A Low Carbon Fuel Standard in Washington State

Revised Analysis with Updated Assumptions

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Abbreviations

AEO	Annual Energy Outlook
ARB	Air Resources Board
B&T	Banking and trading
BAU	Business-as-Usual
BEV	Battery electric vehicle
CEC	California Energy Commission
CI	Carbon Intensity
CNG	Compressed natural gas
EER	Energy economy ratio
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EVSE	Electric vehicle supply equipment
FFV	Flex Fuel Vehicle
GHG	Greenhouse Gas
HDV	Heavy duty
HEV	Hybrid electric vehicle
ICE	Internal combustion engine
ILUC	Indirect land use change
LCFS	Low Carbon Fuel Standard
LDA	Light duty auto
LDT	Light duty truck
LDV	Light duty vehicle
LFG	Landfill gas
LNG	Liquefied natural gas
MDV	Medium duty vehicle
MGY	Million gallons per year
OFM	Washington State Office of Financial Management
PADD	Petroleum Administration Defense District
PEV	Plug-in electric vehicle
PHEV	Plug-in Hybrid Electric Vehicle
RD	Renewable diesel
RNG	Renewable natural gas
RFS	Renewable Fuel Standard
TTW	Tank-to-Wheel
VMT	Vehicle miles travelled
WSDOT	Washington State Department of Transportation
WSDA	Washington Department of Agriculture
WTW	Well-to-Wheel
WWT	Wastewater treatment
UCO	Used cooking oil

Executive Summary

In May 2009, Washington's governor directed the Department of Ecology to assess whether a low carbon fuel standard (LCFS) would best meet Washington's greenhouse gas emission reduction goals. The objective of an LCFS is to reduce the overall carbon intensity of transportation fuels. Carbon intensity is defined as the well-to-wheel greenhouse gas (GHG) emissions of a fuel pathway per unit energy. Well-to-Wheel (WTW) emissions include the emissions produced during feedstock production/recovery, feedstock transport to the fuel production plant, fuel production, fuel transport to refueling stations, combustion in the vehicle and any indirect emissions from land use change. A bounding scenario analysis was performed to quantify fuel types and volumes needed for compliance, changes in consumer spending on vehicles and fuel, infrastructure costs and the corresponding macro-economic impacts. The study concluded that volumes of alternative fuels would increase, petroleum consumption would decrease, GHG emissions would decrease, and there would be a small (in most scenarios positive) impact on the state economy relative to the business-as-usual (BAU) projection.

Governor Inslee's Executive Order 14-04, directed the Office of Financial Management (OFM) to commission an update to the earlier analysis to reassess the impacts of an LCFS with advice from subject matter experts, affected industries, and public interests. Since the original analysis in 2009, there have been a number of changes to the underlying assumptions including improvements in vehicle fuel economy, reductions in projected vehicle miles travelled, changes in fuel carbon intensity values, changes in low carbon fuel availability and emergence of new low carbon fuels. This report summarizes the assumptions, methodology and findings of this update to the analysis.

The LCFS considered here assumes that transportation fuel carbon intensity will be reduced 10 percent from 2012 levels by 2026, with reductions beginning in 2017 at 0.25 percent. The compliance curve assumes a gentle start to the 2026 goal with minimal reductions required in the first several years (please refer to Figure 4-1).

First, an assessment was performed of the types and volumes of low carbon fuels that could be available for use in Washington state for compliance with an LCFS. Carbon intensity values were then assigned to each compliance fuel pathway. There are an infinite number of combinations of fuels and advanced vehicles that can be utilized to comply with an LCFS.

To bracket the technological and economic range of possible compliance with the standard, four scenarios were developed to bound potential market responses. These scenarios are summarized in Table E-1. Because the scenarios attempt to bound the response to an LCFS, each focuses on a compliance theme: advanced vehicles with mixed biofuels, cellulosic fuels, non-cellulosic fuels. Actual compliance with the LCFS is likely to be somewhere in the middle of the bounding scenarios, possibly including new emerging fuel pathways not part of this analysis.

Table E-1. Description of Bounding Scenarios Used to Evaluate LCFS

Scenario A Advanced Vehicles	Compliance achieved through "ZEV Mandate" levels of electric and hydrogen fuel cell vehicles, and a 50 percent increase in CNG new vehicle market shares. To supplement the low carbon intensity fuels consumed by these vehicles, a balanced mix of additional low carbon biofuels was utilized.
Scenario B Cellulosic Biofuels	Compliance achieved through BAU levels of advanced vehicles and mixed biofuels in the early years, transitioning to cellulosic ethanol and cellulosic gasoline in later years.
Scenario C Minimum Cellulosic, E85	Compliance achieved through BAU levels of advanced vehicles and high volumes of non-cellulosic biofuels. To achieve compliance with a minimum of cellulosic biofuels, more volumes of conventional biofuels are needed. To consume this volume of ethanol, flex fuel vehicles must consume E85 rather than gasoline.
Scenario D Minimum Cellulosic, E15	Compliance achieved through BAU levels of advanced vehicles and high volumes of non-cellulosic biofuels. To achieve compliance with a minimum of cellulosic biofuels, more volumes of conventional biofuels are needed. To consume this volume of ethanol, motor gasoline blend level increases from 10% to 15% (E15).

Each scenario has been evaluated assuming that gasoline and fuels substituting for gasoline comply separately from diesel and fuels substituting for diesel, and that these two fuel pools must comply with the standard each year. We have also evaluated these scenarios assuming that Washington would provide compliance flexibility with banking and trading (B&T) provisions. Banking allows regulated parties to over-comply with the standard in early years and use these banked credits for compliance in later years. Trading allows credits generated in one pool to be freely used for compliance in the other pool.

Figure E-1 compares the 2026 fuel use levels to 2016 BAU fuel use levels. As indicated in the plot, biodiesel consumption is a key to LCFS compliance. It was assumed in all scenarios that by 2026, the statewide average biodiesel blend level would be 15 percent. CNG use increases by a factor of 1.8 for the BAU and Scenarios B-D and 2.7 for Scenario A (advanced vehicles). Electricity use increases by a factor of 2.3 in the BAU and Scenarios B-D and by a factor of 5.3 for Scenario A. Ethanol use increases by a factor of 1.2 to 1.5 for Scenarios C and D relative to 2016 levels, but is only 77 to 80 percent of the 2016 level for the BAU and Scenario A in 2026. In 2026, 90 MGY of cellulosic gasoline is utilized in Scenario B (cellulosic); this isn't shown in the figure since no cellulosic gasoline is utilized in 2016. Relative to the previous analysis, the current analysis projects a larger increase in biodiesel and smaller increases in electricity and CNG consumption.

Without an LCFS, improving fuel economy and a lower forecast of vehicle miles travelled results in a 20 percent reduction in BAU petroleum consumption between 2016 and 2026. The LCFS scenarios modeled predict a 5 to 11 percent reduction in petroleum consumption from 2026 BAU levels. The scenarios yield a 24 to 29 percent reduction in petroleum use from 2016 levels. Figure E-2 provides reductions in petroleum consumption relative to the BAU for 2023 through 2026. The reductions due to the LCFS (scenarios compared to BAU) are similar to the reductions estimated in the previous analysis; however the reductions in the BAU from 2016 to 2026 are significantly larger.

Assuming that credit prices are $100 per tonne and that the entire cost of the credits is added to the price of gasoline and diesel, the LCFS scenarios with banking and trading considered in this analysis result in a projected range of gasoline price increases of 2 cents in 2020 and 10 cents by 2026. Diesel prices are projected to increase by 2 cents in 2020 and up to 12 cents in 2026 (Figure 4-6 and Figure 4-7).

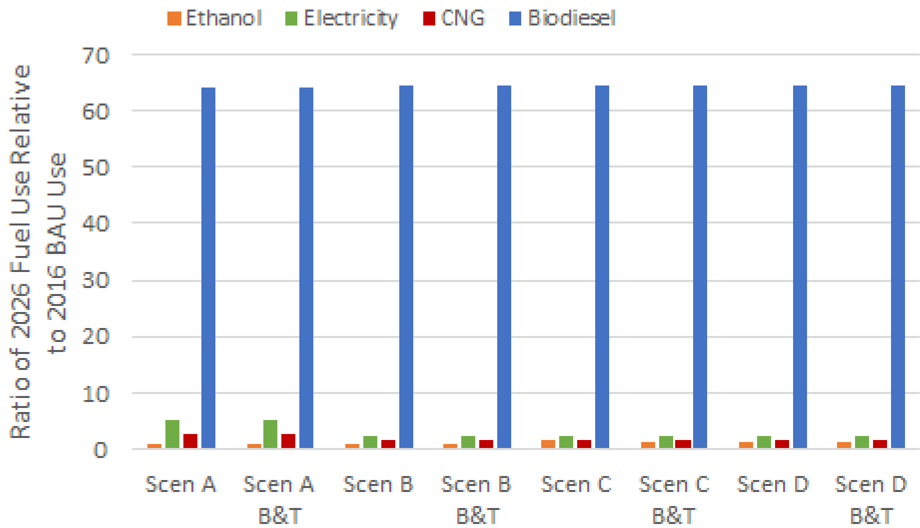

Figure E-1. Ratio of Scenario Fuel Use in 2026 to BAU Fuel Use in 2016.

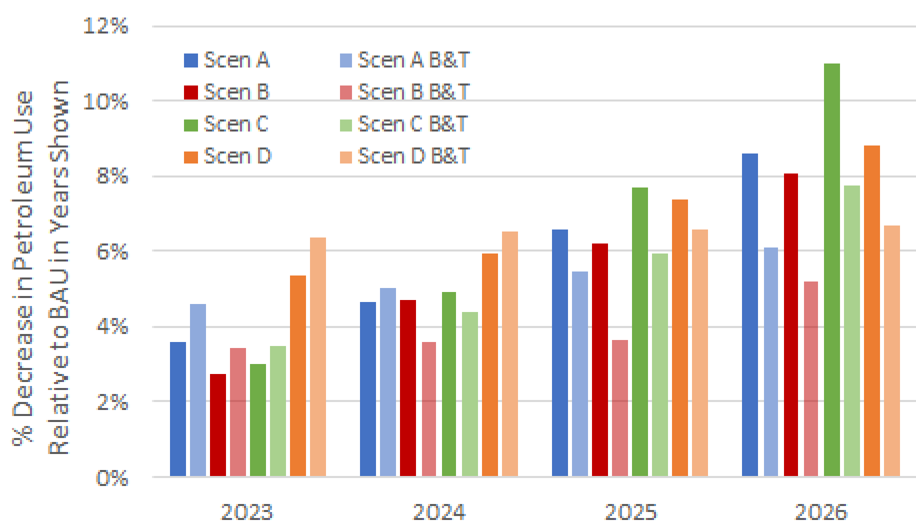

Figure E-2. Reduction in Petroleum Consumption Relative to BAU.

Figure E-3 summarizes the WTW GHG reductions relative to 2026 BAU GHG emissions. These reduction estimates are similar to the previous study. The bank and trade scenarios have lower reductions in 2026, but higher reductions in the early years of the program.

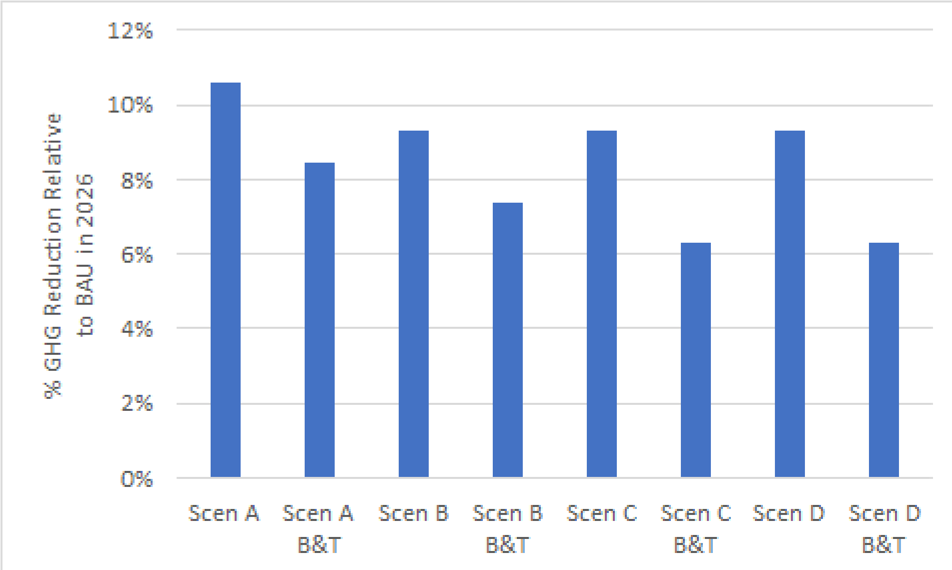

Figure E-3. Decrease in WTW GHG Emissions Relative to BAU in 2026.

Finally, Table E-2 summarizes the macro-economic results for the LCFS compliance scenarios considered in the analysis. Each compliance scenario provides small but positive impacts on employment, personal income and gross state product.

Table E-2. Summary of Macro-Economic Results for Compliance Scenarios.

	Range of Impact Relative to BAU (Units)	Range of Impact Relative to BAU (Percentage)
Annual Average Change in Employment	1,130 - 2,870 Added	0.03% - 0.07%
Annual Average Change in Income	\$82M - \$248M Added	0.02% - 0.06%
Annual Average Change in Gross State Product	\$130M - \$300M Added	0.03% - 0.07%

1. Introduction

In 2008, the Washington State Legislature established greenhouse gas reduction goals to reduced state emissions to 1990 levels by 2020 with additional goals for 2035 and 2050.[1] Because the transportation sector is responsible for almost half of the state's GHG emissions, reductions from vehicles and fuels are fundamental to achieving its goals. One way to reduce greenhouse gas (GHG) emissions from transportation is to implement a Low Carbon Fuel Standard (LCFS) in which fuel carbon intensity is required to meet a declining standard. Carbon intensity is defined as the well-to-wheel carbon emissions per unit of fuel energy content. Well-to -Wheel (WTW) emissions include the emissions produced during feedstock production/recovery, feedstock transport to the fuel production plant, fuel production, fuel transport to the refueling stations and vehicle emissions.

In 2009-11, Washington Department of Ecology's (Ecology) Air Quality Program commissioned an analysis of the implications of launching an LCFS to reduce emissions from the transportation sector.[2] In 2013 a review of the original analysis was conducted to consider the degree to which updated assumptions might alter the original conclusions.[3] Governor Inslee subsequently 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 lower carbon 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 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 effects within the state of Washington of implementing a Washington LCFS.
- Identify and assess various policy mechanisms to avoid escalating fuel costs.

This report describes the analysis performed by the Life Cycle Associates team to evaluate the possible effects of an LCFS in Washington state. Because regulation of carbon intensity does not dictate specific combinations of fuels and vehicles, compliance with the standard could take many forms, depending upon many market forces. To analyze the impacts of an LCFS in Washington state, a scenario analysis approach was adopted, with each scenario focused on significant levels of implementation of a particular strategy. In this way, the analysis attempts to bracket the range of possible compliance; actual compliance would likely have fuel consumption somewhere in between the scenarios and may include new low carbon fuel pathways not currently considered.

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[1] RCW 70.235.020
[2] *A Low Carbon Fuel Standard in Washington: Informing the Decision,* TIAX LLC, 2011
[3] *WA LCFS Analysis: Implication of Updated Assumptions,* Life Cycle Associates, 2013

This analysis has been conducted in a collaborative and transparent manner. Phone conferences were held every other week from late June through early October 2014 to solicit comments and input from stakeholders and to apprise them of progress and assumptions utilized.

This final draft of the report reflects the update made in early October by by OFM's Transportation Revenue Forecast Council to their forecast of vehicle miles traveled (VMT)[4] projections. The new forecast significantly reduces VMT in the later years of the analysis. To be consistent with other transportation related studies being conducted for the state, the new VMT projection has been incorporated into the LCFS analysis.

Section 2 of this report reviews potential supplies of low carbon fuels that could be utilized for compliance, recognizing that there is competition for these fuels from other regions that have and are considering implementing similar standards.

Section 3 provides a discussion of the carbon intensity values for petroleum and alternative fuel pathways utilized in the analysis.

Section 4 describes the structure of the analysis and establishes the underlying assumptions for the Business-as-Usual (BAU) projection of fuel use and vehicle purchases in Washington state. The parameters for each compliance scenario evaluated are also provided.

Section 5 provides the results from the VISION model for each of the compliance scenarios. This includes projections of fuel consumption by type, vehicle sales by technology type, and changes in emissions. Spending on fuel, vehicles and infrastructure required to support low carbon fuels and vehicles is also provided.

Section 6 presents the macro-economic modeling methodology and Section 7 provides the results of the macro-economic modeling of each scenario compared to the BAU case, including impacts on employment, gross state product, and personal income.

[4] http://www.ofm.wa.gov/budget/info/Sept14transpovol4.pdf

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 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 carbon intensity (CI)[5] 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. It is important to note that by design, an LCFS encourages further GHG reductions in existing low CI fuel pathways and development of new low CI fuels. Consistent with the overall conservative approach of this analysis, we do not assume reductions in CI for existing fuel pathways[6] nor do we assume that new fuel pathways are developed during the analysis timeframe (2016-2026).

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 LCFS. For each fuel and feedstock we note how much if any is assumed to be produced in-state. 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. The LCFS is blind to location of fuel production except as it relates to the impact of transport emissions on CI; cost will dictate the source of fuels utilized to comply with a Washington LCFS. This analysis does not employ a cost analysis to determine the geographic source of low CI fuel compliance fuels. Rather, it is assumed that when a low CI fuel is needed for compliance, existing in-state fuel production capacity will be utilized where available. To quantify the impact of assuming in-state production on Washington's economy, a sensitivity analysis is performed for one of the scenarios, comparing the effect of three in-state cellulosic biofuel plants to no in-state cellulosic biofuel plants.

The analysis does try to take into account competing needs for low CI fuels. If Washington and Oregon both implement an LCFS, three states and British Columbia would require low CI compliance fuels. In several instances, estimates of Washington's share of projected available

[5] Carbon intensity of a fuel is defined as the total GHG emissions associated with fuel production (includes feedstock production/recovery, feedstock transport, fuel production, fuel transport and vehicle emissions) per unit energy of finished fuel. Typical units are gCO_2e/MJ.

[6] As discussed in the next section, carbon intensity values are maintained at constant levels throughout the analysis period with the exception of fuels produced in-state; fuels produced in-state have slight reductions in CI over time due to a lower carbon electricity grid and lower projected lifecycle natural gas GHG emissions.

fuel volumes are required. Because Washington consumes 14 percent of the gasoline and diesel consumed in California, Oregon, Washington and British Columbia[7], 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 available low CI fuel volumes could come to Washington State.

Table 2-1 summarizes the low CI fuel availability assumptions utilized for the scenario analysis exercise. It is important to be clear that the volumes in the table are not projections of fuel volumes that will be needed in Washington State to comply with an LCFS; rather these volumes give an upper limit to what could be available if needed. More detailed discussion for each fuel type, including terms used in the table, sources consulted, and rationales for specific assumptions follows in the paragraphs below. Assumptions regarding additional required infrastructure and vehicles to support needed supply appear later in the report.

Table 2-1 Summary of Potential Fuel Supply in 2026

Fuel Pathway	2026 Potential Supply	Notes
Ethanol	Consumption limited by amount that can be blended into motor gasoline and the number of FFVs that can consume high level blends.	
Conventional Corn	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	Based on 14% of EIA AEO2014 projection
Molasses	20 MGY	ARB has registered ~ 100 MGY. Assume capacity grows 3%/yr and that Washington receives up to 14%
Cellulosic	63 – 300 MGY (eth gallons)	Low end is EIA projection for RFS2, high end is UC Davis "Leapfrog" potential. Assumes 50% of total cellulosic volume is as ethanol (in ethanol gallons)
Cellulosic Gasoline and Cellulosic Diesel "Drop-in-Fuels"	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 drop-in fuel (gal gasoline equiv).
CNG (gallons gasoline equiv)		
Fossil	Sufficient	Limited by vehicle sales and refueling station capacity
Renewable	170 MGY	16 MGY existing pipeline injection capacity in-state
Hydrogen	Sufficient	Limited by vehicle sales and refueling station capacity
Electricity	Sufficient	Limited by vehicle sales and charging infrastructure
Biodiesel (gal biodiesel)	Sufficient	In-state production capacity is 108 MGY. A B15 blend in 2026 requires ~ 73 MGY.
Used cooking oil, tallow	22 MGY	Washington state feedstock supply, though could source from out-of-state
Vegetable Oil	100 MGY	Washington biodiesel production capacity
Renewable Diesel	0	Assume that California attracts all renewable diesel

[7] 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).

2.1 Conventional Corn 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[8] 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 percent denatured ethanol by volume in motor gasoline. EPA has approved the use of E15 in model year 2001 and newer vehicles. In the BAU we have assumed that motor gasoline contains 9.6 percent denatured ethanol. One of the compliance scenarios assumes that the motor gasoline blend level ramps up in a linear fashion to E15 by 2025. The rest of the compliance scenarios assume that motor gasoline is E10.

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

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

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.

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.[9] It may be that total supply of sorghum/wheat ethanol is greater than the amount that has been consumed in California to date. For this analysis, we make the assumption that total volume grows by 3 percent per year (approximately 80 MGY additional supply) and that 14% of it could 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, that this volume grows by 3 percent per year (an additional 40 MGY by 2026), 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.[10] The AEO projection dips after 2022, likely due to uncertainty about continuation of EPA's RFS2[11]. We have smoothed the projection here and assume that up to 14 percent is available for use in Washington state (146 MGY by 2026).

[8] Jerry Buendel, Washington State Department of Agriculture, Weights and Measures Program
[9] Low Carbon Fuel Standard Reporting Tool Quarterly Summaries
[10] Annual Energy Outlook 2014 (AEO2014)
[11] Please refer to discussion of AEO2014 cellulosic fuel projection in Section 2.4

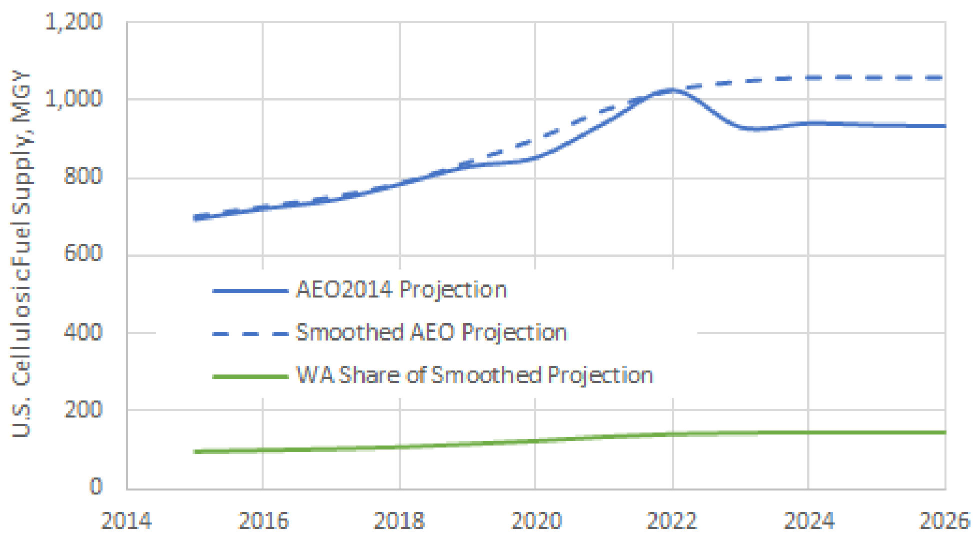

Figure 2-1. Projected sugarcane ethanol imports.

2.2 Biodiesel

Biodiesel is produced from waste oils (used cooking oil and tallow) and a variety of vegetable oils (soybean, canola, corn). Despite 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 percent.[12] A 15 percent average blend level corresponds to approximately 73 MGY of biodiesel in 2026. It is assumed this biodiesel is consumed as B20 and lower level blends. Washington's installed production capacity is provided in Table 2-3. Because current in-state production capacity is substantially greater than future demand, we have assumed that all biodiesel consumed is produced in-state.

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

For the macro-economic modeling exercise, we need to make assumptions regarding biodiesel feedstock sources. Table 2-4 provides the estimated quantities of in-state feedstock potential. Canola oilseed production in 2013 was 30,600 tons[13], 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. We assume here that up to 43 MGY of canola oil biodiesel is available for use.

[12] 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.

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

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 by 2026 and 12 MGY of tallow biodiesel are available for use. The 2026 used cooking oil quantity assumes some growth from current estimates of supply.

Table 2-4. Biodiesel Feedstock Supplies

Feedstock	Current 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

Corn oil is 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 35 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 of soybean oil is available for use in the state.

2.3 Renewable Diesel

Renewable diesel (RD) 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. RD is produced through hydro-treating vegetable or waste oils. California has had significant imports of used cooking oil and tallow based renewable diesel in the last several years for compliance with its LCFS.

In California there is concern that biodiesel blended with CARB diesel causes increased tailpipe NOx emissions; it appears that biodiesel blended into the diesel formulation utilized in Washington state does not have the same effect.[14] ARB is currently working on a rule to address the issue of elevated NOx emissions from biodiesel use. The potential remedies include use of approved NOx control additives, approved biodiesel formulations, or blending with a "B20-ready" diesel fuel. Because RD does not increase NOx emissions, California will likely preferentially utilize RD over biodiesel for compliance with the LCFS. We have therefore assumed in our compliance scenarios that no RD is available in Washington state.

[14] *Effect of Biodiesel Blends on North American Heavy-Duty Diesel Engine Emissions,* Yanowitz and McCormick, Eur. J. Lipid Sci. Technol. 2009, 111, 763–772.

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 LCFS. 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 given that the price signal is sufficient to cover the required investments.

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.[15] It is reasonable to assume that with consistent and sufficiently strong regulatory signals, the volumes produced and consumed could increase. With RFS2 2014 final rules still pending, they are not available as a signal for future policy. However, administration commentary and funding from other departments continue to support cellulosic fuel development. We have assumed here that the shape of the increase is similar to the AEO2013 "liquids from biomass" projection (in yellow). The "liquids from biomass" category includes cellulosic fuels, so it is a reasonable proxy for cellulosic ethanol growth rate. This extension results in 450 MGY of cellulosic ethanol in 2026.

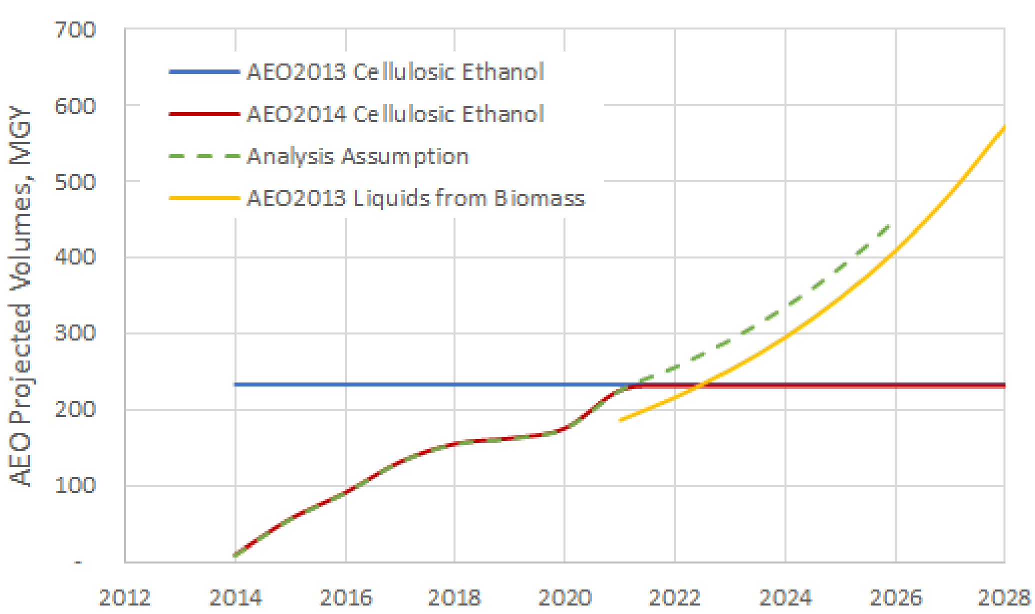

Figure 2-2. EIA cellulosic ethanol consumption projections.

[15] 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.

Figure 2-3 provides the AEO2013 and AEO2014 "liquids from biomass" projections. The "liquids from biomass" category includes Fischer-Tropsch fuels from biomass feedstocks as well as pyrolysis based gasoline and diesel.[16] 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. We note here that cellulosic gasoline would need to be registered with EPA and possibly go through a multi-media impact analysis before it could be sold.

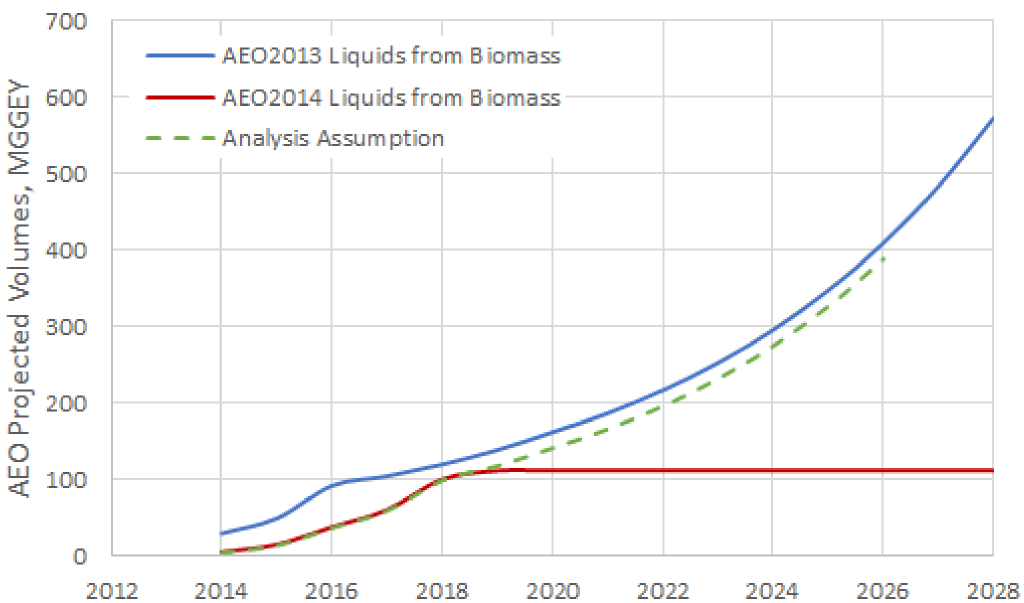

Figure 2-3. EIA cellulosic gasoline and diesel consumption projections.

In addition to EIA projections, other organizations have projected U.S. cellulosic fuel volumes. For example, E2[17] 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[18] 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 LCFS. 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.

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

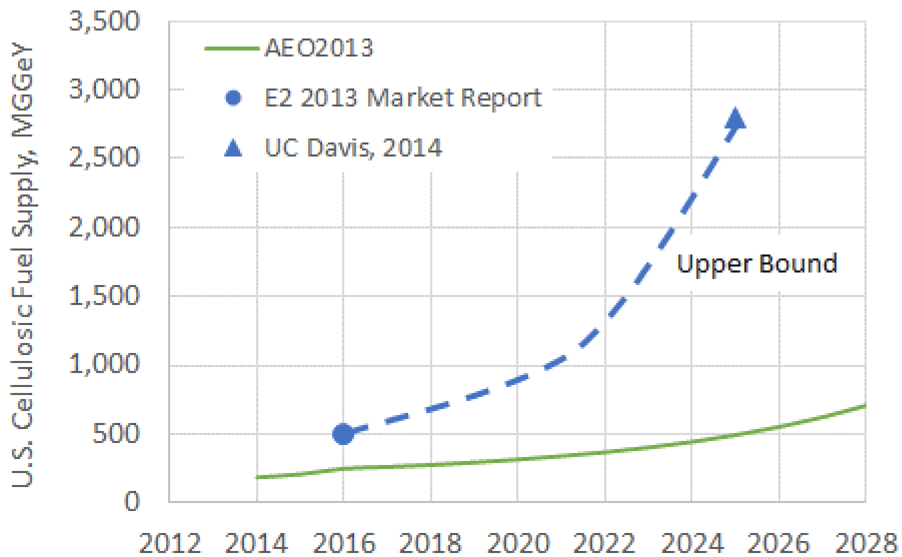

Figure 2-4. Range of predicted cellulosic biofuel availability.

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.[19] have projected that by 2030, 2.24 million tonnes of sustainably removed straw could 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[20] 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[21] estimates that by 2025 between 1.2 and 2 million bone dry tons of woody biomass could 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

[19] "Sustainable agricultural residue removal for bioenergy: A spatially comprehensive US national assessment", D.J. Muth Jr., K.M. Bryden, R.G. Nelson, October 2012.
[20] 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.
[21] Washington Forest Biomass Supply Assessment, Washington Department of Natural Resources March 2012.

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. It is important to note that these volumes have not been determined based on a comparative economic analysis; it is assumed that these feedstocks/fuels will be cost competitive under the LCFS scenarios (although the feedstock quantities are based on a modest feedstock price).

2.5 CNG

One of the lower CI fuels considered for transportation in the scenario analysis is natural gas. Because the VISION model does not have an LNG vehicle category we have made the simplifying assumption that CNG is a proxy for any natural gas consumed as LNG. The carbon intensity values are similar and the quantities are likely low in the short-run, so the impact of this assumption on the analysis results is negligible. 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 pipeline injected RNG to CNG pathways registered with the California LCFS. Table 2-5 summarizes the current and potential pipeline quality 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 more than sufficient for projected 2026 consumption.

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

Feedstock	Current Capacity pipeline injection 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 assumptions about 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. Note that electricity consumed by electric rail is not included here; California's program will allow electric rail to opt-in to the program, generating credits for use in compliance.

3. Carbon Intensity Estimates

When comparing alternative fuel GHG emissions, total emissions occurring over the entire fuel cycle need 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. WTT emissions include feedstock production/recovery, transport of the feedstock and other inputs to the fuel production plant, emissions from the fuel production plant, and transport of the fuel to the vehicle. For example, the WTT emissions associated with ethanol production from corn include all of the farming inputs (tractor fuel use, fertilizer and other agricultural chemical production and transport emissions), transport by truck to the ethanol plant, fuel production emissions (fuel combustion, electricity use, credits for displacing soybean meal with co-products), transport of the ethanol to the fuel terminal, and then transport by truck to refueling stations. 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); carbon intensity is referred to as CI throughout this report.

To estimate WTT CI values for a selection of transportation fuels, the most recent version of Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model was utilized (GREET1_2013 released in October 2013).[22] GREET is a widely used, publicly available, Microsoft Excel based model. EPA and ARB have used GREET to support transportation policy. ARB adapted an earlier version of the GREET model for use in establishing CI values for the California LCFS. This model is referred to as CA-GREET. ARB is in the process of transitioning to CA-GREET2 which is an adaptation of the GREET1_2013 version of the model. Because GREET's default inputs are average values for the U.S., we have made modifications to reflect Washington state conditions.

The GREET model is utilized to quantify WTT emissions. TTW emissions are assumed to consist of CO_2, N_2O and CH_4. CO_2 emissions are dictated by fuel carbon content and published emission factors for tailpipe N_2O and CH_4 emissions are utilized. WTT and TTW emissions are direct emissions. Indirect emissions associated with land use change (ILUC) are also included where appropriate. ILUC emissions arise when demand for a feedstock (e.g. soybeans for biodiesel production) diverts crops away from their prior use (food/feed) to fuel. To compensate for the loss of soybeans to fuel production, cultivation of some other crop occurs on other land. This incremental cultivation may result in carbon emissions that are an indirect result of biofuel production. Quantification of ILUC values requires the use of general equilibrium models. ARB and EPA have both estimated ILUC values for biofuels. For this analysis we have utilized preliminary updated ILUC values presented by ARB in March of 2013. Recent ARB updates to the ILUC estimates are lower than the March values utilized in this analysis. Lower ILUC values would mean that we have over-estimated the quantity of low CI biofuels needed for compliance.

[22] Argonne has released a new version of the GREET model since this analysis was initiated; GREET1_2014 was released on October 3, 2014.

Throughout this report, CI values are used to refer to these estimates of lifecycle carbon intensity used in the policy (which may deviate from actual impacts due to measurement error, or uncaptured variation and market feedback effects). 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	Blaine	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.

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 2011	**2012**	2013	On-Road Diesel 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.[23] In 2012 there were no imports from other PADDs[24] into Washington, however there were shipments from Alaska to PADD 5 which includes Washington, Oregon, California, Arizona, Nevada, and Hawaii. Since there is no refining capacity in Oregon, Arizona, and 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.[25] 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.

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%		

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

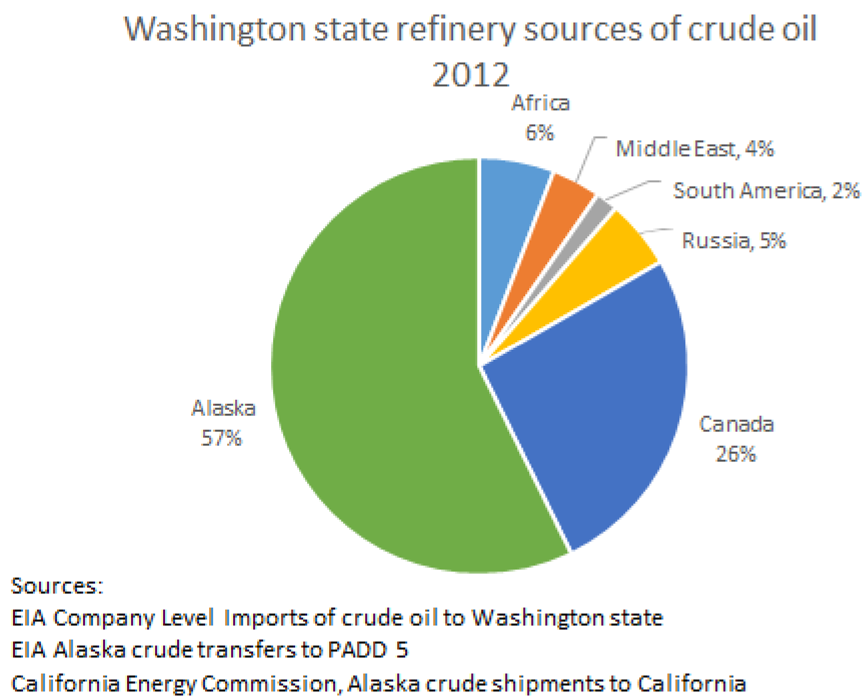

Figure 3-1. Sources of Crude Oil Supplied to Washington State in 2012 by Region.

It is also important to determine how much of the crude oil sourced from Canada is conventional and how much is oil sands crude because recovery of oil sands crude is more energy intensive than recover of conventional fuels. 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[26], so this mix is representative of the Canadian crude in Washington. Approximately half of the crude is conventional, half is from oil sands.

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

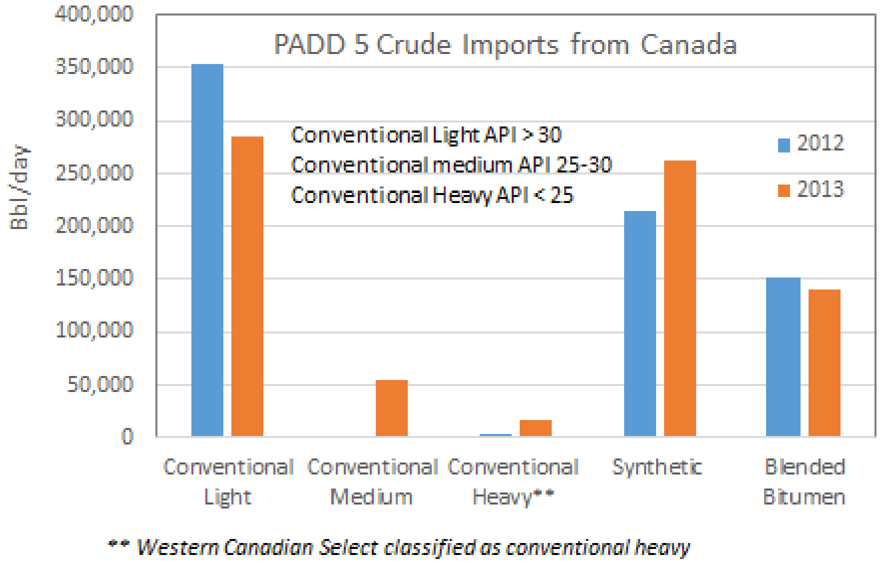

Figure 3-2. PADD 5 crude imports from Canada by type.

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.[27] The types of crude oil imported from Canada into PADD 4[28] 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%

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

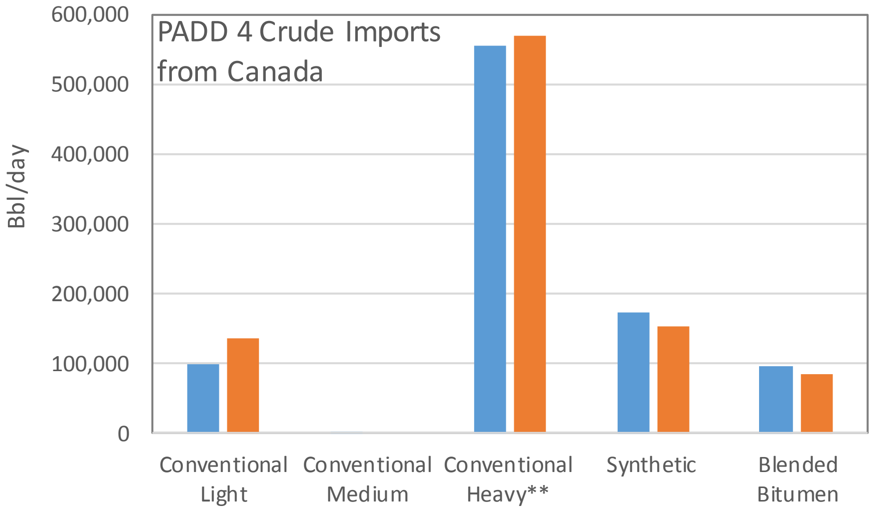

Figure 3-3. Types of crude oil imported from Canada to PADD 4.

Crudes Refined in Utah

Table 3-5 provides pipeline crude oil receipts by source.[29] 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) because Utah is also PADD 4. 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[30] to quantify carbon intensity for crude oil recovery and transport by oil field.

[29] Utah Geological Survey, http://geology.utah.gov/emp/energydata/oildata.htm#refinery

[30] https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator

We utilized the most recent version of the OPGEE model (Version 1.1 Draft C) 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 a simple unweighted 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. For the 2012 baseline, only Montana utilized a small amount (3 percent from Montana) of crude that may have been recovered using hydraulic fracturing. Since gasoline and diesel from Montana represent only 12 percent of the fuel consumed in Washington, no more than 0.36% of the fuels consumed in Washington in 2012 were produced from crude oil recovered with hydraulic fracturing. Moreover, since crude recovery is a small fraction of the total gasoline and diesel lifecycle carbon emissions, if carbon emissions from hydraulic fracturing are significantly different from conventional recovery, only a small error would be introduced into the baseline values.

Although the most recent complete set of petroleum data (2012) did not include delivery of North Dakota crude by rail to Washington, we note that Washington is currently receiving shale oil from North Dakota and this is anticipated to continue. If Washington adopts an LCFS, the petroleum carbon intensity values should be updated regularly. The baseline carbon intensity values might also be updated.

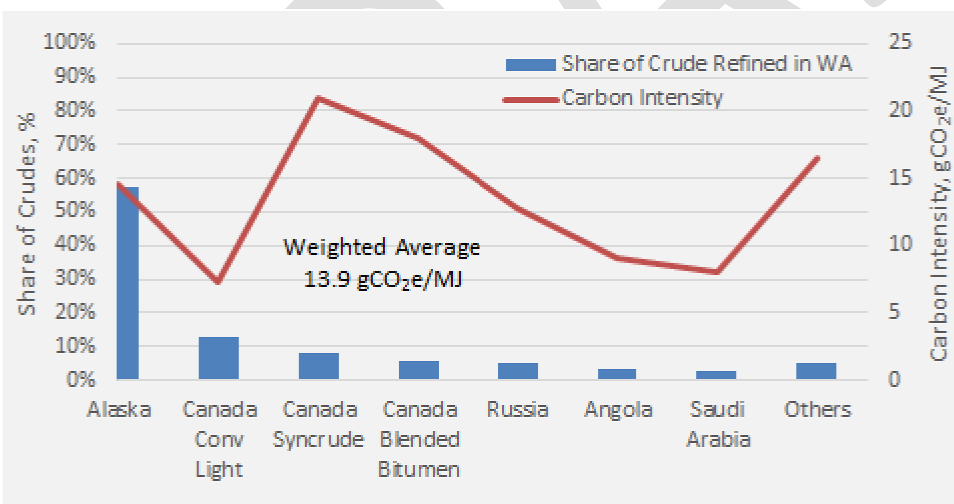

Figure 3-4. Average CI for crude oils refined in Washington.

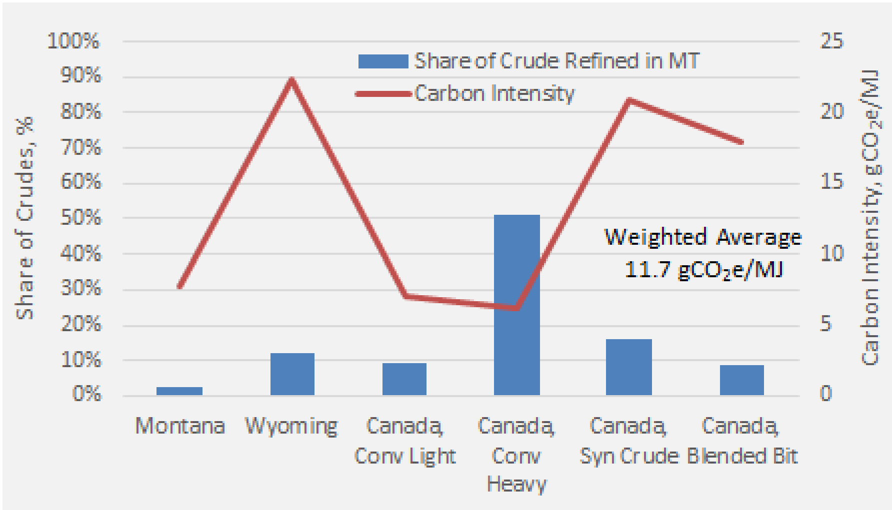

Figure 3-5. Average CI for crude oils refined in Montana

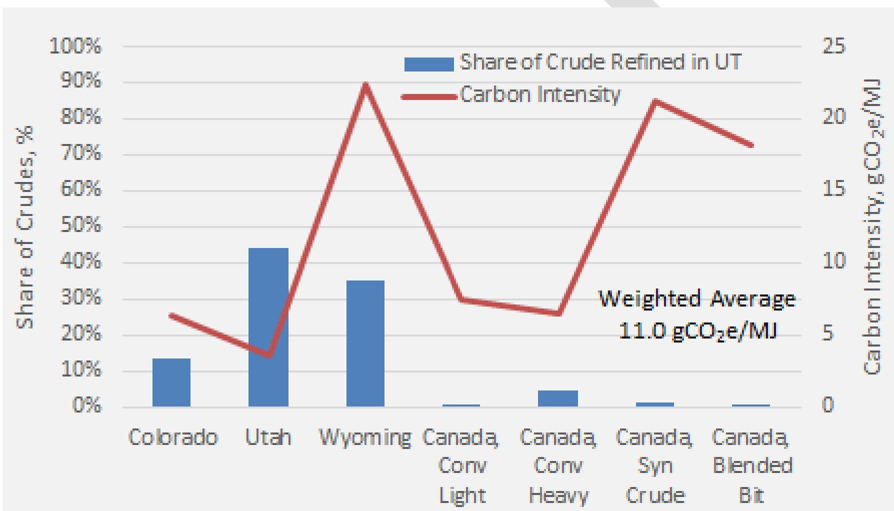

Figure 3-6. Average CI for crude oils refined in Utah.

3.1.4 Refining and Finished Fuel Transport Emissions

The WA-GREET1 model was utilized to calculate crude refining and transport carbon emissions per unit of fuel produced. Carbon emissions for gasoline and diesel production are based on an assumed value for refining efficiency. Refining efficiency dictates the amount of fuel consumed per unit of fuel produced. The GREET model calculates refining efficiency based on crude API and sulfur content. If these values are unknown, GREET supplies average API and sulfur content values depending on crude oil source. The GREET calculated refining efficiencies based on crude oil source 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 total fuel consumed (calculated from refining efficiency) 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. Natural gas utilized in the western half of the state comes from the northeastern portion of British Columbia and travels south and west, connecting to the northwest pipeline system in Sumas. The pipeline distance is estimated at 700 miles. To date there has been no commercial hydraulic fracturing in Canada[31], so we have assumed that all natural gas consumed in Washington is conventional natural gas.

Montana is a net exporter of natural gas, but because of infrastructure limitations, all natural gas consumed is from Alberta.[32] The pipeline transmission distance from Alberta to Butte and then Billings is estimated at 700 miles; the natural gas is recovered conventionally. Natural gas utilized in Utah refineries is from the Uinta basin[33] and is all recovered through hydraulic fracturing. The assumed pipeline transport distance is 100 miles.

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.[34]

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.

[31] http://www.capp.ca/canadaIndustry/naturalGas/ShaleGas/Pages/default.aspx
[32] http://deq.mt.gov/ClimateChange/Energy/EnergySupply/OilGasProduction.mcpx
[33] Phone conversation with Carolyn Williams, State of Utah, Department of Natural Resources, 6-20-14
[34] http://www.eia.gov/electricity/data/state/

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

3.1.5 Vehicle Emissions

Tailpipe GHG pollutants consist of CO_2, N_2O and CH_4. The tailpipe emissions for gasoline and diesel are provided in Table 3-10.

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

ear decrease to the 2020 values.

Table 3-11 summarizes the carbon intensity estimates for 2012, the year utilized to develop the LCFS 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 blendstock and diesel in 2012 are estimated at 100.7 and 101.7 gCO_2e/MJ, respectively. These values are utilized for establishing the CI baseline. Because the electricity grid reduces its carbon intensity over time (please refer to the electricity section below) and because the natural gas CI values decrease slightly as well, gasoline and diesel WTT emissions experience slight decreases. Gasoline blendstock decreases to 100.6 g/MJ in 2020 while diesel decreases to 101.6 g/MJ. We set the 2015 values equal to the 2012 values and assumed a linear decrease to the 2020 values.

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	
% of Washington Consumption	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

3.2 Ethanol

For the scenario analysis exercise, ethanol produced from a range of feedstocks was considered. Because denatured ethanol (ethanol blended with a small amount of gasoline) rather than neat ethanol is blended with gasoline blendstock to produce motor gasoline, we present denatured ethanol carbon intensity values here. For the analysis we assumed that denatured ethanol consists of 2% gasoline and 98% neat ethanol on a volume basis. The quantification methodology and denatured CI value for each ethanol feedstock type are provided in Table 3-12.

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 model output is utilized as the 2015 CI value. 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 the low carbon corn and corn+ pathways are based on reported average values for fuels sold in California,[35] 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. Although it is possible that the CI values for low carbon corn and corn+ could be reduced further during the analysis timeframe, we have refrained from speculation and kept these values constant through 2026.

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

The molasses ethanol pathway CI is a simple 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 the CI values were set in the analysis, ARB had not posted any cellulosic fuel pathways, so the GREET1 default values for corn stover (proxy for wheat straw) and forest residue ethanol were utilized (15 g/MJ). ARB has recently posted a cellulosic ethanol pathway at 7 gCO_2e/MJ, so 15 gCO_2e/MJ assumed for the analysis is slightly higher, but a conservative value is appropriate given the uncertainty associated with the range of feedstocks that could be used for future cellulosic ethanol production. The default value assumes 800 rail miles of transportation to the petroleum terminal and 30 miles by truck to the refueling station, adding approximately 1 g CO_2e/MJ. We have conservatively assumed that this value remains constant throughout the analysis period. Neither of these feedstocks induce ILUC emissions.

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
CA LCFS Average 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. ARB ILUC Workshop on March 10, 2013 (23.2 g/MJ)
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 methodology employed for the cellulosic ethanol pathway, we have utilized the average GREET1_2013 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.

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. Because all biodiesel is assumed to be produced in-state, the electricity grid mix and natural gas consumed utilize Washington specific inputs (described above in the petroleum refining section). 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[36] 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.

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

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

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. We have utilized the pipeline injection pathway for RNG because this method is already practiced in Washington state. 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. Note that this newer version of the GREET model estimates higher CI values than the previous version originally utilized by ARB due to increased estimates of methane leakage. ARB's updated values calculated with the CA-GREET2 are also higher than the previous values.

For LFG, the ARB inputs for LFG recovery energy use and fuel shares were utilized. For WWT, the GREET defaults for energy use were utilized. The HSAD value developed by ARB[37] was utilized directly; HSAD has much lower CI than LFG because it receives a credit for avoiding the landfill entirely (methane leakage and flaring) while the LFG pathway receives a credit for avoided flaring only.

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 and updating these values would be a worthwhile exercise.

Table 3-15. Summary of CNG carbon intensity values utilized in the 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

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

3.6 Electricity

Due to large amounts of hydro, Washington enjoys some of the lowest carbon electricity in the country. Figure 3-7 provides the 2012 resource mix. Despite the low carbon grid mix, Washington has an existing renewable portfolio standard (RPS) 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 GREET calculated CI value (without EER applied) for 2015 is 50.1 gCO_2/MJ, decreasing to 44.0 gCO_2e/MJ in 2020. These values have been utilized to calculate CI values of fuels produced in-state (gasoline, diesel, CNG, biodiesel). With the assumed EER of 3.4,[38] this corresponds to a CI for electric vehicles of 14.7 gCO_2e/MJ and 13.0 gCO_2e/MJ for 2015 and 2020, respectively.

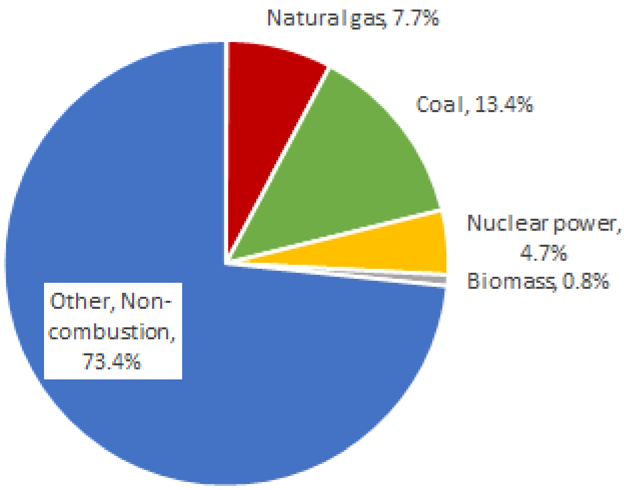

Figure 3-7. Washington State 2012 electricity resource mix.

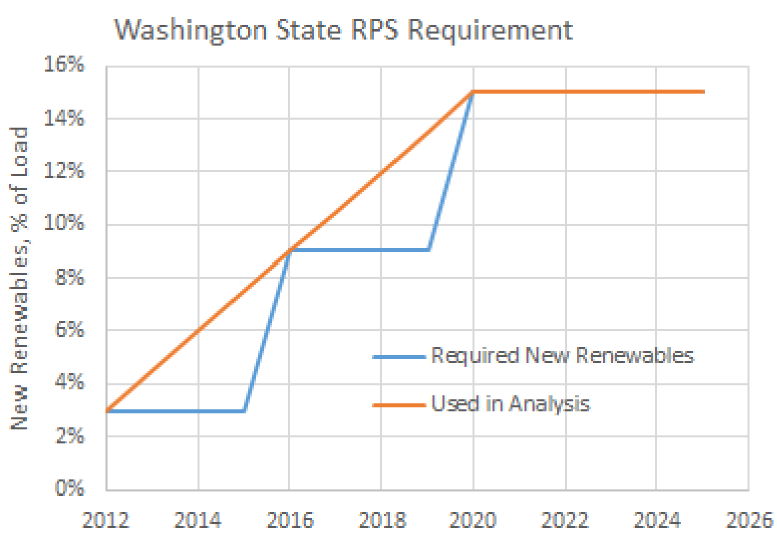

Figure 3-8. Renewable Portfolio Standard requirement.

[38] Consistent with ARB's LCFS assumption. Please refer to Vehicle Fuel Economy section in the Appendix for more information on EERs.

The California LCFS Lookup Table provides two electricity CI values. One value reflects the estimated average grid resource mix and the other value is a "marginal" mix. The marginal mix was developed to reflect the resources that would come online to service a new sustainable long-term load. It was determined that these resources are combined cycle natural gas turbines combined with new renewables needed to comply with California's renewable portfolio standard. Electric utilities creating LCFS credits; either the average or marginal value may be utilized.

The electricity CI values developed for Washington state reflect the average grid mix. Determining the resource mix that corresponds to "marginal" depends upon the definition of marginal. Marginal could mean the resources that are online when electric vehicles are charged. If this is the definition of marginal, then the resource mix would consist of hydro and nuclear, nearly zero carbon resources. However, not all EVs will charge at night and as workplace charging becomes more common place, daytime charging will be more prevalent.

If marginal is defined as the generation that would come online to service a new sustained load, it could be natural gas combined cycle combined with RPS, the ARB marginal approach. However, the Northwest Power and Conservation Council[39] evaluated several very aggressive EV penetration scenarios and found that no new generation capacity would need to be installed to support the load. All new demand would be met by ongoing conservation efforts. We assume here that conservation, results in an even reduction in generation across resource type, so in this definition of marginal, the average grid mix is appropriate.

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 (taken from ARB), 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

Table 3-16 summarizes the carbon intensity estimates for 2015 described in the paragraphs above. Values for 2020 are also provided. All values are assumed constant from 2020 through 2026. This assumptions results in slight over-prediction of the quantity of low CI fuels required for compliance.

[39] Northwest Power and Conservation Council Sixth Power Plan (pp 3-12 – 3-15)

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

Fuel Pathway	2015					2020
	WTT	TTW	WTW	ILUC	Total	Total
Petroleum						
Gasoline Blendstock	26.2	74.5	100.7	0.0	100.7	100.6
Low Sulfur Diesel	26.0	75.6	101.7	0.0	101.7	101.6
Denatured Ethanol						
Average MW Corn	63.4	3.1	66.5	22.5	89.0	86.2
CA LCFS Average Corn			62.7	22.5	85.2	85.2
Corn+			40.5	17.5	58.0	58.0
Brazil Sugarcane	14.9	3.1	17.9	25.7	43.6	37.2
Molasses			30.0	0.0	30.0	30.0
Cellulosic			15.0	0.0	15.0	15.0
Cellulosic Gasoline					17.0	17.0
CNG						
Fossil	14.8	58.8	73.6	0.0	73.6	73.5
LFG	-51.1	58.8	7.7	0.0	7.7	7.2
WWT	-49.3	58.8	9.6	0.0	9.6	11.1
HSAD					-15.3	-15.3
Electricity (w/o EER)	50.1	0.0	50.1	0.0	50.1	44.0
Hydrogen (w/o EER)	102.4	0.0	102.4	0.0	102.4	101.6
Biodiesel						
MW Soybean	26.6	4.0	30.5	30.2	60.7	60.4
Canola	31.7	4.0	35.7	41.6	77.3	77.1
UCO	14.3	4.0	18.3	0.0	18.3	18.1
Tallow	25.7	4.0	29.7	0.0	29.7	29.4
Corn Oil (dry DGS)			4.0	0.0	4.0	0.0

4. BAU and Scenario Definition

To better understand the range of possible economic effects if an LCFS was adopted in Washington state, a scenario analysis was conducted. First, a Business-As-Usual (BAU) projection of vehicle sales and fuel consumption was developed. Next, rather than trying to project the actual fuel mix that achieves compliance with the standard, a set of compliance scenarios were designed to be technologically feasible and to bound the range of possible compliance strategies. 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 LCFS

For the purposes of this analysis, we assume that the Washington LCFS 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 (ethanol, cellulosic gasoline, electricity, hydrogen, and CNG). The diesel pool consists of all diesel fuel utilized as well as compliance fuels consumed by heavy duty vehicles (biodiesel, CNG). This analysis includes only on-road transportation fuels; marine, rail, aviation and off-road equipment fuel use is not included.

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 an average of 9.72% ethanol on a volume basis[40]. 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. Note that opt-in fuels (electricity, CNG) are not included in the baseline.

The diesel carbon intensity value for 2012 is 101.7 gCO_2e/MJ. It is estimated that diesel contained 0.22% biodiesel in 2012[41] and that the biodiesel was 50% soybean, and 25% used cooking oil, and 25% canola.[42] The resulting average biodiesel CI is 53.3 gCO2e/MJ. When blended with diesel, the on-road diesel baseline value is 101.6 gCO2e/MJ. Figure 4-1 provides the assumed shape of the compliance curve, showing annual percentage CI reductions required relative to the 2016 gasoline and diesel baselines.

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

[41] 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.

[42] Biodiesel Shares from Leidos CLEW Report, Oct 2013.

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)

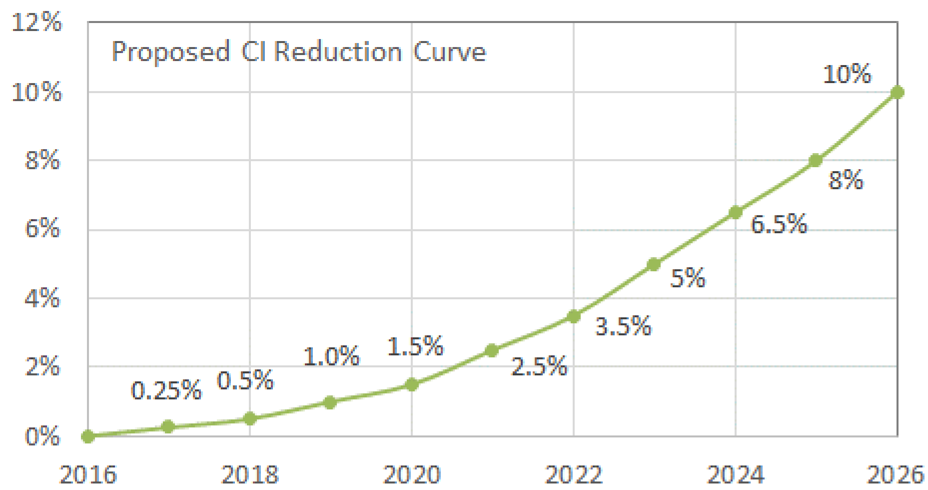

Figure 4-1. Assumed shape of the LCFS compliance curve.

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 conservative estimates of required low CI fuel volumes. The separate compliance and adherence to the standard each year is conservative because Washington state representatives have indicated that if a LCFS 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 in early years for use at a later date. To estimate the required low CI fuel volumes under this more flexible program, we have also run the compliance scenarios with banking and trading in place.

4.2 Potential Cost Containment Mechanisms

In an LCFS, regulated parties are required to reduce the average carbon intensity of the fuels they provide over a period of 10 years. For each energy unit of fuel sold, either credits or debits are generated. If the fuel sold has a carbon intensity below the standard, then credits denominated in tonnes are generated. The quantity of credits is simply the difference in g/MJ between the standard and the CI of the fuel sold multiplied by the quantity of fuel sold (in MJ) divided by 1 million grams per tonne. Conversely, if the fuel CI is higher than the standard, then debits are generated. At the end of each compliance year, regulated parties must offset all debits with credits. Any surplus credits may be sold or traded to another regulated party for use in compliance.

One potential concern with an LCFS is whether it will cause fuel prices to increase as a result of low CI fuel supply shortages which drive up the price of credits. As credit prices increase, the amount of money that low CI fuels command also increase, increasing the price of fuel at the pump. Washington state has signaled that if an LCFS is implemented, it would have credit banking and trading provisions to increase compliance flexibility. Trading provisions would allow credits created in the diesel pool to be utilized for compliance in the gasoline pool and vice versa. Banking provisions allow extra credits created in the early years of the program through over compliance to be used for compliance in later years.

In addition to banking and trading provisions, other mechanisms can be employed to help contain costs. ARB and UC Davis recently reviewed several different cost containment mechanisms; this section of the report describes the leading mechanisms considered by ARB: the credit window option and the credit clearance option. The approach employed to incorporate cost containment into the modeling effort is discussed later in Section **Error! Reference source ot found.**.

4.2.1 Credit Window and Non-Compliance Penalty Mechanisms

In the Credit Window option, if credits are not available in the market for purchase, regulators would provide credits for sale at a specified price. Revenue from credit sales would subsequently be utilized to incentive production of low CI fuels. In the Non-Compliance Penalty option, if regulated parties are unable to acquire sufficient credits for compliance, a $/tonne penalty would be assessed. Revenues from penalties would be utilized to incentive production of low CI fuels. In practice, these two mechanisms are equivalent – the credit window price and the penalty cost act as a credit price cap.

These two mechanisms provide certainty to the market with a known maximum cost of compliance; they also incentivize investment in low CI fuel production. However, neither mechanism ensures that the LCFS GHG emission reductions occur, although if the LCFS is a subset of a larger cap and trade program, the reductions originally planned for the transportation sector would be provided by a different sector. Another potential disadvantage is that the regulator would need to administer distribution of credit window/penalty revenue. Finally, regulated parties likely prefer the credit window option to the penalty option since there is a stigma associated with being out of compliance.

4.2.2 Credit Clearance

In the Credit Clearance option, at the end of each reporting period, regulated parties report the number of credits required for compliance. If an overall credit shortage exists, regulators establish a maximum credit price (credit cap) and issue a call for available credits at that price. Credit holders pledge the number of credits they will supply at up to the price cap. The regulated parties then negotiate directly with credit holders to purchase credits. If more credits are pledged by credit holders than are needed, then all regulated parties will be in compliance after purchasing these credits at a price not to exceed the cap. If there are not enough credits pledged at the price set by the regulator, then each regulated party purchases their share of the pledged credits. The remaining deficit would roll to the next year.

The Credit Clearance option is similar to the credit window/penalty option in that the maximum cost of compliance is known. The main benefit of the credit clearance option over the previous two mechanisms is that in the long run, all LCFS GHG emissions reductions are achieved. Because this mechanism ultimately requires all CI reductions to occur, the regulation is more durable, encouraging investment in low CI fuel production capacity. Another feature of this mechanism is that it allows direct negotiation between the regulated parties and the low CI fuel providers, possibly fostering mutually beneficial relationships.

4.2.3 Ceilings and Floors

Each of the mechanisms discussed above employs a cost ceiling to prevent credit price spikes. Setting the price of the cap is extremely difficult. The cap needs to be high enough so that it incentivizes investment in low CI fuel production capacity. It also needs to be high enough so that it is not routinely triggered. However, the cap shouldn't be set so high that it increases the price of fuel above acceptable levels if triggered.

Establishing a floor or minimum price for credits provides low CI fuel producers with certainty on minimum returns, facilitating financing for installing new production capacity. However, a credit price floor is difficult to implement in practice. If credit price dropped below the floor, then the regulator would need to reduce the supply. This could be accomplished by purchasing and retiring credits or by reducing the face value of credits. This seems to be a difficult and potentially costly mechanism for the regulator to administer. It would also be difficult to set the value of the floor – if the value is too high, it artificially inflates the cost of low CI fuels and if it is too low, it does not incentivize investment in low CI fuels.

4.3 Business-as-Usual Forecast

The VISION[43] 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, transitioning to 35 percent soybean oil, 30 percent UCO, 30 percent canola, and 5 percent corn oil in 2020. We assume all CNG use is fossil based; all developed pipeline RNG is sold into LCFS markets.

These assumptions result in slight carbon intensity declines in the BAU, mainly for the gasoline pool, due to increased sales of EVs and CNG vehicles (Figure 4-2). The figure also provides corresponding GHG[44] emission reductions calculated based on assumed CI values for the fuels used. Both gasoline and diesel pool emissions decrease because of the combined impact of reduced CI and reduced gasoline and diesel consumption (please refer to Appendix A for fuel consumption projections). The BAU achieves 1.4 percent CI reduction in the gasoline pool and 0.2 percent CI reduction in the diesel pool by 2026, compared to the 10 percent that would be achieved by an LCFS.

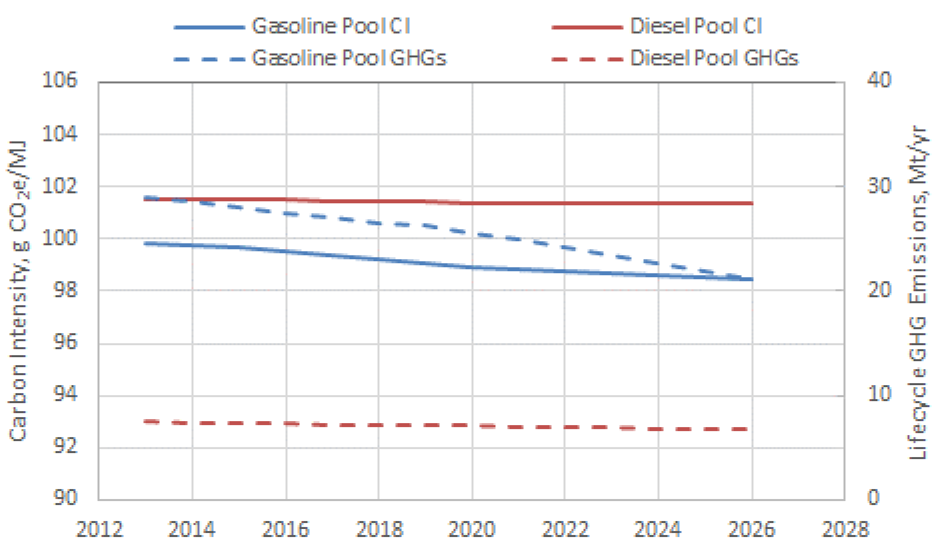

Figure 4-2. BAU Carbon Intensity and Lifecycle GHG Emission Forecasts.

[43] Argonne National Laboratory model for on-road transportation

[44] GHG emission factors include both WTW and ILUC emissions

4.4 Compliance Scenario Definition

Because the LCFS 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 – Minimum Cellulosic Biofuels, E85
Scenario D – Minimum Cellulosic Biofuels, E15

In Scenario A, it is assumed that more plug-in electric vehicles (PEVs), hydrogen fuel cell vehicles (FCVs), and CNG vehicles are sold. Scenario B is a bounding scenario that explores compliance with higher volumes of cellulosic biofuels. Scenario C is another bounding scenario that explores compliance with minimum supplies of cellulosic biofuels. Because the CI of non-cellulosic ethanol is higher than cellulosic ethanol, more ethanol is needed for compliance; this scenario requires FFVs to consume E85[45]. Scenario D is also a minimum cellulosic fuel scenario, but instead of utilizing E85, it 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 on average[46], 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 more flexible 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 at present low CI fuels substituting for diesel are more available than low CI fuels 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. This bank balance criteria was selected somewhat arbitrarily because program stringency after the first 10 years is unknown. While the credit banking provision provides compliance flexibility if sufficient volumes of low CI fuels do not emerge when needed, these fuels must be available by 2026 for the program to achieve continued reductions beyond the analysis period.

Table 4-2 depicts the vehicle populations and biofuel blend levels for each of these scenarios. The table also summarizes available quantities of low CI fuel outlined in Section 2 of this report above; not all of these volumes are required for each of the scenarios. For example, even though

[45] The term E85 refers to the use of high level ethanol blends; in our analysis we assume 75% denatured ethanol.
[46] Both VISION and ARB's EMFAC models employ declining VMT with vehicle age.

the upper bound for cellulosic ethanol is 300 MGY, Scenario B, the cellulosic fuel focused scenario, utilizes less than one third of this upper bound.

Determining the volumes of low CI fuels each year to meet the standard consisted of substituting increasing volumes of lower CI fuel each year, reserving the lowest CI fuels until later in the program when they could be more available, and attempting to keep a balanced mix of low CI fuels rather than consuming as much as possible of one type of low CI fuel.

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% if needed	**0%**	Up to 85% if needed	Up to 85% if needed
Max Biodiesel Blend %	Up to 15%	Up to 15%	Up to 15%	Up to 15%
Ethanol Volumes				
Average MW Corn	Balance	Balance	Balance	Balance
CA LCFS Corn	Up to 250 MGY	Up to 250 MGY	Up to 250 MGY	Up to 250 MGY
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 146 MGY	Up to 146 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 MGY**	**< 63 MGY**
Cell Gasoline and Diesel	**55 to 200 MGY (gasoline equiv)**	**55 to 200 MGY (gasoline equiv)**	**< 55 MGY (gasoline equiv)**	**< 55 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 35 MGY	Up to 35 MGY	Up to 35 MGY	Up to 35 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

For the advanced vehicle scenarios (Scenario A and Scenario A with Banking and Trading) we have utilized the California Zero Emission Vehicle (ZEV) "Likely Compliance Scenario" market shares[47] for BEVs, PHEVs, and hydrogen FCVs. Although Washington state does not have a ZEV rule it currently experiences BEV and PHEV market shares that are similar to California's ZEV program. Figure 4-3 provides the new vehicle market shares for the three affected ZEV types. Figure 4-4 compares the assumed BAU and Scenario A new vehicle market shares for light duty vehicles (light duty auto combined with light duty trucks). For Scenario A we have also assumed that CNG market shares are 50 percent higher than BAU levels. Please refer to Appendix A for more details on new vehicle market share assumptions.

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

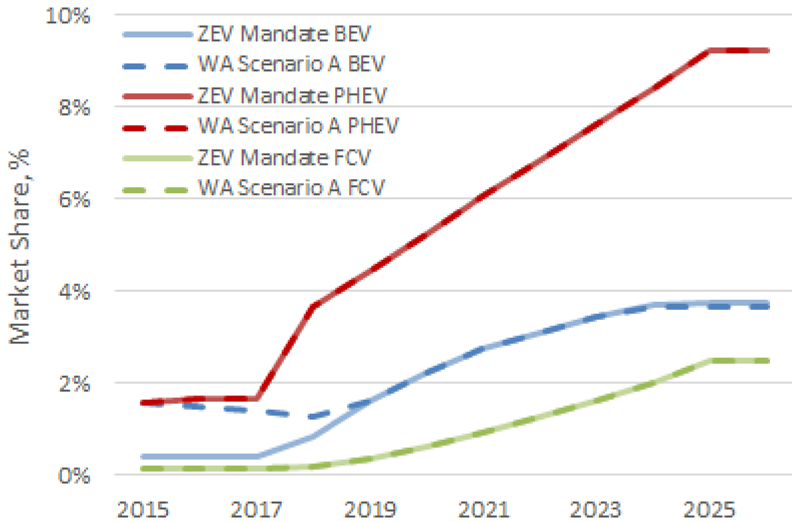

Figure 4-3. Scenario A and Scenario A with B&T light vehicle market shares.

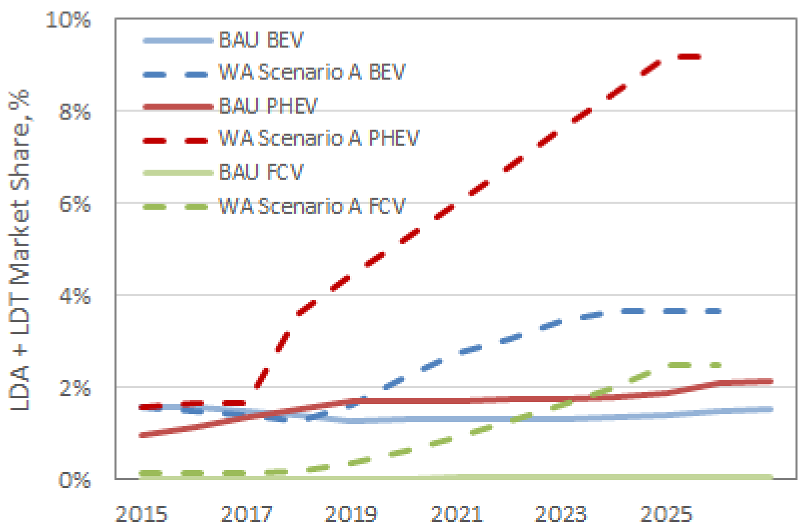

Figure 4-4. Comparison of Scenario A and BAU LDV Market Shares.

4.5 Opt-in Volumes

Because only parties that sell gasoline and diesel are regulated parties in an LCFS, 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,[48] all of the electric 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[49] reports that 80

[48] Conversation with Manisha Singh, ARB
[49] The EV Project is a DOE program established to deploy electric vehicles and charging equipment. Charging data for program participants may be found here: http://www.theevproject.com/documents.php

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. Electricity consumed at home is provided by the electric utilities. Since we assume 100% of utilities will opt-in, 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 LCFS 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. We conservatively assume that this low opt-in rate holds for the analysis period.

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.

4.6 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[50] provide the calculations for overall carbon intensity in gCO_2e/MJ. The values labeled "MJ" are shorthand for total energy consumed in MJ.[51] Multiplying g/MJ by MJ yields grams. To convert to tonnes, one must divide by 1 million.

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

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

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):

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

[50] Note that all electricity and hydrogen is in the gasoline pool. CNG consumed by light and medium duty vehicles is in the gasoline pool. CNG consumed by heavy duty vehicles is in the diesel pool.
[51] All fuel energy densities utilized are lower heating values from the GREET model. Consistent with ARB.

4.7 Effect of LCFS Credit Prices

In an LCFS, regulated parties will need to acquire credits to offset deficits generated by the sale of fuels with CI values greater than the standard. 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 theoretically increases proportionally with the number of credits the fuel generates. The lower the CI, the more the regulated parties would pay for the fuel at a given credit price. Credit price is a reflection of relative availability of low CI fuels. If there is a shortage of low CI fuels, the credit price would be bid upwards. As credit prices rise, more low CI fuels become profitable to produce and would enter into the mix. The resulting increased supply puts downward pressure on credit prices.

It is impossible to predict with certainty the value of credit prices during the analysis period. For the scenario analysis we have assumed a credit price profile that starts at $15 per tonne of CO_2e and increases over time as the LCFS becomes more stringent (Figure 4-5). The profile assumes that a cap on credit prices is set at $100 per tonne and that credit prices hit this cap and remain there for 2024 – 2026. Please refer to Section 4.2 above for a discussion of cost containment mechanisms.

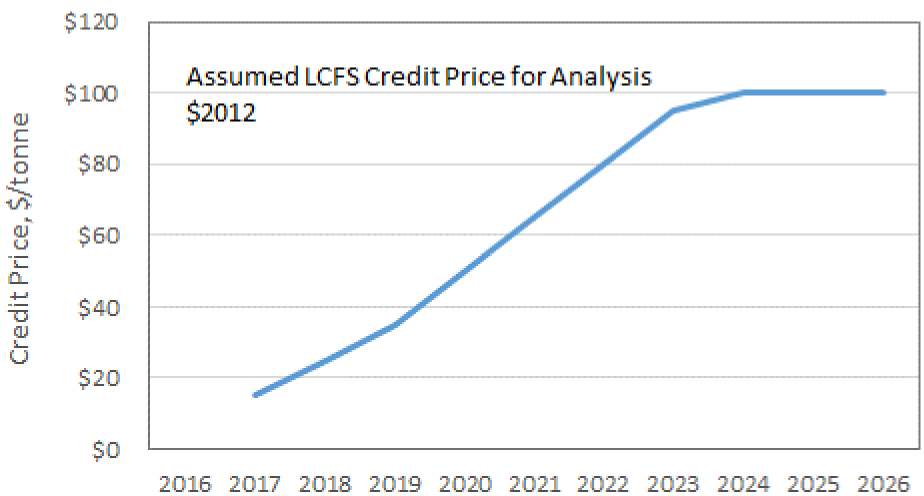

Figure 4-5. Assumed LCFS credit price profile.

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 blendstock and diesel. In reality, not all of the credit costs would translate to a commensurate increase in gasoline and diesel price, but without a detailed economic analysis of petroleum pricing to provide a more accurate estimate of fuel price impact, a conservative modeling approach was selected. Moreover, depending on fuel type and market conditions, a portion of the revenue received by low CI fuel producers for credit sales could be passed on to consumers in the form of reduced prices for low CI fuels. Additional conservatism has been built into this analysis since we have not assumed any price decreases for low CI fuels due to increased credit revenues to low CI fuel providers.

Figure 4-6 and Figure 4-7 illustrate the effect of the assumed LCFS credit price profile on gasoline blendstock and diesel prices, respectively. For our assumed LCFS credit price profile, gasoline blendstock prices increase by 9 to 13 cents per gallon in 2026 while diesel prices increase by 10 to 14 cents per gallon. The credit banking and trading 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. Because each of the scenarios without banking and trading have the same overall CI each year (they meet the standard each year), the resulting fuel price is the same. The banking and trading scenarios all have slightly different CI values each year, so do not have the same fuel price increase profile.

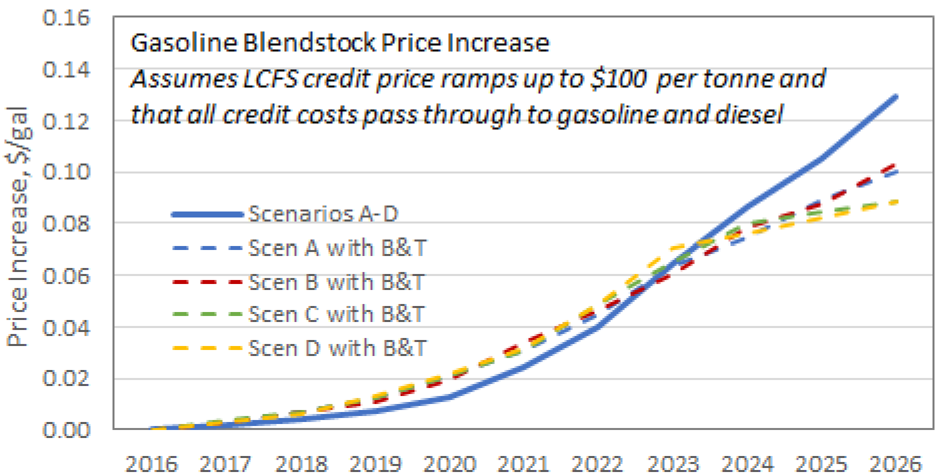

Figure 4-6. Gasoline blendstock price increase due to assumed LCFS credit price profile.

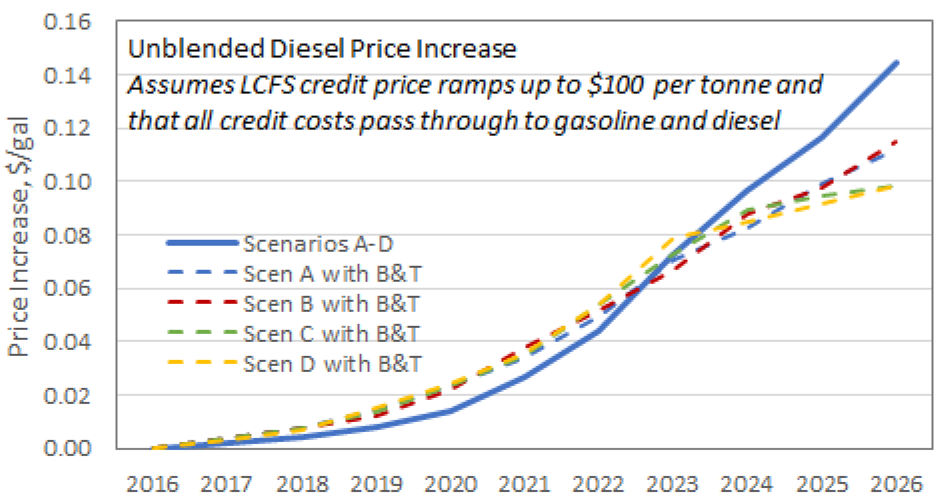

Figure 4-7. Diesel (unblended) price increase due to assumed LCFS credit price profile.

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,[52] 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.

To evaluate the impact of higher credit prices on macro-economics, sensitivity runs with credit prices capped at \$50, \$150, and \$250 per tonne CO_2e were performed for Scenario C (low cellulosic) with Banking and Trading. The credit cost profiles for these cases are shown in Figure 4-8. The analysis assumes that all of the costs incurred by the regulated parties in the form of LCFS credit prices are passed on to the consumer in the form of increased gasoline and diesel prices. Figure 4-9 and Figure 4-10 provide the corresponding impact of the assumed credit prices on gasoline blendstock and diesel prices, respectively. Again, the analysis is conservative in that all of the cost associated with credit purchases is passed on to gasoline and diesel consumers while potential reductions in low CI fuel prices are not modeled.

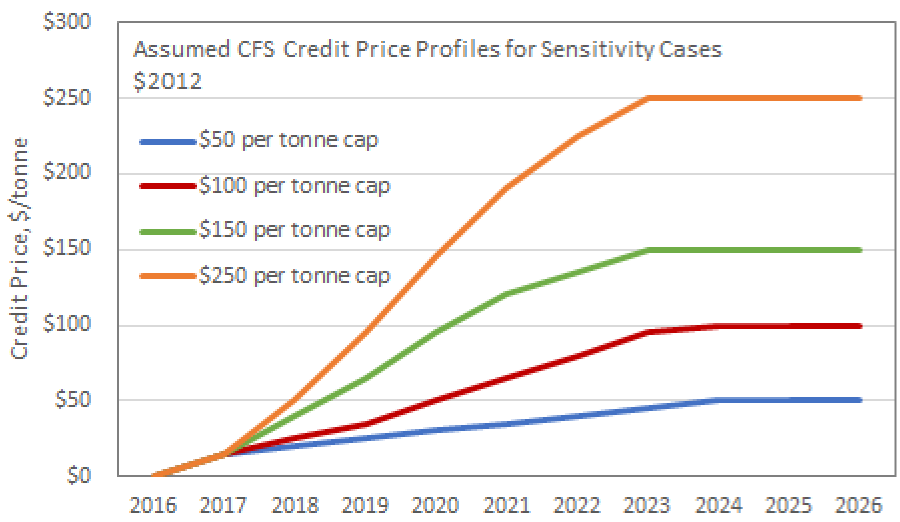

Figure 4-8. Assumed credit price profiles for sensitivity cases.

[52] "Understanding Transport Demands and Elasticities", Victoria Transport Policy Institute, March 2013. Value selected is from Table 18, the Gillingham (2010) study of California from 2005-2008, average of medium run fuel price sensitivity results. Value is at high end of Brand short-run elasticity values for 20007-2008.

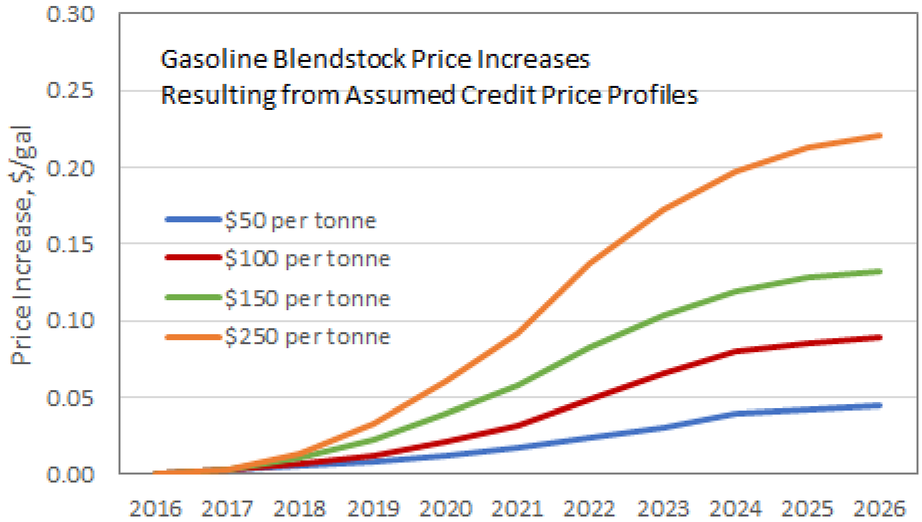

Figure 4-9. Impact of credit price on gasoline blendstock price for Scenario C with B&T.

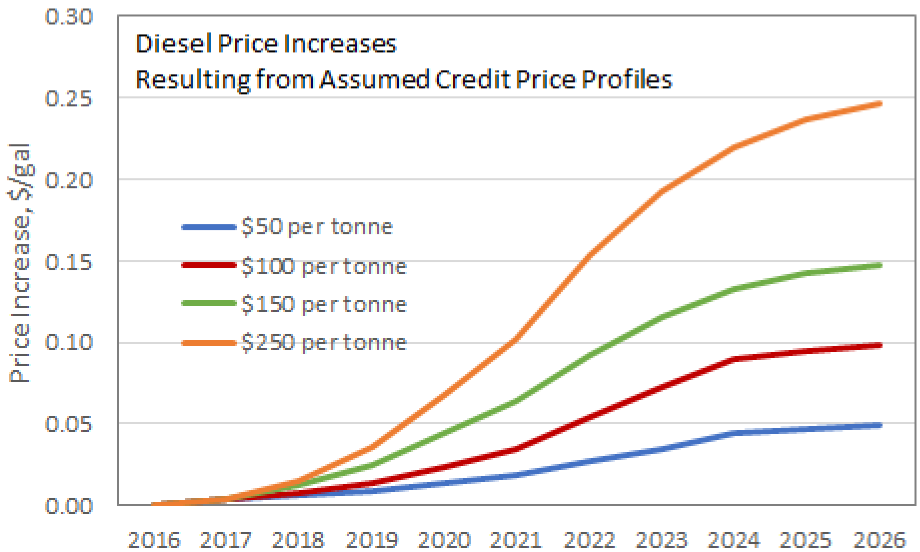

Figure 4-10. Impact of credit price on unblended diesel prices for Scenario C with B&T.

5. Scenario Analysis VISION Model Results

5.1 Biofuel Blend Levels and E85 Use

All compliance scenarios assume a 9.6 percent (volume) blend of denatured ethanol in motor gasoline in 2016, increasing to 10 percent by 2019 and remaining constant at 10 percent throughout the analysis period. Scenario D, the low cellulosic E15 scenario, increases to a statewide average of 14 percent by 2021 and then slowly increases to slightly less than E15[53] by 2024. The banking and trading variant of Scenario D has an earlier transition to E14 and a similar ramp to E15. Although this may be an aggressive schedule for required refueling station modifications, it is assumed that in the banking and trading scenarios, regulated parties would increase lower CI fuel blend levels as rapidly as possible to bank early credits. Figure 5-1 provides the ethanol blend levels for the two Scenario D cases.

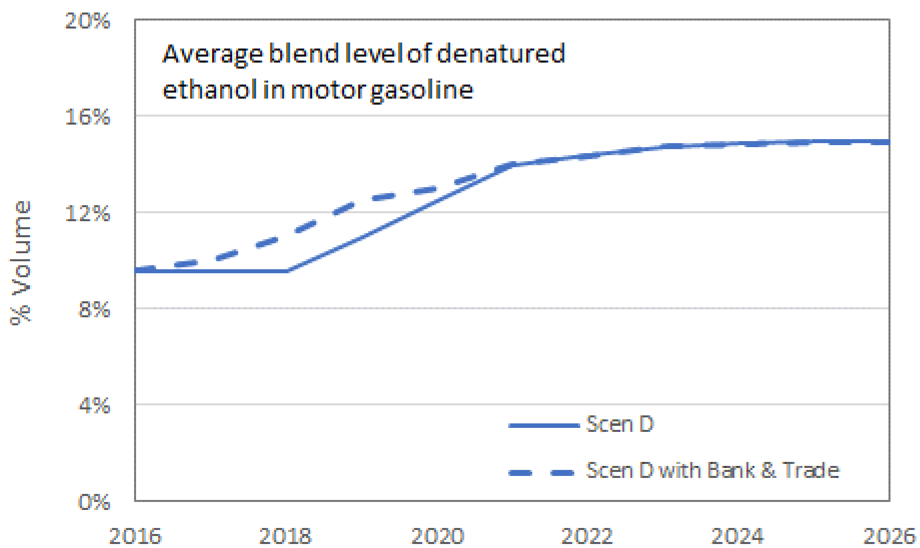

Figure 5-1. Ethanol blend levels in gasoline for Scenario D (all other scenarios E10).

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. Please refer to Appendix A for infrastructure requirements to increase the biodiesel blending levels in Washington state.

[53] Since EPA has approved E15 use for MY2001 and newer vehicles, we have reduced the blend level by the percent of older vehicles still in the fleet, but use the term E15 in the narrative.

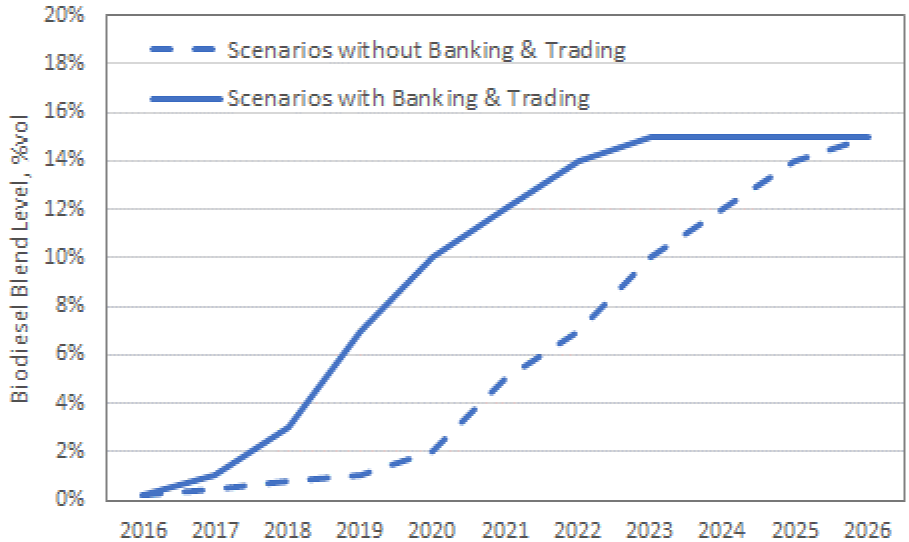

Figure 5-2. Assumed biodiesel blend levels.

Scenario C with and without banking and trading assume that 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 as at this level no additional blending components are required[54]. Figure 5-3 provides the shares of FFV E85 use. Scenario C (low cellulosic) required up to 85 percent of FFV fuel use to be E85. Scenario C with banking and trading required up to 70 percent of FFV fuel use to be E85. Please refer to Appendix A for a discussion of the infrastructure requirements to support E85 use.

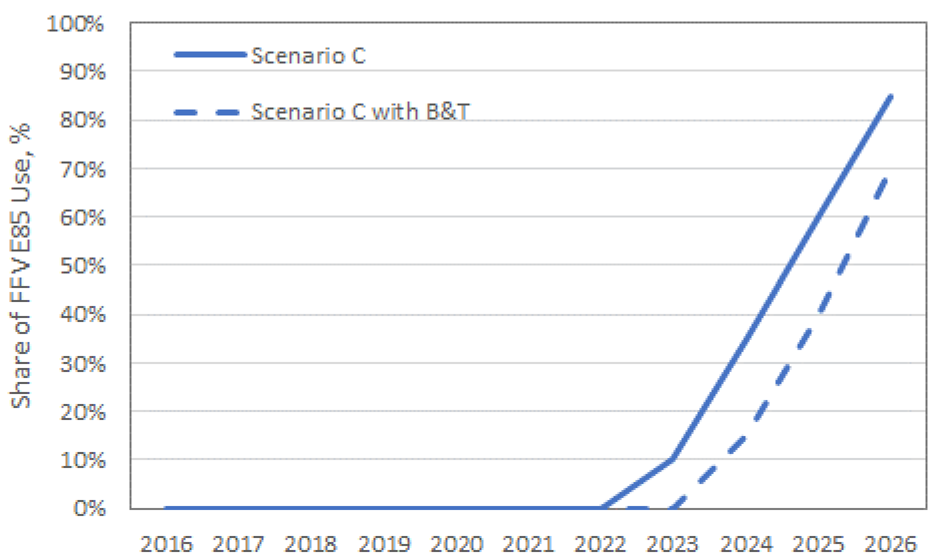

Figure 5-3. Assumed FFV E85 use.

[54] *E85 Demonstration Program*, Jim Uihlein, Chevron, May 2011

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 0 to 90 MGY (gasoline equiv). The two low cellulosic scenarios (C and D) with banking & trading did not require any cellulosic fuel to comply with the standard. However it is important to note that even though we have assumed a 25% bank balance for 2027 in the banking and trading scenarios, cellulosic fuel volumes (or another type of fuel with CI levels similar to cellulosic fuels) will need to be available to allow for compliance in 2027 and beyond.

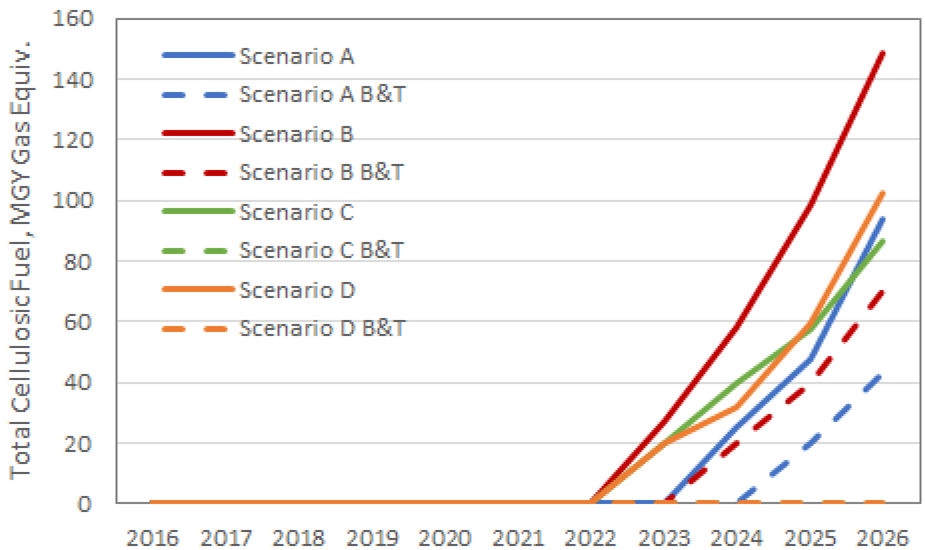

Figure 5-4. Total cellulosic fuel volumes required, MGY (gas equiv).

The macro-economic modeling presented in Sections 6 and 7 of this report make an assumption that by 2026 up to three cellulosic biofuel plants each producing up to 30 MGY of fuel are operating in Washington state. To determine the magnitude of this impact a sensitivity case for Scenario B with banking and trading was run with no in-state production of cellulosic fuel. Please refer to Section 7 of this report for the macro-economic results. Figure 5-5 summarizes the in-state and imported cellulosic ethanol and gasoline for each of the scenarios.

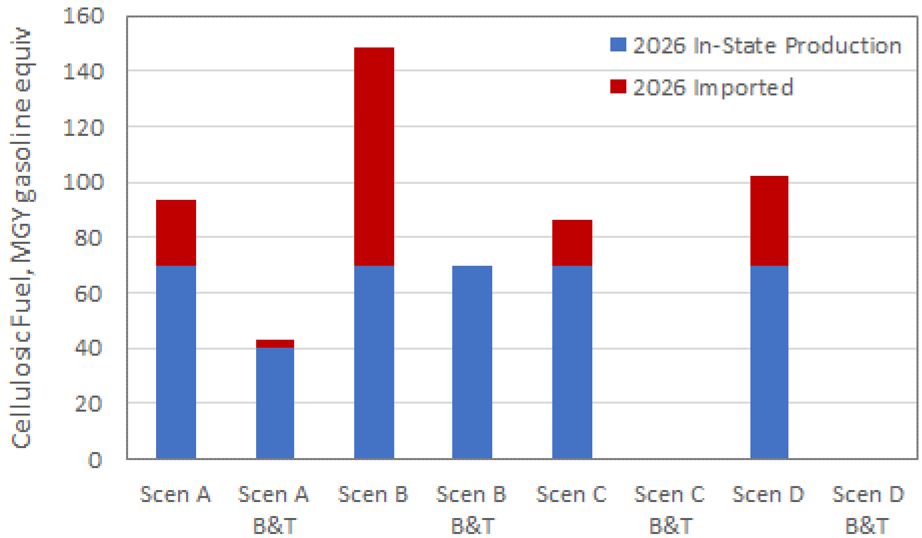

Figure 5-5. Assumed Source of Cellulosic Ethanol and Gasoline in 2026.

Consumption of sugarcane ethanol is provided in Figure 5-6. Washington's share of the EIA projection for RFS2 is estimated at 146 MGY. The maximum amount of sugarcane ethanol utilized in the compliance scenarios ranges from 80 MGY to 146 MGY.

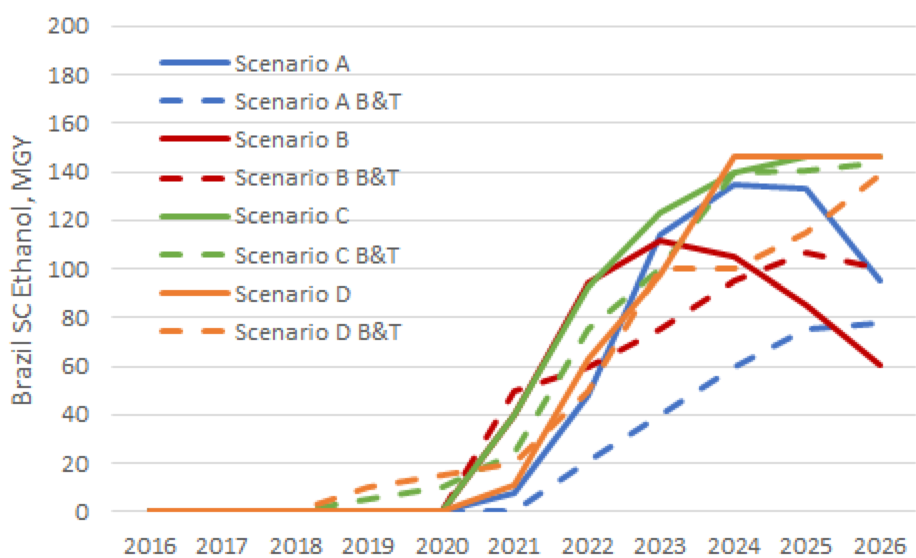

Figure 5-6. Brazil Sugarcane Ethanol Consumption.

Figure 5-7 provides the opt-in electricity volumes. Electricity consumption under the ZEV vehicle market shares scenarios (Scenario A and A with banking & trading) is more than twice the electricity consumption in the BAU and other compliance scenarios by 2026.

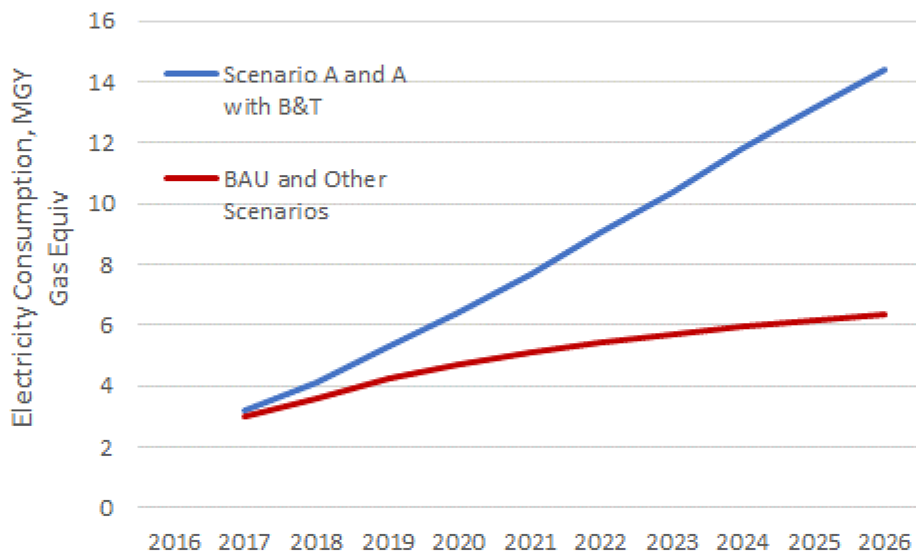

Figure 5-7. Electricity consumption, MGY (gas equiv).

Volumes of used cooking oil and tallow based biodiesel and not shown, but in each scenario, these biodiesel volumes increase to a total of 22 MGY. Finally, RNG consumption is provided in Figure 5-8. Up to 13 MGY are utilized by the CNG fleet in the Advanced Vehicles scenarios, with total volumes less than 9 MGY in the other cases. There is currently approximately 12 MGY diesel equivalent of pipeline RNG capacity in-state (please refer to Section 2). The bank and trade versions of the scenarios switch to RNG from CNG earlier than the base scenarios to take advantage of banking provisions.

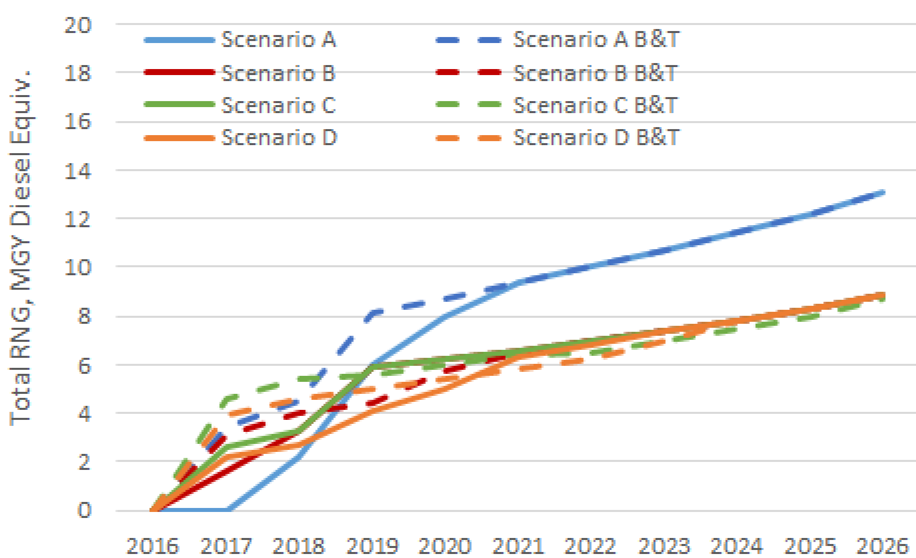

Figure 5-8. Total RNG Consumption, MGY Diesel Equivalent.

5.3 CFS Credits

Figure 5-9 through Figure 5-20 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. Recall 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. As mentioned in Section 5.2, while the banking & trading scenarios allow the introduction of very low CI fuels to be delayed, they will be required post 2026. To clarify the labels in the figures, cellulosic gasoline refers to “drop-in” gasoline produced from cellulosic feedstocks. The ethanol category includes all types of ethanol including ethanol produced from cellulose. The biodiesel category includes all biodiesel and the CNG category includes all CNG produced from fossil and renewable natural gas.

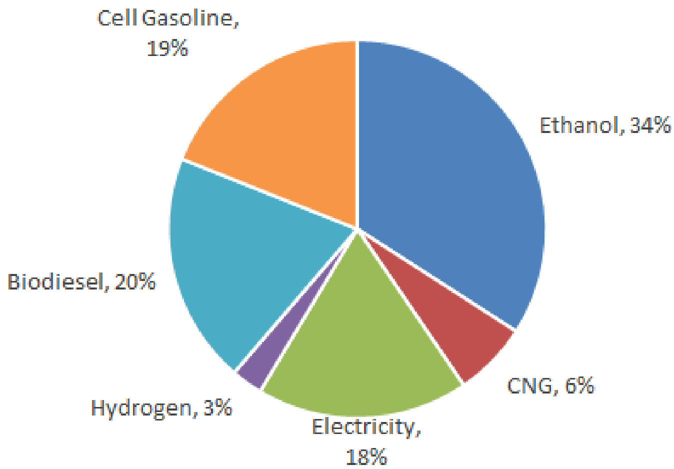

Figure 5-9. Relative contributions to compliance in 2026, Scenario A (Advanced Vehicles).

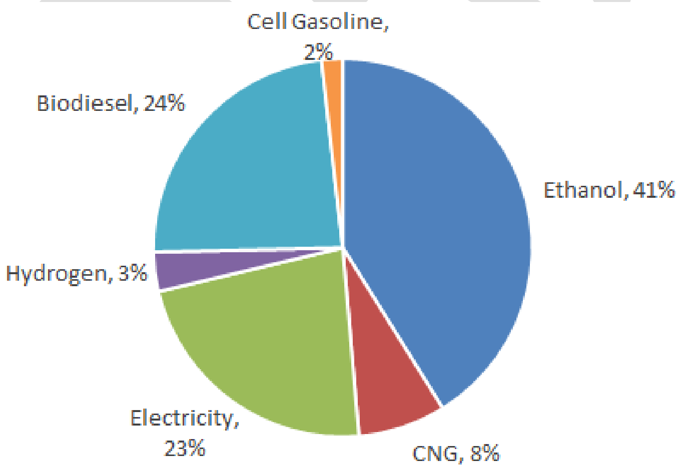

Figure 5-10. Relative contribution to compliance in 2026, Scenario A with B&T.

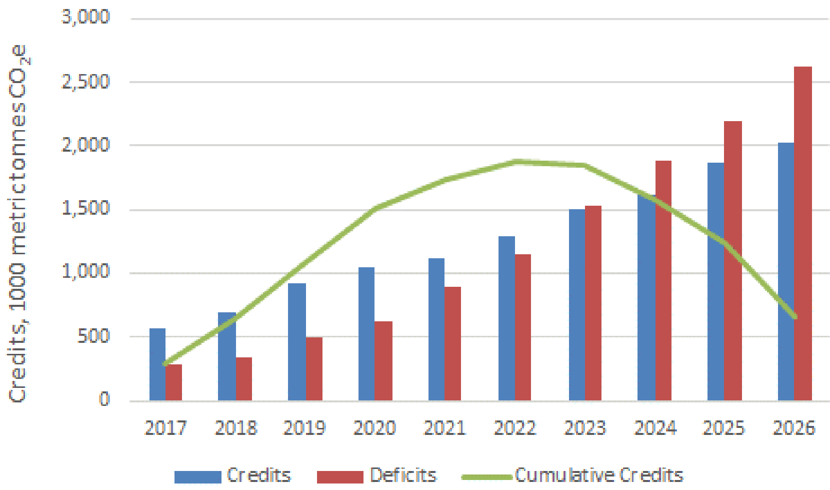

Figure 5-11. Credits, debits, and cumulative credits for Scenario A with B&T.

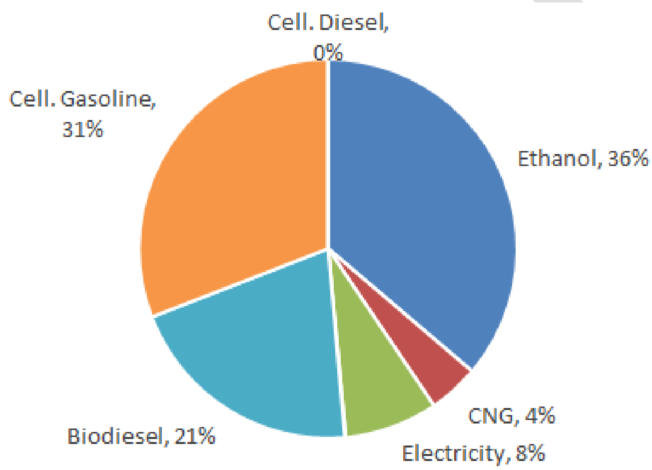

Figure 5-12. Relative contribution to compliance in 2026, Scenario B (abundant cellulosic).

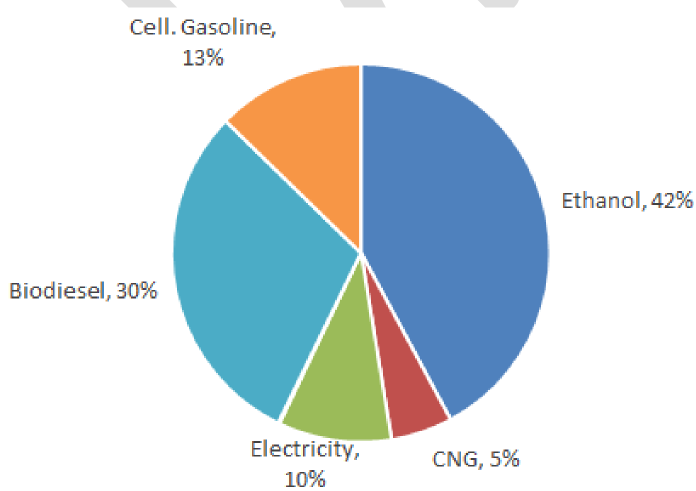

Figure 5-13. Relative contribution to compliance in 2026, Scenario B with B&T.

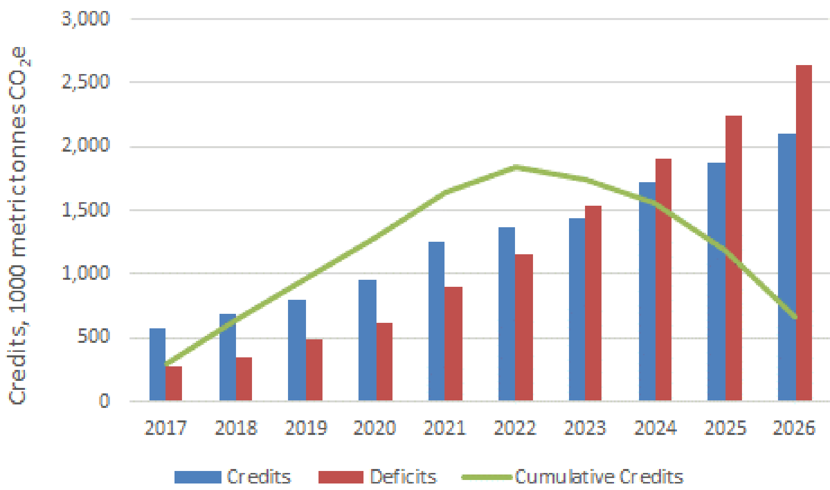

Figure 5-14. Credits, debits, and cumulative credits for Scenario B with B&T.

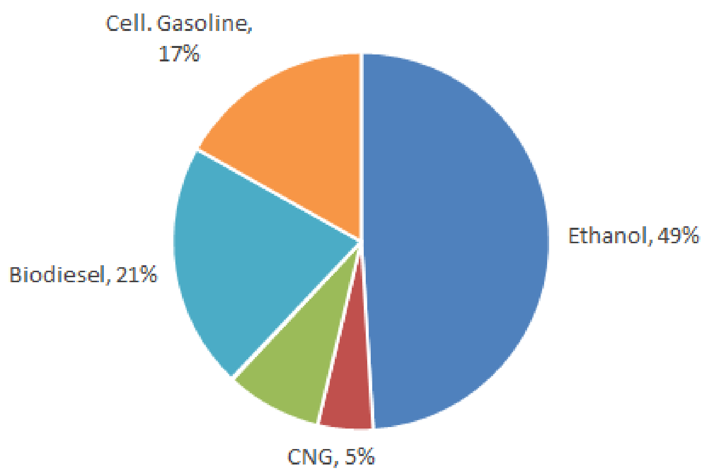

Figure 5-15. Relative contribution to compliance in 2026, Scenario C (low cellulosic)

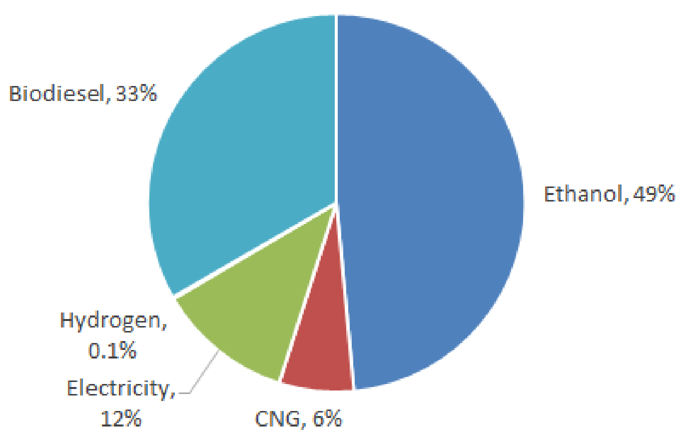

Figure 5-16. Relative contribution to compliance in 2026, Scenario C with B&T

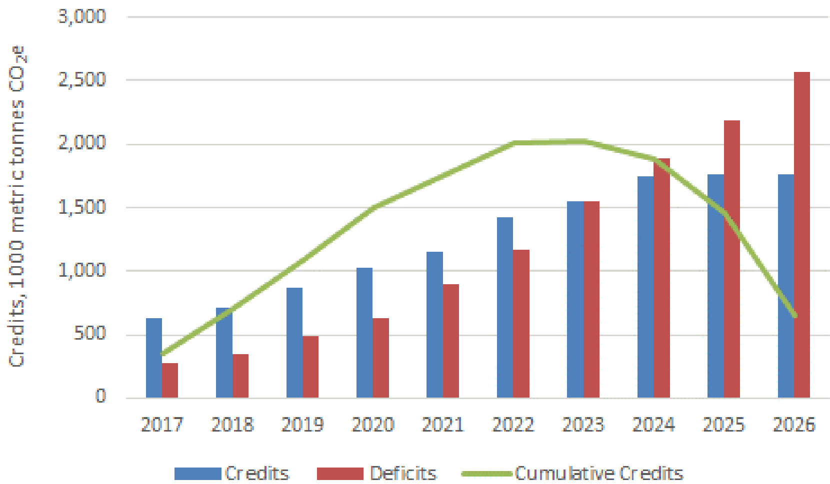

Figure 5-17. Credits, debits, and cumulative credits for Scenario C with banking & trading

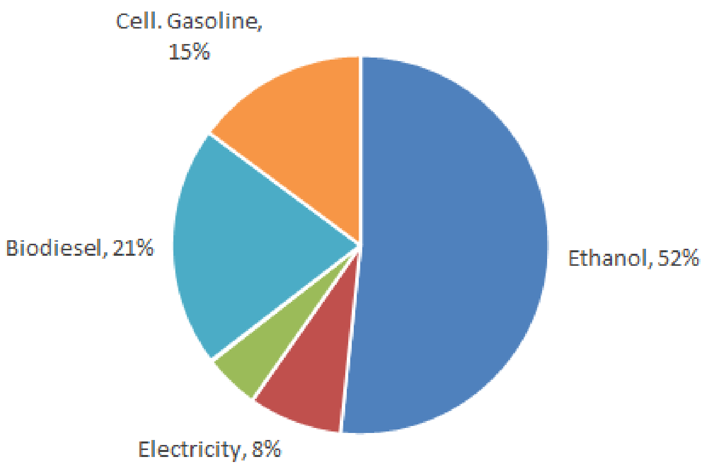

Figure 5-18. Relative contribution to compliance in 2026, Scenario D (low cellulosic E15)

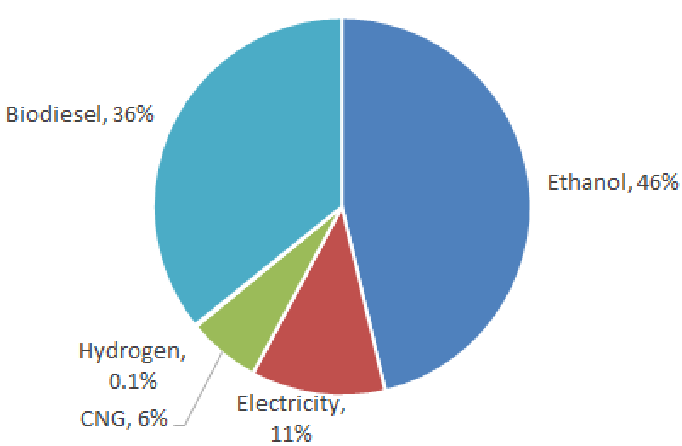

Figure 5-19. Relative contribution to compliance in 2026, Scenario D with B&T

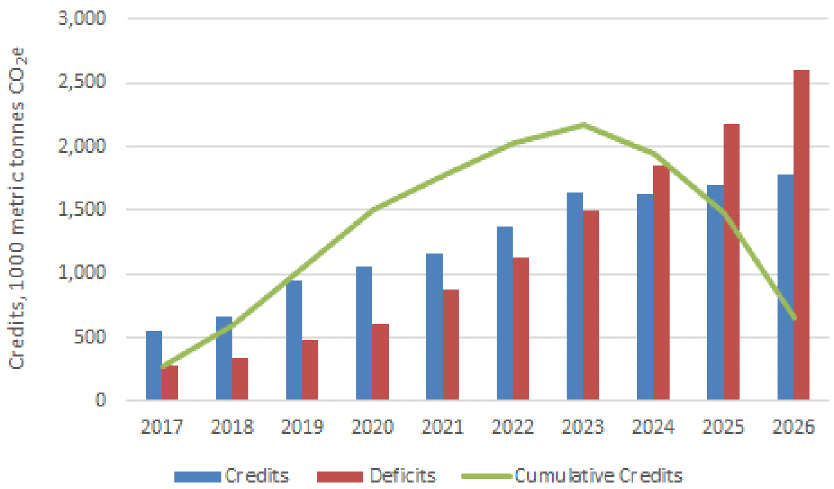

Figure 5-20. Credits, debits, and cumulative credits for Scenario D with banking & trading

5.4 Petroleum Consumption

Higher fuel economy standards and decreasing projections of VMT result in reduced gasoline consumption through the analysis period. Figure 5-21 shows the projected decrease in gasoline blendstock consumption while Figure 5-24 provides the percent reduction relative to year 2016. Without an LCFS, gasoline consumption is projected to decrease by 22 percent from 2016 levels by 2026. With an LCFS, a 20 to 30 percent decrease is projected for the scenarios analyzed.

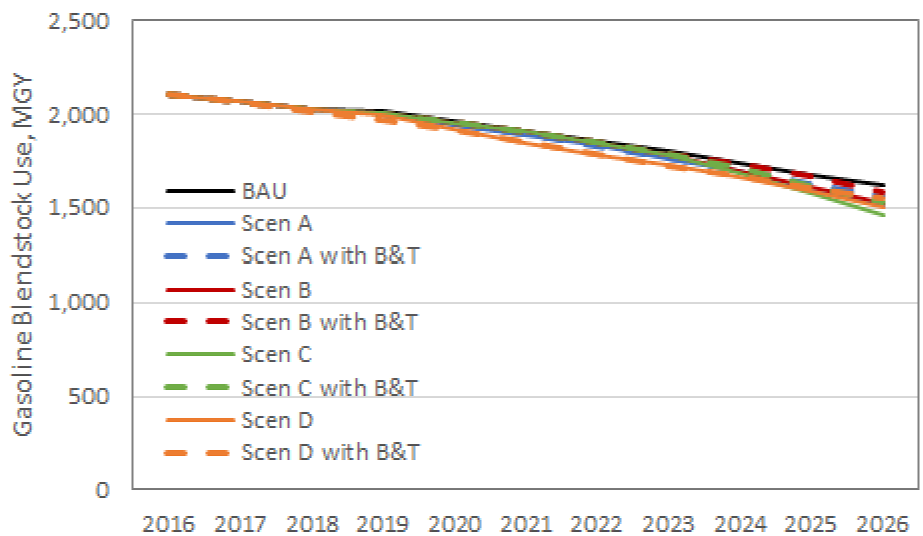

Figure 5-21. Projected Decrease in Gasoline Blendstock Consumption.

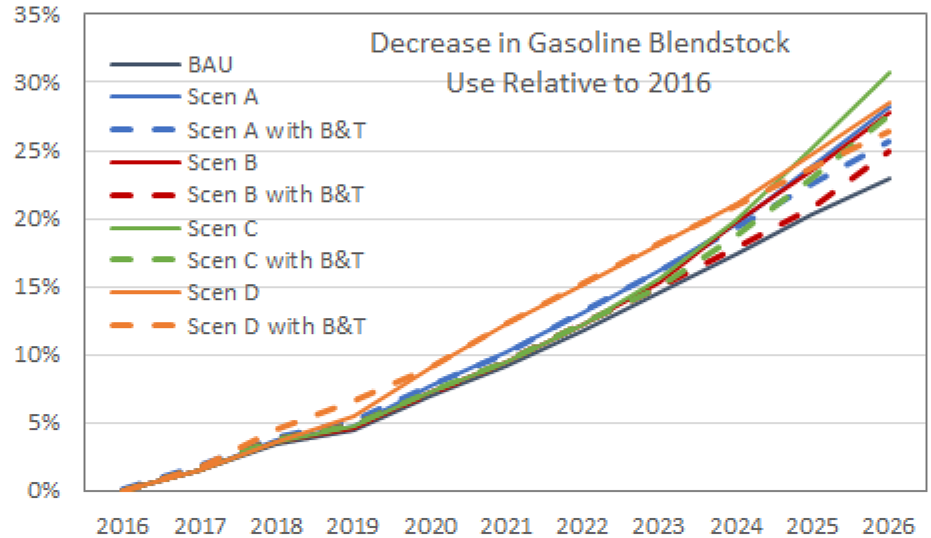

Figure 5-22. Percent Reduction in Gasoline Blendstock Use Relative to 2016.

Figure 5-23 provides the projected diesel consumption for the BAU and compliance scenarios. Diesel consumption is expected to decrease by 8 percent over the analysis period for the BAU case, and decrease by 22 percent for the compliance scenarios.

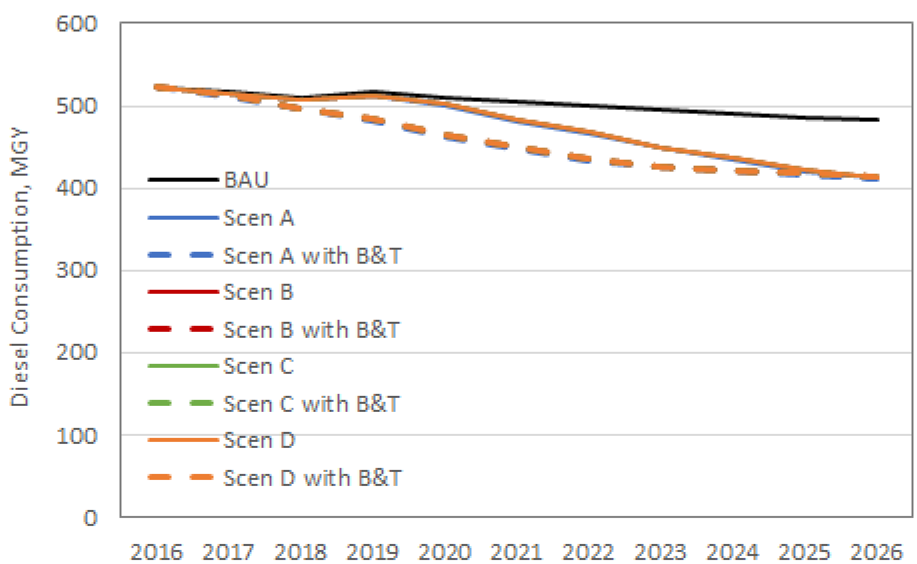

Figure 5-23. Percent Reduction in Diesel Blendstock Use Relative to 2016.

5.5 GHG Emissions

Figure 5-24 provides the well-to-wheel (WTW) GHG emission reductions relative to the BAU. Table 5-1 provides the cumulative GHG reductions for each scenario relative to the BAU. GHG emissions are calculated by multiplying the carbon intensity (g/MJ) by the total fuel consumption (MJ). All scenarios without banking and trading have the same emission reduction relative to the BAU except for the advanced vehicle case (Scenario A). This is because total fuel consumption in the advanced vehicle scenario is lower than the other scenarios, resulting in lower total emissions, and a larger reduction relative to the BAU. The scenarios with banking and trading have more emission reductions than the scenarios without banking & trading due to the requirement to have a 25 percent bank balance at the end of 2026.

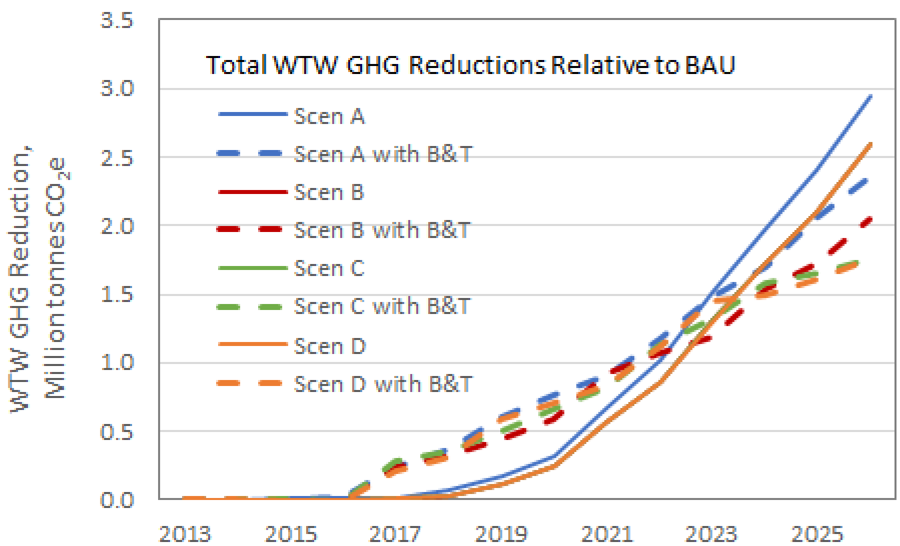

Figure 5-24. WTW GHG Emission Reductions Relative to BAU

Table 5-1. Cumulative WTW GHG Reductions Relative to BAU (Million tonnes)

Scen A	Scen A with B&T	Scen B	Scen B with B&T	Scen C	Scen C with B&T	Scen D	Scen D with B&T
11.1	11.6	9.5	10.1	9.5	10.1	9.5	10.1

5.6 Criteria Pollutant Emissions

Changing vehicles and fuel types in Washington state will impact criteria pollutant emissions. While new fuel production plants and increased truck transportation of fuels to terminals will impact criteria pollutant emissions, quantifying this WTW impact did not fit into the budget or time schedule for the present analysis. The change in vehicle (TTW) emissions have been quantified. To estimate the impact of the compliance scenarios on TTW criterial pollutant emissions, emission factors from EPA's MOVES model[55] for Washington state were utilized. Emission factors for gasoline, diesel and E85 were provided for LDA and LDT categories. Factors for gasoline and diesel were provided for medium duty vehicles; for heavy duty vehicles, factors were provided for gasoline, diesel and CNG. The following assumptions were made:

- Vehicles consuming E15 utilize the same emission factors as motor gasoline
- Light vehicles consuming CNG utilize the same emission factors as motor gasoline
- Vehicles consuming biodiesel blends utilize the same emission factors as diesel vehicles
- Medium duty CNG vehicles utilize the same emission factors as diesel

Only the two versions of Scenario A (advanced vehicles) and Scenario C (E85 use by FFVs) have projected vehicle emission reductions relative to the BAU; the other scenarios (B and D) had the same projected emissions as the BAU. Figure 5-25 through Figure 5-27 provide the percent reduction relative to the BAU projection for Scenarios A and C. A careful estimate of WTW emission impacts should be performed if Washington state moves forward with an LCFS.

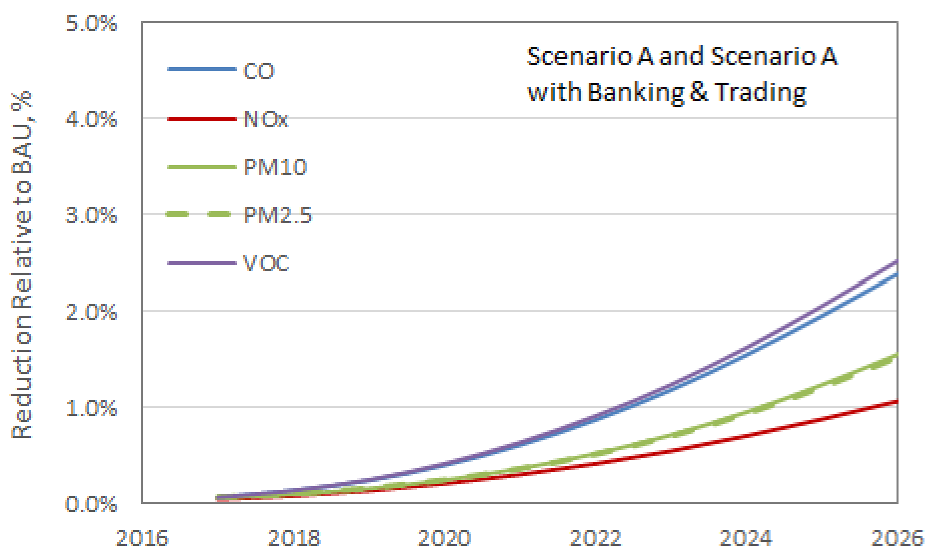

Figure 5-25. Emission reductions relative to BAU for both versions of Scenario A.

[55] Provided by Sally Otterson, Washington State Department of Ecology.

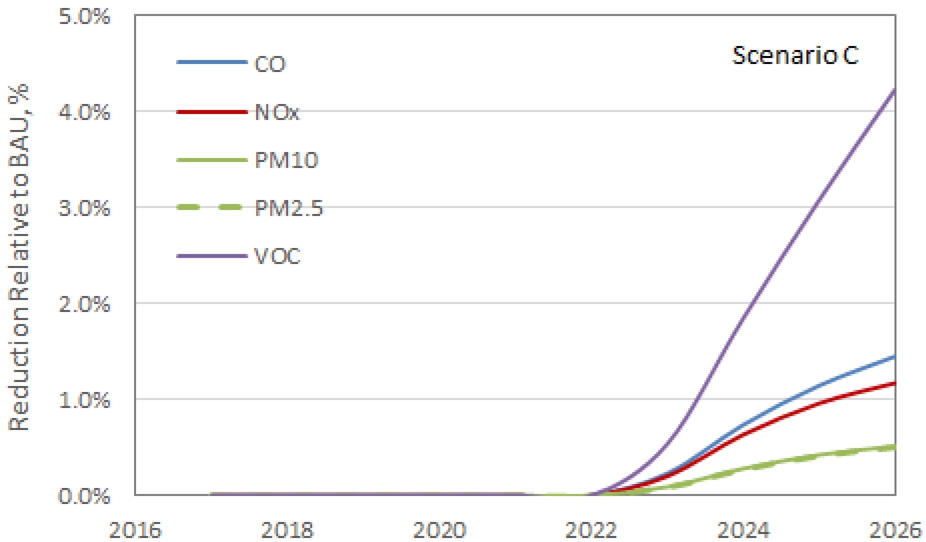

Figure 5-26. Emission reductions relative to BAU for Scenario C

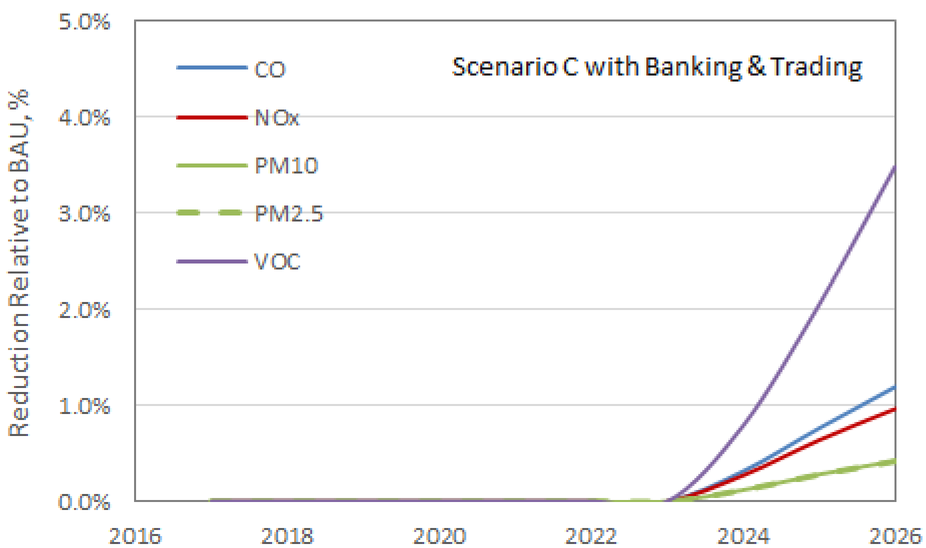

Figure 5-27. Emission reductions relative to BAU for Scenario C with Banking & Trading.

5.7 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. It is worth noting that an LCFS does not influence the types of vehicles sold, therefore the increased consumer spending on vehicles in Scenario A are not attributable to the LCFS, but rather to an alternate BAU case or to some other program (ZEV Mandate or incentives) implemented by Washington state.

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 5-28 provides incremental consumer spending relative to the BAU on vehicles for both Scenario A cases. Up to $250 million ($2012) is spent on vehicles by 2026 with most spent on PHEVs.

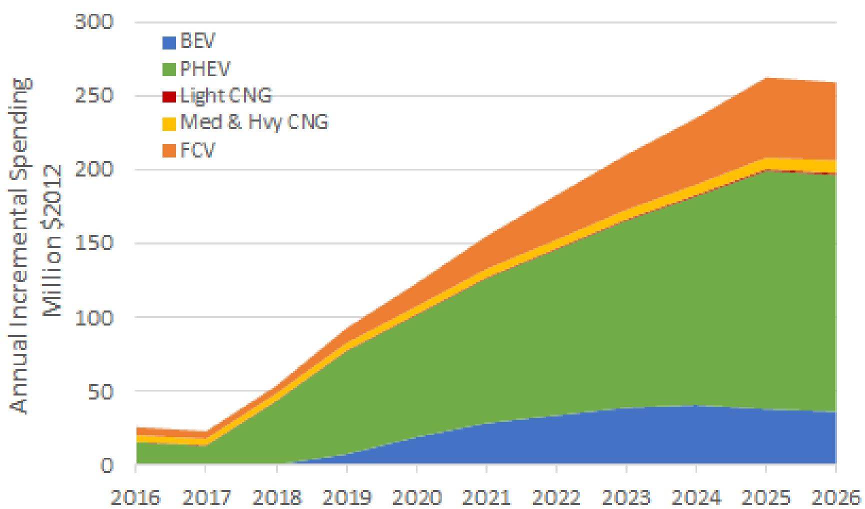

Figure 5-28. Incremental consumer spending on vehicles relative to BAU for Scenario A

5.8 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 5-29. 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.

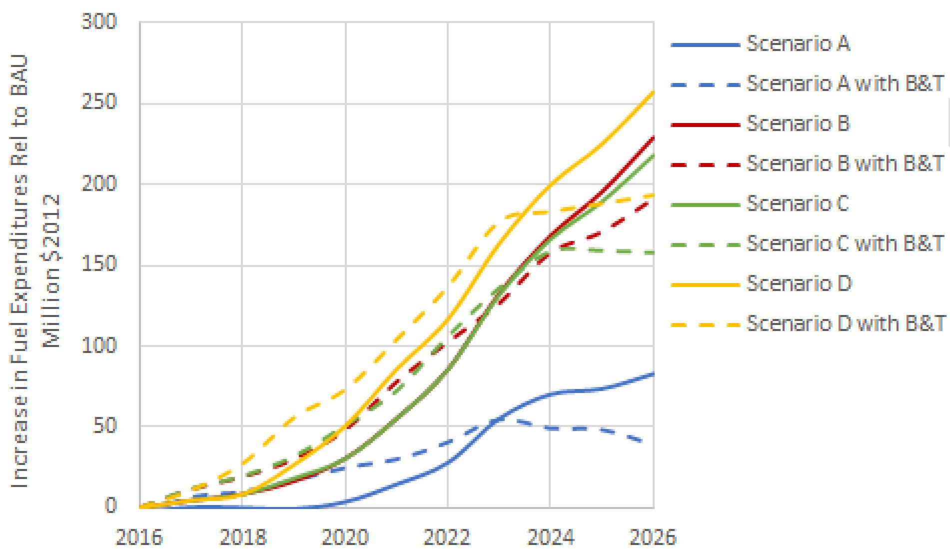

Figure 5-29. Increases in consumer spending on fuel relative to BAU.

5.9 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 advanced vehicle refueling (Scenario A), pipeline quality RNG production plant costs, cellulosic biofuel plant costs, and infrastructure costs to support increased biodiesel and ethanol consumption. Note that similar to the consumer spending on vehicles, costs to support PEV, hydrogen FCV and CNG refueling for Scenario A should really be assigned to an alternate BAU or to a State program that incentives or requires sales of advanced vehicles.

EV Charging Infrastructure

Table 5-2 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 5-2. 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
4.8	5.2	6.8	24.6	0.8	1.1	12.4	30.9
4.5	6.6	6.8	24.6	0.6	1.0	12.0	32.2
4.6	8.2	5.1	18.5	0.5	0.8	10.2	27.5
4.6	10.4	4.3	15.4	0.3	0.6	9.1	26.4
4.6	12.4	3.4	12.3	0.2	0.5	8.2	25.3
4.6	14.0	2.6	9.2	0.2	0.4	7.4	23.6
4.7	15.7	1.7	6.2	0.2	0.3	6.6	22.1
4.9	17.0	1.4	4.9	0.2	0.2	6.4	22.1
5.3	17.9	1.0	3.7	0.1	0.1	6.4	21.7
5.6	18.2	1.0	3.7	0.1	0.2	6.7	22.1

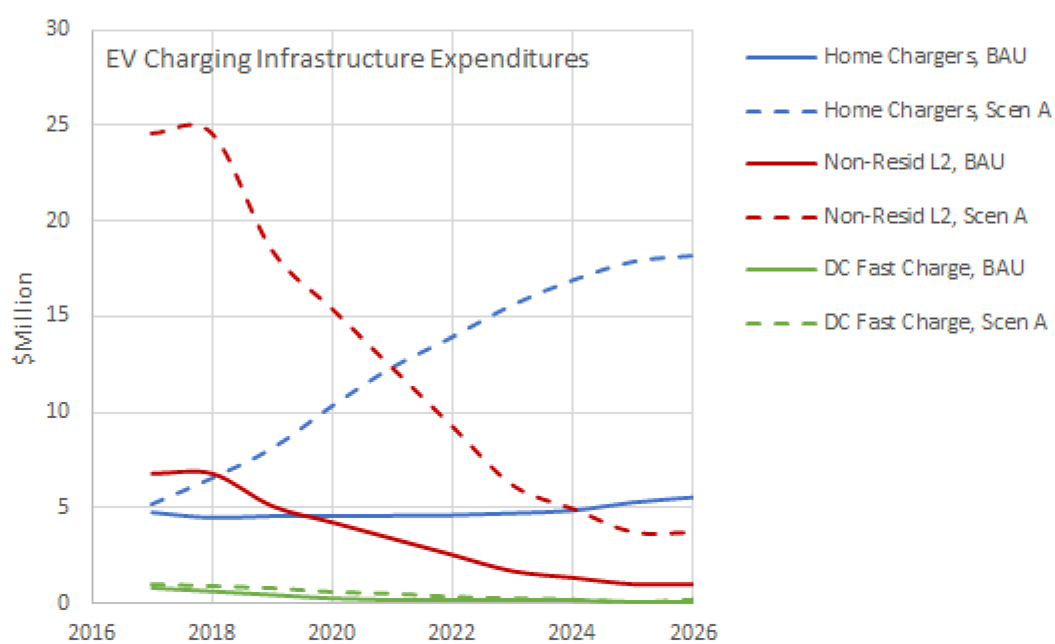

Figure 5-30. Scenario A EV charging costs relative to BAU

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 5-31 provides the BAU and Scenario A annual expenses for hydrogen refueling stations.

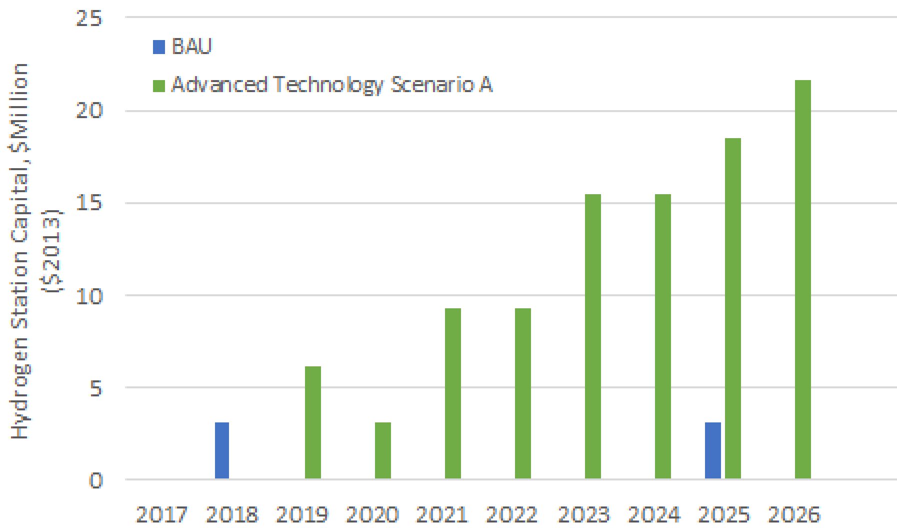

Figure 5-31. Estimated hydrogen refueling station costs for BAU and Scenario A

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 5-32 summarizes cumulative expenditures on refueling stations.

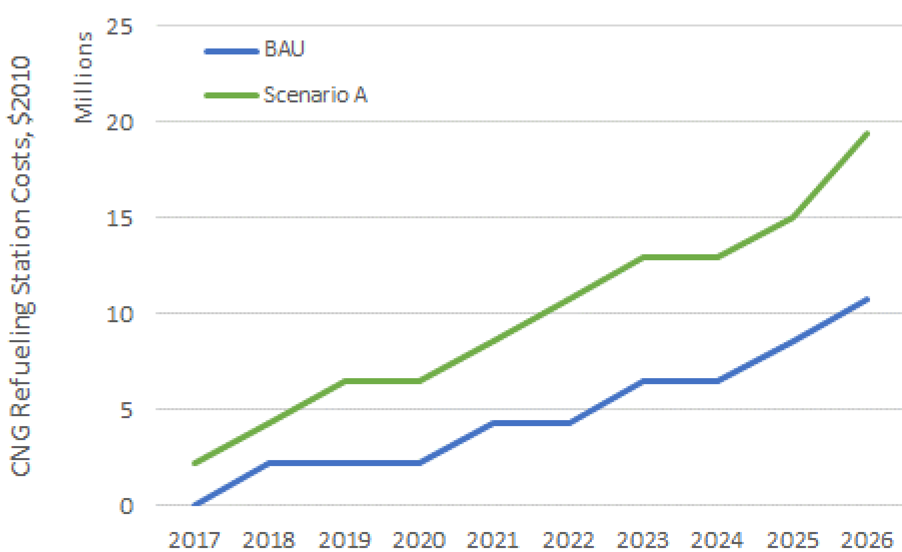

Figure 5-32. Projected cumulative CNG refueling infrastructure spending.

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 5-3 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 5-3. 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	4.0	7.8	4.4	4.5	2.7	5.6	3.3	5.6	3.3	7.8	2.9	6.7	3.2	8.9	2.2	5.6
Cost	20.1	39.0	21.8	22.3	13.4	27.9	16.7	27.9	16.7	39.0	14.5	33.5	16.2	44.6	11.2	27.9
2017	10.0		10.9		13.4		8.4		8.4		14.5		8.1		5.6	
2018			10.9				8.4		8.4				8.1		5.6	
2019	10.0															
2020																
2021																
2022		19.5		11.2		13.9		13.9		9.8		16.7		11.2		7.0
2023										9.8		8.4		11.2		7.0
2024		19.5		11.2		13.9		13.9		9.8		8.4		11.2		7.0
2025										9.8				11.2		7.0
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, a sensitivity test for one scenario considers all 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 5-33 provides the cumulative capital costs for building cellulosic biofuel plants ($2014).

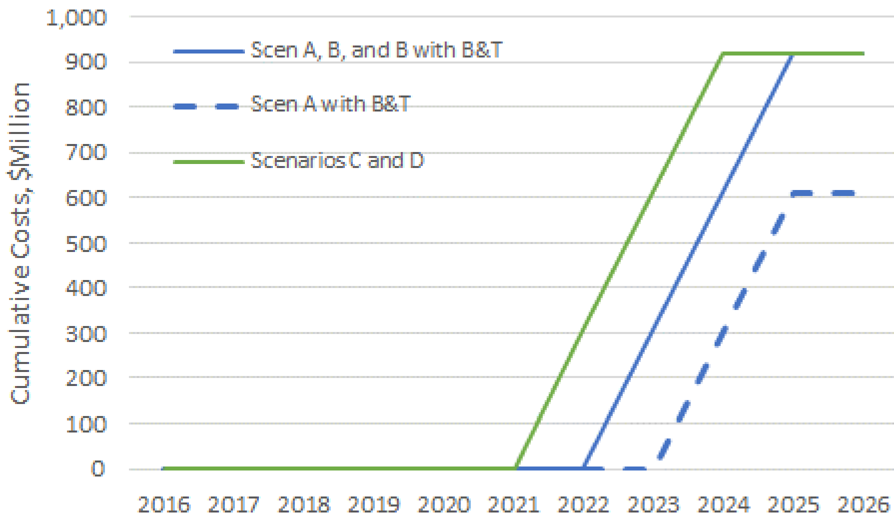

Figure 5-33. Cumulative costs for cellulosic biofuel plant construction in Washington state.

Infrastructure to Support Changes in Ethanol Use
Several different infrastructure cost categories were considered in response to changes in ethanol consumption:

- Marine, rail, and 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 5-34 provides cumulative costs for ethanol related infrastructure relative to the BAU case.

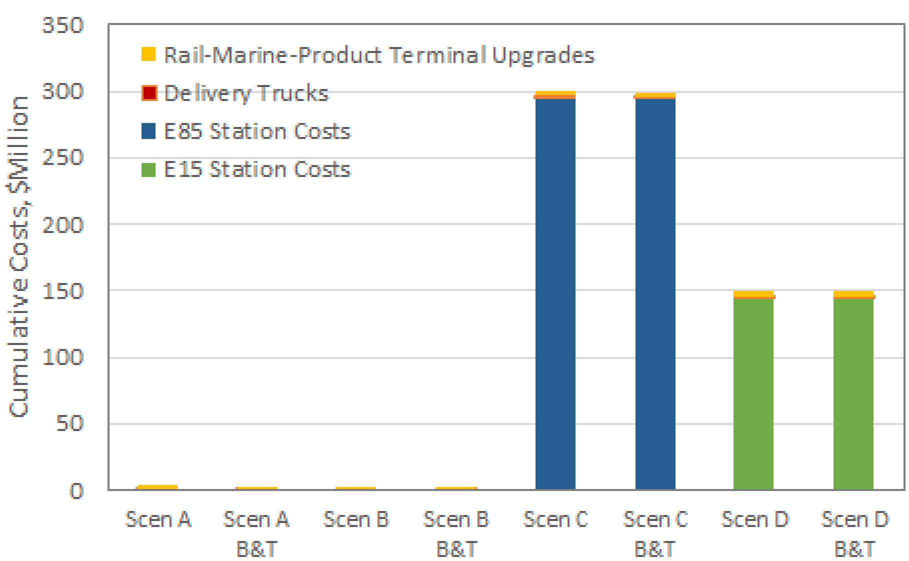

Figure 5-34. Cumulative ethanol infrastructure costs relative to BAU.

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 and upgrades at petroleum terminals; no spending at refueling stations is required. Appendix A provides the assumptions utilized to calculate these infrastructure costs. Approximately 5 million dollars ($2014) is required for terminal upgrades and an additional $1 million ($2014) is required for trucks.

6. Macro-Economic Modeling Methodology

Impact analyses are always framed within the context of “with” and “without” (benchmark) perspectives. The impact of an exogenous event, such as the application of an LCFS, is defined and measured in terms of the differences between the state of the economy with and without the change. Thus, impact analysis requires the ability to forecast a baseline condition. In ex post analyses, the only forecast required is of what the economy would have been without the change, since the state with the change is directly observable. In ex ante analyses such as the present study, research is required to estimate what the economy is expected to look like in both the “with” and “without” scenarios. This framework is required whether the analysis is qualitative or quantitative. Impacts cannot be ascertained otherwise.

All impact analyses require an explicit or implicit model that explains how the economy is affected by a variety of factors determined outside the control of private decision makers. Because there is a wide range of opinions on the likely direction of energy use and travel, it may be wise to define alternative benchmark scenarios that will meet the LCFS. To complete the analysis of the Washington state LCFS scenarios, the project team created a baseline that includes not only the fuel mix today, but the mix in each year between the current year and a forecast year without the potential Washington state LCFS. The end year for this analysis is 2026. The baseline, or BAU case, is described in the Sections above and in Appendix A of this report. In future studies, Washington state might want to consider extending the analysis over a longer term, such as 2035 or even 2050. The longer term horizon might reveal trends that are not anticipated. For example, hydrogen fuel is unlikely to play a major role in meeting the current goal, but may be an important option in the longer term. This analysis develops baseline and annual alternative impacts only over the period from 2017 to 2026.

Many issues must be considered in the baseline, including the underlying growth in Washington state population and economic activity. For this analysis we are utilizing REMI PI+ which is the same model used by OFM to predict the future structure of the Washington economy. This growth in income and employment will include the expected change in demand for gasoline and diesel fuel to power transportation. These expectations are in the baseline scenario (referred to as the “Business-As-Usual” or “BAU” scenario). The baseline scenario changes will proceed in a dynamic fashion, the pace of which will be crucial in defining the impact and viability of a lower carbon intensity fuel driven Washington state economy. Note that there are both microeconomic and macroeconomic baseline considerations. As such, both the VISION (vehicle inventory and use) and REMI (Input-Output, Computable General Equilibrium, and Economic Geography) tools must generate a baseline from which scenarios under consideration can be evaluated in later steps. These modeling tools and their application are discussed below.

6.1 Types of Economic Impacts

The estimation of economic impacts due to public policy often focuses on three types of impacts. Direct economic impacts refer to the changes in behavior and costs that result from actions to comply with the LCFS. For example, the development of distilling resources to produce fuel ethanol would be a direct impact. Indirect economic impacts are defined as the behavior and costs that result in the economy to facilitate the direct impacts. An example of indirect impacts is the economic impact resulting from the likely changes in spending on labor and materials, which are needed to collect forest wastes that will serve as feedstock for an ethanol production facility. The labor and materials needed to build and run such a facility are another indirect impact. Finally, induced economic impacts are the behavior and expenditures by households given the changes in income earned as a result of both direct and indirect activities. Induced impacts may occur across the entire economy.

Most environmental regulations result in higher production costs for the regulated industries. Tailpipe emissions regulations require additional vehicle emissions control technology which increases the production cost of the vehicle. Air quality regulations that limit plant emissions require production modifications or emissions post production processing to comply with emissions limits. The additional cost of compliance is compared to the benefits of reduced emissions such as improved health and quality of life. If the benefits of the regulation are deemed to exceed the costs, the regulation is considered cost effective.

The proposed Washington state LCFS is distinct in its economic impact from typical environmental regulation, as it provides an opportunity for economic gains as domestic and in-state production of replacement fuels stimulates the U.S. and Washington state economies. This stimulus results from a reduction in petroleum imports and an increase in domestic investment to provide feedstock and production/generation facilities for the replacement fuels. In this study, alternative fuel supply investment within Washington state is deemed to come from capital outside the state. This external investment in productive facilities in Washington state creates employment, income and state product greater than would exist without this stimulation. We also investigate alternative investments structures that include a split of investment between state and external sources. In-state alternative fuel production investments are deemed to crowd out other in-state investments and may result in some economic losses, particularly in the early years.

The potential decision by Washington state to institute an LCFS will provide opportunities for economic development within Washington state that would not occur in the absence of such a rule. Such investments will not occur in the absence of the rule, as investors would have no guarantee that the market for alternative fuels would materialize. Indeed, the petroleum sector could modify delivery prices in areas where such investments were made to make these investments uneconomic. However, with the rule in place, low carbon fuel suppliers are effectively guaranteed a market for their product as the fuel mix is required to meet the carbon intensity requirements of the regulation. Without a supply of these low carbon substitutes, traditional petroleum could not be sold in the Washington state market.

The level of investment assumed in the macroeconomic model is considered fixed in the baseline. Thus, new investment from outside of Washington state will increase economic activity in Washington state in the scenarios. This is particularly true in the short run as there is very little alternative transportation fuel produced in Washington state today. If these investments, or even a portion of these investments, came from within Washington state, they would replace other Washington state investments. The economic impacts would then be measured as the impacts of the new investment less that of the displaced investment. This origin of capital analysis is undertaken in the sensitivities analysis. In the sensitivity analysis of capital origins, the measured economic impacts are likely to be positive, as only a portion of the investments would displace existing investments and the impacts of the displaced and new investments are likely to be similar in aggregate. Also, regardless of the source of the investment dollars, the CFS policy (under most scenarios) would achieve a displacement of imports by domestically produced fuels, which allows the state to gain economic benefits associated with the production and sale of fuels – benefits currently enjoyed almost exclusively by out-of-state providers.

This analysis considers impacts to over 160 distinct sectors of the economy. The nature of the expected impacts under the scenarios considered suggests that certain specific sectors would be likely to see significant impacts. The anticipation of the construction of new biofuels refining facilities suggests likely gains for the construction sector. Because construction is labor-intensive work (when considered in terms of the number of full-time-equivalent positions per dollar expended in the sector), employment is also anticipated to rise, and as a further consequence, incomes and consumer spending are expected to rise as well. Petroleum production would be expected to show a loss in economic activity as alternative fuels displace gasoline and diesel fuel. The modeling and analyses produced results which agree with these expectations.

6.2 Scenario Development

This scenario analysis is not a forecasting effort. Forecasting economic conditions in a particular year is a challenging prospect. Projections of future economic conditions depend on the expected growth in population and in economic activities, but are subject to the effects of natural, economic and political conditions during the forecast period that are impossible to predict with precision. Natural disasters, international banking collapses, war, embargos and many other unpredictable events will determine the future level of economic activity. The best that can be done is to develop a state economic forecast that is consistent with the national forecast and recognizes any unique characteristics of the Washington state economy. This forecast is the BAU scenario, without an LCFS either in Washington state or nationwide. Fortunately, this analysis requires only a baseline, and not a full economic forecast, to assess the impacts of the standard.

The transportation fuel supply industry in Washington state will have a range of options available to it to supply transportation fuel to the state while meeting the LCFS. The OFM and Ecology, working with the advisory committee and LCA, developed a set of compliance scenarios that are believed to bracket the range of potential fuel supply options. All of the selected compliance scenarios result in compliance with the LCFS, and they are expected to bracket a range of realistic assumptions regarding the low carbon fuels available in the future.

A compliance scenario combines information from a fuels assessments and the calculation of carbon intensities to estimate the volume of various low carbon fuels that would be needed to achieve the LCFS each year in the projection. There are several purposes for developing compliance scenarios:

- Scenarios allow the State to determine the quantity of low carbon fuels needed for compliance with an LCFS
- Scenarios allow the State to identify any gaps in alternative fuel availability that would need to be filled to have a feasible program. This allows regulators to identify investment needs and economic development opportunities for Washington state to increase the availability of lower carbon alternatives fuels by 2026.

- The different compliance scenarios allow the state to evaluate the reasonable range of possible economic impacts associated with different compliance options.

Impacts are measured by comparing each compliance scenario to the BAU scenario. The direct, indirect, and induced impacts are catalogued for each scenario compared to the BAU for macroeconomic variables such as employment, personal income, and state product.

6.3 Translating VISION Outputs to REMI Inputs

Macro- and micro-economic models seek to evaluate economic activity at two very different levels. Micro analysis is concerned with activities for individuals or small groups of economic factors such as households, firms or agencies. In this case, the modeling seeks to understand how the demand for transportation fuel is impacted by vehicle technology changes, driving patterns and fuel choice. VISION includes a full accounting of these decisions in the base year and in each forward year through 2026. It keeps track of the fleet over time so that the amount of fuel used, by type, is accounted for. While the VISION model is a valuable tool for measuring the impacts of changes to vehicle fleets and fuels, it does not produce macroeconomic impacts that show how such changes might reverberate through the broader economy.

Macroeconomic models are broad aggregates of the economy. Sectors in the macro model include many products and industries collected and measured together. Significant increases in the consumption of biofuels, particularly of biofuels produced in-state, can be expected to impact forestry, farming, and agricultural sectors of the economy. Significant shifts away from petroleum-based fuels (gasoline and diesel) can be expected to have impacts on businesses involved in oil production, refining, and transportation. Significant new utilization of natural gas or electricity produced in-state would also affect related industries. Macroeconomic models seek to estimate these broader impacts. Thus, both micro and macro models are required to simulate the economic impacts of the LCFS. These models can be separate stand-alone models or they can be combined in a single program that translates and transfers the micro changes caused by this regulation to the macro model. In this case, we took advantage of the microeconomic detail of the VISION model and the capacity for macroeconomic aggregation of the REMI PI+ model produced by Regional Economic Models, Inc. Other individual and combined models are available, but none offers more detail than those applied.

As mentioned above, VISION provides projections of consumer spending on fuels and vehicles, but these are not the only values necessary to fully inform the REMI PI+ model of the direct economic expenditures expected under the different scenarios. The team has also developed estimates for infrastructure investment for each scenario, presented above and in Appendix A.

7. Macro-Economic Modeling Results

The macroeconomic analysis was accomplished with the use of the REMI PI+ model, Version 1.6.5. First, the BAU case was run for Washington using the REMI default case. Then, a model run was conducted and the results were compared to the BAU for each scenario. The analysis focused on change in employment, personal income and gross state product, but more detailed comparisons are available for each economic sector characterized in the 160 sector REMI as well as all categories of final demand. The following sections provide results for the eight compliance scenarios and the sensitivity tests on credit price and location of cellulosic biofuel plants.

7.1 Compliance Scenario Results

The eight compliance scenarios were designed to include a wide range of potential compliance scenarios for the Washington fuel supply sector. The graphs below indicate how macroeconomic variables such as income, employment and state product vary across scenarios. All three macro variables move together as the scenarios alter the low carbon fuel mix. In all cases the Washington economy and fuel supply system is treated as the responder to the LCFS as it purchases and supplies the needs of Washington vehicles for fuel that meets the standard. No national LCFS is assumed. The potential supply of fuel from each source is determined in the scenario and limited if there is a capacity constraint. The macroeconomic results of this analysis for the LCFS compliance scenarios considered are summarized below in Table 7-1.

Table 7-1. Summary of Economic Impacts for LCFS Compliance Scenarios

	Range of Impact Relative to BAU (Units)	Range of Impact Relative to BAU (Percent)
Annual Average Change in Employment	1,130 - 2,870 Added	0.03% - 0.07%
Annual Average Change in Income	$82M - $248M Added	0.02% - 0.06%
Annual Average Change in Gross State Product	$130M - $300M Added	0.03% - 0.07%

All scenarios that rely on liquid fuels demonstrate similar macro impacts. Investment in new plants and equipment to produce these fuels and the required infrastructure stimulates the Washington economy in the years when plants are built and in their continuing operation. Positive economic impacts in Washington stem from the importation of less petroleum fuel and its replacement with Washington produced products. To the extent that the Washington LCFS reduces national petroleum imports, similar economic impacts will be realized. In the longer term, vehicle fuel economy is expected to continue improving, resulting in further reductions in petroleum consumption through 2030.

The macroeconomic modeling analysis produced estimates of overall economic impacts, as well as specific impacts to approximately 160 different sectors of the economy, for all eight different compliance scenarios. The full results are included in this report as Appendix B.

The first metric utilized to evaluate macroeconomic impacts is gross state product (GSP). Figure 7-1 demonstrates the change in GSP relative to the BAU for each scenario without banking and trading. Figure 7-2 provides the change in GSP for the scenarios with banking and trading. In every scenario, the overall GSP changes are positive, indicating that the scenarios drive growth in economic activity in the state. Each line can be understood by two characteristics: its general trend and scale of that trend, and GSP spikes. The general trend is upward for all scenarios, as evidenced by the final levels in the year 2026. Most scenarios also contain a rapid upward jump shortly after 2020 as the construction of major biofuel manufacturing facilities (each costing roughly $306 million) are constructed. Where two plants are built in successive years (one per year), the spike contains a plateau. Where the plant construction is separated by a year or more, the GDP line for that scenario is characterized by two separate spikes (as in Scenario A). Note that Scenarios C and D with banking and trading do not utilize cellulosic fuels, so there are no spikes associated with cellulosic biofuel plant construction.

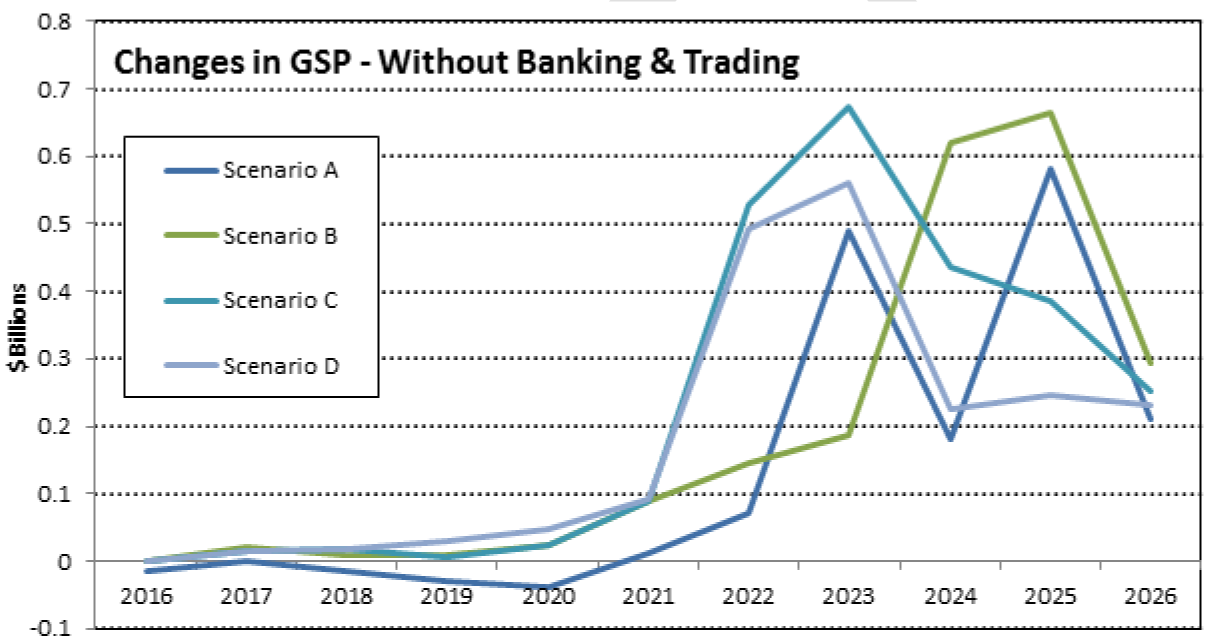

Figure 7-1. Change is GSP Relative to BAU for Scenarios without Banking and Trading.

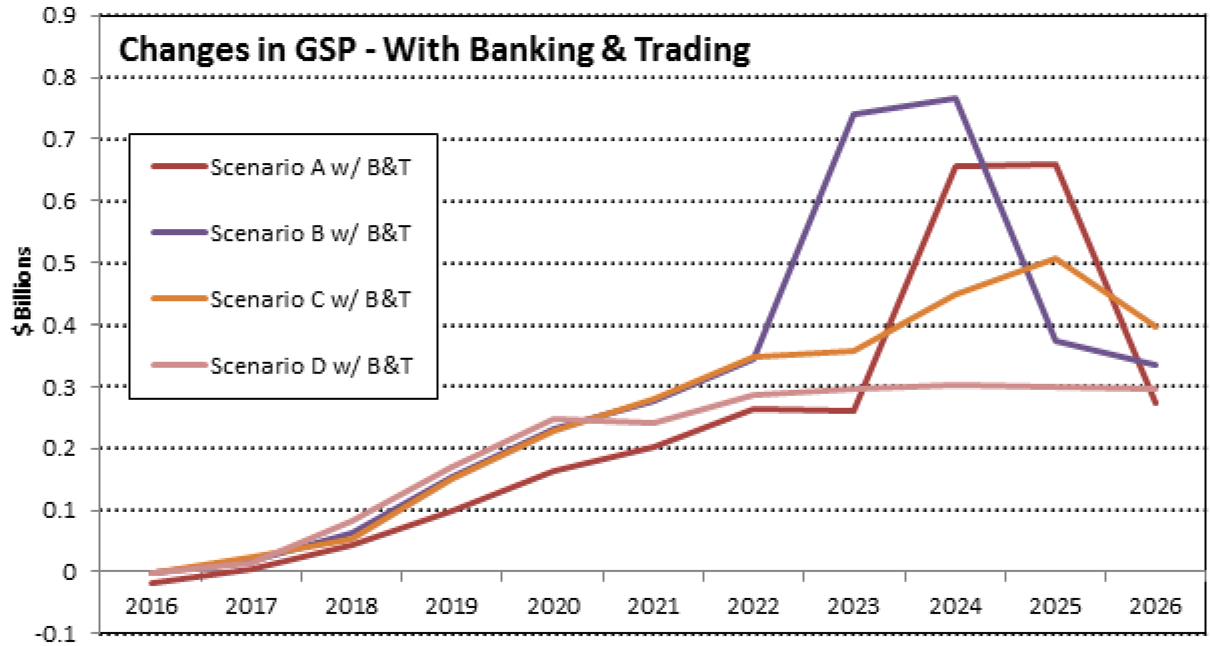

Figure 7-2. Change is GSP Relative to BAU for Scenarios with Banking and Trading.

The eight different scenarios represent four different possible market responses to the LCFS, and variations on those four which assume that credit banking and trading are in place. Their overall impact in GSP over the entire 2016-2026 period is visualized below in Figure 7-3. The banking and trading scenarios consistently produce better outcomes despite the absence of construction of major fuel-manufacturing plants in Scenarios C and D.

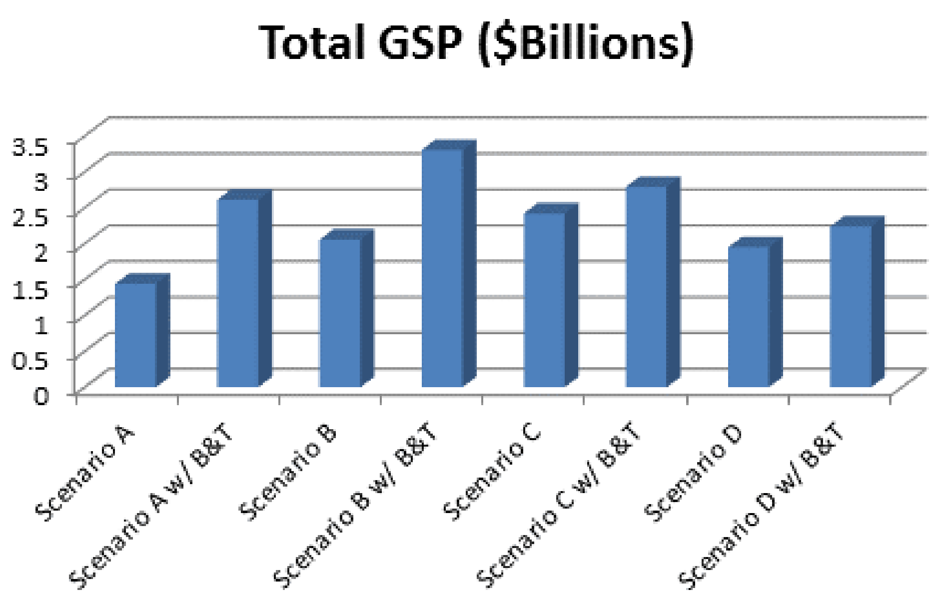

Figure 7-3. Cumulative GSP Relative to the BAU.

Two other metrics used to evaluate macroeconomic impacts not captured as sectors are employment and overall person income. Figures 7-4 and 7-5 provide annual employment impacts (measured in jobs) for the scenarios with and without banking and trading. As with GSP, employment impacts are higher in the banking and trading scenarios (stabilizing at 2,300 and 3,600 new jobs by 2026), than they are in the scenarios where no such trading mechanism is present (new jobs stabilize between 1,800 and 2,700). That said, all scenarios show positive employment results.

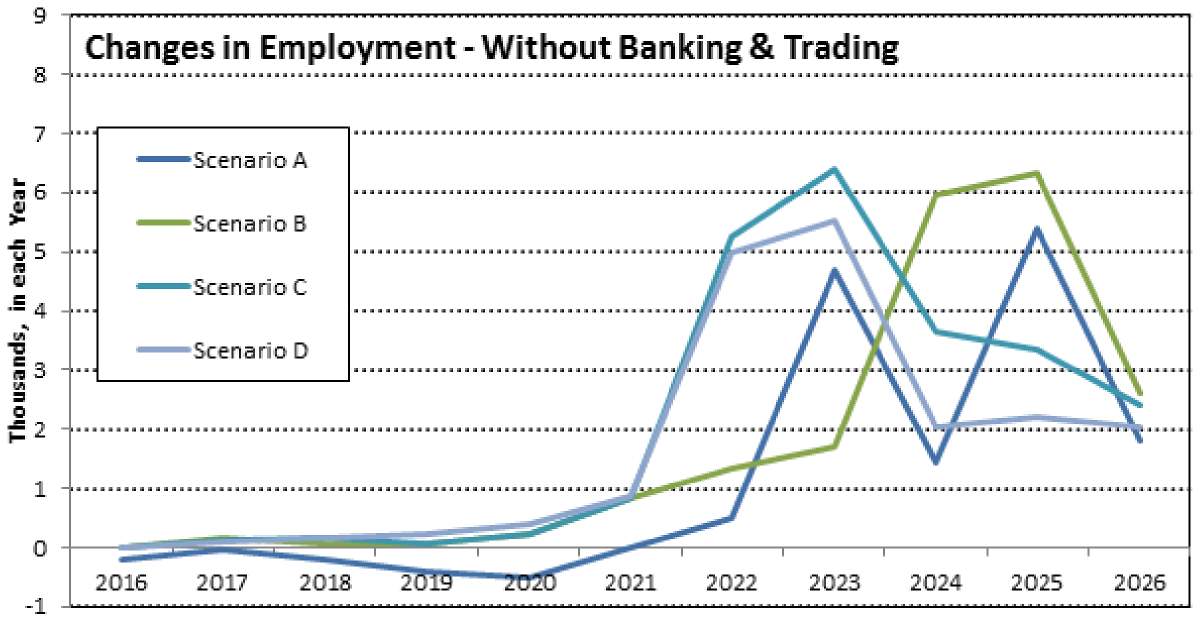

Figure 7-4. Change in Employment Relative to BAU for Scenarios without B&T.

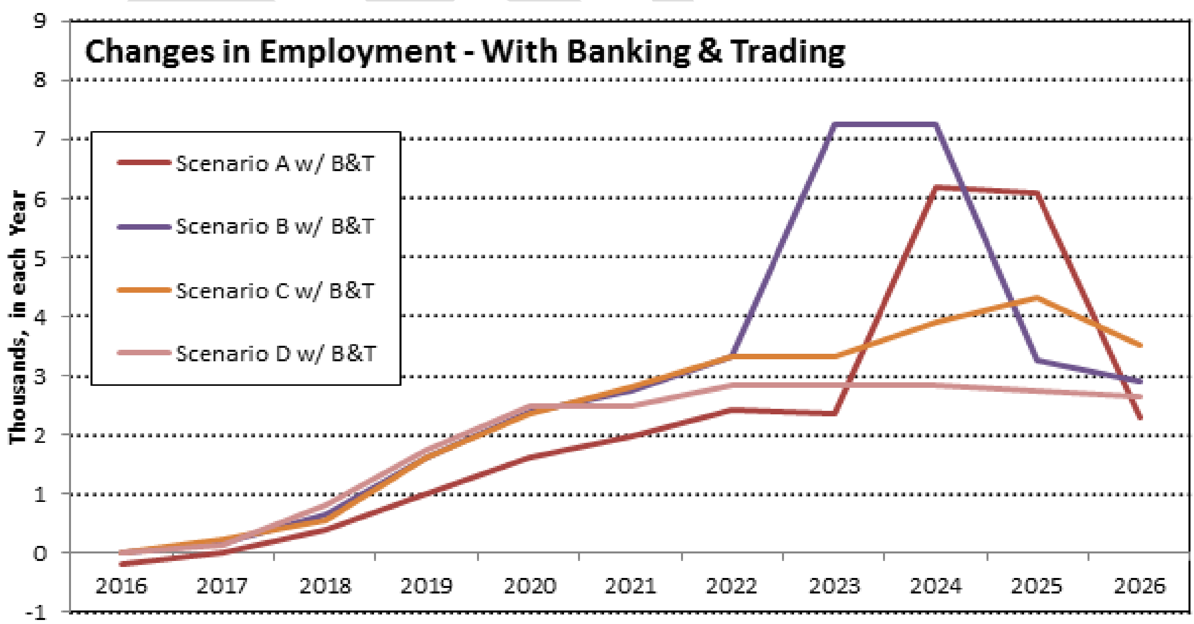

Figure 7-5. Change in Employment Relative to BAU for Scenarios with Banking and Trading.

The scenarios reflect a correlation between the intensity of investment, which tracks with the timing of refinery construction, and increases in employment. Once plants are built, they directly employ relatively small numbers of people (below 100 per plant). During the construction phase, by contrast, the spending involved works through the economy to create employment for thousands of people. Income levels (Figures 7-6 and 7-7) again follow a familiar pattern. Additional employment drives income changes at equivalent points in time across the analysis period.

It is interesting to note that for all three major indicators, Scenario A (advanced vehicles) produces a temporary reduction, rather than gains from the earliest years that characterize the other scenarios. This is only true in the version of Scenario A that does not assume any banking and trading mechanism. The major driver of the early negative results for that scenario is the increase in costs for new vehicles, which constitute a price effect that lowers the available money that consumers who buy cars have available for other spending and savings behavior. This remains the most important factor for the first three to five years, until the positive effects from the domestic production of biodiesel and the construction of plants overwhelm this downward pressure before the halfway point of the 2016-2026 period. Importantly, even after the plant construction is finished, the 2026 results for Scenario A never return to this negative-impact level, but instead stay positive - though smaller in the scale of positive impact than the other scenarios.

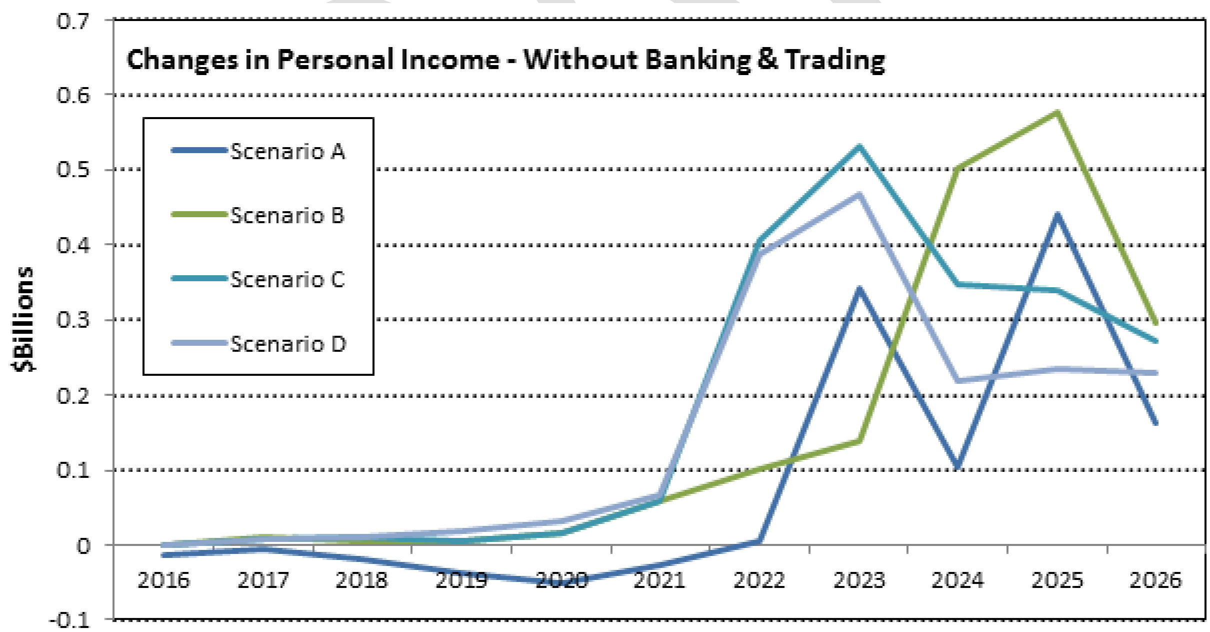

Figure 7-6. Change in Personal Income Relative to BAU for Scenarios without B&T.

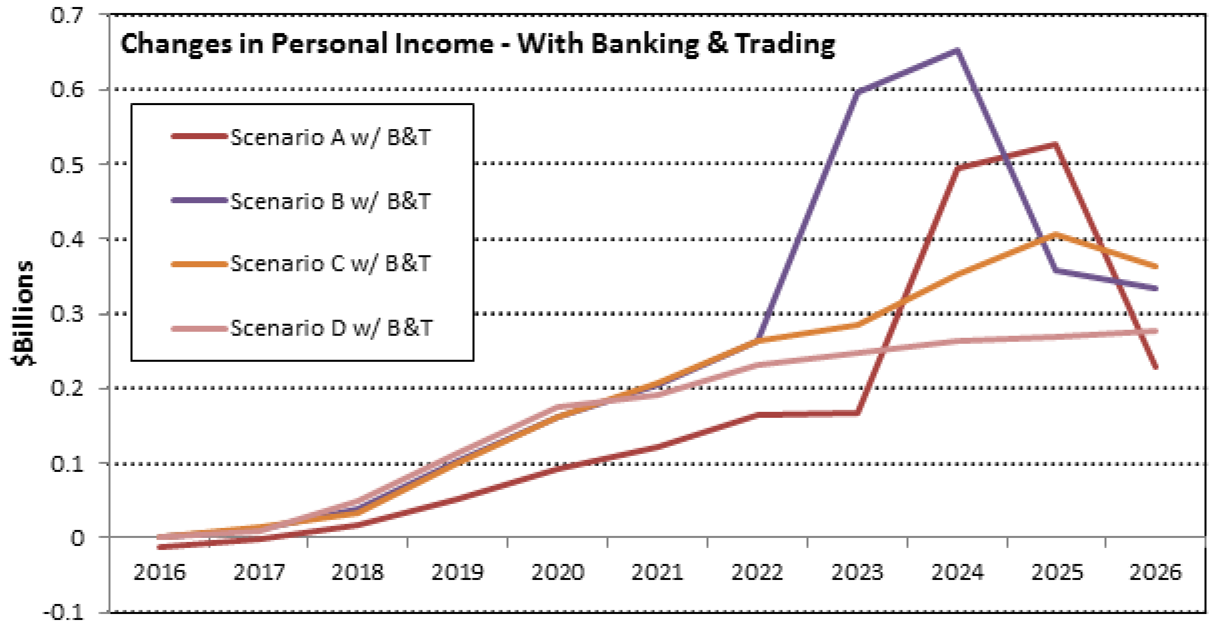

Figure 7-7. Change in Personal Income Relative to BAU for Scenarios with B&T.

7.2 Impact of Credit Price

If Washington state adopts an LCFS and implements a cost containment mechanism that involves a credit cap, it is of interest to estimate the impact of different credit price caps on macro-economics. As mentioned in Section 4.7, all of the scenarios were evaluated with the assumed credit price profile shown in Figure 4-5 with a maximum price (cap) at $100 per tonne. In addition, Scenario C with banking and trading was evaluated according to three additional credit price profiles (shown in Figure 4-8) with credit prices capping out at $50, $150 and $250 per tonne.

Figures 7-8 through 7-10 summarize GSP, jobs and personal income as a function of maximum credit price. Although these three indicators show that this Scenario has a positive economic impact over the range of credit prices, benefits decline as credit prices rise.

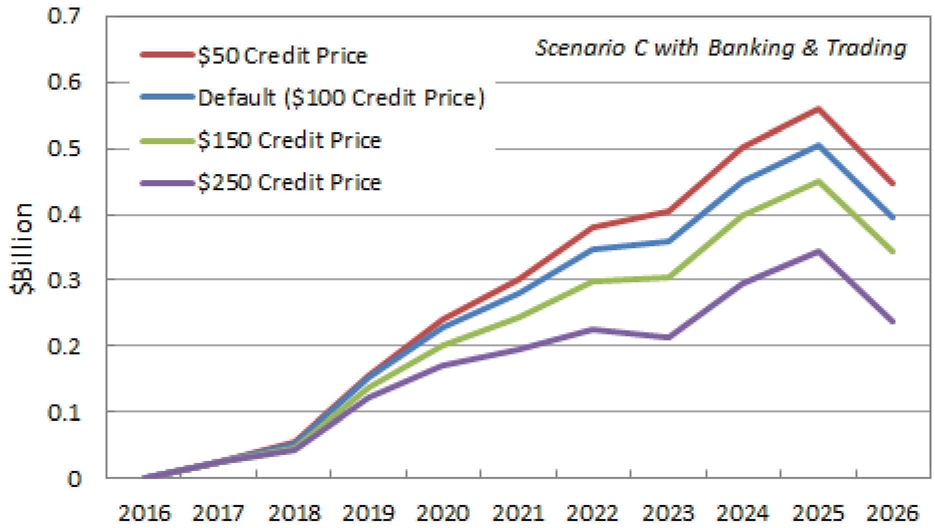

Figure 7-8. Change in GSP Relative to BAU as a function of credit price.

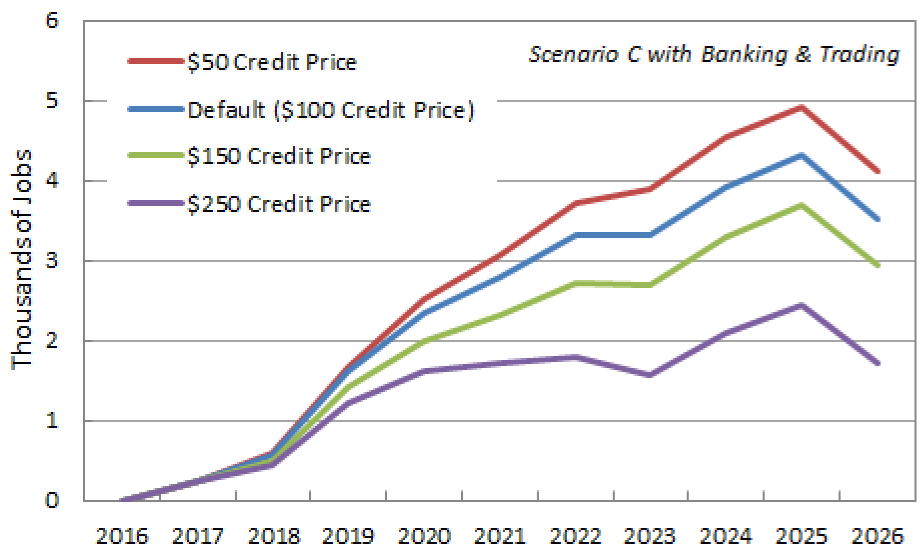

Figure 7-9. Change in Employment Relative to BAU as a function of credit price.

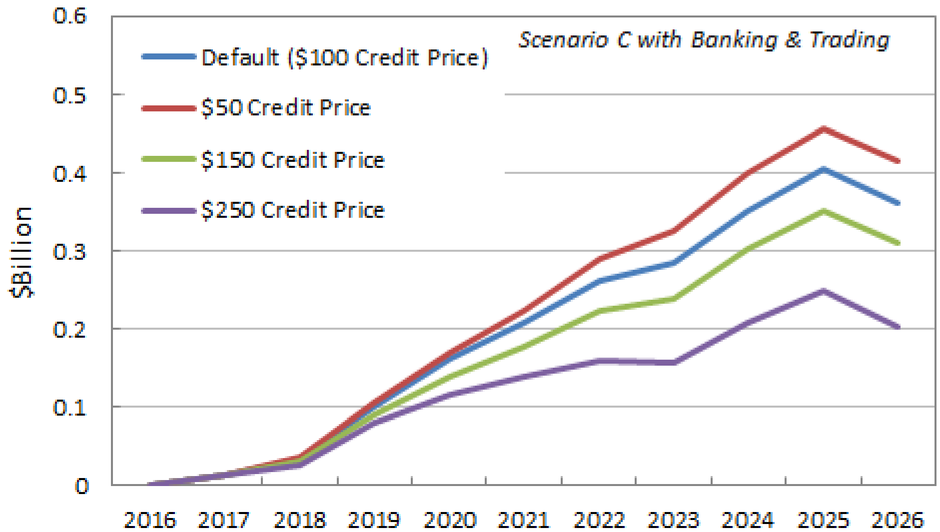

Figure 7-10. Change in Personal Income Relative to BAU as a function of credit price.

7.3 Impact of In-State vs Out-of-State Cellulosic Plants

An additional sensitivity test was performed to quantify the impact of having cellulosic production capacity within Washington state. Recall that the base assumption was that up to three cellulosic plants would be sited in-state. Figures 7-11 through 7-13 provide economic indicators for Scenario B with banking & trading for the base case (three cellulosic fuel plants in-state) and assuming that all cellulosic fuel is imported into Washington. While the GSP, employment and personal income are all still positive when cellulosic fuel is imported, in-state fuel production is beneficial; if the state implements an LCFS, it may want to consider incentivizing in-state production.

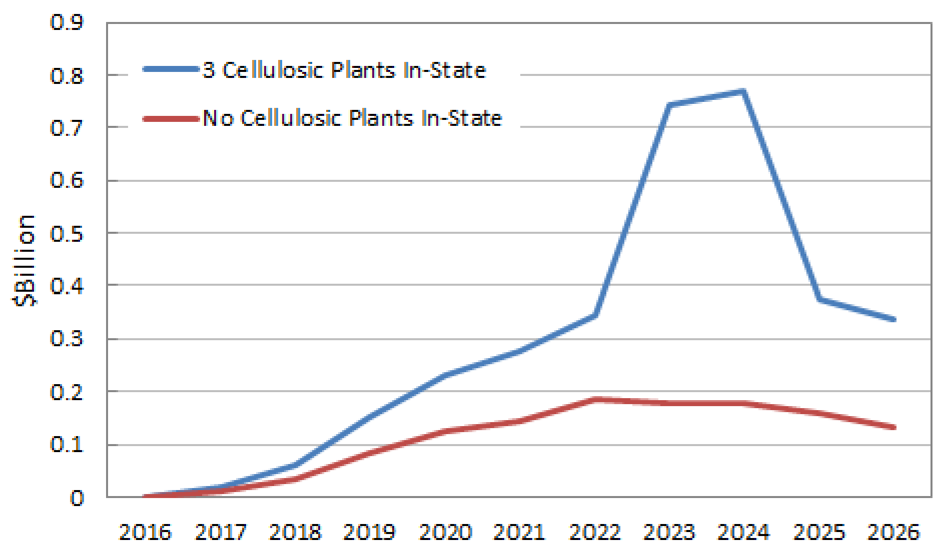

Figure 7-11. GSP Relative to BAU with and without In-State Cellulosic Fuel Production.

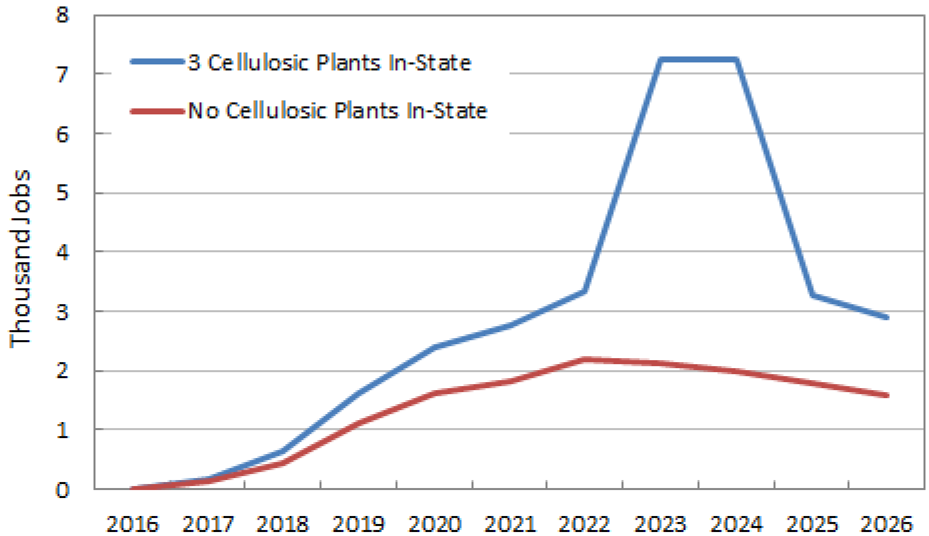

Figure 7-12. Employment Relative to BAU with and without In-State Cellulosic Fuel Production.

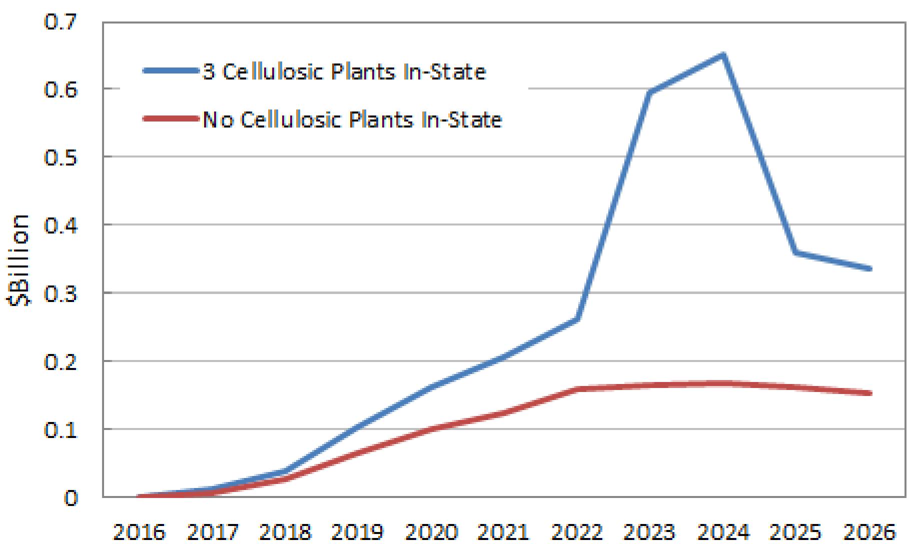

Figure 7-13. Personal Income Relative to BAU with and without In-State Cellulosic Fuel Production.

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 vehicle energy consumption, consumer spending on fuel and vehicles, 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-dependent fuel use for the existing fleet (1970 to present). To project characteristics of the future fleet, the model uses assumptions about 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 total vehicle sales utilized in the BAU and all compliance scenarios.

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%

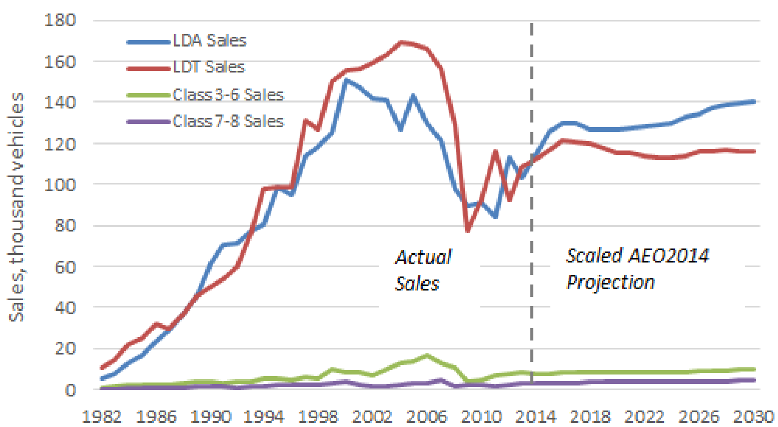

Figure A-1. Projected vehicle sales in Washington State by class.

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 paragraphs.

For light auto plug-in electric vehicles (PEVs), we set the population in 2020 to be consistent with the Washington state PEV goal[56] of 50,000 cumulative vehicle sales by 2020. The VISION model default (AEO2013 projection) 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 and smooth from most recent actual data (2013) to this point by 2018. We feel that this it is reasonable to decrease the BEV share despite strong performance to date; this early surge in BEV market shares relative to PHEV shares may be anomalous relative to long term trends due to early model availability and favorable leasing terms. 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 current Washington state PEV sales are more than two times higher than AEO values.

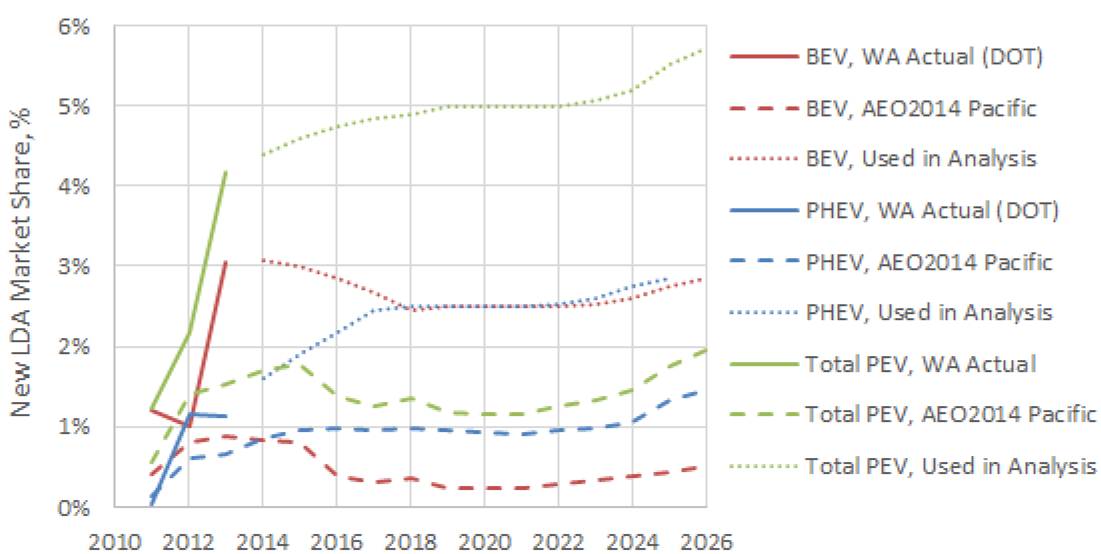

Figure A-2. Forecast light auto PEV Market Shares for Washington State

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. Washington's current market share for CNG vehicles is much lower than the AEO market shares for 2011-2013. Based on discussions with Washington's Department of Transportation, CNG refueling investment is

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

occurring, so we assume here that market shares gradually approach AEO levels. For hydrogen FCVs, we have assumed half of the AEO market share because Washington is not a ZEV state; we assume most of these vehicles in AEO's projection will be sold into California. For diesel HEVs, we utilize the AEO forecast.

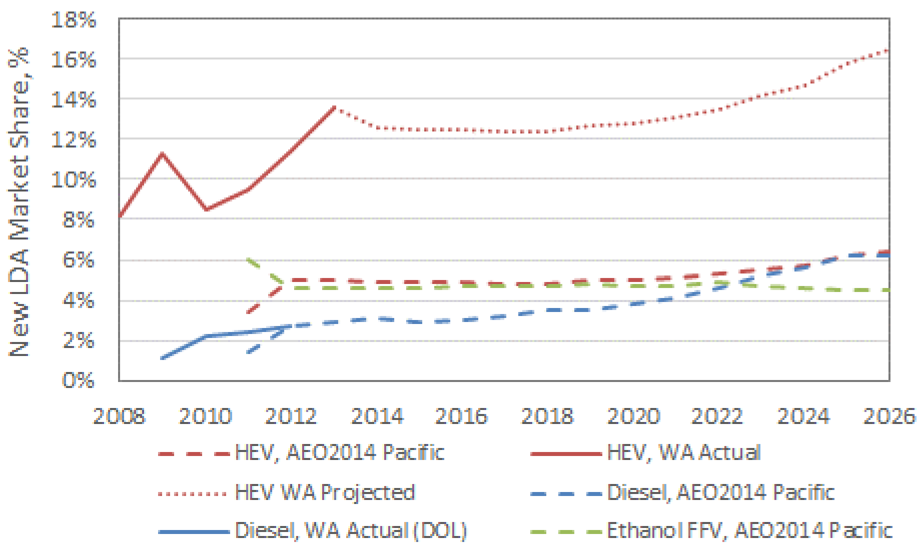

Figure A-3. LDA market shares for HEVs, diesel and ethanol FFVs.

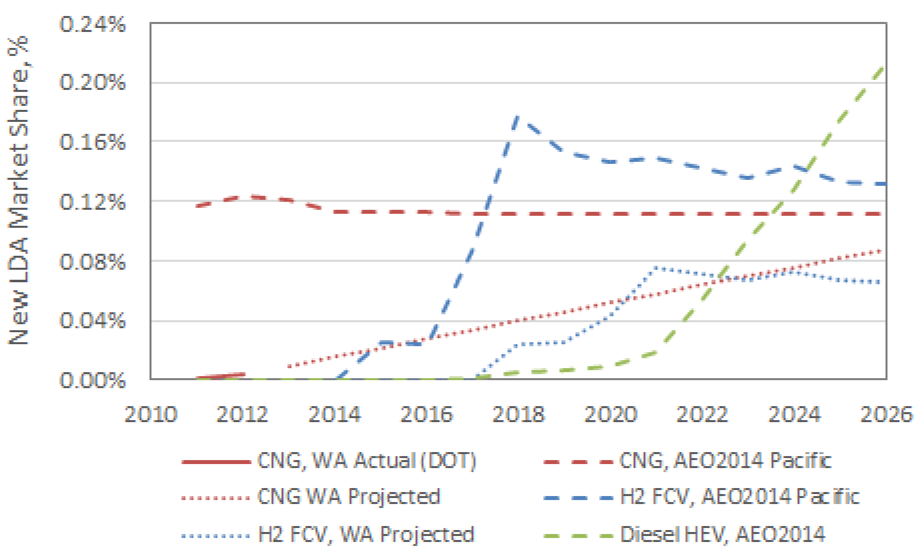

Figure A-4. LDA market shares for CNG, H2 FCV, and diesel HEVs.

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.

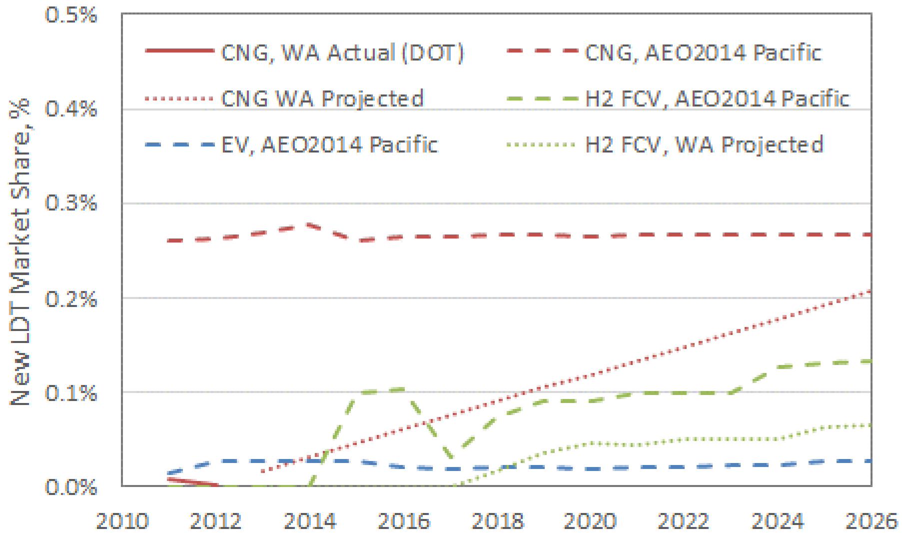

Figure A-5. Light truck market share projections for BEVs, CNG and FCVs

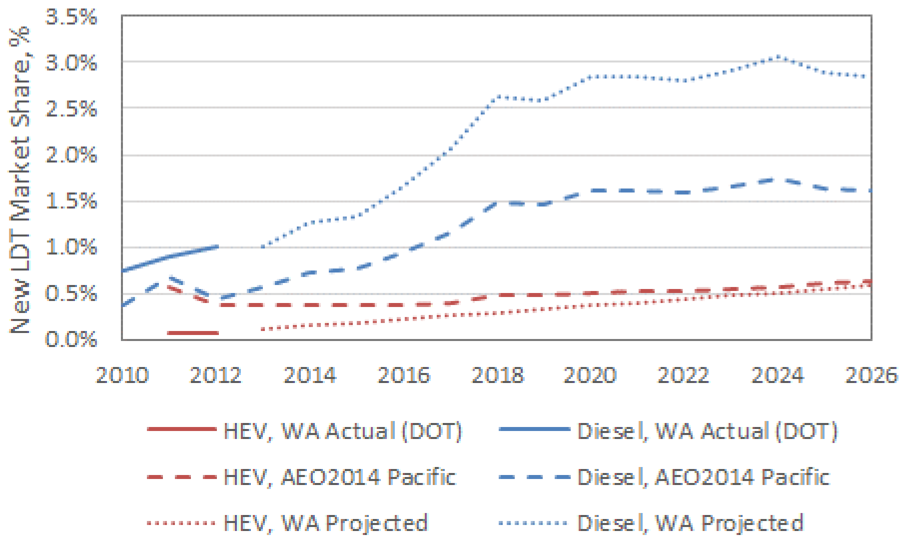

Figure A-6. Light truck market share projections for HEV and diesel

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.[57] The resulting market shares are provided in Figure A-7. The balance of vehicles are diesel.

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

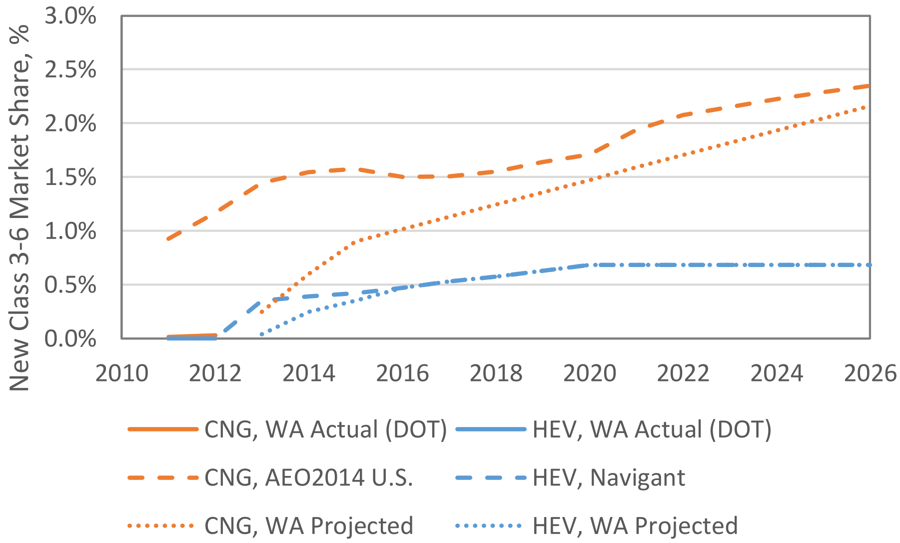

Figure A-7. MDV market share forecasts for HEV and CNG vehicles.

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. The balance of vehicles sold are diesel.

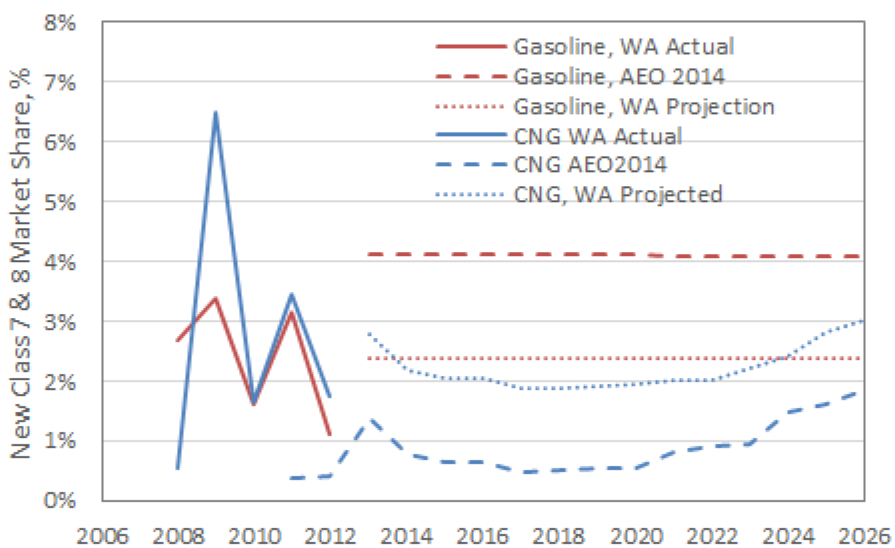

Figure A-8. HDV market share forecasts for gasoline and CNG vehicles.

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.

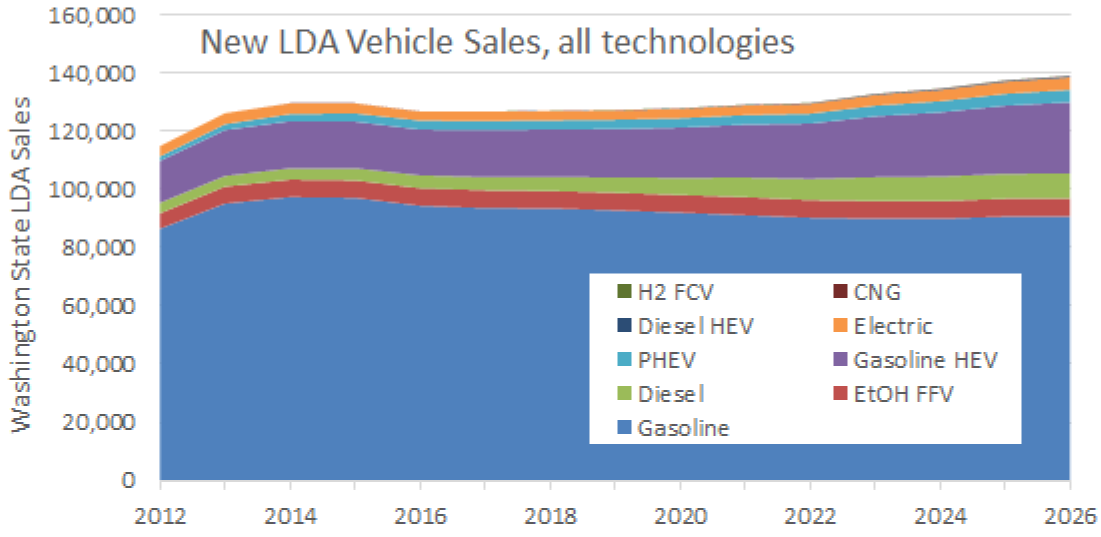

Figure A-9. Forecast light duty auto vehicle sales.

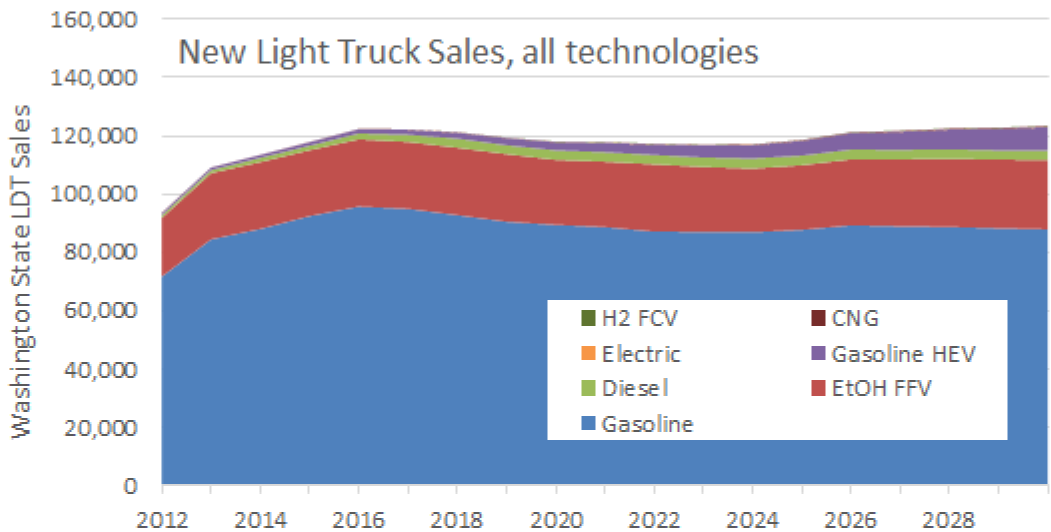

Figure A-10. Forecast light duty truck vehicle sales.

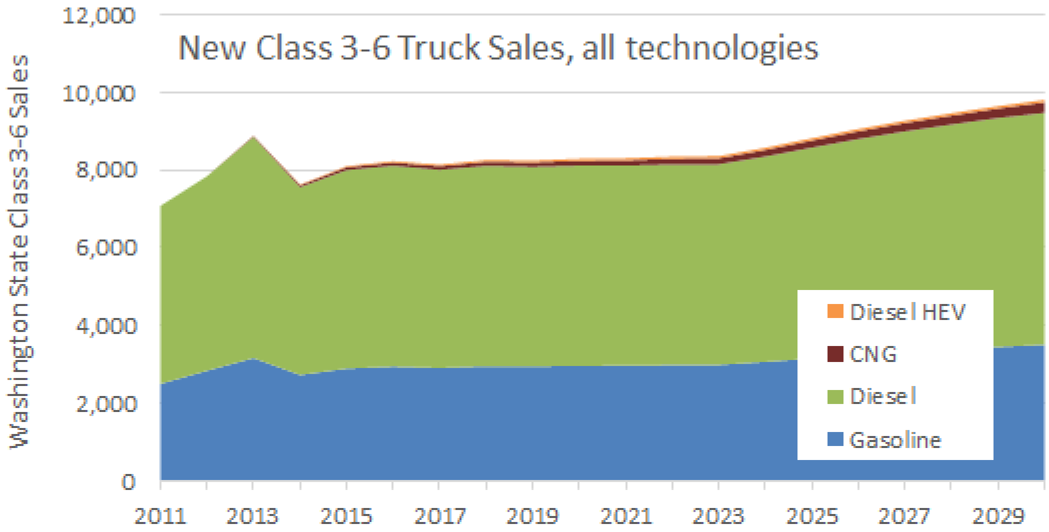

Figure A-11. Forecast medium duty vehicle sales.

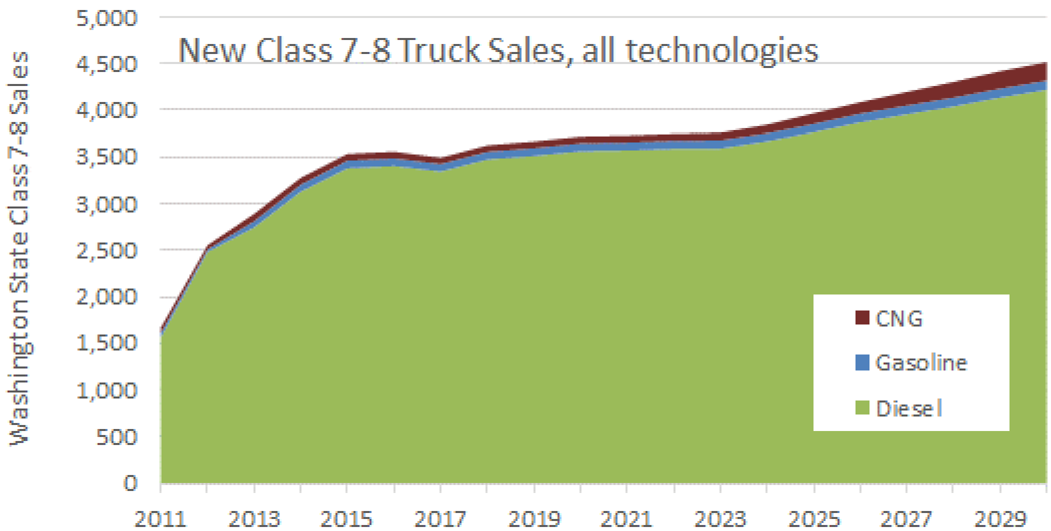

Figure A-12. Forecast heavy duty vehicle sales.

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

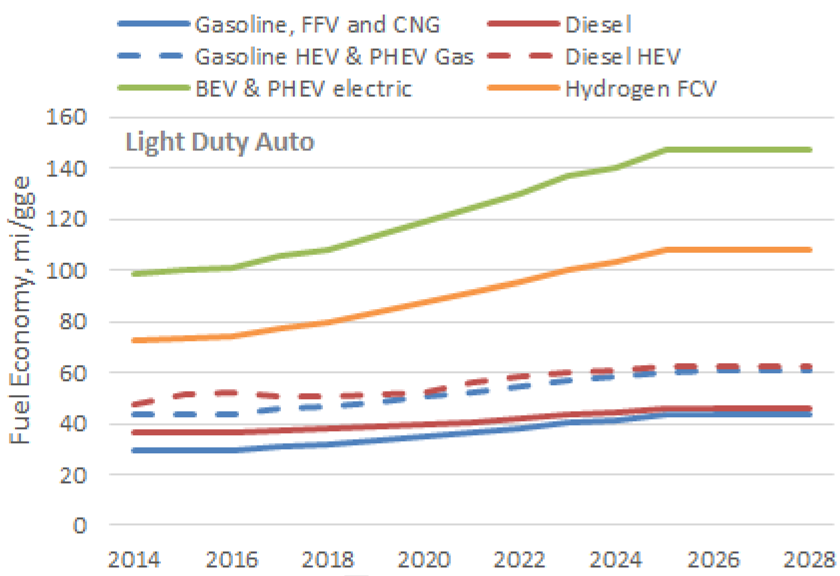

Figure A-13. Projected light duty auto fuel economy.

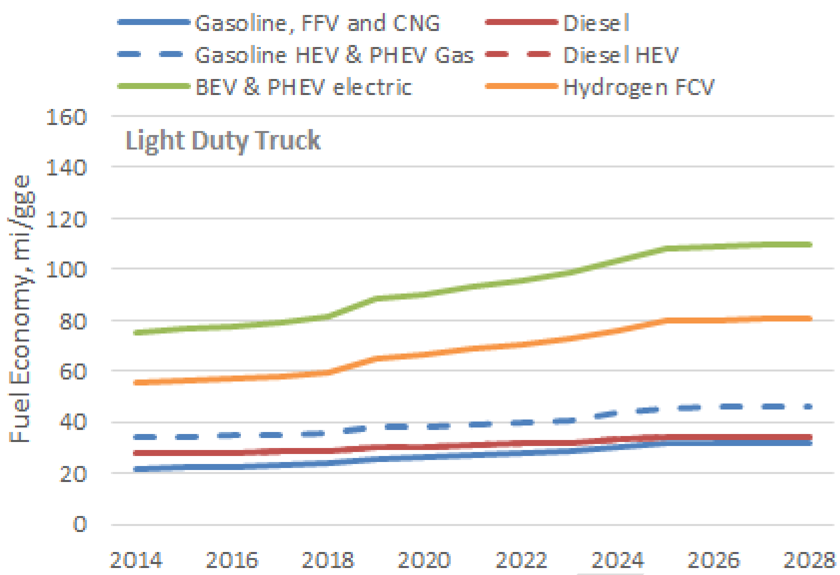

Figure A-14. Projected light duty truck fuel economy.

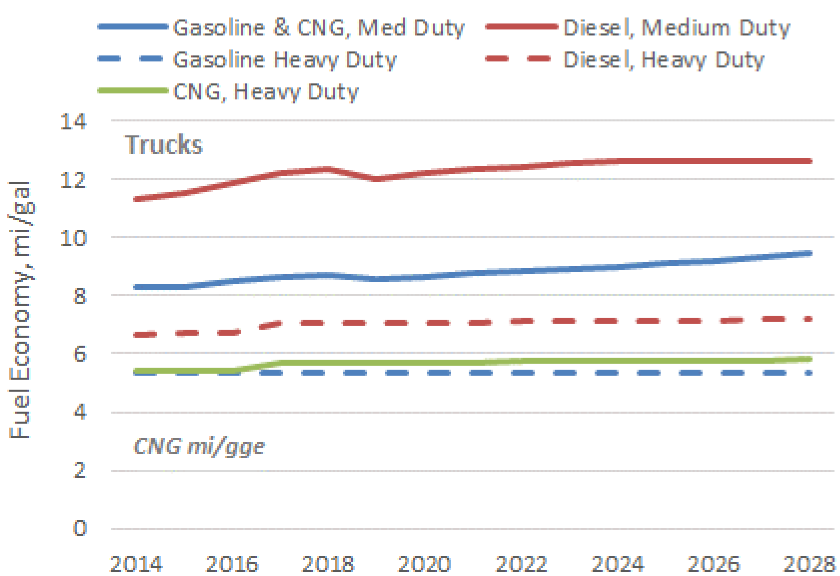

Figure A-15. Projected medium and heavy truck fuel economy.

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.

Throughout the analysis, we have utilized WSDOT's 2013 projections of VMT; however in late September the 2014 projections were published showing significant decreases in VMT. WE have updated the analysis to reflect the new VMT projections. 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. To match the WSDOT trajectory, we apply a factor to the VISION VMT values. Figure A-17 provides the actual and VISION calculated gasoline consumption with the adjusted and trimmed VMT values. The projected 2026 gasoline consumption with the updated VMT projection is approximately 12% lower than the consumption resulting from WSDOT's 2013 VMT projection.

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.

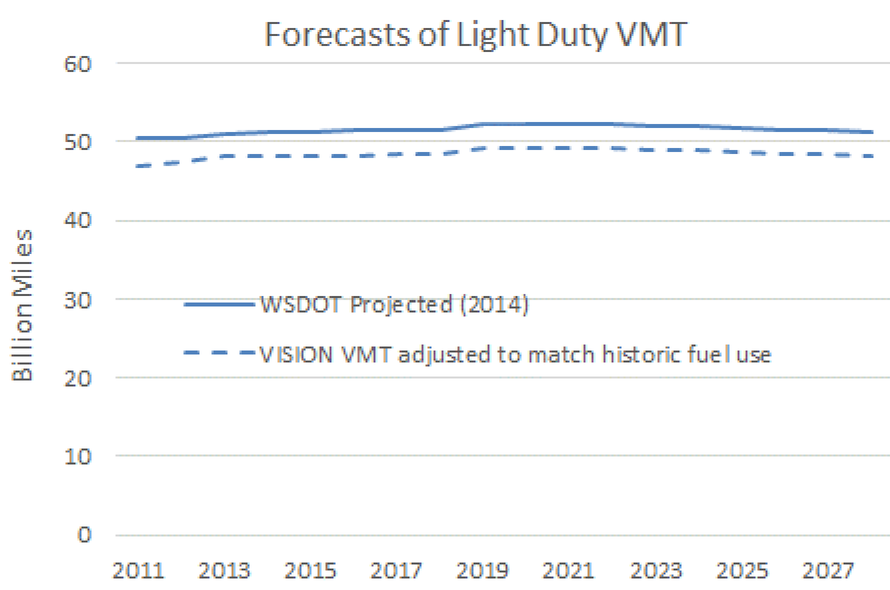

Figure A-16. Light duty VMT forecasts (updated to WSDOT 2014 projection).

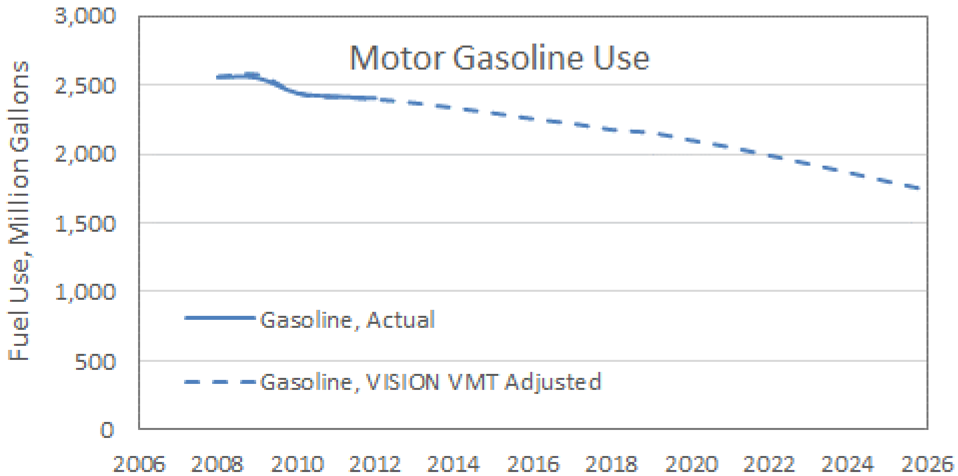

Figure A-17. Actual and calculated gasoline consumption.

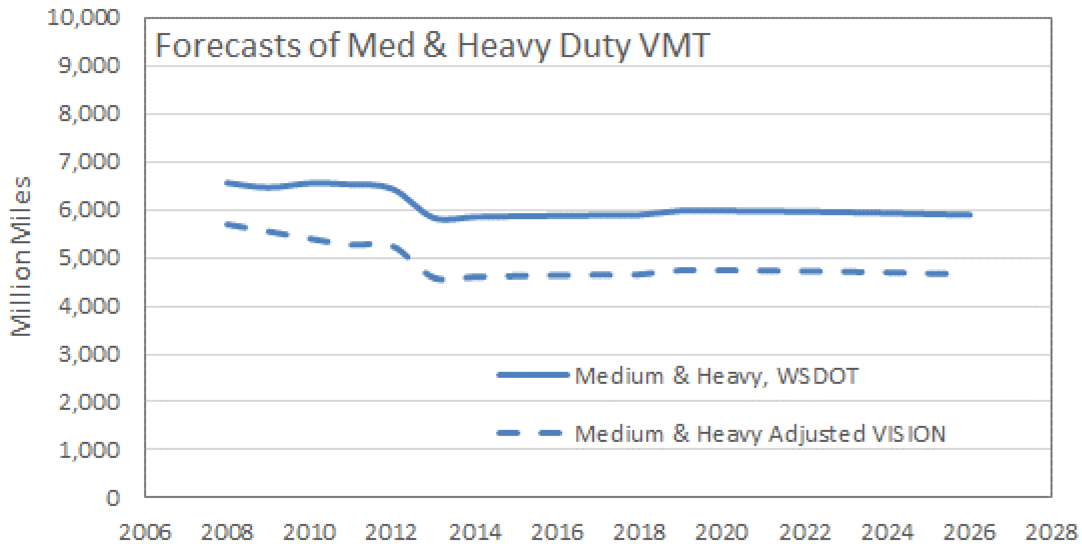

Figure A-18. Medium and heavy duty VMT forecasts.

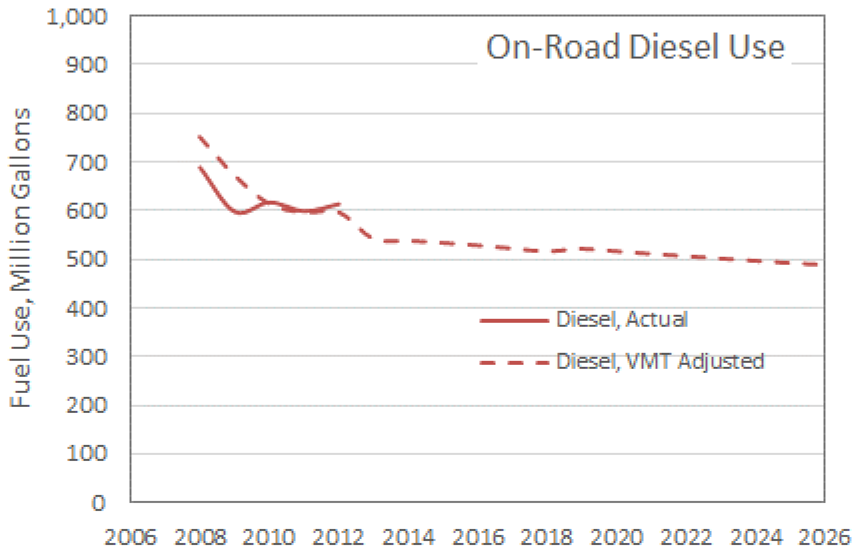

Figure A-19. Actual and calculated diesel consumption.

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 without 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)[58] study. The NAS analysis compares like vehicle to establish incremental retail prices. Figures A-20 and A-21 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. Preliminary pricing announced by Honda and Toyota for the first FCVs to be sold in 2015 is $69,000, at the suggestion of the workgroup we have set the FCV price in 2016 at the same incremental price as the BEV and then allow it to approach 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.

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

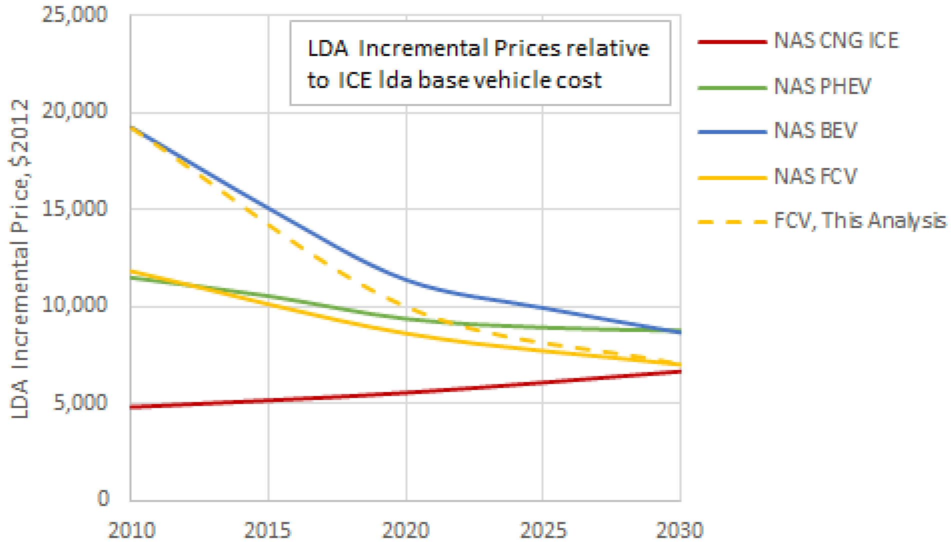

Figure A-20. Light duty auto incremental vehicle prices.

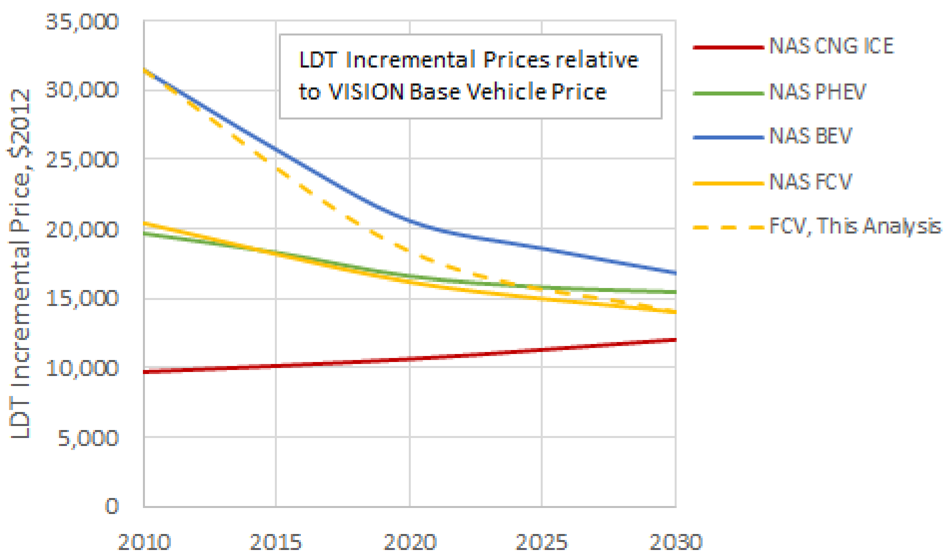

Figure A-21. Light duty truck incremental vehicle prices.

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. All fuel prices shown are in $2012.

We have utilized EIA's AEO2014 fuel price projections for the pacific region where available. Figure A-22 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.

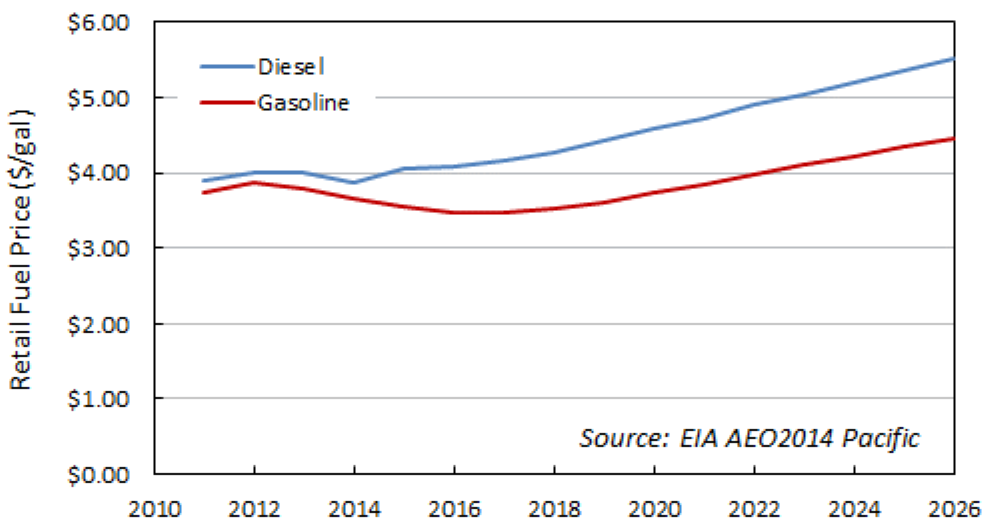

Figure A-22. EIA Gasoline and diesel fuel price projections.

Figure A-23 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 gasoline. 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-24 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. Ethanol as a blending component does add value an octane enhancer.

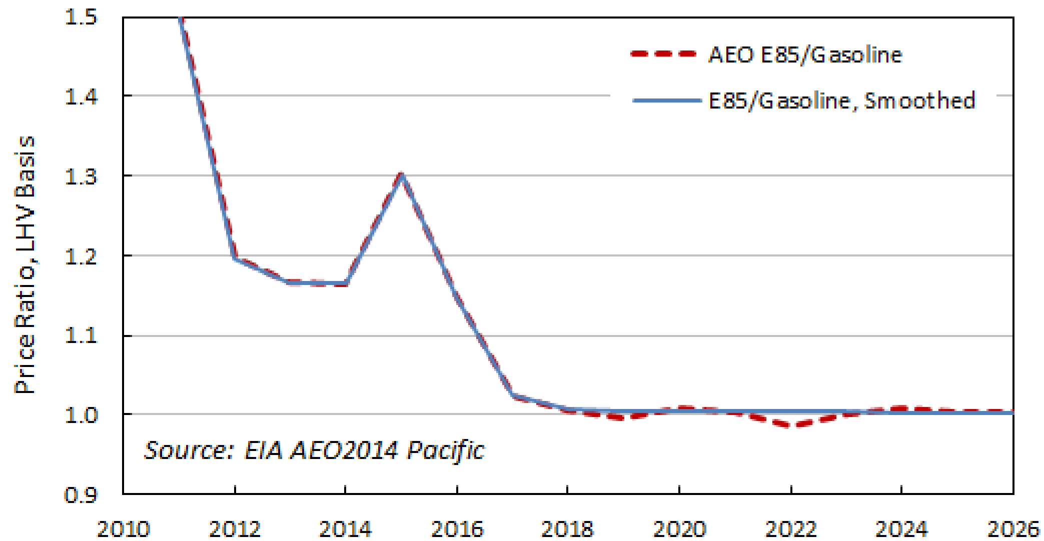

Figure A-23. EIA forecast of ethanol prices sold as E85.

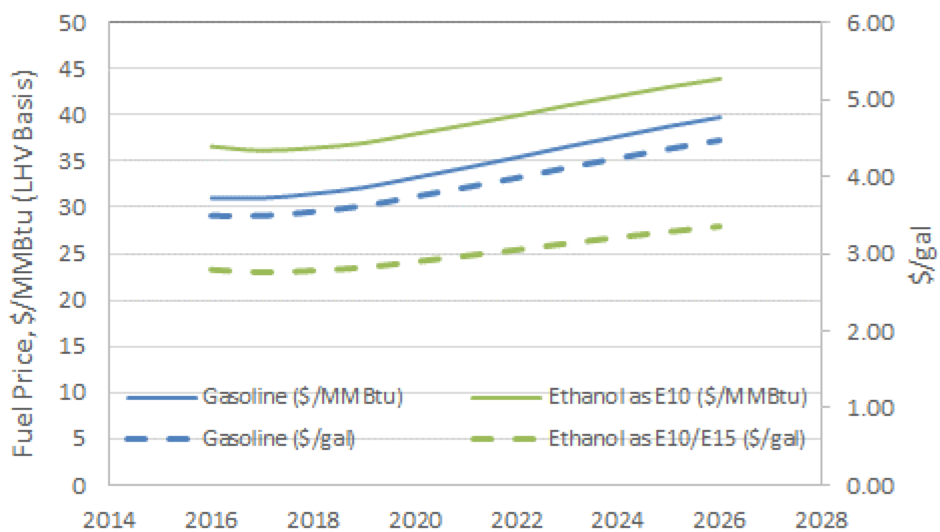

Figure A-24. Price projection for ethanol sold as E10/E15.

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 LCFS credits). Figure A-25 provides the biodiesel price projection compared to the diesel price projection.

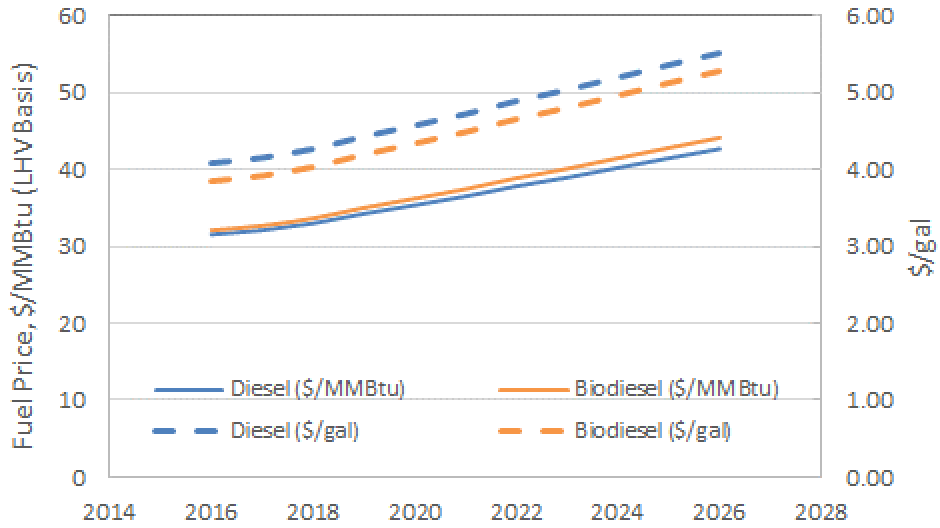

Figure A-25. Assumed biodiesel price projection.

We have utilized AEO's forecast for CNG prices. Figure A-26 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.

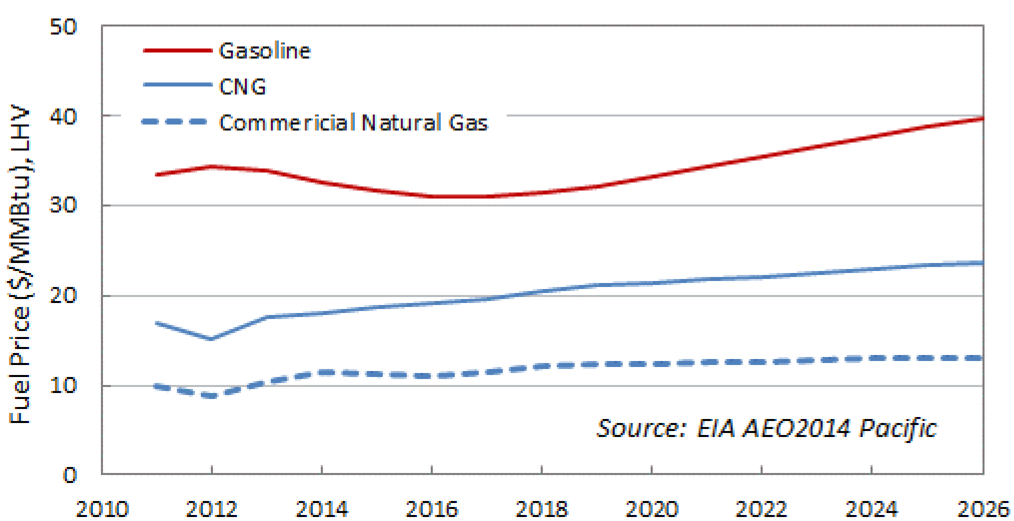

Figure A-26. Forecast CNG prices.

Washington electricity prices for transportation have historically been 78 percent of EIA's pacific prices.[59] We assume this discount persists and have applied a factor of 0.78 to EIA's projected electricity prices for this analysis. The forecast prices are provided in Figure A-27. Prices are shown in $/kWh and $/MMBtu with the EER (3.4) applied.

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

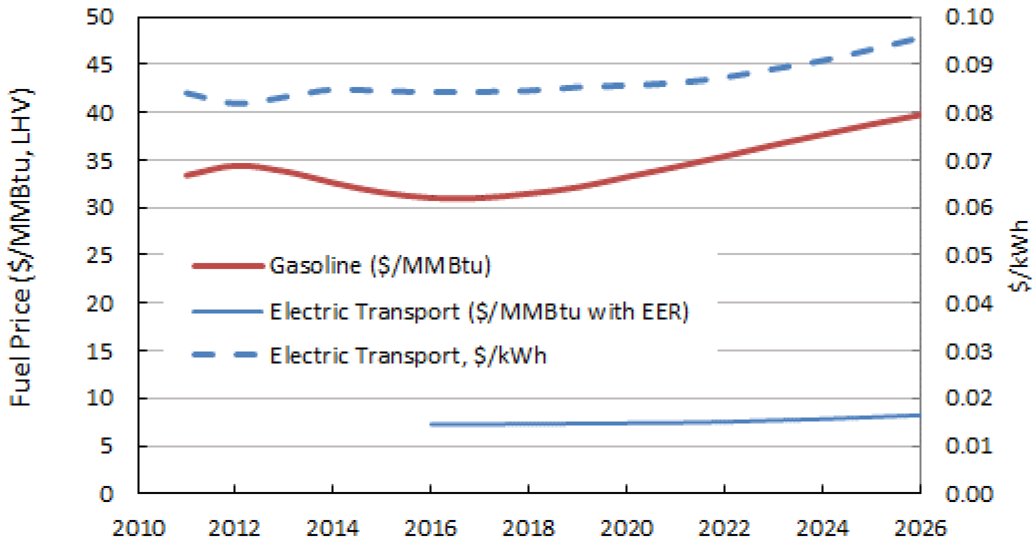

Figure A-27. Forecast electricity price.

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 PEV populations than the BAU case, so these assumptions are only utilized to estimate differences between Scenario A and the BAU. Several classifications of electric vehicle supply equipment (EVSE) were considered: residential, urban area public Level 2, workplace Level 2, and DC fast chargers. For residential charging equipment, it was assumed that for each BEV sold, 90% purchased Level 2 charging equipment and that for each PHEV sold, 30% purchased Level 2 charging equipment.[60] Level 1 charging equipment comes with the vehicle and can simply be plugged into a standard electrical outlet, so no additional costs are incurred for Level 1. These estimates may over-estimate costs as some PEV buyers may be purchasing a second PEV.

To quantify workplace Level 2 charging equipment, we utilized the CEC estimate of workplace charging for 15% of the PEV population with 2.4 charges per day per unit. To estimate the amount of urban area public charging equipment needed for the BAU and Scenario A, a recent CEC PEV infrastructure assessment[61] estimated number of EVSEs per 100 square miles of urban space for two scenarios: home dominant and high public access. Table A-3 provides the EVSE 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 EVSE density values. The urban area in Washington state is provided in Table A-4.

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

Table A-3. Urban Area EVSE 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

To estimate the number of DC fast charge stations located along major highways, we assume 40 miles between chargers for the BAU case (consistent with Washington's portion of the West Coast Green Highway) and 25 miles between chargers for Scenario A. Table A-5 provides the estimated miles of major highways in Washington state. Table A-6 summarizes the total annual sales of EVSE.

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

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 Summary of Annual EVSE Sales for BAU and Scenario A

	Residential L2		Workplace L2		Urban L2		Urban DC Fast		Highway DC Fast	
	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A	BAU	Scen A
2017	3,981	4,374	715	2,671	67	161	3	5	6	10
2018	3,750	5,510	715	2,671	67	161	1	4	6	10
2019	3,824	6,812	536	2,003	51	120	1	4	4	8
2020	3,831	8,668	447	1,669	42	100	0	3	3	6
2021	3,839	10,355	358	1,336	34	80	0	2	2	6
2022	3,863	11,669	268	1,002	25	60	0	2	2	3
2023	3,945	13,059	179	668	17	40	0	1	2	3
2024	4,065	14,132	143	534	13	32	0	1	2	2
2025	4,419	14,940	107	401	10	24	0	0	1	1
2026	4,640	15,192	107	401	10	24	0	1	1	2

Installed costs for residential Level 2 EVSE, public Level 2 EVSE, and DC fast charge stations are assumed to be $1,200,[62] $8,700,[63] and $92,000[48] respectively. For the analysis we have assumed these costs are constant through 2026 although they may decrease.

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 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	638,770	806,362	6	7		
2017	676,368	887,245	6	8	0	1
2018	713,245	963,507	7	9	1	1
2019	764,287	1,055,137	7	10	0	1
2020	805,501	1,131,081	7	10	0	0
2021	851,748	1,211,912	8	11	1	1
2022	902,208	1,297,144	8	12	0	1
2023	954,722	1,384,411	9	13	1	1
2024	1,010,306	1,475,991	9	13	0	0
2025	1,077,617	1,583,591	10	14	1	1
2026	1,150,864	1,699,287	11	16	1	2

[62] Rocky Mountain Institute, "Pulling back the Veil on EV Charging Station Costs", May 2014

[63] *New Approaches to Financing the Publicly Available Electric Vehicle Charging Network*, Center for Climate Energy Solutions, materials utilized in Washington State Legislature Joint Transportation Committee Study of Business Models to Sustain Electric Vehicle Charging Station Networks, 2014.

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[64] and utilizes the "more stations" or second wave cost estimates. The costs are assumed to remain constant throughout the analysis period.

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	398	0.0	1.2	0	2				
2017	0	598	0.0	1.3	0	2	0	0	0.0	0.0
2018	27	838	0.1	1.8	1	2	1	0	3.1	0.0
2019	68	1,321	0.1	2.9	1	4	0	2	0.0	6.2
2020	124	2,091	0.3	4.6	1	5	0	1	0.0	3.1
2021	195	3,181	0.4	7.0	1	8	0	3	0.0	9.3
2022	264	4,629	0.6	10.2	1	11	0	3	0.0	9.3
2023	326	6,389	0.7	14.0	1	16	0	5	0.0	15.5
2024	387	8,492	0.8	18.6	1	21	0	5	0.0	15.5
2025	448	10,960	1.0	24.0	2	27	1	6	3.1	18.5
2026	507	13,385	1.1	29.4	2	34	0	7	0.0	21.6

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.[65] The cost for both WWT and HSAD pipeline injected 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.

[64] "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

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

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	4.0	7.8	4.4	4.5	2.7	5.6	3.3	5.6	3.3	7.8	2.9	6.7	3.2	8.9	2.2	5.6
Cost	20.1	39.0	21.8	22.3	13.4	27.9	16.7	27.9	16.7	39.0	14.5	33.5	16.2	44.6	11.2	27.9
2017	10.0		10.9		13.4		8.4		8.4		14.5		8.1		5.6	
2018			10.9				8.4		8.4				8.1		5.6	
2019	10.0															
2020																
2021																
2022		19.5		11.2		13.9		13.9		9.8		16.7		11.2		7.0
2023										9.8		8.4		11.2		7.0
2024		19.5		11.2		13.9		13.9		9.8		8.4		11.2		7.0
2025										9.8				11.2		7.0
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 of 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 assumed to be built in Washington state the year the capacity is needed. Note that a sensitivity case was run to compare the impact of in-state production and out-of-state projection on the state economy.

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	0	0	1	0	1	0
2024	1	0	1	1	1	0	1	0
2025	1	1	1	1	1	0	1	0
2026	1	1	1	1	0	0	0	0

To estimate capital cost of the biofuel production plants, we utilize a survey of published installed plant costs.[66] The average installed cost (Table A-11) is $10.2 per gallon of capacity. Members of the Washington LCFS workgroup advised that this number represents first generation plant costs and that 8 years from now when the plants that would supply a Washington LCFS 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.[67] 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-28 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 stored[68] and apply this to the incremental amount of storage needed each year.

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

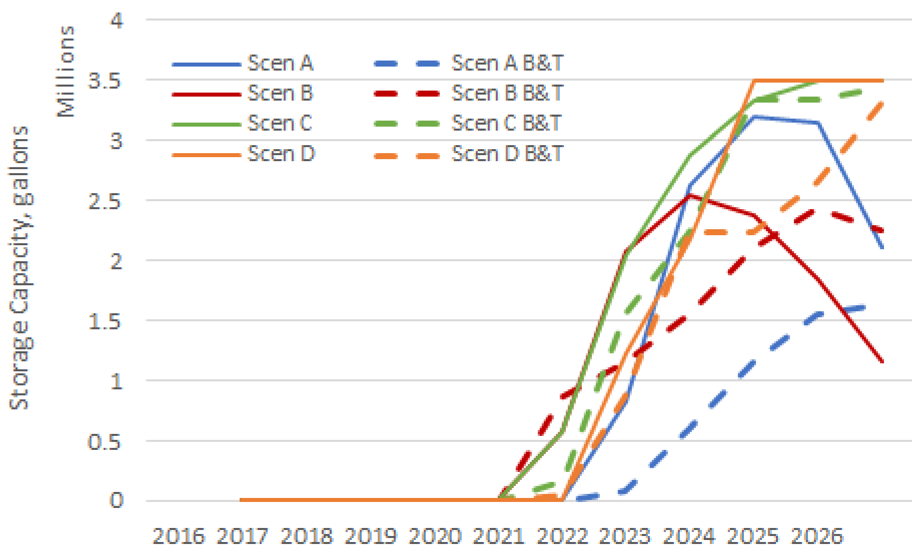

Figure A-28. Additional marine terminal storage capacity needed for a 10 day supply.

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		116,264		120,170		119,976		120,170
2018		22,771		30,161		29,960		479,522
2019							433,245	914,526
2020							968,282	680,032
2021							1,272,736	1,103,719
2022							274,391	524,606
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 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[69] yields the costs in the table.

Table A-13. Conversion of tanks at petroleum terminals from gasoline to ethanol ($2007)

	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 fuel 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	
2020	1	0	0	0	0		2	
2021	0	0	0	0	0		2	
2022	0	0	0	0	0		1	
2023	0	0	0	0	1		0	
2024	0	0	0	0	3		0	
2025	0	0	0	0	4		0	
2026	0	0	0	0	3		0	

[69] EPA RFS2 RIA final, 2007

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. Relative to the BAU, very few additional trucks are required. Each truck is assumed to cost $180,000 in current dollars.

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	159	159	159	159	159	159	159	159	159
2017	157	157	157	157	157	157	157	157	157
2018	154	154	154	154	154	154	154	154	155
2019	152	152	152	153	153	153	153	153	154
2020	149	148	148	149	149	149	149	150	150
2021	145	144	144	145	145	145	145	147	147
2022	141	139	139	141	141	141	141	143	143
2023	136	134	134	136	136	137	136	138	138
2024	132	129	129	129	132	133	132	134	134
2025	127	122	124	123	127	128	129	128	129
2026	123	115	119	116	121	123	126	122	125

Scenario D with and without banking and trading assumes a ramp up to E15 by 2024. The Petroleum Equipment Institute[70] has surveyed refueling station owners on estimated costs to accommodate selling E15. Table A-16 summarizes the results. We have assumed here that half of the stations retrofit dispensers and hanging hardware only and that the other half replaces a tank, retrofits dispensers, and replaces hanging hardware. We also assume that on average the stations have 4 dispensers and that 100% of the 1,914[71] refueling stations in Washington make these modifications. These assumptions result in a total cost of $143.9 Million in $2013.

Table A-16. Summary of PEI Station Costs to Accommodate E15 ($2013).

	Retrofit Dispensers and replace hanging hardware	Retrofit Dispensers only, keep hanging hardware	Replace Tank, retrofit dispensers, replace hanging hardware
2 dispenser	$7,600	$6,452	$126,170
4 dispenser	$15,200	$13,000	$135,200
6 dispenser	$22,800	$19,500	$152,800
10 dispenser	$38,000	$32,500	$188,000

[70] Letter from Robert Renkes of PEI to Todd Campbell of USDA dated September 6, 2013
[71] http://www.eia.gov/state/print.cfm?sid=WA

Scenarios C and C with banking and trading utilize significant volumes of E85. Scenario C assumes that in 2023, 10% of the FFV fleet utilizes E85, ramping up to 85% using E85 by 2026. We assume that by 2025, 100% of refueling stations will offer E85. Scenario C with banking and trading assumes that 15% of the FFV fleet utilizes E85 in 2024, ramping up to 70% in 2026. We assume that by 2026 100% of refueling stations will offer E85. In the RIA for RFS2[72], EPA estimated that the cost for a new 2 nozzle dispenser with a new 15,000 gallon tank (installed) is $154,000. Total cumulative costs for these scenarios is $293 million.

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,[73] that is estimated to be approximately 450,000 gallons. Table A-17 provides the estimated additional storage required for each of the compliance scenarios.

Table A-17. 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	103,866	0	105,208	0	105,208	0	105,208
2020	0	352,680	0	354,767	0	354,767	0	354,767
2021	0	512,714	0	515,401	0	515,401	0	515,401
2022	85,666	670,768	87,317	674,089	87,317	674,089	87,317	674,089
2023	327,407	742,464	329,910	746,232	329,910	746,232	329,910	746,232
2024	483,397	730,377	486,594	734,382	486,594	734,382	486,594	734,382
2025	636,315	717,931	640,339	722,246	640,339	722,246	640,339	722,246
2026	707,409	707,409	712,046	712,046	712,046	712,046	712,046	712,046

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[74] 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)[75] has advised that these estimates are accurate except for the blending equipment estimate; blending

[72] EPA RFS2 Final RIA, Feb 2010
[73] Todd Ellis, Imperium Renewables estimates that sufficient storage and blending capacity exists to support B5.
[74] EPA RFS2 Final RIA, February 2010
[75] Provided by NBB Petroleum Liaison to Shelby Neal (NBB), email dated September 11, 2014

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. All costs in current dollars. 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.[76] 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. Required labeling to reflect the BD blend level being sold consists of attaching stickers to the pumps. The stickers are provided free of charge.

[76] http://www.cleanairchoice.org/pdf/BDFAQMinnesota.pdf

Appendix B – Macro-Economic Modeling

To Be Completed