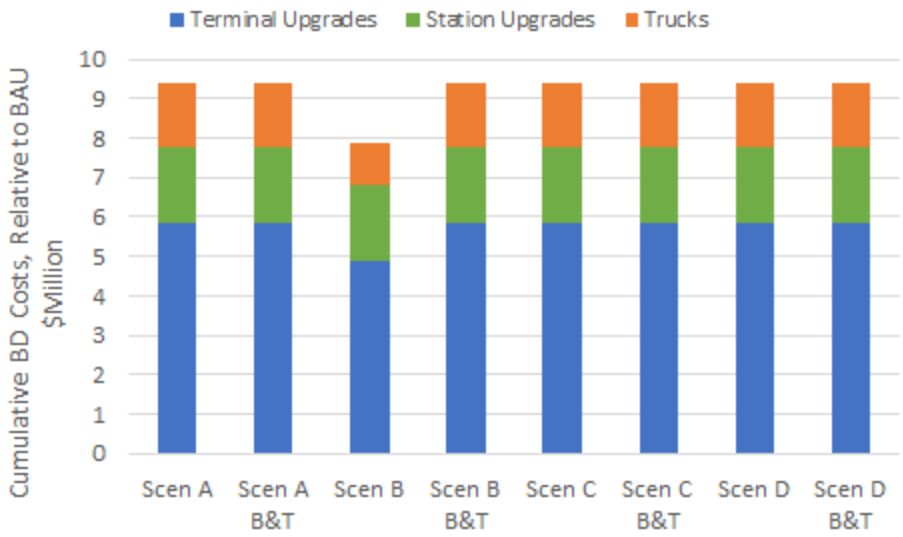

Figure 5-27. Summary of cumulative biodiesel infrastructure costs relative to BAU.

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6. **Economic Analysis Results**
7. **Cost Containment Mechanisms**

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Appendix A – VISION Model Input Assumptions

The VISION model is a U.S. on-road transportation fleet turnover model developed and maintained by Argonne National Laboratory. It provides forecasts of energy use, consumer fuel and vehicle spending, and vehicle populations by vehicle class and technology type through the year 2100. VISION uses historic U.S. sales data, combined with annual U.S. fleet turnover data by model year to estimate vehicle survival and age-dependant usage characteristics of the legacy fleet (1970 to present). To project the future fleet characteristics, the legacy fleet data is combined with future sales of conventional and alternative fuel vehicles based on the most recent EIA Annual Energy Outlook (AEO) forecast. The current version of the model reflects the AEO2013 projections through 2030. Some of the assumptions have been modified for this analysis and these modifications are explained in the following paragraphs.

Vehicle Populations by Class

The VISION model divides vehicles into four classes: light duty auto (lda), light duty truck (ldt), medium duty vehicles (MDV, class 3-6), and heavy duty vehicles (HDV, class 7 & 8). The first step in modifying the VISION model to reflect the Washington fleet is to replace the U.S. vehicle sales for each of these four categories with Washington State vehicle sales for the legacy fleet. We have utilized the sales data for 1978-2007 from the analysis done in 2009 and added sales for 2008-2013 provided by the Washington State Department of Licensing.

To project future sales by class, we apply the ratio of Washington State sales to U.S. sales to the VISION U.S. sales projections. Table A-1 provides the five-year average ratio of Washington to U.S. vehicle sales by class. Figure A-1 provides the historic and projected vehicle sales.

Table A-1. Ratio of Washington State vehicle sales to U.S. vehicle sales.

	LDA			LDT			MDV			HDV		
	WA	U.S.	WA %	WA	U.S.	WA %	WA	U.S.	WA %	WA	U.S.	WA %
2009	89,663	4,987,176	1.8%	77,142	5,200,478	1.5%	4,290	177,505	2.4%	2,440	133,885	1.8%
2010	91,252	5,682,258	1.6%	92,953	5,513,693	1.7%	4,451	208,697	2.1%	2,404	151,920	1.6%
2011	84,448	6,521,729	1.3%	115,791	6,099,211	1.9%	7,080	256,911	2.8%	1,670	197,414	0.8%
2012	113,227	7,278,122	1.6%	92,901	6,663,358	1.4%	7,845	242,781	3.2%	2,552	220,784	1.2%
2013	103,495	7,494,247	1.4%	108,400	7,086,260	1.5%	8,883	257,068	3.5%	2,890	235,831	1.2%
Average			1.5%			1.6%			2.8%			1.3%

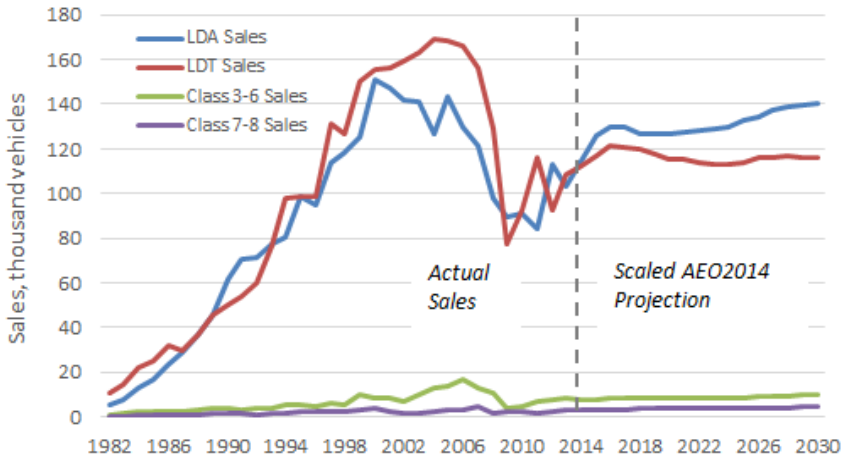

Figure A-1. Projected vehicle sales in Washington State by class.

Vehicle Technology Market Shares

After total vehicle sales by class for Washington State have been projected, the vehicle technology market shares need to be determined. Market shares for each technology type are discussed in the following pararaphs.

For light auto plug-in electric vehicles (PEVs), we set the population in 2020 to be consistent with a Washington State EV goal[40] of 50,000 cumulative vehicle sales by 2020. The VISION model default assumes 25/75 split between BEVs/PHEVs while Washington sales data for 2011-2013 shows a 75/25 BEV/PHEV split. For this analysis we assume a 50/50 BEV/PHEV split. These assumptions yield the market shares shown in Figure A-2. In the figure, historic sales are solid lines, large dashes are AEO2014 Pacific projections, and small dots are the projections used for the current analysis. Note that Washington State PEV sales are more than two times higher than AEO projections.

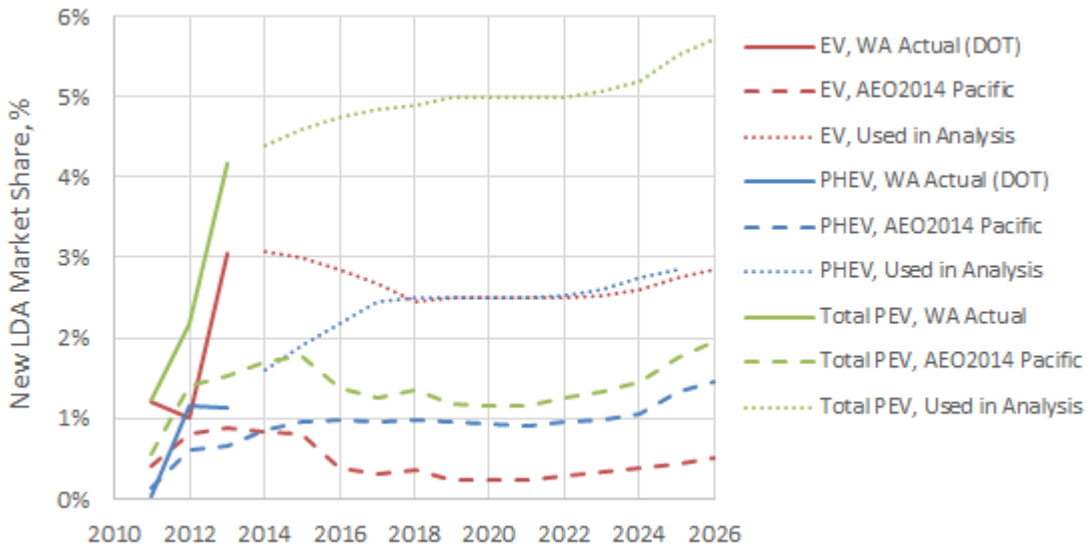

Figure A-2. Forecast light auto PEV Market Shares for Washington State

Figure A-3 provides market share forecasts utilized for light auto hybrid electric vehicles (HEVs), diesel and ethanol FFVs. For HEVs, the historic market share in Washington State is 2.6 times the AEO2014 Pacific projection. For the analysis we apply a factor of 2.6 to the AEO projection. For diesel and FFVs, we utilize the AEO projection.

Figure A-4 provides LDA market shares for CNG and hydrogen FCVs. For Washington's market share for CNG vehicles is much lower than the AEO market shares for 2011-2013. We assume that market shares gradually approach the AEO levels. Because Washington is not a ZEV state and we have assumed half of the AEO market share for hydrogen FCVs. For diesel HEVs, we utilize the AEO forecast.

[40] Results Washington Electric Vehicle Action Plan, Goal 5.2.3.b

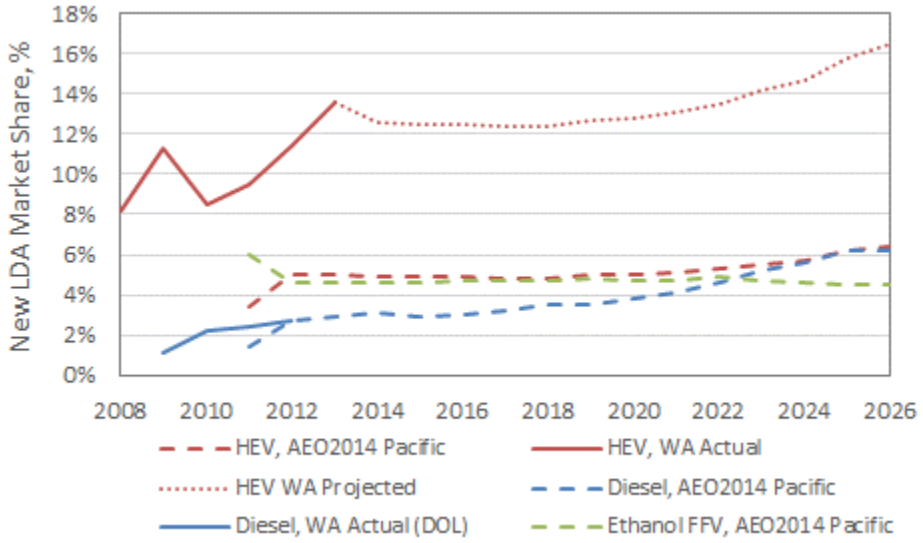

Figure A-3. LDA market shares for HEVs, diesel and ethanol FFVs.

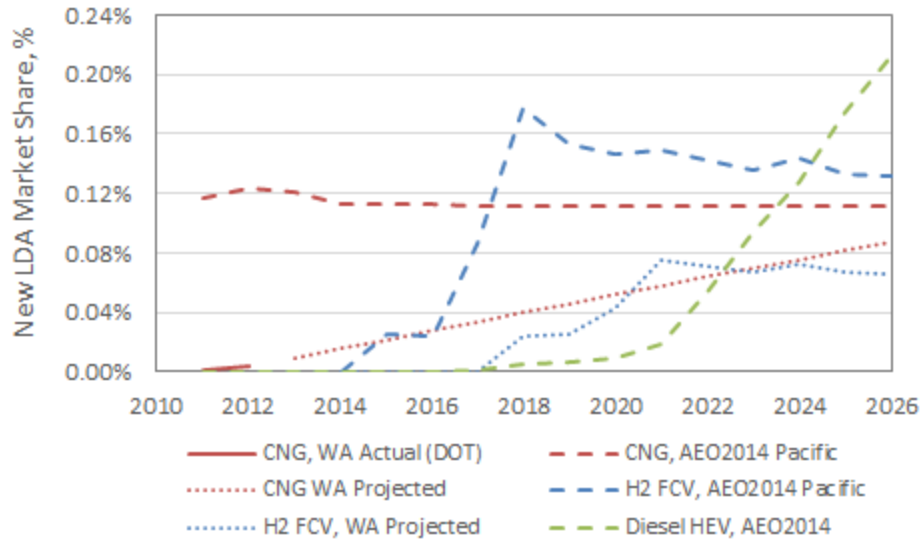

Figure A-4. LDA market shares for CNG, H2 FCV, and diesel HEVs.

Forecast market shares for light truck BEV, CNG and hydrogen FCVs are illustrated in Figure A-5. We utilize the AEO forecast for BEVs. We adopt the LDA approach for FCVs (1/2 AEO) and CNG vehicles (slow ramp to AEO forecast). Figure A-6 provides the market shares for light truck HEVs and diesel vehicles. We assume that HEV shares ramp to the AEO forecast. For diesel light trucks, sales in Washington State have been 1.8 times higher than the AEO estimates for 2010-2012. For this analysis, we apply a factor of 1.8 to the AEO diesel projections.

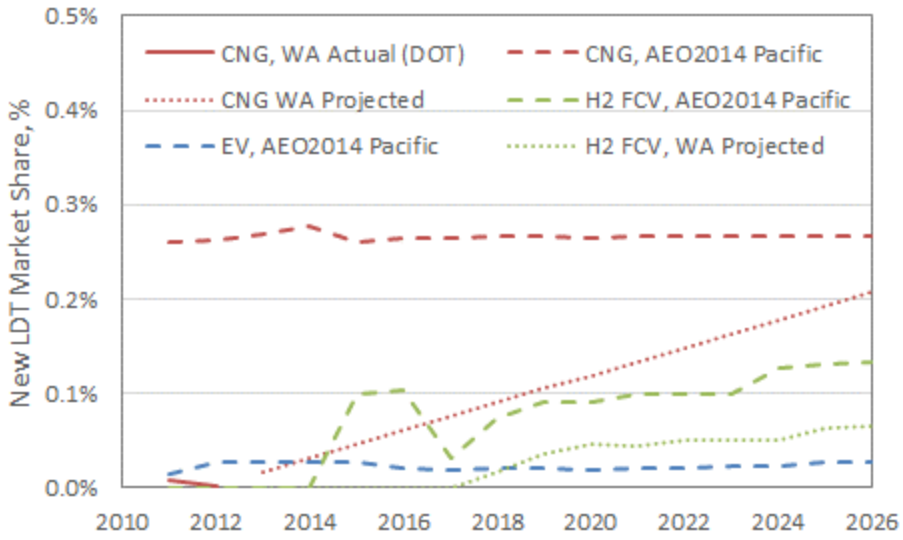

Figure A-5. Light truck market share projections for EVs, CNG and FCVs

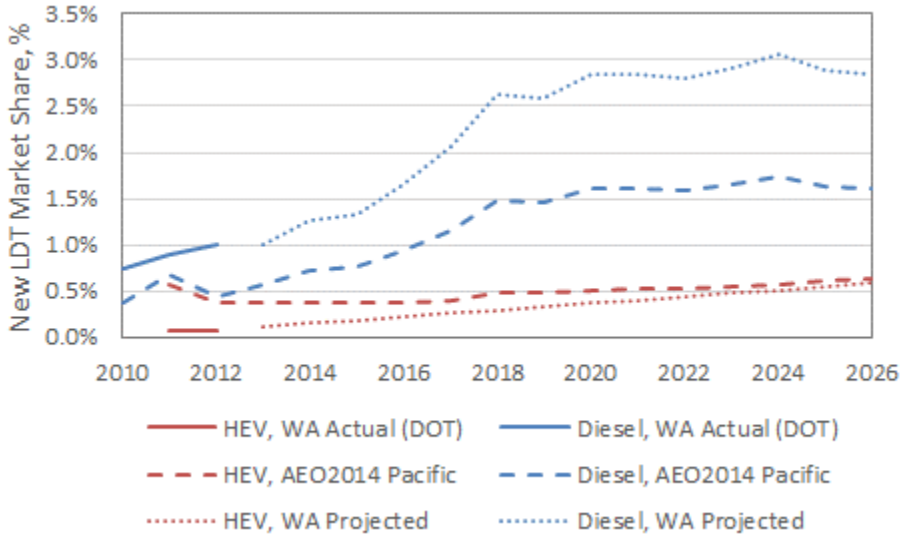

Figure A-6. Light truck market share projections for HEV and diesel

For medium duty vehicles (MDVs), we utilize historic shares for gasoline (36%). Similar to light duty CNG vehicles, we assume a gradual ramp up to the AEO projected market share. AEO does not have a forecast for diesel HEVs, so we utilize a recent publication by Navigant[41]. The resulting market shares are provided in Figure A-7.

For heavy duty vehicles, we utilize historic shares for gasoline (2.4%). For CNG, we set 2013 at the 2008-2012 average, and then follow the AEO projection. Figure A-8 provides these forecasts.

[41] http://www.truckinginfo.com/channel/fuel-smarts/article/story/2014/03/the-latest-developments-in-hybrid-electric-medium-duty-trucks.aspx

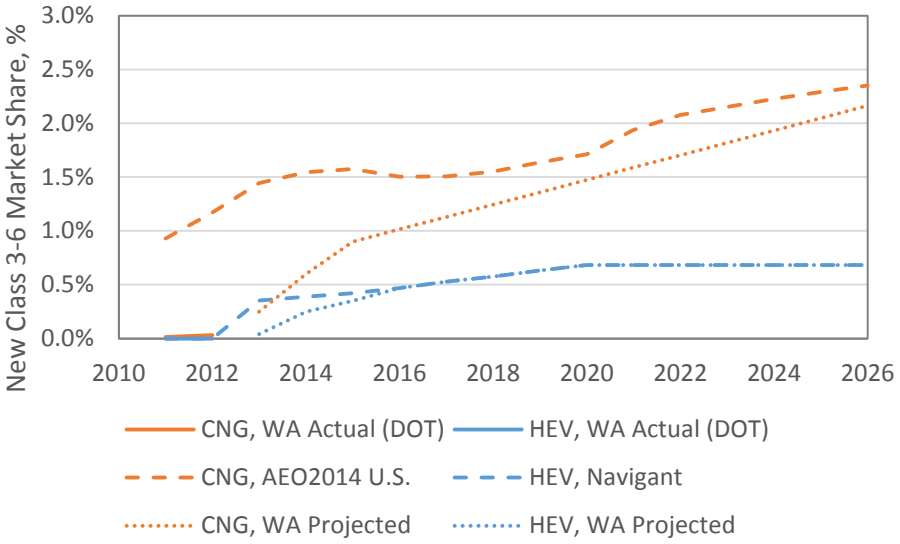

Figure A-7. MDV market share forecasts for HEV and CNG vehicles.

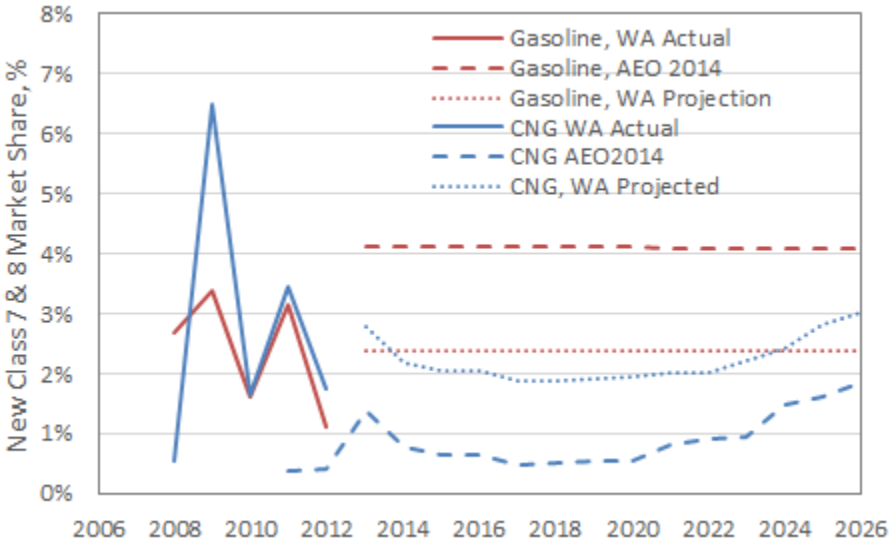

Figure A-8. HDV market share forecasts for gasoline and CNG vehicles.

Total vehicle sales forecasts by class (discussed in the previous section) combined with market share forecasts yield vehicle sales by technology type shown in Figures A-9 through A-12.

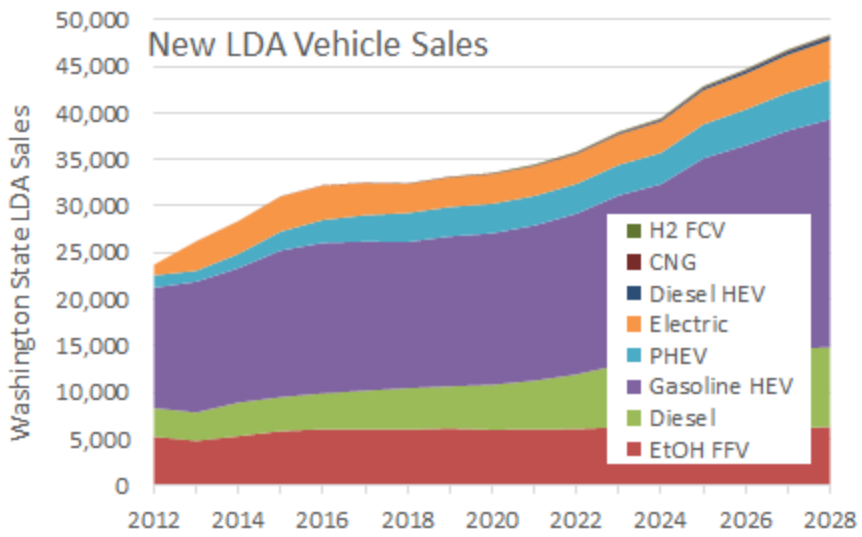

Figure A-9. Forecast light duty auto vehicle sales.

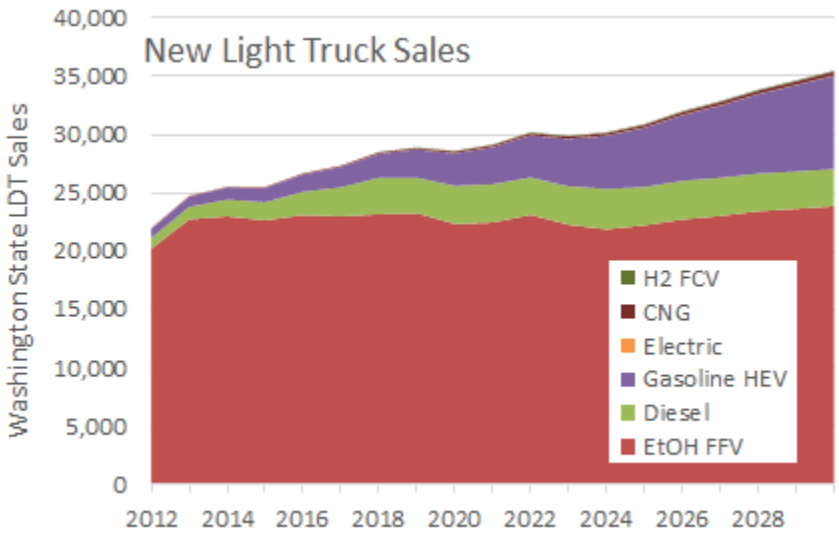

Figure A-10. Forecast light duty truck vehicle sales.

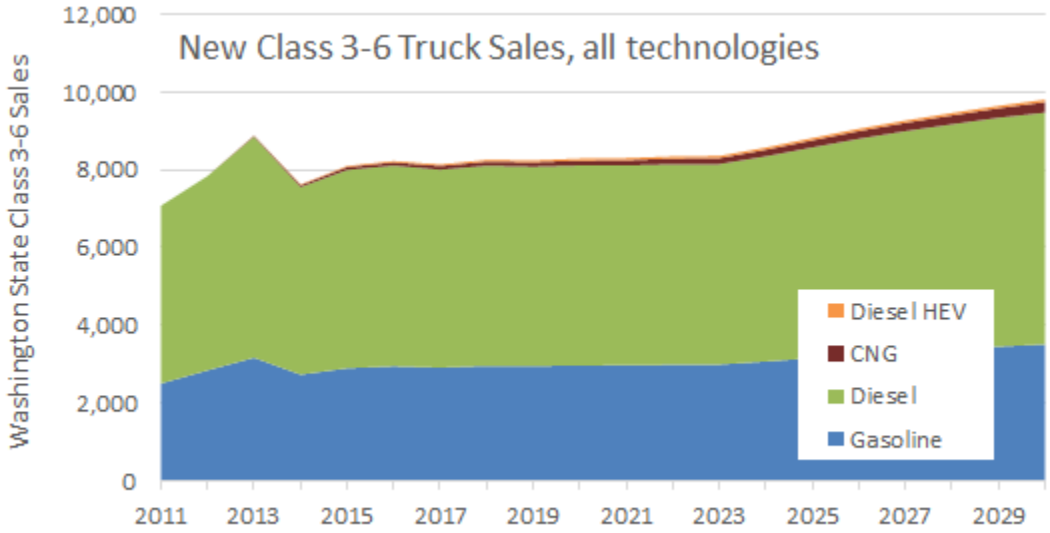

Figure A-11. Forecast medium duty vehicle sales.

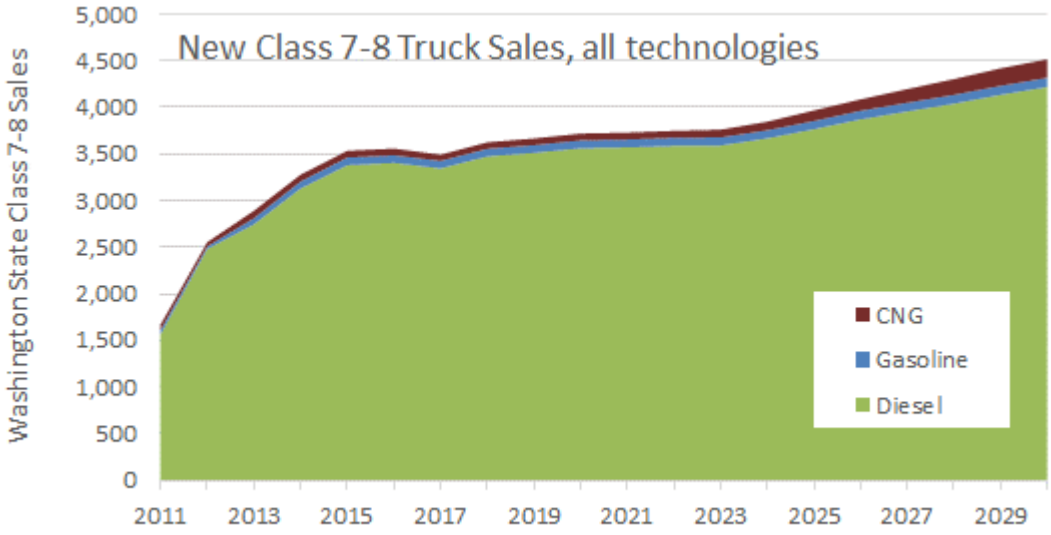

Figure A-12. Forecast heavy duty vehicle sales.

Vehicle Fuel Economy

The VISION model utilizes sales weighted averages of AEO fuel economy projections. The fuel economy values are EPA rated fuel economies; the VISION model applies EIA's degradation factors to arrive at on-road fuel economy. We have utilized the AEO projections for most of the vehicles, but have utilized ARB's LCFS energy economy ratios (EERs) for several vehicles. The EER is a ratio of energy input per mile for the conventional vehicle over the energy input per mile for the alternative fuel vehicle. These ratios are applied to the conventional vehicle fuel economy to estimate alternative fuel vehicle fuel economy. Table A-2 provides the EER values utilized here to project fuel economy. Figures A-13 through A-15 provide the fuel economy projections for light autos, light trucks and trucks.

Table A-2. EER values utilized to project alternative vehicle fuel economy

Vehicle Technology	EER
Light and medium duty CNG	1.0
Light duty ethanol FFV	1.0
Light duty EV (and electric portion of PHEV)	3.4
Light duty hydrogen FCV	2.5
Heavy duty CNG	0.9

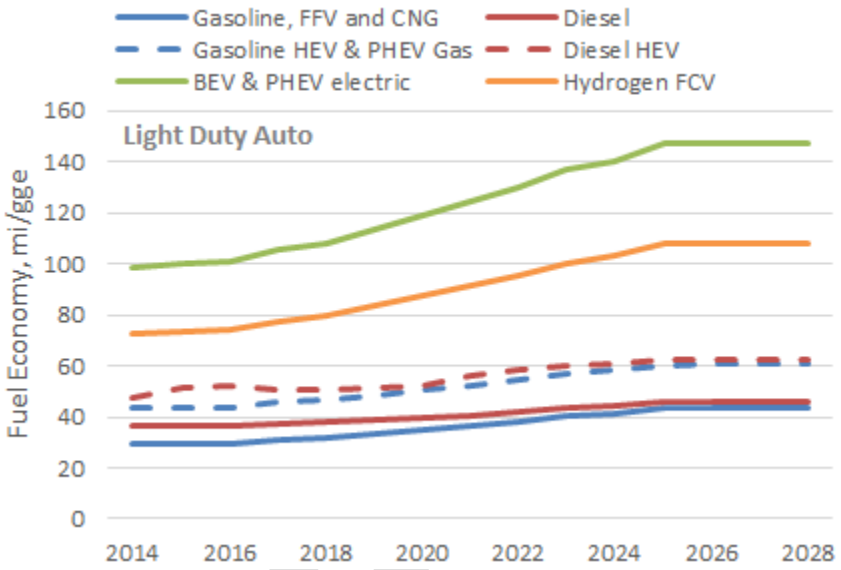

Figure A-13. Projected light duty auto fuel economy.

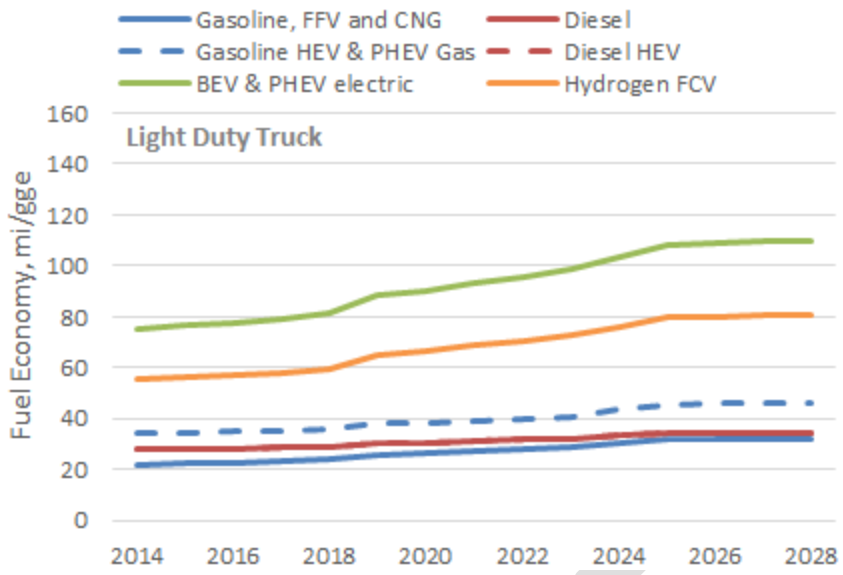

Figure A-14. Projected light duty truck fuel economy.

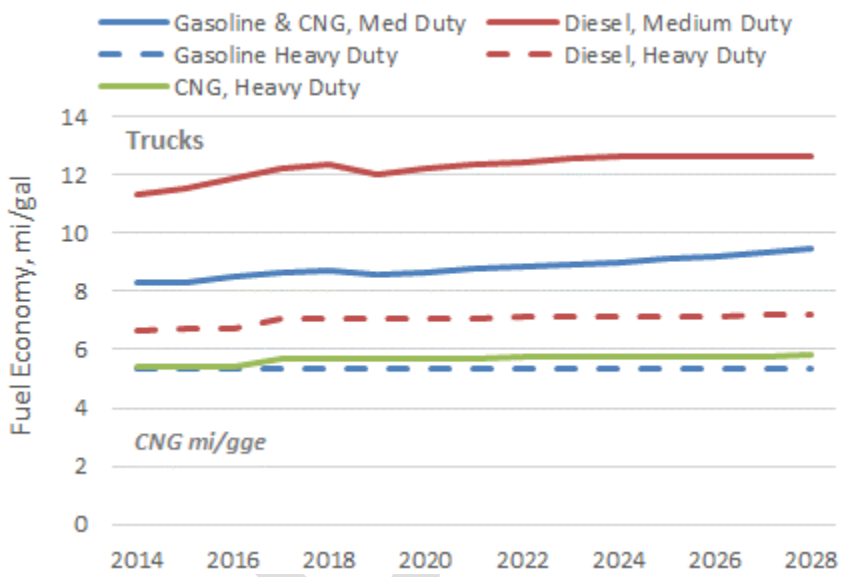

Figure A-15. Projected medium and heavy truck fuel economy.

Vehicle Miles Traveled

The VISION model calculates total vehicle miles traveled (VMT) by vehicle class based on population and a VMT per vehicle estimate which declines as vehicles age. Total VMT for each vehicle technology is combined with the fuel economy estimate (provided above) to determine fuel consumption by fuel type and vehicle class. The VISION predicted gasoline and diesel consumption for 2008-2013 can be compared to actual gasoline and diesel consumption; we apply factors to the VMT estimates to calibrate the VISION model so that calculated gasoline and diesel use match actual gasoline and diesel use. We have adjusted the default VMT assumptions to ensure that model estimates of gasoline and diesel consumption for 2008-2013 match actual gasoline and diesel consumption.

Figure A-16 provides the WSDOT light duty VMT forecast. The figure also provides the VISION VMT forecast after adjusting to match 2008-2012 gasoline consumption. Because the VISION projection drops off more than the WSDOT projection in the out years, we apply another factor so that the VMT in the future is trimmed to the same shape as the WSDOT projection. Figure A-17 provides the actual and VISION calculated gasoline consumption with the adjusted and trimmed VMT values.

The heavy duty VMT was adjusted in a similar fashion to calibrate the model to accurately predict diesel consumption. Figures A-18 and A-19 provide the medium and heavy duty VMT forecasts and corresponding diesel fuel consumption.

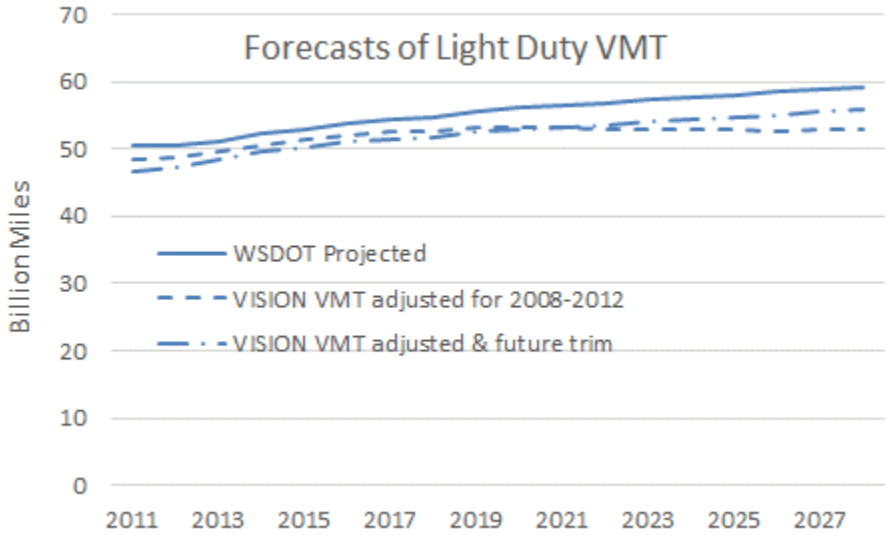

Figure A-16. Light duty VMT forecasts.

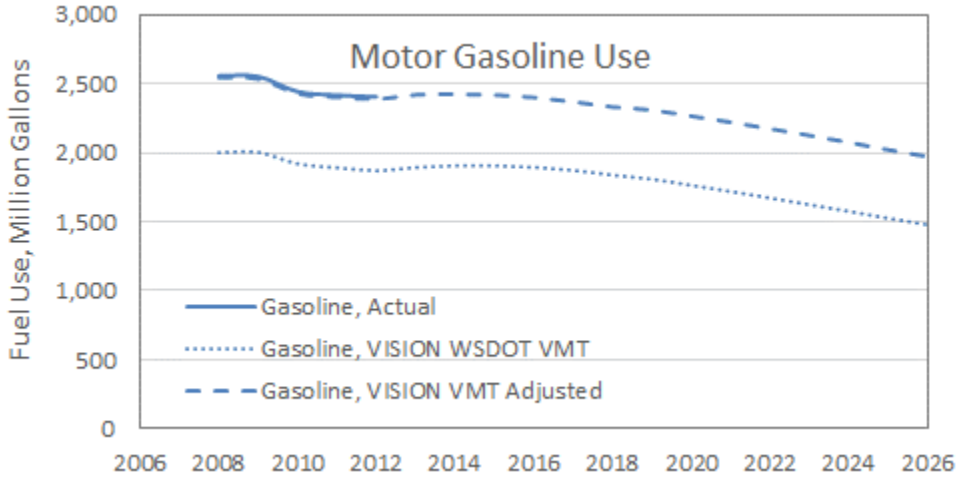

Figure A-17. Actual and calculated gasoline consumption.

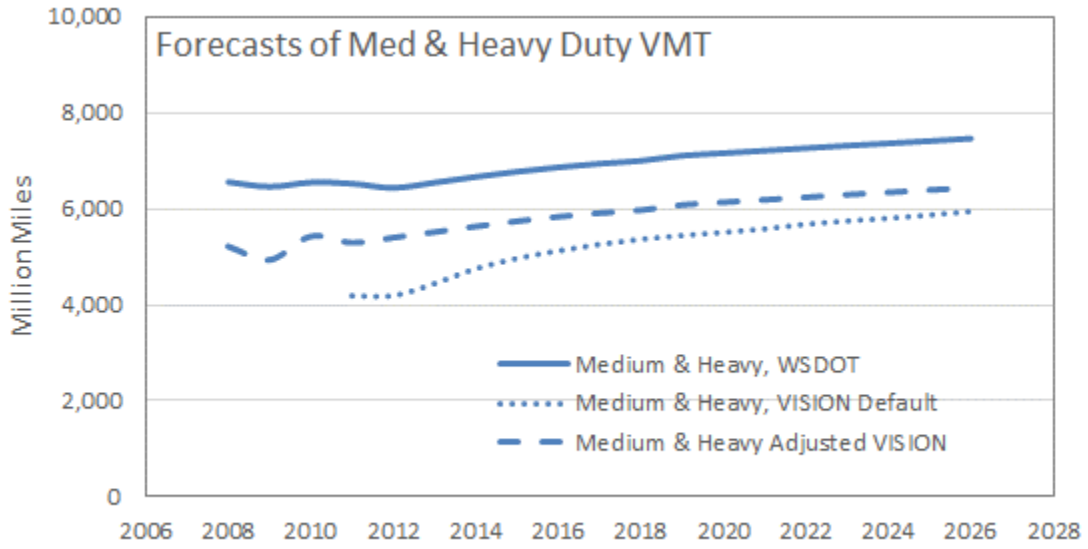

Figure A-19. Medium and heavy duty VMT forecasts.

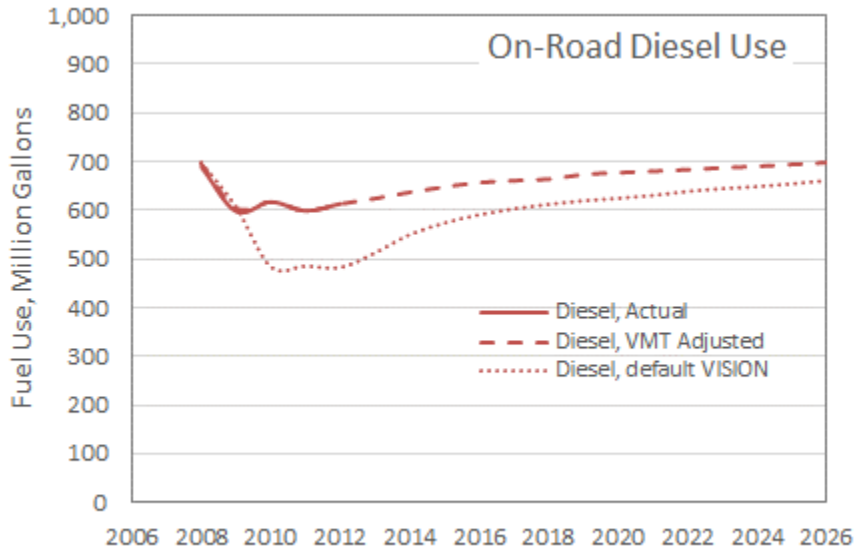

Figure A-20. Actual and calculated diesel consumption.

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Vehicle Prices

The macro-economic model will evaluate the effect of incremental consumer spending on vehicles relative to the BAU. As discussed above, the VISION model quantifies the number of vehicles sold by class and technology each year. Incremental spending on vehicles relative to a base vehicle can be quantified for the BAU and each compliance scenario by multiplying the sales by the assumed incremental vehicle cost. Only Scenario A (with and with banking and trading) has different vehicle populations than the BAU, so the following discussion only applies to incremental vehicle spending in Scenario A. Only populations of BEVs, PHEVs, FCVs, and CNG vehicles have been modified for Scenario A, so these are the incremental vehicle price assumption presented here.

For light duty vehicles, we have utilized incremental prices from a recent National Academy of Sciences (NAS)[42] study. The NAS analysis compares like vehicle to establish incremental retail prices. Figures A-21 and A-22 provide the incremental fuel prices utilized in this analysis. The NAS incremental prices for hydrogen FCVs is substantially lower than the BEV increment in 2010. We have modified this assumption so that the FCV starts at the same incremental price as the BEV and then approaches the NAS value in 2030.

We have reduced the incremental prices shown for BEVs and PHEVs to reflect the federal tax credit of $7,500 (~$3,000 of PHEV20s). This tax credit phases out for each manufacturer when that manufacturer sells 200,000 vehicles in the U.S. To date approximately 63,000 Chevy Volts and 55,000 Nissan Leafs have been sold. We assume that the tax credit begins to phase out in 2018. Washington State does not collect its vehicle use tax on BEVs, PHEVs, FCVs and CNG vehicles. If we assume an average vehicle price of $40,000 this is a $1,200 credit.

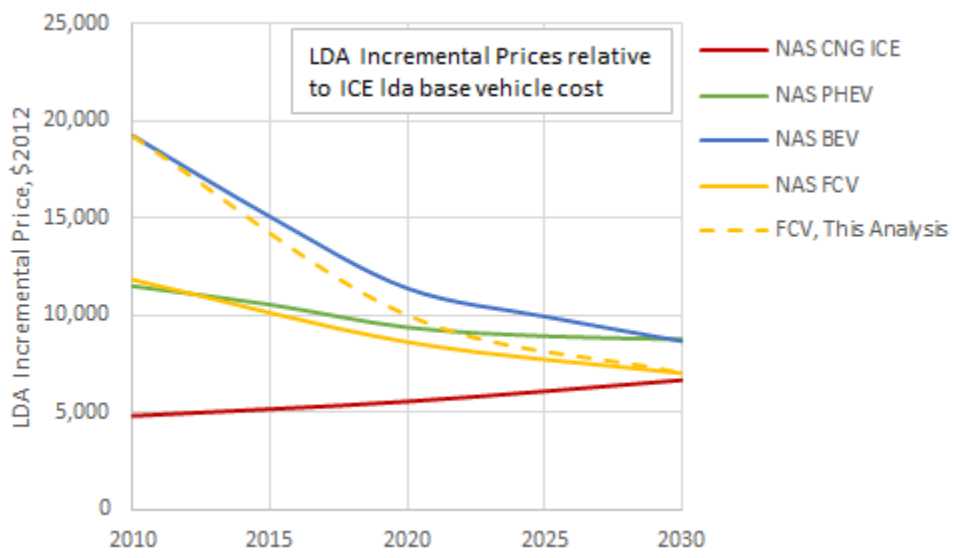

Figure A-21. Light duty auto incremental vehicle prices.

[42] Transitions to Alternative Vehicles and Fuels, National Academy of Sciences, 2013

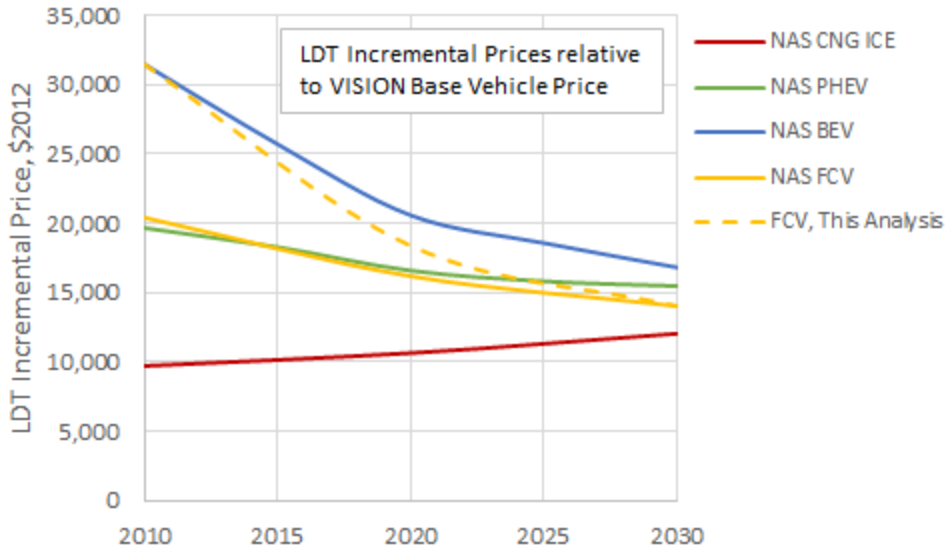

Figure A-22. Light duty truck incremental vehicle prices.

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Fuel Price Projections

One key assumption for the economic analysis is consumer spending on transportation fuel. The assumptions made to quantify fuel consumption with the VISION model have been provided above. Fuel consumption and fuel price projections yield projected consumer spending on fuel. This section provides the fuel price projections utilized.

We have utilized EIA's AEO2014 fuel price projections for the pacific region where available. Figure A-23 provides the projected gasoline and diesel prices. Gasoline prices are forecast to increase to approximately $4.50 per gallon by 2016 and diesel prices are forecast to increase to $5.50 per gallon. Because cellulosic gasoline is indistinguishable from fossil gasoline at the pump, we assume that cellulosic gasoline has the same price as fossil gasoline.

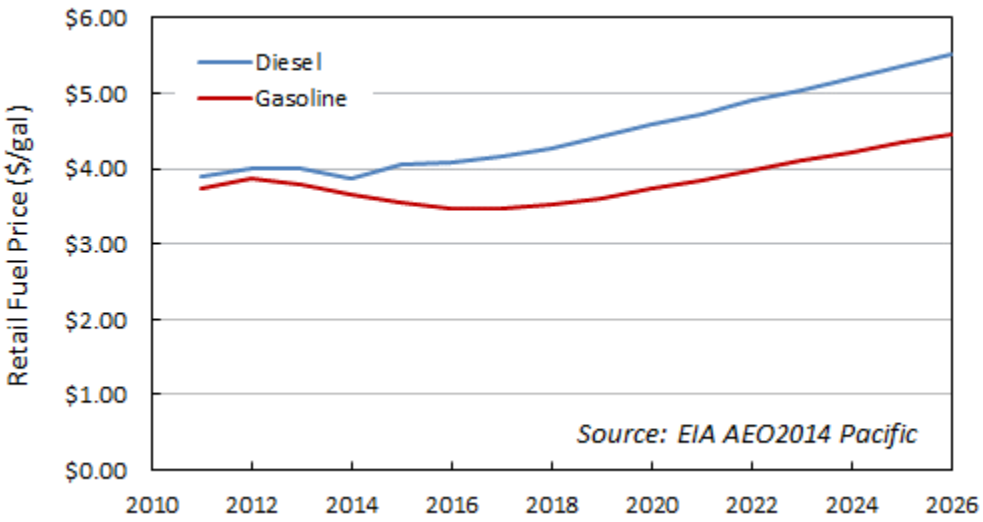

Figure A-23. EIA Gasoline and diesel fuel price projections.

Figure A-24 provides the ratio of EIA's forecast of ethanol prices (E85) and forecast gasoline prices. Historical data indicates that on an energy basis, ethanol has been price at a premium to diesel. EIA projects that by 2017 ethanol (as E85) prices will be at parity with gasoline on an energy basis. We have assumed a ratio of 1 for 2017 through the end of the analysis period.

EIA does not provide a price estimate for ethanol sold as a blending component with gasoline. For this analysis we assume the price starts at the current E85 premium (on an energy basis) and that this premium declines at a rate of 5% per year. Figure A-25 provides the assumed price projection for ethanol sold as a gasoline blending component. Although the price per gallon is lower than that for gasoline, a large premium on an energy basis persists.

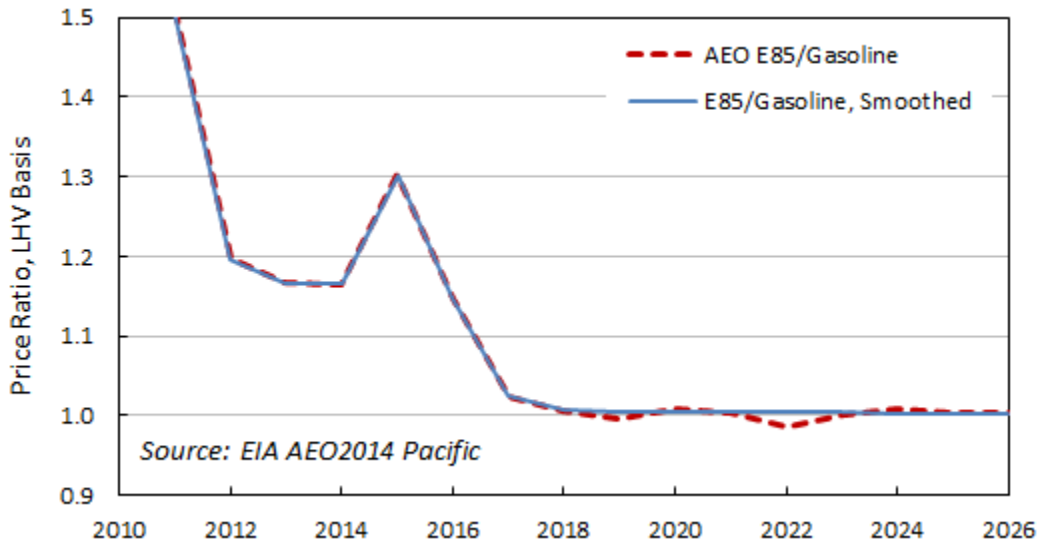

Figure A-24. EIA forecast of ethanol prices sold as E85.

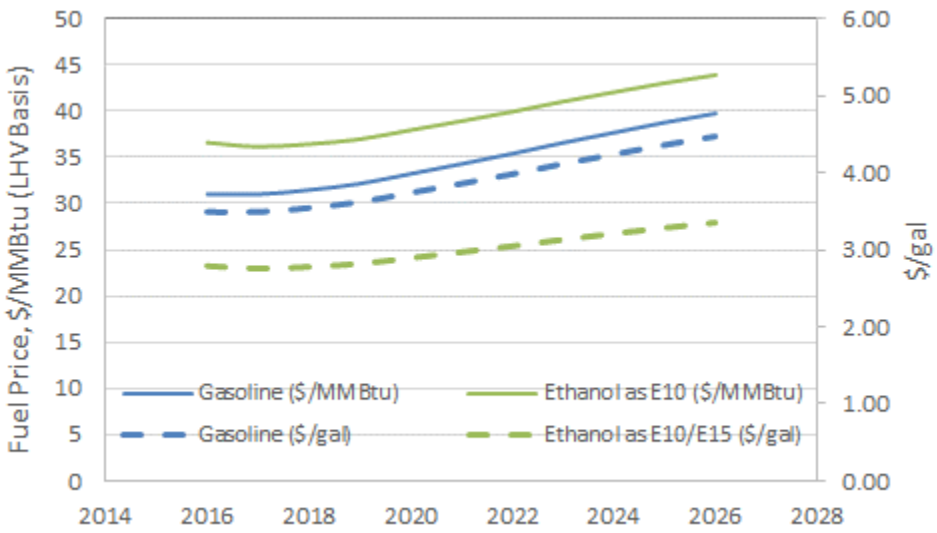

Figure A-25. Price projection for ethanol sold as E10/E15.

EIA does not project prices of biodiesel, however data show that biodiesel prices have tracked the price of diesel, generally with a price premium over diesel. The magnitude of the price premium has been due to the valuation of RINs, LCFS credits, and other market factors. Volatility in the RIN market has resulted in volatility in the price spread between biodiesel and diesel. Based on discussions with biodiesel producers, energy traders, and representatives of the National Biodiesel Board, the net price after the value of RINs must be lower than that for diesel fuel on a volumetric basis. Biodiesel blenders do not realize any additional value related to the properties of biodiesel. In fact, the energy content is slightly lower than that of conventional diesel. However, this difference in energy content does not appear to affect marketing or pricing. For the purposes of this analysis, we have assumed a 25 cent per gallon discount (excluding the value of RINs and CFS credits). Figure A-26 provides the biodiesel price projection compared to the diesel price projection.

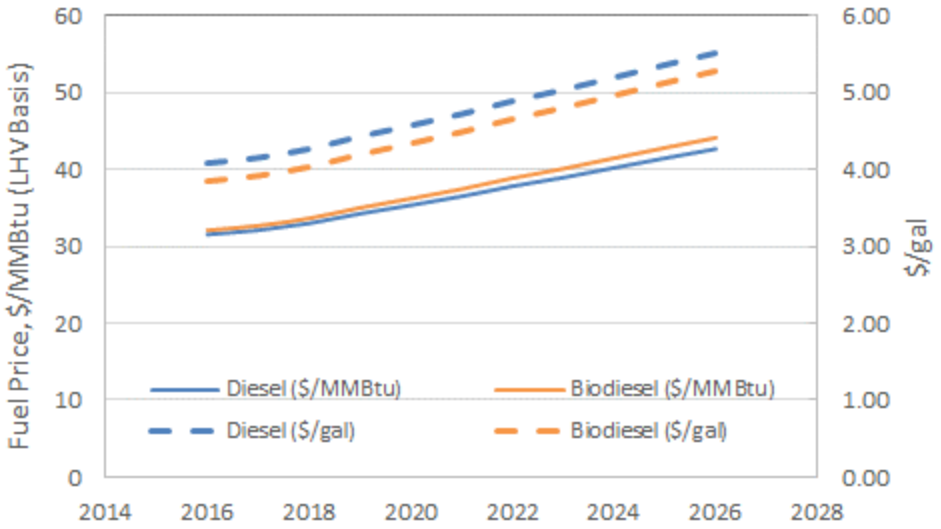

Figure A-26. Assumed biodiesel price projection.

We have utilized AEO's forecast for CNG prices. Figure A-27 provides the forecast CNG price compared to the gasoline price and commercial natural gas prices. On an energy basis, CNG is approximately 60 percent of the price of gasoline.

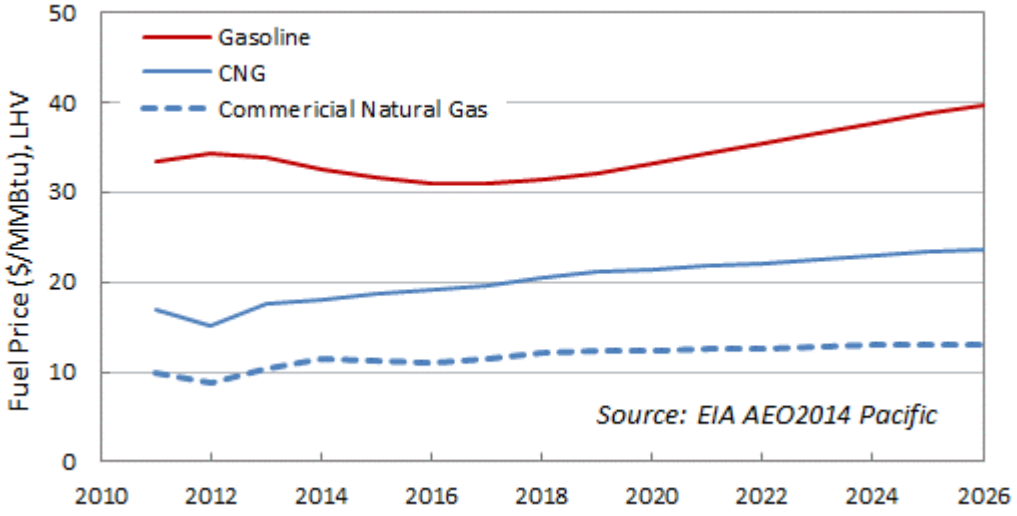

Figure A-27. Forecast CNG prices.

Washington electricity prices for transportation have historically been 78 percent of EIA's pacific prices[43]. We have applied a factor of 0.78 to EIA's projected electricity prices for this analysis. The forecast prices are provided in Figure A-28. Prices are shown in $/kWh and $/MMBtu with the EER (3.4) applied.

[43] U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

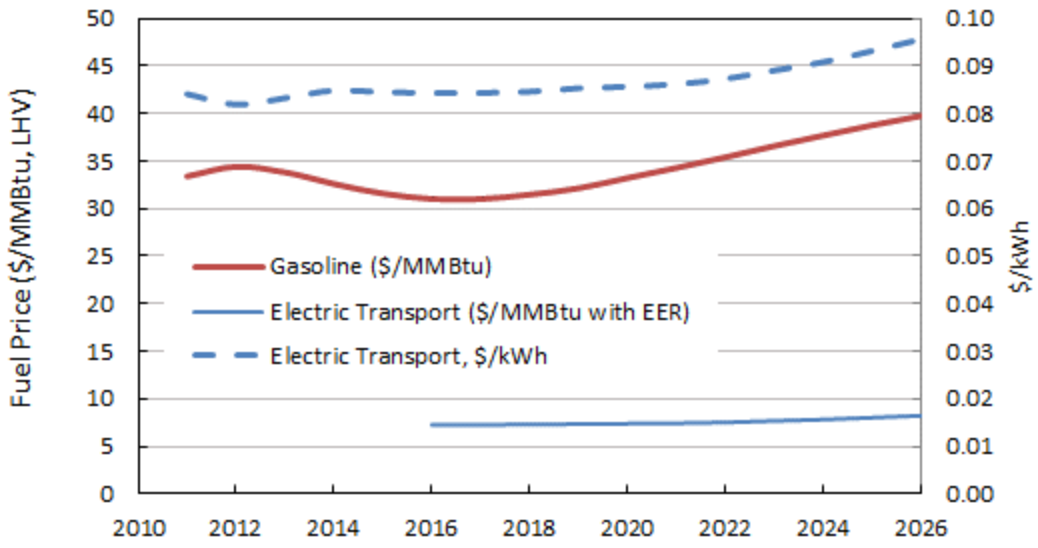

Figure A-28. Forecast electricity price.

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Infrastructure Requirements

To support increased utilization of low carbon fuels, significant investment in infrastructure is required. The following sections provide the assumptions utilized to quantify the needed infrastructure spending relative to the BAU for each compliance scenario.

EV Charging

Only Scenario A with and without banking and trading had different EV populations than the BAU case, so these assumptions compare only Scenario A to the BAU. Three classifications of EV charging equipment were considered: residential chargers, urban area public chargers, workplace level 2 chargers, and DC fast chargers. For residential chargers, it was assumed that for each 100 new BEVs sold, 90 new level 2 residential chargers are installed and 10 new level 1 chargers are installed[44]. For each 200 PHEVs sold, there are 30 new L2 chargers and 70 new L1.

To estimate the number of urban area public chargers needed for the BAU and Scenario A, a recent CEC PEV infrastructure assessment[45] estimated number of chargers per 100 square miles of urban space for two scenarios: home dominant and high public access. Table A-3 provides the charger density recommendations. For the BAU scenario, we have assumed that the number per 100 square feet is the average of the home dominant and high public access scenarios. For Scenario A we assume that more public access would be needed, so utilize the high public access charger density values. The urban area in Washington State is provided in Table A-4.

Table A-3. Urban Area Charger Density Assumptions.

Urban Area Chargers per 100 sq. miles	Home Dominant	High public access	BAU	Scenario A
Level 2 Public	127	294	211	294
DC-FC Stations	3.5	9.8	7	9.8

CEC-600-2014-003

Table A-4. Washington State Urban Area (Sq. Miles)

City Center	Sq Miles
Seattle	142
Bellevue	34
Tacoma	63
Everett	48
Port Orchard	5
Bellingham	32
Spokane	58
Vancouver	46
Olympia	18.5
Tri-cities	92.5
Yakima	20
Total	559

[44] Center for Sustainable Energy PEV Owner Survey, Feb 2014
[45] "California Statewide Plug-in Electric Vehicle Infrastructure Assessment", CEC-600-2014-003, May 2014

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To estimate the number of workplace level 2 chargers, the CEC estimate of workplace charging for 15% of PEVs with 2.4 charges per day per charger.

Table A-5 provides the estimated miles of major highways in Washington State. To estimate the number of DC fast charge stations located along major highways, we assume 40 miles between chargers for the BAU case and 25 miles between chargers for Scenario A. Table A-6 summarizes the total annual sales of chargers.

Table A-5. Major Highway Miles in Washington State.

Highway		Miles	# Chargers	
			BAU	Scen A
I-5	Vancouver to Blaine	246	7	11
I-90	Spokane Valley to Seattle	297	8	13
I-82	Ellensburg to Umatilla	137	4	6
195	Spokane to Lewiston	118	4	6
395	Spokane to Christina Lake	116	4	6
20	Kettle Falls to Anacortes	430	12	18
16	Tacoma to Kitsap	44	2	3
	Total	1388	41	63

Table A-6 summarizes the total numbers of chargers sold annually.

	Resid. L1		Resid. L2		Urban L2		Urban DC Fast		Workplace L2		Hway DC Fast	
	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A
2017	2,098	3,275	4,085	4,590	34	80	0	2	404	489	3	5
2018	2,330	3,248	3,981	4,374	34	80	1	3	391	784	3	5
2019	2,491	6,596	3,750	5,510	34	80	0	2	387	951	3	5
2020	2,540	7,978	3,824	6,812	34	80	1	2	372	1,149	3	5
2021	2,546	9,426	3,831	8,668	34	80	0	3	355	1,335	3	5
2022	2,551	10,885	3,839	10,355	34	80	1	2	338	1,490	3	5
2023	2,567	12,307	3,863	11,669	34	80	0	2	328	1,644	3	5
2024	2,621	13,744	3,945	13,059	34	80	1	2	321	1,772	3	5
2025	2,700	15,169	4,065	14,132	34	80	0	3	339	1,886	3	5
2026	2,936	16,804	4,419	14,940	34	80	1	2	341	1,855	3	5

The installed cost assumed for residential level 1 chargers is $200[46]. Installed costs for residential level 2 chargers, public level 2 chargers, and DC fast charge stations are assumed to be $1,200, $4,734, and $59,825 respectively[47].

CNG Refueling

Only Scenario A with and without banking and trading had different CNG vehicle populations than the BAU case, so these assumptions compare only Scenario A to the BAU. The CNG refueling station costs utilized in the previous version of this analysis are utilized here. Clean Energy Fuels stated that average station size is 8,000 gge/day and operates at a 30% capacity factor. We divide the CNG consumption by the station throughput to determine number of

[46] CalETC TEA Phase 1 Report, Aug 2014
[47] Rocky Mountain Institute, "Pulling back the Veil on EV Charging Station Costs", May 2014

stations required. Each station is assumed to cost $2.15 million, installed. Table A-7 provides the number of new stations required each year.

Table A-7. Number of new CNG refueling stations each year.

	CNG Use, MMBtu/yr		Total # Stations		# New Stations	
	BAU	Scen A	BAU	Scen A	BAU	Scen A
2016	760,378	953,739	7	9		
2017	815,796	1,062,523	7	10	0	1
2018	868,771	1,165,035	8	11	1	1
2019	929,938	1,275,036	8	12	0	1
2020	986,656	1,376,307	9	13	1	1
2021	1,047,774	1,481,530	10	14	1	1
2022	1,112,212	1,589,815	10	15	0	1
2023	1,181,989	1,704,904	11	16	1	1
2024	1,255,912	1,826,206	11	17	0	1
2025	1,348,491	1,973,858	12	18	1	1
2026	1,449,932	2,134,001	13	19	1	1

Hydrogen Refueling

Only Scenario A with and without banking and trading had different hydrogen fuel cell vehicle populations than the BAU case, so these assumptions compare only Scenario A to the BAU. For simplicity, we have assumed all hydrogen is produced from on-site natural gas steam reforming. The number and cost of on-site natural gas reforming stations needed (Table A-8) is based on recent H2A efforts[48] and utilizes the "more stations" estimates.

Table A-8. Hydrogen infrastructure cost estimates.

$2,013	H2 Use, kg/day		Tot# Plants		Tot# Plants		# New Plants		Capital $Million	
	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A
2016	0	420	0.0	1.3	0	2				
2017	0	633	0.0	1.4	0	2	0	0	0.0	0.0
2018	29	892	0.1	2.0	1	2	1	0	3.1	0.0
2019	73	1,406	0.2	3.1	1	4	0	2	0.0	6.2
2020	133	2,243	0.3	4.9	1	5	0	1	0.0	3.1
2021	210	3,431	0.5	7.5	1	8	0	3	0.0	9.3
2022	288	5,042	0.6	11.1	1	11	0	3	0.0	9.3
2023	359	7,027	0.8	15.4	1	16	0	5	0.0	15.5
2024	430	9,430	0.9	20.7	1	21	0	5	0.0	15.5
2025	503	12,302	1.1	27.0	2	27	1	6	3.1	18.5
2026	575	15,188	1.3	33.3	2	34	0	7	0.0	21.6

[48] "Hydrogen Station Cost Estimates Comparing Hydrogen Station Cost Calculator Results with other Recent Estimates", M. Melaina and M. Penev, NREL/TP-5400-56412, September 2013

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RNG Production

Capital required to recover, treat and inject biogas into natural gas pipeline system is estimated for WWT and HSAD gases. Sufficient RNG from LFG production capacity exists in-state to satisfy demand in each of the compliance scenarios. All cost estimates are taken from a recent report by the National Petroleum Council[49]. The cost for both WWT and HSAD RNG production is 1 $/gge. If we assume a capital recovery factor of 0.2, this results in 5 $/gge/yr of capacity. Table A-9 provides the capacity and cost to produce the volumes of WWT and HSAD RNG utilized in each of the compliance scenarios.

Table A-9. WWT and HSAD RNG Demand and Associated Costs

$Million	Scenario A		Scenario A B&T		Scenario B		Scenario B B&T		Scenario C		Scenario C B&T		Scenario D		Scenario D B&T	
($2012)	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD	WWT	HSAD
Capacity	5.5	8.9	5.5	4.5	3.2	5.6	4.9	5.6	4.9	11.2	4.2	11.2	4.9	11.2	4.9	5.6
Cost	27.3	44.6	27.3	22.3	16.2	27.9	24.5	27.9	24.5	55.8	21.2	55.8	24.5	55.8	24.5	27.9
2017	13.7		13.7		16.2		12.3		12.3		21.2		12.3		12.3	
2018			13.7				12.3		12.3				12.3		12.3	
2019	13.7															
2020																
2021																
2022		22.3		11.2		13.9		13.9		13.9		27.9		13.9		
2023										13.9		13.9		13.9		
2024				11.2		13.9		13.9		13.9		13.9		13.9		
2025		22.3								13.9				13.9		
2026																

Cellulosic Biofuel Production

Each of the compliance scenarios utilizes some volume of cellulosic biofuel. It is assumed that up to three plants with capacity up to 30 MGY could be built in Washington State and that the balance of the cellulosic biofuel volumes are imported. Table A-10 provides the number of plants needed to be built in the year they are needed.

Table A-10. Number of new cellulosic biofuel plants needed in year shown.

	Number of new cellulosic plants needed in year shown							
	A	A w/B&T	B	B w/B&T	C	C w/B&T	D	D w/B&T
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	1	0	1	0	0	0
2024	2	0	0	1	0	0	1	0
2025	0	1	1	2	1	1	1	1
2026	1	1	1	0	1	2	1	2

[49] National Petroleum Council Report, "Advancing Technology for America's Transportation Future", 2012

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To estimate capital cost of the biofuel production plants, we utilize a survey of published installed plant costs[50]. The average installed cost (Table A-11) is $10.2 per gallon of capacity. Members of the Washington CFS workgroup advised that this number represents first generation plant costs and that 8 years from now when the plants that would supply a Washington CFS are built, the costs could be as low as $8 per gallon. We have utilized the higher value for this analysis to be conservative.

The plant capacity needed for each scenario is multiplied by $10.2 per gallon to arrive at the capital needed each year for new plants. The spending is shifted forward to allow a year for construction and commissioning.

Table A-11. Installed cost of cellulosic biofuel plants

Plant	Cost $Million	Size MGY	Cost $/gal
KiOR Natchez Facility	350	41	8.5
ClearFuels Collinwood	200	20	10.0
Sundrop, Louisiana	500	50	10.0
Zeachem	391	25	15.6
Abengoa Hugoton	350	25	14.0
Beta Renewables, NC	170	20	8.5
DuPont, Iowa	276	25	11.0
Poet, Iowa	250	20	12.5
Mascoma Kinross	232	40	5.8
Volume weighted Avg			10.2

Ethanol Infrastructure

To support changes in ethanol consumption, infrastructure investments are needed in several areas: marine and rail terminals, petroleum terminals, trucks, and refueling station upgrades.

All of the compliance scenarios utilize some amount of sugarcane ethanol from Brazil. Marine terminals in Seattle and Tacoma currently have the ability to receive shipments of ethanol from Brazil.[51] It is therefore assumed that piping, pumps, vapor handling exists, so the only costs required at marine terminals are for increased storage capacity. We assume here that the marine terminals need capacity to store a 10-day supply and that existing storage capacity is 500,000 gallons. Figure A-29 provides the additional storage required at marine terminals for each compliance scenario.

To estimate the cost of the additional storage, we assume $40 per bbl of ethanol[52] and apply this to the incremental amount of storage needed each year.

[50] "Commercial-scale cellulosic biofuels projects in the United States", Tristan R. Brown and Robert C. Brown, Iowa State University, March 2013
[51] EIA State Energy Data System
[52] EPA RFS2 Final Feb 2010 page 787

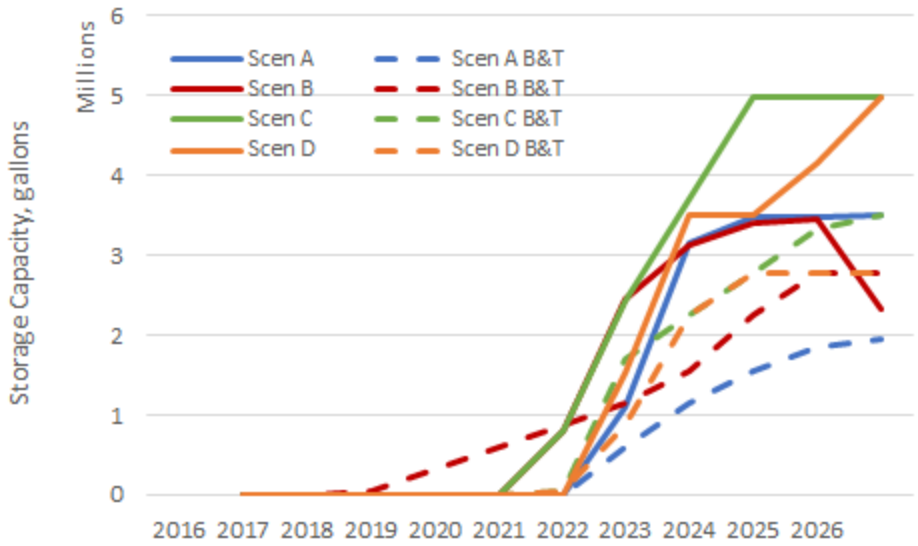

Figure A-29. Additional marine terminal storage capacity needed for a 10 day supply.

Ethanol is also delivered by rail, so we next considered additional storage required at rail terminals. The total rail receipts of ethanol is anticipated to decrease in the long-run, however there are sizeable increases for Scenario C and D. Table A-12 provides the increase in weekly gallons expected to be received by rail for each scenario relative to the BAU case. To estimate the cost of increased storage needs at rail terminals, the incremental storage required each year was multiplied by the $40 per barrel cost previously mentioned.

Table A-12. Estimated increase in U.S. rail receipts over 2016 BAU

gallons/ wk	Scen A	Scen A B&T	Scen B	Scen B B&T	Scen C	Scen C B&T	Scen D	Scen D B&T
2016								
2017		133,653				137,589		137,794
2018		57,351	65,224			65,010	65,010	546,783
2019			20,535		20,313	20,313	497,227	1,026,776
2020							1,112,759	1,540,421
2021							1,387,313	1,437,961
2022							337,637	799,410
2023								
2024								
2025								
2026								

At the petroleum terminals, infrastructure costs associated with a shift from gasoline storage to ethanol storage for some of the scenarios needs to be estimated. Total volumes of gasoline and ethanol consumption decrease from 2016 to 2026 in all scenarios, therefore no increase in total storage is needed, however some storage may need to be converted from gasoline to diesel. Total

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ethanol consumption increases above the 2016 BAU level in Scenarios C and D with and without banking and trading. Total ethanol decreases below 2016 BAU levels in the other scenarios. If we assume that the current tanks are 300,000 gallons and that a 6 day capacity is required, Table A-13 provides the total number of tanks converted and the incremental number of tanks converted each year. Assuming $20,750 to convert each tank[53] yields the costs in the table.

Table A-13. Conversion of tanks at petroleum terminals from gasoline to ethanol

	Total Tanks Converted				Tanks converted each year				Cost, $			
	Scen C	Scen C B&T	Scen D	Scen D B&T	Scen C	Scen C B&T	Scen D	Scen D B&T	Scen C	Scen C B&T	Scen D	Scen D B&T
2016	0	0	0	0								
2017	0	1	0	1	0	1	0	1	0	20,750	0	20,750
2018	0	1	1	2	0	0	1	1	0	0	20,750	20,750
2019	1	1	2	4	1	0	1	2	20,750	0	20,750	41,500
2020	1	1	4	6	0	0	2	2	0	0	41,500	41,500
2021	1	1	6	6	0	0	2	0	0	0	41,500	0
2022	1	1	6	6	0	0	0	0	0	0	0	0
2023	2	1	6	6	1	0	0	0	20,750	0	0	0
2024	4	3	10	7	2	2	4	1	41,500	41,500	83,000	20,750
2025	7	6	13	6	3	3	3	0	62,250	62,250	62,250	0
2026	10	10	15	6	3	4	2	0	62,250	83,000	41,500	0

The number of trucks needed to transport ethanol from marine/rail terminals and in-state production plants and to transport gasoline and E85 from the blending terminals to the refueling stations is considered. Assuming that each truck carries 8000 gallons of ethanol and that it can make 5 trips per day from the marine/rail terminal or in-state production plant to the blending terminal, the number of new trucks needed each year is provided in Table A-14.

Table A-14. New trucks for ethanol transport from marine/rail terminals and cellulosic plants.

New Trucks	Scen A	Scen A B&T	Scen B	Scen B B&T	Scen C	Scen C B&T	Scen D	Scen D B&T
2016								
2017	0	1	0	1	0	1		1
2018	0	0	0	0	0			1
2019	0	0	0	0	0		2	1
2020	1	0	0	0	0		2	
2021	0	0	0	0	0		3	
2022	0	0	0	0	0		0	
2023	0	0	0	0	1		0	
2024	0	0	0	0	4		2	
2025	1	0	0	0	5		0	
2026	0	0	0	0	2		0	

[53] EPA RFS2 RIA final, 2007

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New trucks are also needed to transport gasoline and E85 from the petroleum terminals to the refueling stations. If we assume 8000 gallons per truck and 5 trips per day, Table A-15 provides the total number of trucks required. Clearly, relative to the BAU case, very few if any additional trucks are required; a maximum of 4 new trucks are needed in Scenario D, 3 needed in D with B&T, 2 in Scenario C with B&T and 1 for Scenario C. Each truck is assumed to cost $180,000.

Table A-15. Trucks needed for E10/E15/E85 transport to refueling stations.

Trucks	BAU	Scen A	Scen A B&T	Scen B	Scen B B&T	Scen C	Scen C B&T	Scen D	Scen D B&T
2016	170	170	170	170	170	170	170	170	170
2017	168	167	168	168	168	168	168	168	168
2018	165	165	165	165	165	165	165	165	166
2019	163	163	163	164	164	164	164	164	165
2020	160	160	160	161	160	161	160	162	163
2021	157	156	156	157	157	157	157	160	160
2022	154	152	152	154	154	154	154	156	157
2023	151	149	149	149	151	151	151	153	153
2024	147	144	144	143	147	148	148	150	150
2025	143	138	140	138	142	144	146	147	146
2026	140	133	135	132	136	139	142	143	141

Biodiesel Infrastructure

Infrastructure to support increased biodiesel use includes increased storage capacity, and blending equipment, and piping at storage terminals, and station upgrades. We have assumed that 6 days of storage is required at petroleum terminals. Some storage capacity currently exists[54], but to be conservative we have assumed all new storage is required. Table A-16 provides the estimated total storage required for each of the compliance scenarios.

Table A-16. Estimated total biodiesel storage needed for a 6-day supply at terminals.

Gallons	Scen A	Scen A B&T	Scen B	Scen B B&T	Scen C	Scen C B&T	Scen D	Scen D B&T
2016	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	279,809	0	281,628	0	281,628	0	281,628
2020	0	618,946	0	621,849	0	621,849	0	621,849
2021	63,023	848,904	148,644	852,730	64,609	852,730	64,609	852,730
2022	289,942	1,081,541	405,250	1,086,369	292,343	1,086,369	292,343	1,086,369
2023	633,941	1,204,049	637,660	1,209,651	523,793	1,209,651	523,793	1,209,651
2024	866,935	1,210,917	642,532	1,216,987	871,780	1,216,987	871,780	1,216,987
2025	1,103,920	1,219,325	648,518	1,226,000	1,052,285	1,226,000	1,052,285	1,226,000
2026	1,227,636	1,227,636	654,457	1,234,943	1,234,943	1,234,943	1,234,943	1,234,943

[54] Todd Ellis, Imperium Renewables estimates that sufficient storage and blending capacity exists to support B5.

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There are 19 petroleum terminals in Washington State, and blending, piping and ancillary equipment is in place at 14 of these terminals (3 in Seattle, 3 in Vancouver, 3 in Spokane, 3 in Pasco, 2 in Tacoma). Therefore, 5 terminals need to install blending, piping and ancillary equipment.

The installed cost for heated and insulated biodiesel storage tanks was estimated by EPA[55] to be $70 per barrel. For blending, piping and ancillary equipment, EPA estimated $400,000 per terminal for blending equipment, $60,000 per terminal for piping, 500,000 per terminal for ancillary receiving, blending and storage equipment. The National Biodiesel Board (NBB)[56] has advised that these estimates are accurate except for the blending equipment estimate; blending equipment is approximately $200,000 per terminal. We have utilized all of the EPA cost estimates, but have substituted $200,000 for blending equipment, for a total cost of $760,000 per terminal at 5 terminals. We have assumed that terminal infrastructure costs are incurred as biodiesel use increases.

To transport biodiesel from the production plants (all located in Washington State) to the petroleum terminals it is assumed that half travels by rail and half by truck. It is further assumed that any additional rail cars required are available from the rail industry. To estimate the number of new trucks required, we assume an 8,000 gallon capacity and 2 trips per day. These assumptions result in up to 9 additional trucks at $180,000 each for the compliance scenarios.

A number of states have begun selling significant amounts of biodiesel. For example Minnesota allows blends of up to B20 to be dispensed from existing diesel dispensers as long as they are calibrated to the blend that is being sold[57]. In addition, blends of up to B20 may be stored in existing diesel fuel storage tanks. Therefore, the costs incurred at refueling stations are limited to labeling costs. We have assumed $1,000 is spent on labeling at each refueling station. According to DOE[58], Washington State has 1,914 retail gasoline stations. To be conservative we assume that each sells diesel and pays to modify its labeling to reflect the BD blend levels sold.

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[55] EPA RFS2 Final RIA, February 2010
[56] Provided by NBB Petroleum Liaison to Shelby Neal (NBB), email dated September 11, 2014
[57] http://www.cleanairchoice.org/pdf/BDFAQMinnesota.pdf
[58] http://www.eia.gov/state/print.cfm?sid=WA