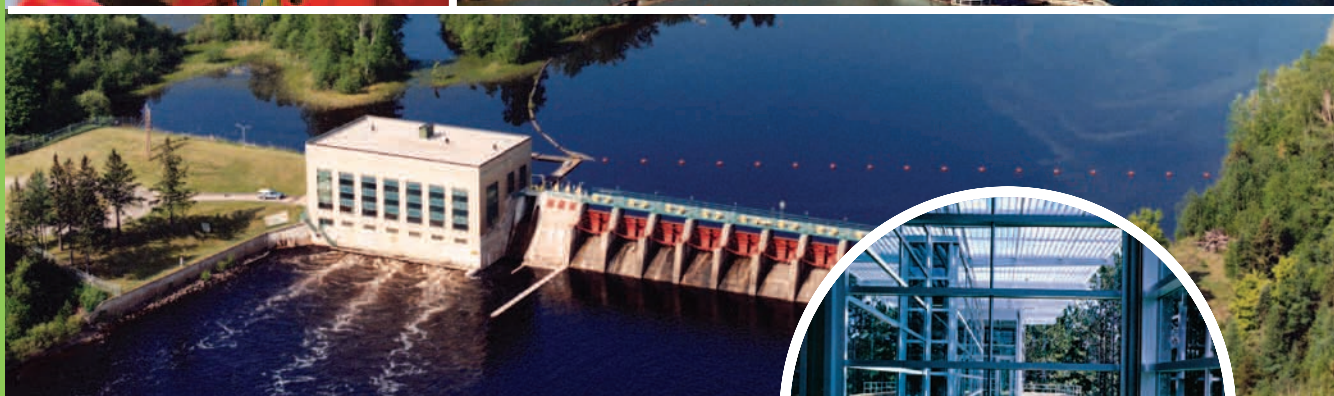
ENERGY SECURITY AND CLIMATE STEWARDSHIP PLATFORM FOR THE MIDWEST



LOW CARBON FUEL
POLICY ADVISORY GROUP
RECOMMENDATIONS

2010

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Appendices:

I. DEFINITION OF TERMS AND ACRONYMS

ARI	Advanced Resources International
AFCI	Average Fuel Carbon Intensity
B5	Fuel blend containing 5 percent biodiesel
Biogas	Methane-based gas produced through anaerobic digestion of agricultural waste
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
Dieselization	The use of diesel fuel as a substitute for gasoline in passenger vehicles
DOE	U.S. Department of Energy
E10	Fuel blend containing 10 percent ethanol
E85	Fuel blend containing up to 85 percent ethanol
eGRID	Emissions & Generation Resource Integrated Database
EER	Energy Economy Ratio
EIA	Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EV	Electric Vehicle
FFV	Flex Fuel Vehicle

GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
ISO	Independent System Operator
ILUC	Indirect Land Use Change
LCA	Lifecycle Assessment or Lifecycle Analysis
LCFP	Low Carbon Fuel Policy
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
MGA	Midwestern Governors Association
MJ	Megajoule
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
RCB	Regional Coordinating Body
RFS/RFS2	Renewable Fuel Standard (RFS2 refers to the 2009/2010 policy)
RTO	Regional Transmission Operator
STC	Scientific and Technical Committee
USDA	U.S. Department of Agriculture

II. INTRODUCTION

The Midwestern Governors Association (MGA) Low Carbon Fuel Policy (LCFP) Advisory Group was appointed by governors to make recommendations on the design of an LCFP that would complement the region's unique characteristics. This includes the region's burgeoning biofuels industry, vast reserves of coal and underground formations for carbon capture and storage (CCS), significant agricultural production, tremendous wind power potential, oil reserves (which can be used for enhanced oil recovery), and proven manufacturing capabilities. The advisory group members represented oil companies, biofuel producers, environmental and conservation organizations, automakers, electric utilities and regulatory agencies (see Appendix A for a full list).

The advisory group was tasked with developing an LCFP rather than fundamentally revisiting previous MGA commitments. Therefore, participants were asked not whether they support an LCFP, but instead how the benefits of such a policy could be maximized and how to minimize the potential negative impacts. Of particular interest to the MGA is what a "Midwestern" approach to an LCFP would look like and how this could influence federal and state policy-making efforts.

Some participants in the advisory group do not support an LCFP in principle; their participation in the process should not be taken as support for an LCFP. Specific policies, principles and recommendations in this document reflect the opinions of the majority of participants in the process, but should not be interpreted as the positions of any individual participant or the firm he or she represents.

Most participants who support an LCFP prefer a unified federal approach, rather than a patchwork of state policies. However, given uncertainties about federal policy priorities and ongoing legislative activity in a number of Midwestern states, a coordinated regional approach is preferred as the next best option.

The advisory group followed the MGA's previous direction that an LCFP should:

- Create a framework and incentives for development of, and demand for, low-carbon fuels in the Midwest;
- Decrease the carbon intensity of transportation fuels;
- Take advantage of the agricultural and industrial strengths to benefit our regional economy while protecting the natural resources of the Midwest; and
- Complement other policies focused on improving transportation efficiency and reducing carbon intensity emissions in the region.

Furthermore, based on recommendations from a previous working group, the advisory group worked under the following numeric targets in making its recommendations:

- The overall carbon intensity should be reduced by at least 10 percent within 10 years after implementation by jurisdictions in the Midwest.
- The program should use the average carbon intensity of the 2005 fuel supply as the baseline for future reductions.

PREAMBLE

The LCFP Advisory Group deliberated for a year. It held three in-person meetings and many conference calls and webinars to finalize these recommendations. In the formulation of these recommendations, the group emphasized that a series of overarching principles should be taken into account in the implementation of any LCFP policy.

The advisory group believes there is value in creating a policy for the region and the nation that is different in many respects from the low carbon fuel standard (LCFS) policies developed in other jurisdictions. To mark this distinction, the advisory group refers to its recommendations as LCFP recommendations, as opposed to an LCFS. The recommendations developed by the advisory group incorporate principles and design criteria that are compatible with the Midwest's unique strengths and opportunities.

To ensure that an LCFP is economically beneficial, the advisory group recommends that an economic impact analysis be performed before moving forward with any policy recommendations in this document. An economic analysis has not informed the deliberations of this group. An analysis should include impacts of the policy on jobs, economic growth and fuel prices. An LCFP should be implemented in a manner that is consistent with robust regional economic growth. It should be implemented in a manner that develops new industries, while minimizing disruptions to existing industries and fuel consumers.

An LCFP should lead to increased regional economic security and make the Midwest more reliant on regionally produced domestic fuels and energy from the North American market.

The advisory group prefers a unified and consistent national policy to encourage the development of low-carbon fuels rather than a patchwork of state policies. If Midwestern states decide to move forward on an LCFP in lieu of federal action, the advisory group strongly encourages a coordinated approach among the states in the region to encourage improved efficiencies, reduce costs and avoid barriers to trade between states. Whether or not the Midwestern states move forward with a regional LCFP, we recommend that regional policymakers support additional carbon intensity reductions for transportation fuels using existing and new policies, such as:

- Enhance the ability of Midwestern states to achieve Renewable Fuel Standards (RFS/RFS2) by pursuing strategies that would enable the Midwest to achieve a 10 percent carbon intensity intensity reduction through the existing RFS guidelines.
- Use the RFS2 framework to reward carbon intensity reductions that exceed RFS2 requirements.
- Enhance the market opportunity for non-renewable fuels that offer carbon intensity reductions relative to gasoline and diesel and that are not currently included under the RFS.
- Adopt a state-level reporting framework that tracks both absolute carbon emissions and intensity for the transportation sector and that measures reductions from existing policies.

The advisory group applauds the MGA for its leadership on the region's new energy economy and was honored to serve on behalf of the MGA in developing these LCFP recommendations.

III. RECOMMENDATIONS
Section I: Recommendations for a Federal Low-Carbon Fuel Policy

INTRODUCTION

The MGA's LCFP Advisory Group makes several recommendations in this document for the development of a future federal-level LCFP. These recommendations represent positions held by diverse stakeholders in our region. We believe that the federal government should incentivize the use of a wide range of low-carbon fuels and not just traditional bio-based fuels. Regardless of the policy mechanism, one important principle is to ensure that the same, widely agreed upon metrics be applied to all fuels.

RECOMMENDATIONS:

1. **Evaluate the Incremental Costs and Benefits of a Federal LCFP over the Policy Status Quo.**

    a) Federal policymaking on an LCFP should demonstrate the incremental benefits, if any, of an LCFP over status quo policies that encourage the use of low-carbon fuels and/or carbon intensity reductions. This analysis should be peer reviewed and include a comparison of the LCFP's costs and benefits with the costs and benefits of the current policy structure (for example, the RFS2, Corporate Average Fuel Efficiency and others). A feasibility analysis should also be completed on any proposed LCFP.

2. **Evaluate the Possibility of Enhancing Existing Federal Policies to Achieve Desired Carbon Intensity Reductions from All Potential Fuel Pathways.**

3. **A Federal LCFP Should Be Designed to Achieve a Unified and Consistent National Approach to Encourage the Development of Low-Carbon Fuels.**

    a) In the event that state or regional LCFPs do not sunset as the result of federal rules, the federal government should develop a lifecycle assessment/analysis (LCA) methodology for all fuels to be used consistently across all similar programs.

4. **Use a Fair and Consistent, Science-Based Calculation Methodology for All Fuels in an LCA.**

    a) If indirect effects are included, they ought to be included consistently for all transportation fuels.

    b) To ensure consistent treatment, use a nationally recognized domestic and global agricultural/economic model(s) for biofuel land-use evaluations as part of the carbon intensity calculations. The model(s) should be flexible enough to reflect regional differences when evaluating fuel pathways. The model(s) should also reflect the fact that regions have different fuel sources and feedstocks and may face greater or lesser difficulty in complying with a national LCFP.

    c) The determination of current and future carbon intensity values should be based on current feedstock and process parameters. Periodic updates should be performed to reflect feedstock or process improvements in the future. This should be done consistently across all pathways.

    d) The U.S. Environmental Protection Agency (EPA), or another regulatory agency, should conduct periodic reviews of the baseline carbon intensity of the individual fuels in the fuel mix and the science of carbon intensity scoring to ensure that the environmental integrity of the program is maintained.

    e) Changes to LCA scores should be based on the best available science and should not be applied retroactively, thus allowing impacted parties to implement and make adjustments as needed.

    f) Provide opportunities for the public to suggest methodological improvements in order to maintain transparency about the regulatory process and to give the agency the best possible information in making carbon intensity determinations.

5. **Utilize the Best Available Data.**

    a) The best available data on the relevant technologies is necessary to reflect the changing science and to keep the program as effective and flexible as possible.

    b) All models used should be available in the public domain, or have been fully vetted in a peer-review environment, and assumptions and uncertainties about those results should be identified.

    c) Create an expert review panel to enroll the best available data and information at all times in the LCFP.

        i. This panel should:

            1. Involve the EPA, U.S. Department of Energy (DOE) and U.S. Department of Agriculture (USDA) in gathering data for carbon intensity values;

2. Consider the best available information as it changes with time and allow the public to submit suggestions or data;

3. Be equipped with the ability to conduct verification audits at sample facilities for each fuel type to verify carbon intensity assumptions and scores; and

4. Assess the annual cost and feasibility of compliance with the policy.

6. **Base the Overall Carbon Intensity Reduction Target of the Program on an Ambitious but Realistically Achievable Goal.**

a) The intensity reduction goal should be supported by an analysis of what carbon reductions are achievable in transportation fuels.

b) The reduction schedule should begin modestly and become increasingly stringent in later years in order to balance the environmental and economic goals, to make the transition to an LCFP feasible for regulated parties and to give time for innovation.

7. **Flexibility Mechanisms Must be Included to Keep the Cost of Compliance Down and to Maximize Carbon Intensity Reductions from the Program.**

a) Regulations should include a flexible, clearly defined procedure or process that allows the affected parties to petition the regulatory agency to change the carbon intensity value of fuels from the default level. This will maintain fairness for regulated parties and give the agency a way of monitoring technological change in fuels.

b) Regulations should include a system that allows regulated parties to trade LCFP credits among themselves in order to be in compliance. Such a system not only makes it easier for regulated parties to comply, but also ensures the policy is implemented in the most cost-effective manner.

c) Regulations should include a mechanism that allows regulators to decrease the annual reduction target in the case of a significant fuel pathway disruption or other market circumstances, such as a lack of fuels or LCFP credits. The regulations should also include a mechanism to strengthen requirements if cost-effectiveness is high.

8. **Given the Uncertainty Around Measuring the Effects of Indirect Land Use Change (ILUC) on Carbon Intensity Scores for Biofuels, a Federal LCFP Should Delay the Inclusion of ILUC Until a General Consensus Exists Within the Scientific Community on the Existence and Magnitude of This Effect.**

a) Additional scientific study is needed to improve estimates of the level of ILUC actually occurring for various fuels in order to provide an acceptable level of certainty for regulatory purposes.

b) Relevant federal agencies should convene an expert panel and reassess ILUC prior to including it in the program. The USDA, Oak Ridge National Laboratory, Argonne National Lab/Purdue University, EPA/National Academy of Science and the California Air Resources Board all have studies planned or underway. These studies consist of expert working groups that are expected to help inform decisions as to how ILUC affects an LCFP.

c) It should be determined whether ILUC is an appropriate parameter for inclusion in an LCA.

d) The U.S. EPA should consider the feasibility of using a certification process for companies to demonstrate that domestic or international ILUC is not occurring as a result of biofuels production.

e) Other alternatives, such as creating an indirect-land-use fund to offset potential emissions from ILUC, should also be explored.

f) An LCFP should include a defined schedule for updates as the science of an ILUC assessment improves.

Section II: Midwestern LCFP Design Principles

DESIGN CRITERIA

- Design of the LCFP program should be based on a credit trading and banking system.
- Determination of obligated parties should be based on administrative feasibility, cost-effectiveness and availability of data, should support the achievement of an LCFP program objectives, and should avoid placing obligations on parties for technology changes over which they have no control. For example, fuel suppliers have limited control over the sale of vehicles.
- The design should be structured to most effectively achieve goals of the LCFP.
- The design should be cost effective.
- The design should be structured to provide certainty to applicable industries and should be clear in order to provide a clear pathway for achieving compliance.
- Evaluation of fuels should be done in an equitable, transparent and peer-reviewed fashion.
- The design should provide a level playing field and not select technology winners.
- The design should rely on measurable (existing rather than projected) and verifiable data.
- The design should be flexible and durable in order to enable and support technology development and to support industry in finding the most efficient pathway to compliance.
- Design should support and stimulate technology innovation and investment that demonstrate long-term carbon-reduction potential at scale and can be done cost effectively.
- The design should allow mechanisms for non-regulated fuel users to get credit for integrating lower-carbon fuels (including liquid and non-liquid fuels).
- The design should avoid conflict with existing state and federal regulations.
- The design should provide adequate lead-time for compliance; unrealistic near-term targets and timetables need to be avoided.
- The design should include technology/feasibility reviews every five years to allow for appropriate regulatory adjustments.

- The design should be structured consistently and be harmonized across jurisdictions to reduce costs and administrative burden and to increase effectiveness for administrators and obligated parties.

- The design should be structured to avoid conflicting overlap with regional and/or federal carbon intensity programs.

- The program, to the extent possible and practical, should build off the RFS2 Renewable Information Number (RIN)[1] system.

DESIGN PRINCIPLES

1. **Carbon Intensity Reduction Goals.** The advisory group recommends the following compliance schedule for transportation fuels that are required to comply with an LCFP.

    1.1 **Carbon Intensity Reduction Goal.** The overall intensity reduction target is at least 10 percent within 10 years after implementation by individual states or jurisdictions.

    1.1.1 Jurisdictions should also examine the feasibility of an increased standard in future years or over longer timelines (such as 30 percent over 20 years).

    1.1.2 Jurisdictions should set goals and timeline decisions based on best available modeling and should be consistent with existing carbon intensity reduction regulations.

    1.1.3 Projections of future fuel demand should be consistent with existing or proposed regulations.

    1.1.4 Jurisdictions should set feasible intensity-reduction goals according to best the available modeling and projections. Policy frameworks should allow for a periodic review of the goals, timelines and annual intensity-reduction requirements. These frameworks should be adjusted when proven infeasible.

    1.2 **Baseline Average Fuel Carbon Intensity (AFCI).** The program should use the AFCI of the 2005 Midwestern fuel supply as the baseline for future reductions. The baseline should acknowledge previous efforts in the Midwest that established substantial production of biofuels within the region, while recognizing that increased production of biofuels in the years since the 2005 baseline may have resulted in the region meeting a portion of the overall intensity-reduction goal.

    1.2.1 The following information is needed to establish a baseline AFCI (actual data preferred, if not available, use default values):

[1] RINs are used by the US EPA to track compliance with the RFS. They are generated by the producer or importer of renewable fuel and attached to a batch of fuels. They may be traded. A regulated party under the RFS must have a certain required number of RINs at the end of a compliance period in order to be in compliance with the RFS.

1.2.1.1 The volume of all fuel used in the region and the pathway used to produce it.

1.2.1.2 The feedstock source for each liquid fuel produced. For petroleum fuels this should either be the feedstock grade as defined by the International Crude Oil Market Handbook or, if that is not available, the country of origin, America Petroleum Institute gravity, sulfur content and description of any previous upgrading prior to the refinery that produces the fuel. If multiple crude types are used, quantities of each should be reported to allow determination of average grade.

1.2.1.3 The energy content per unit volume of fuel produced by each fuel production pathway (Megajoules per gallon, or MJ/gal).

1.2.1.4 The default carbon intensity for each fuel production pathway (grams of carbon dioxide equivalent per Megajoule, or gCO_2e/MJ).

1.2.1.5 An energy economy ratio to adjust for the drive-train efficiency in alternative fuel vehicles.

1.2.1.6 Section 4.5 presents the equation used for calculating AFCI based on the above factors.

1.2.1.7 Jurisdictions may examine a later year baseline AFCI .

1.2.2 To establish baseline fuel production volumes and default carbon intensities in order to calculate the baseline AFCI, jurisdictions may:

1.2.2.1 Rely on a Regional Coordinating Body (RCB) or Scientific and Technical Committee (STC), as defined in section 6.1 for RCB and section 6.2 for STC.

1.2.2.2 Conduct an analysis with state energy offices, natural resource departments, commerce departments or other technical experts as appropriate.

1.2.2.3 Contract with a third party or university to conduct an analysis of the state's baseline fuel consumption.

1.2.3 At the time of this writing, much of the information necessary to calculate the AFCI was not available publicly through either state or federal databases. If the necessary data does not exist upon completion of a jurisdiction's baseline AFCI study, the jurisdiction should consider establishing reporting requirements that are applied consistently across all transportation fuels and to allow for the confidential compiling of industry production data in order to calculate a baseline AFCI.

1.3 **Lifecycle Analyses and Carbon Intensity Scores.** All fuels covered by the program should be subject to a consistently applied lifecycle analysis (LCA) scoring process to determine carbon intensity. An LCA on all fuels should include the same system boundaries and should include appropriate consideration for drivetrain efficiencies related to each fuel. Several LCA models are available to establish default LCA values. However, these models may apply inconsistent lifecycle methodologies to each fuel pathway. Therefore:

1.3.1 LCAs and carbon intensity scores should be based on consistent and established models, such as the Greenhouse Gases Regulated Emissions and Energy Use in Transportation (GREET) model, with a demonstrated and validated ability to quantify outcomes based on model inputs. A jurisdiction may use multiple models to analyze different aspects of the fuel life cycle if the methodology is consistent across fuels and jurisdictions. For the GREET or another model to move from an academic to a regulatory context, it needs to be updated more frequently with current industry numbers, such as those listed in section 1.2.

1.3.2 Modeling methodologies should be consistent and/or uniform across jurisdictions.

1.3.3 Carbon intensity models and methodologies, when possible, should be consistent with those used in existing federal policies such as the RFS2. The STC may be used to determine the applicability of EPA numbers for the region or jurisdictions.

1.3.4 For the purposes of an LCA for electricity, the AFCI should be based on the attributes of the average electric generation grid mix for the Midwest. While electricity fuel producers or suppliers may refer to default carbon intensity values, the policy should also allow suppliers to petition for consideration of renewable sources, marginal electricity use, and other factors that may result in a carbon intensity value lower than the default value for the geographic region where the fuel was produced. The Climate Registry has been engaged in establishing reporting protocols for the electricity sector. These protocols could be considered by participating jurisdictions.

1.3.5 Pathways established for fuels that are not yet commercialized will require validation of their carbon intensity determination within 12 months of selling fuel used for compliance under the program. Obligated parties should receive credit for the provisional carbon intensity values until new carbon intensity values based on real-world data are available from the commercial industry.

1.4 **Timeline for Carbon Intensity Requirements.** Jurisdictions should determine an appropriate start date based on the availability of low-carbon fuels (see section 1.1).

1.5 **Yearly Reduction Levels.** Yearly reduction levels will be legally set by individual jurisdictions through statute; however, participating jurisdictions should strive for a uniform schedule. Jurisdictions should take into consideration the overall timeline for reduction and adjust for other factors, such as availability of various fuel types. Participating jurisdictions should:

- Set yearly reduction levels based on available modeling (see section 1.1);
- Strive for a uniform schedule of yearly reduction levels to make the policy workable and achievable; and
- Consider a 'back end loaded' reduction schedule, which starts modestly in early years and ramps up over time.

1.5.1 Yearly reduction levels set a standard carbon intensity that a fuel blend must meet each year. Separate standards should be applied to gasoline and diesel according to their baseline carbon intensity. However, if jurisdictions allow dieselization as a compliance strategy, the jurisdictions may need to establish a single standard that applies the same yearly reduction level to both gasoline and diesel.

1.5.2 Jurisdictions may allow dieselization as a means of compliance if it is proven that doing so will reduce the carbon intensity of the jurisdiction's fuel blend.[2] This requires refiners to change the ratio of diesel and gasoline production and relies on the availability of diesel-fueled passenger vehicles.

1.5.2.1 Dieselization may require the use of a combined baseline carbon intensity for gasoline and diesel.

1.5.2.2 To allow dieselization, the jurisdiction must determine a method of tracking dieselization (such as tracking vehicle registrations) as an effective method for replacing gasoline fuel, while being consistent with other jurisdictions. Jurisdictions must make it a priority to set consistent baselines and annual reduction standards.

1.5.3 Each alternative fuel should be judged against the yearly reduction level of the fuel that it displaces. When applying this policy to alternative fuels, necessary adjustments should be made to account for unique engine efficiencies of the vehicles required to use each fuel. The energy economy ratio defined in section 4.5 can be used to make this adjustment.

[2] Dieselization is defined as the increased production of diesel fuel for use as a replacement to gasoline for light duty passenger vehicles.

2. **Applicability.** The advisory group recommends the following ground transportation fuels to be included under an LCFP.

2.1 **Fuels Covered.** An LCFP should apply to providers of the ground transportation fuels used in participating jurisdictions. All transportation fuels consumed in the jurisdiction should also be subject to a consistently applied LCA scoring process to determine carbon intensity. No fuel should be presumed to comply with an LCFP. This policy applies to the list of transportation fuels below that are sold, supplied or offered for sale but are not limited to the following:

2.1.1 **Gasoline:** A volatile mixture of liquid hydrocarbons that generally contains small amounts of additives and is suitable for use as a fuel in spark ignition, internal combustion engines.

2.1.2 **Diesel Fuel:** All products meeting the definition of a motor vehicle, non-road, locomotive and marine diesel fuel that are produced or imported during a compliance period.

2.1.3 **Electricity:** Electricity used to charge on-board vehicle batteries.

2.1.4 **Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG):** Natural gas means a mixture of gaseous hydrocarbons and other compounds with at least 80 percent methane (by volume) and is typically sold or distributed by public utility companies and regulated by jurisdictions' public utilities commissions. CNG means natural gas that has been compressed to a pressure greater than ambient pressure. LNG means natural gas that has been liquefied.

2.1.5 **Biogas CNG or Biogas LNG:** A mixture of hydrocarbons that is a gas at 60 degrees and 1 atmosphere of pressure that is produced through the conversion of organic matter. The biogas that is used must be renewable. Biogas includes propane, landfill gas, manure digester gas and sewage waste treatment gas.

2.1.6 **Compressed or Liquefied Hydrogen:** Hydrogen produced from any source, including but not limited to biofuels, natural gas, electrolysis, and other chemical and electrochemical processes.

2.1.7 **Fuel Blend Containing Hydrogen:** Fuels such as natural gas mixed with hydrogen gas to improve the environmental attributes of the original fuel. Hydrogen components of this type of fuel should be evaluated using the same criteria for gaseous and liquid hydrogen above.

2.1.8 **Biomass-Based Diesel.**

2.1.8.1 **Biodiesel:** The monoalkyl esters of long chain fatty acids derived from plant or animal matter that meets:

- The registration requirements for fuels and fuel additives established by the EPA under Section 211 of the Clean Air Act (42 U.S.C. 7545); and

- The requirements of the American Society of Testing and Materials D6751.

2.1.8.2 **Renewable Diesel:** Liquid fuel derived from biomass (as defined in Internal Revenue Code Title 26, Section 45k (c) (3)) which meets:

- The registration requirements for fuels and fuel additives established by the EPA under Section 211 of the Clean Air Act (42 United States Code 7545); and

- The requirements of the American Society of Testing and Materials (ASTM) D975.

2.1.9 **Ethanol:** Also known as "Denatured Fuel Ethanol" meeting ASTM D4806 standards specification. It is intended to be blended with gasoline for use as a fuel in a spark-ignition, internal combustion engine. The denatured fuel ethanol is first made unfit for human consumption by the addition of the Alcohol and Tobacco Tax and Trade Bureau-approved substances before blending with gasoline.

2.1.10 **Advanced Biofuel:** Any renewable fuel that has lifecycle carbon emissions that are at least 50 percent less than baseline lifecycle carbon emissions.

2.2 **Exemptions for Specific Applications.** Jurisdictions should consider specific applications that would be exempt from compliance. Exemptions may be optional and petitioned for on a volunteer basis. If an obligated party provides sufficient proof that a portion of its fuel was produced for exempt applications, than it receives an exemption. An exemption should not cause additional compliance burden by requiring obligated parties to conduct further data tracking or reporting. A review process conducted internally, or in cooperation with a Science and Technology Committee or Regional Coordinating Body, may consider applications.

2.3 **Exemption for Small Producers and Importers.** Jurisdictions may consider whether parties that refine or import less than 10,000 gallons of fuel per year should be exempt from an LCFP. Jurisdictions may periodically review exemptions to determine compliance feasibility for small refiners and importers.

2.4 **Point of Regulation.**

2.4.1 Obligated parties for liquid fuels should be the same obligated parties used for RFS2.

2.4.2 The advisory group recommends that the obligated parties for an LCFP should be any refinery in the Midwest that produces gasoline or diesel fuel or any importer that imports gasoline or diesel into the region. A party that only blends renewable fuel into gasoline or diesel fuel should not be an obligated party under an LCFP. An obligated party should comply with the policy requirements for all imported gasoline and diesel fuel in the aggregate.

2.4.3 A refiner that operates in multiple jurisdictions covered under the policy may choose to comply with the requirements in the aggregate or for each refinery individually.

2.4.4 An obligated party that is both a refiner and an importer should determine compliance for imported gasoline or diesel separately from gasoline or diesel produced by the refinery or refineries in the covered jurisdictions.

2.4.5 When a refinery or import facility is jointly owned by two or more parties, regulation compliance should be met by either by:

2.4.5.1 One of the joint owners for all gasoline and diesel produced or imported to the facility, or

2.4.5.2 Each party may choose to comply with the regulation for only the portion of fuel it produces or imports at the facility.

2.4.6 Applicable fuels detailed in section 2.1 that are covered under the LCFP but not produced by the obligated parties, would be classified as credit generators. The producers of these fuels will generate credits for sale, transfer or trade to an obligated party.

2.4.6.1 For liquid fuels blended with gasoline or diesel (fuel ethanol, biomass- based diesel and advanced biofuel), the credits generated will be transferred with the sale of the fuel.

2.4.6.2 For fuels produced that are not sold to an obligated party (biogas CNG or LNG, compressed natural gas or liquefied natural gas, electricity, fuel blends containing hydrogen, and compressed or liquefied hydrogen), an obligated party may enter into an agreement with a fuel producer to sell, transfer or trade fuel credits without having to purchase the fuel.

2.4.6.3 For liquid fuels produced but not sold to an obligated party for blending with gasoline or diesel (fuel ethanol, biomass based diesel, or advanced biofuel), the producers may also sell, transfer or trade credits to an obligated party without the purchase of the fuel.

2.4.7 **Definitions.**

2.4.7.1 **Refinery:** Any facility, including but not limited to a plant, a tanker truck or a vessel where gasoline or diesel fuel is produced, including any facility at which blendstocks are combined to produce gasoline or diesel fuel, or at which blendstocks are added to gasoline or diesel. A refiner is any person who owns, leases or operates, controls or supervises a refinery.

2.4.7.2 **Importer:** An importer of transportation fuel is someone who:

- Brings transportation fuel into the 48 contiguous states of the United States or Hawaii from a foreign country or from an area that has not opted into the program requirements; or

- Brings transportation fuel into an area that had opted into the program requirements from a foreign country or from an area that has not opted into the program requirements.

2.4.7.3 **Credit Generators:** Producers of gasoline and diesel substitutes with carbon intensities lower than the gasoline and diesel baseline LCAs and/or lower than the annual carbon intensity standard. According to current modeling, this may include producers of: electricity, compressed or liquefied natural gas, biogas CNG or LNG, hydrogen, fuel ethanol, biomass-based diesel or advanced biofuel.

- To qualify for credit, the volume of fuel must not have been sold to a producer or blender of gasoline or diesel.

- Credits are generated only for the portion of the product used for transportation fuel.

2.5 **Opt-In.** An opt-in provision should be included in an LCFP to allow small refiners and importers—who are exempt from the requirements—to participate in the trading program if they are able to meet all of the compliance and reporting requirements.

3. **Indirect Impacts.**

3.1 If indirect impacts are included, they should be included for all transportation fuels consistently.

3.2 Because of uncertainty regarding the estimation of indirect-land-use change (ILUC) impacts on the carbon intensity scores of biofuels, the Midwest should delay consideration of inclusion of ILUC in any Midwestern LCFP until 2014, when studies either planned or underway by the USDA, Oak Ridge National Laboratory, Argonne National Labs/Purdue University, EPA/National Association of Science and the California Air Resource Board expert working group have concluded. The advisory group recommends establishing a study group to examine issues related to indirect-land-use and other indirect impacts. The study group should investigate options for accounting and mitigation of indirect effects, including:

3.2.1 To ensure consistent treatment, determine a nationally recognized domestic and global agricultural/economic model(s) for biofuel land-use evaluations as part of the carbon intensity calculations. The model(s) should be flexible enough to reflect regional differences when evaluating fuel pathways and the fact that regions have different fuel sources and feedstocks.

3.2.2 Determine whether ILUC is an appropriate parameter for inclusion in an LCA.

3.2.3 Determine the feasibility of using a certification process for companies to demonstrate that domestic or international ILUC is not occurring as a result of biofuel production.

3.2.4 Compare various modeling efforts that currently yield varying estimates for ILUC to improve understanding and the precision of estimates.

3.2.5 Study other market-mediated and indirect carbon impacts resulting from all fuels, which may include carbon impacts from military spending.

3.2.6 Study other alternatives for addressing ILUC, such as creating an indirect-land-use fund to offset potential emissions from ILUC. Ideas include:

3.2.6.1 Establishment of a program where producers invest directly in preventing ILUC. Investments might include offsets through voluntary offset markets such as the United Nations Reducing Emissions from Deforestation and Degradation program. States would need to make decisions regarding the following:

- What investments are allowed?
- Who has to make offset payments and at what level?
- Who monitors payments by producers?

3.2.7 The policy should include a defined schedule for updates as the science of such assessments improves.

4. **Determination of Carbon Intensity.** The following methods are recommended by the advisory group in order to determine the carbon intensity of all fuels under an LCFP.

4.1 **Method 1–Default Values.** Not all regulated entities will have the resources to do a site-specific LCA; the regulatory body should recommend default values for fuels based on their unique lifecycle characteristics. There should be a sufficient number of default values to capture a variety of production practices that result in different potential carbon intensity/values for the same fuel type. The default values should be as reflective as possible of current performance across the lifecycle of each fuel, capturing any recent efficiency improvements. Default values should be reviewed and updated every three years — or more frequently if significant technological advances have occurred.

4.2 **Method 2–Propose New Fuel Pathway from Default Values.**

4.2.1 In cases where fuel pathways listed in the default values do not accurately reflect the production pathway used by a fuel provider, the fuel provider may propose a modification to the modeling used to establish a new LCA score unique to the fuel pathway. Modification to the modeling may include the alteration of input assumptions on existing production pathways, or the inclusion of new or different pathway components.

4.2.2 Firms should be able to provide their own carbon intensity/values based on a site-specific LCA incorporating unique processes or characteristics for their product that differ from the default assumptions, using the same LCA methodology as established by the regulatory body. Firms' assessments should be verified by the regulatory body, by participating jurisdictional government entities, or by approved third-party certifiers.

4.3 **Method 3 – Submission of LCA for New Fuels.** For next-generation fuels that are developed after the policy is implemented, producers may submit pathway modifications or new LCA studies as outlined in section 4.2.

4.4 **Third-Party Certifiers.** Because jurisdictional administrators might not have the technical resources to conduct individual LCA evaluations, the use of approved third-party certifiers should be allowed to determine site-specific LCAs, propose modifications to a fuel pathway from the default values, or submit an LCA for new fuels. All LCA modifications, or the submission of new LCAs by firms or through a third-party certifier, will need to be reviewed and approved by the jurisdiction administrator for the program. The Regional Coordinating Body (RCB) can provide assistance to program administrators in reviewing LCA submissions. The RCB can also approve a list of qualified third-party certifiers. Detailed criteria for what constitutes a qualified third-party certifier will need to be developed by participating jurisdictions and the RCB, but it should include the following: availability to conduct follow-up assessments, a familiarity with established LCA methodology and a demonstrated ability to conduct site-specific assessments.

4.5 **Calculation of Total Average Fuel Carbon Intensity (AFCI).**

$$\text{AFCI or CI} = \frac{\Sigma_n (F_n\, En\, I_n / EER_n)}{\Sigma_n F_n E_n}$$

n	= Fuel pathway
F_n	= Volume from fuel pathway *n* (gal, etc)
E_n	= Energy content of fuel *n* (MJ/gal)
I_n	= Average fuel carbon intensity of fuel *n* (g/MJ)
EER_n	= Energy efficiency ratio of fuel *n*

5. **Compliance.**

5.1 **Credit Generation and Trading.** An equitable system should be established for managing credits and deficits that may include credit acquisition, banking, borrowing and trading. The following criteria should guide the development of a credit generation and trading system:

- Administratively feasible;
- Reward lowering the carbon intensity beyond the standard;
- Support innovation;
- Provide market-based mechanisms to lower costs; and
- Limit credit trading to obligated parties.

5.1.1 Based on the above criteria, the advisory group recommends the following mechanisms for a credit generation and trading system:

- The obligated party must hold enough credits at the end of a compliance period to equal the carbon emissions of their regulated fuels;
- Credit generation provides the economic incentive to develop low-carbon fuels and participate in the market;
- The more fuels that are regulated, the more robust the market becomes, the cheaper credits become and the less costly the LCFP becomes;
- Credits are good for the life of the LCFP;
- Compliance period is a calendar year;
- A verifiable calculation of credit balance is used;
- Deficits carry over from one compliance period to the next; and
- Deficits must be reconciled at the end of the compliance period.

5.1.2 An obligated party will be allowed to retain credits indefinitely for use in an LCFP market and will be allowed to acquire credits from, trade credits with or transfer credits to another obligated party.

5.1.3 An obligated party will be allowed to acquire credits from, trade credits with or sell credits to credit generators and use credits generated outside of the Midwestern LCFP if participating jurisdictions determine credit trading between programs should be allowed. Obligated parties will not be allowed to generate credit from fuels exempted from the LCFP and use anticipated credits from future carbon intensity reductions.

5.1.3.1 Credits should be retained without expiration.

5.1.3.2 Only obligated parties and credit generators can trade credits.

5.1.3.3 Credits generated outside of the participating jurisdiction can be used in the program if the RCB, in consultation with participating jurisdictions, determines other jurisdictions' programs are compatible with a Midwest program.

5.1.3.4 Credits generated from exempt fuels are not allowed.

5.1.4 A regional body may assist jurisdictions in carrying out specific functions in a credit-generation and trading system, where appropriate, to reduce administrative burdens and costs and to improve feasibility. The RCB, as defined in section 6.1, may provide functions including, but not limited to:

5.1.4.1 Facilitating and administering credit trading and verification of credit generation;

5.1.4.2 Providing technical assistance to public and private entities on compliance issues;

5.1.4.3 Providing technical assistance for or administering verification of compliance (for example, develop the methodology and certify the verifiers); and

5.1.4.4 Providing other functions as deemed appropriate to reduce administrative burden, reduce cost of compliance, and increase feasibility.

5.2 **Reporting Requirements.** Any tracking and reporting requirement for an LCFP should be administratively feasible for obligated parties and should be structured to leverage resources already dedicated to tracking and reporting similar data where possible and appropriate. Public access to reported data should balance the interests of public transparency and the need to protect proprietary information. Therefore, the advisory group recommends the following specific reporting requirements:

5.2.1 **Annual Compliance Report.** Obligated parties should be required to produce an annual compliance report that may include the following details:

5.2.1.1 Total credits and deficits;

5.2.1.2 Credits carried over;

5.2.1.3 Deficits carried over;

5.2.1.4 Credits generated and acquired;

5.2.1.5 Credits sold, exported, retired and transferred;

5.2.1.6 Volume of fuel produced, imported and dispensed; and

5.2.1.7 Carbon intensity of the fuel produced.

5.2.2 **Fuel Producer Registration Responsibilities.** An obligated party will need to be supplied with the following information from the fuel producer:

5.2.2.1 Carbon intensity of the fuel;

5.2.2.2 Volume of fuel; and

5.2.2.3 Point of origin of the fuel.

5.2.3 **Record Keeping.** The advisory group recommends the following record-keeping elements (some of which should be provided by fuel producers) to demonstrate compliance with an LCFP by an obligated party:

5.2.3.1 Initial demonstration of delivery methods;

5.2.3.2 Initial demonstration of fuel introduced into the physical pathway;

5.2.3.3 Initial demonstration of fuel removed from the individual pathway;

5.2.3.4 Requirements for changes to the physical pathway; and

5.2.3.5 Periodic audit process.

5.3 **Penalties and Enforcement.** Any penalties for noncompliance with an LCFP should provide an effective deterrent for noncompliance and/or misrepresentation of compliance (for example, penalties for noncompliance with the LCFP should be significantly greater than the costs of compliance).

5.3.1 Penalties for non-compliance with an LCFP should be consistent with existing air quality violations. For violations, jurisdictions may:

5.3.1.1 Implement statutory penalties;

5.3.1.2 Implement a credit recoupment scheme; and

5.3.1.3 Conduct periodic audits.

5.3.2 Penalties and enforcement functions should be carried out by state-level regulatory authorities. Functions related to penalties and enforcement that should be carried out at the state level include, but are not limited to:

5.3.2.1 Enforcement and penalties;

5.3.2.2 Compliance level determination and penalties administration by state regulatory authorities; and

5.3.2.3 States may consult a regional entity, if existing, for technical assistance related to verification of compliance and other technical assistance as needed for administration of penalties and enforcement.

6.0 **Regional Coordination and Market Oversight.**

6.1 **Regional Coordinating Body (RCB):** An RCB should be established during the development of the program or upon consideration by a state to assist in the development, implementation and operation of the LCFP. The RCB should have conference calls quarterly or every two months, and should meet in person at least once a year. The RCB's function is to facilitate collaboration among states in agreeing on common features for a regional system, but the authority for implementing that system ultimately rests with individual states. The RCB is a channel for better coordination among states that have an LCFP, rather than a replacement for jurisdictional authority.

6.1.1 Members of the RCB should be nominated by governors and made up of representation from the relevant regulating entity in each participating jurisdiction. The RCB may or may not be the same group that assists the jurisdictions in implementing other regional programs.

6.1.2 Among other duties, the RCB should serve as a liaison with federal and other regional programs by coordinating with such programs to ensure uniformity, lack of conflict and redundancy.

6.1.3 Other roles for the RCB are specified in previous sections of this document.

6.2 **Scientific and Technical Committee (STC).** Under the coordination of the RCB, jurisdictions should establish a regional cross-functional STC that includes experts from academia, agriculture, government, industry and non-governmental organizations that reflect a broad range of perspectives and knowledge.

6.2.1 The STC should act as a resource to provide input on any scientific and technical issues requiring additional expertise.

6.2.2 The STC should advise jurisdictions in selecting full lifecycle carbon assessment techniques for all applicable transportation fuels.

6.2.3 The STC should assist the jurisdictions in the implementation and monitoring of a regional LCFP.

6.2.4 The STC should assist the jurisdictions in developing a mechanism for conducting periodic reviews of the LCFP program and its impacts in major areas including LCA, ILUC, policy design, compliance and regulatory process, economic impact and potential adverse environmental impacts beyond carbon emissions.

6.3 **Program Review.** Participating jurisdictions should conduct annual reviews of the implementation of the LCFP through the RCB. Each review should include the following considerations but are not limited to the following:

6.3.1 Measure program progress against reduction targets;

6.3.2 Evaluate adjustments to the compliance schedule;

6.3.3 Advances in fuel LCAs;

6.3.4 Advances in fuels and production technologies, including feasibility and cost effectiveness;

6.3.5 Availability of new fuels coming into the market and the feasibility of compliance with an LCFP;

6.3.6 Evaluate supply availabilities and the rates of commercialization of fuels and vehicles;

6.3.7 Impact on fuel supply;

6.3.8 Impact on state revenues, consumers and economic growth;

6.3.9 Public health impacts;

6.3.10 Air quality impacts;

6.3.11 Significant economic issues; and

6.3.12 Opportunities to harmonize with other state, regional or national efforts.

6.4 **Interaction with Other Programs.**

6.4.1 While the primary objective of these design recommendations is the establishment of a credit trading program within the Midwest, it may be highly desirable to enable interaction of credit trading with other jurisdictions outside of the Midwest in order to increase efficiency and minimize the cost of compliance. Jurisdictions, working through the RCB, should determine if other jurisdictions' programs are compatible with a Midwestern program prior to allowing for trading.

6.4.2 **Economic Modeling.** LCFP programs outside of the Midwestern jurisdictions will need to demonstrate that the costs and benefits of the policy have been evaluated and justified and will most likely do so through economic modeling of scenarios that demonstrate various outcomes for different compliance pathways. The Midwestern LCFP likely can benefit greatly from the experience and expertise of the modeling done for other LCFP programs. It is in all states' interests to collaborate on economic modeling, at least for inputs that should be similar across regions. This will help lead to more comparable results and make discussing LCFP benefits and costs easier among states.

6.4.3 **Credit Tracking.** the programs in each jurisdiction will need to collaborate on the administrative system for tracking credits, especially if credits generated in one program can be traded in another jurisdiction. The level of detail associated with each credit may be different among programs, which will make trading more difficult. Additionally, one state may develop a system for tracking that minimizes the administrative burden that could be shared with other states to not only streamline the tracking system, but also reduce the costs to other states. It is thus highly recommended that the region and states that work on the LCFP be in communication with other states and regions that have done so already.

6.5 **Cost Containment.** Jurisdictions should provide a flexible and adaptive cost-containment framework.

6.6 **Program Waiver.** If jurisdictions determine there is a significant fuel-pathway disruption or other significant market circumstances, such as scarcity of fuels and credits, jurisdictions may issue an order to reduce the annual reduction target.

6.7 **Regional Coordination and Reciprocity.**

6.7.1 The credit-generation and trading system should be consistently implemented from participating jurisdiction to participating jurisdiction. Credit generation and trading protocols should be reviewed through a regional process, possibly through the establishment of a regional body. Each jurisdiction reserves the right to select the regionally approved credit generation and trading protocols for which it will provide the administrative support needed to implement the program.

6.7.2 Credits created within any participating jurisdiction should be accepted in every other participating jurisdiction.

Section III: Alternative Approaches to a Low Carbon Fuel Policy

An alternative policies subgroup was convened as part of the advisory group to determine whether policies other than an LCFP could achieve the same goals. The group held a series of conference calls and an in-person meeting hosted by POET in Sioux Falls, S.D. The following recommendations were presented to and adopted by the advisory group. Many participants believe that these policies should be considered as an alternative approach for achieving carbon intensity reductions in the Midwest. Though this approach should be considered regardless of whether or not the region moves forward with an LCFP of some kind.

RECOMMENDATIONS

1. **Reporting.**

   The subgroup recommends that individual Midwestern states publish an annual report that estimates actual carbon emissions from the transportation sector along with a new emissions-efficiency value representing the transportation sector's contribution to emissions with respect to the region's economic activity and per capita mobility. This report would include:

   1.1 The fuel volume and associated estimated fuel carbon intensity = weighted average carbon intensity;[3]

   1.2 An estimate of vehicle miles traveled;

   1.3 An estimate of vehicle efficiency;

   1.4 An estimate of absolute carbon emissions and trends for year over year; and

   1.5 An estimate of economy-wide carbon intensity using absolute carbon emissions divided by an economic activity measure for the state/region.

[3] To calculate carbon intensity, the following data would need to be collected and tracked, including:

- The volume of all fuel used in the region and the pathway used to produce it. The feedstock source for each liquid fuel produced. For petroleum fuels this should either be the feedstock grade or, if that is not available, the country of origin, American Petroleum Institute gravity, sulfur content and description of any previous upgrading prior to the refinery that produces the fuel. The energy content per unit volume of fuel produced by each fuel production pathway (Megajoules per gallon; MJ/gal).
- The default carbon intensity for each fuel production pathway (grams of carbon dioxide equivalent per Megajoule; gCO_2e/MJ).
- An energy economy ratio to adjust for the drive train efficiency in alternative fuel vehicles.

The annual report would also educate the public by providing summaries of the:

1.6 Major assumptions used in the carbon intensity calculations; and

1.7 Major developments in the science of LCA and economic modeling (for example, developments coming out of California's expert working group and new information from the EPA).

Regional reporting requirements should rely on the RFS2 scoring methodology for biofuels whenever possible.

2. **Form a Regional Partnership to Improve LCA Scoring Methodology.** The subgroup recommends an ongoing collaborative partnership among the MGA, industry groups and other regional researchers in order to continue updating lifecycle carbon intensity estimates for biofuels and other low carbon intensity fuels. A model for this collaboration is the recent successful partnership among Argonne National Laboratory, the University of Illinois-Chicago, and various ethanol producers that surveyed energy use at current ethanol plants in order to update LCA scores in Argonne's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model. The Midwest is uniquely positioned to advance the state of knowledge on LCA science given the abundance of biofuel plants and the presence in the region of the "industry standard" LCA model – GREET – invites greater collaboration. The region should also continue to study the impacts of indirect land use change in order to understand it better and learn how to reduce its impact.

3. **Reduce Carbon Intensity of Existing Biofuels.** The region should seek to reduce the carbon intensity of existing biofuels through:

   3.1 Tracking regional carbon emissions and their corresponding intensity;

   3.2 Collaboration to improve the LCA scoring methodology for fuels;

   3.3 A range of complementary policies and strategies;

   3.4 Adopting new technologies in processing plants; and

   3.5 Encourage adoption of practices for growers to reduce their carbon intensity footprint, such as fertilizer use, tillage, stover harvest and other practices.

4. **Partner with Federal Agencies and Others to Implement RFS2 and Enhance Carbon Intensity Reductions Toward the Regional 10 Percent Carbon Reduction Goal.** Initial analysis suggests that implementation of RFS2 at the national level will reduce the average carbon intensity of transportation fuels, assuming the carbon intensity of gasoline remains at 2005 levels. Depending on the assumptions used, the Midwest may achieve carbon intensity reductions above or below that number. Regardless of that fact, RFS2 is clearly an important strategy in achieving carbon intensity reductions in the

Midwest, but successful implementation of this policy is not guaranteed and depends on collaborative efforts on many fronts. The subgroup supports a regional approach that fosters, incentivizes and emphasizes full and organized implementation of RFS2 at the regional level.

The subgroup recommends a collaborative approach with the MGA, industry groups, the environmental community and federal agencies to accelerate regional implementation of RFS2 by overcoming the regulatory barriers that stand in the way of biofuels expansion in the region. All emissions implications of moving to higher blends need to be understood, including carbon intensity emissions and criteria pollutants. This approach should consider the development of blends beyond E10 and B5, including how to overcome market infrastructure and market barriers such as. Some options include, but are not limited to:

4.1 Promoting the introduction of vehicle technology, such as increasing the number of flexible fuel vehicles (FFV) that are compatible with blends beyond E10 and B5;

4.2 Promoting the evaluation of existing infrastructure to determine compatibility with blends beyond E10 and B5;

4.3 Promoting the introduction of necessary infrastructure for blends beyond E10 and B5, such as blender pumps;

4.4 Promoting strategies that have the potential to enhance RFS2 to achieve 10 percent carbon reduction; and

4.5 Promoting the advancement and introduction of advanced cellulosic biofuels, including ethanol, butanol, renewable biodiesel and renewable hydrocarbons.

5. **Support the Development of Infrastructure for Biofuels and Other Low Carbon Fuels.**

The subgroup recommends a multi-fuel infrastructure initiative that allows for the development of a variety of low carbon-intensive fuels, not all of which are renewable. This initiative would have the following elements:

5.1 The Midwest should proceed with a screening process to identify which fuels offer opportunities for lower carbon intensity transportation options, thus allowing the market to determine which fuels and strategies are used. The Midwest should review at least the following fuels: electricity, natural gas, propane, hydrogen, crude produced via enhanced oil recovery resulting in permanently stored CO_2, diesel fuel that displaces gasoline in passenger vehicles, and liquid fuels produced from coal and biomass with significant carbon capture and storage.

5.2 After determining which fuels to prioritize, the Midwest should determine the infrastructure needs and develop a plan for addressing them.

5.3 The Midwest should then move forward in implementing those plans.

5.4 The Midwest should seek assistance and partnership with federal agencies at all stages in this process.

6. **Develop and Pursue Complementary Policies at the Federal and State Level.** The Midwest should pursue other policies at the federal and state level that achieve the following goals:

6.1 **Enhance the Ability to Achieve RFS2 Through State and Federal Policy, as well as Other Initiatives, Including:**

6.1.1 Extend 1 psi[4] waiver for E15;

6.1.2 Create incentives for Flex Fuel Vehicles (FFVs) and blender pumps;

6.1.3 Support enhanced ethanol use past E10;

6.1.4 Encourage development of America Society for Testing Material specifications for fuels;

6.1.5 Occupation Safety and Health Administration approval (personnel exposure);

6.1.6 Modify state fire codes that may impact the development of new biofuels refueling infrastructure;

6.1.7 Make adjustments to the National Council of Weights and Measures Handbook 130 to the extent it impacts the development of biofuel refueling infrastructure;

6.1.8 Modify state regulations preventing greater than E10 blends;

6.1.9 Form a partnership with the EPA and USDA to aggressively implement RFS2 in the Midwest and seek support for building out the necessary infrastructure;

6.1.10 Petition the EPA to encourage biomethane and renewable electricity compliance under RFS2; and

6.1.11 Push for Underwriters Laboratory listing for biofuel refueling equipment.

[4] In order to control emissions of volatile organic compounds under the Clean Air Act, the EPA requires that gasoline not exceed 9.0 psi Reid Vapor Pressure (RVP) during the summer. The requirement is more stringent in non-attainment areas, as low as 7.8 psi. Some states have even more stringent requirements of as low as 7.0 psi, and requirements vary from state to state. As part of Clean Air Act Amendments, conventional gasoline containing 10% ethanol is allowed to exceed Federal RVP requirements by 1 psi.

6.2 **Use RFS2 Framework to Reward Carbon Intensity Reductions that Exceed RFS2 Requirements.**

6.2.1 **Federal.**

6.2.1.1 Explore whether a RIN-based approach that rewards carbon intensity improvements beyond required thresholds can be implemented without reducing required volumes, at either the state or federal level.

6.2.1.2 Consider allowing corn ethanol that meets the required 50 percent carbon intensity threshold to qualify as an advanced biofuel, thereby creating an incentive improve corn ethanol's carbon intensity in order to qualify.

6.1.1.3 Expand the list of qualified technologies for improving the carbon intensity of existing ethanol plants. The list should also motivate improvements in agricultural practices. Create a mechanism for expanding the list.

6.2.2 **State.**

6.2.2.1 Offer grants, tax credits and low-cost loans aimed at reducing carbon intensity of existing biofuel plants.

6.2.2.2 Consider using tax incentives for reducing carbon intensity beyond required RFS2 thresholds. Revise existing job creation and economic development programs to target carbon intensity reductions.

6.3 **Enhance the Market Opportunity for Alternative, Non-Renewable Fuels that Offer Carbon Intensity Reductions Relative to Gasoline and Diesel and that Are Not Currently Included Under RFS2.**

6.3.1 In addition to the carbon intensity reductions offered by RFS2, the region should move to adopt policies that enhance demand for non-renewable, low-carbon fuels in order to ensure that at least an equivalent 10 percent carbon intensity reduction goal is met.

6.3.2 Assure that existing investments are not harmed by any new policy, but rather that the policy provides market signals to encourage future investments.

6.3.3 Explore policies that remove hurdles to the use of non-renewable low-carbon fuels in response to a low-carbon transportation framework. Explore additional policy options, including a "non-renewable fuel standard" or new tax incentives at the state or federal level, which remove hurdles for non-renewable low carbon fuels.

III: ADDITIONAL LOW CARBON FUELS AND PRODUCTION PATHWAYS

There are a number of options available to develop lower-carbon resources for transportation fuels in the Midwest. The Renewable Fuels Standard (RFS2) will reduce the carbon intensity of the nation's transportation fuels by requiring significant levels of renewable fuels to be used. In addition to renewable fuels like ethanol (both conventional and advanced), biodiesel and renewable diesel, the Midwest has the potential to develop low-carbon fuels and production pathways from both renewable and non-renewable sources. These include:

- Natural gas through compression or liquefaction;
- Biogas through the anaerobic digestion of livestock waste;
- Electricity and hydrogen;
- Carbon dioxide (CO_2) enhanced oil recovery (EOR) with carbon capture and storage (CCS), or CO_2-EOR with CCS; and
- Dieselization (the increased utilization of diesel or distillate fuel).

Through the aggressive development of market incentives, infrastructure and regional or local policy, these resources provide a significant potential to supplement the region's transportation portfolio as demand for fuel grows over the next decade. Each equivalent gasoline gallon of fuel produced by these pathways is significantly less carbon-intensive than the average gallon of gasoline, thus providing the potential for reduction in carbon emissions from the Midwest's transportation sector. This overview of renewable and non-renewable low-carbon fuel pathways provides informational resources on the present status, future potential and carbon properties of each fuel. According to the "back-of-the-envelope" calculations in the following pages, the combined utilization of these resources could achieve a greater-than-10-percent reduction of carbon emissions in the Midwest within the next decade.

RENEWABLE FUEL STANDARD

In February 2010, the U.S. Environmental Protection Agency (EPA) released final regulation language on the RFS2. The EPA revised the program to comply with the Energy Independence and Security Act of 2007 (EISA) by increasing the volume requirements for advanced biofuels, revising carbon lifecycle assessment (LCA) modeling methodologies and adjusting other requirements to make compliance more feasible. The RFS2 will require an increased production, and thus consumption, of a variety of biofuels based on certified carbon intensity reduction thresholds.

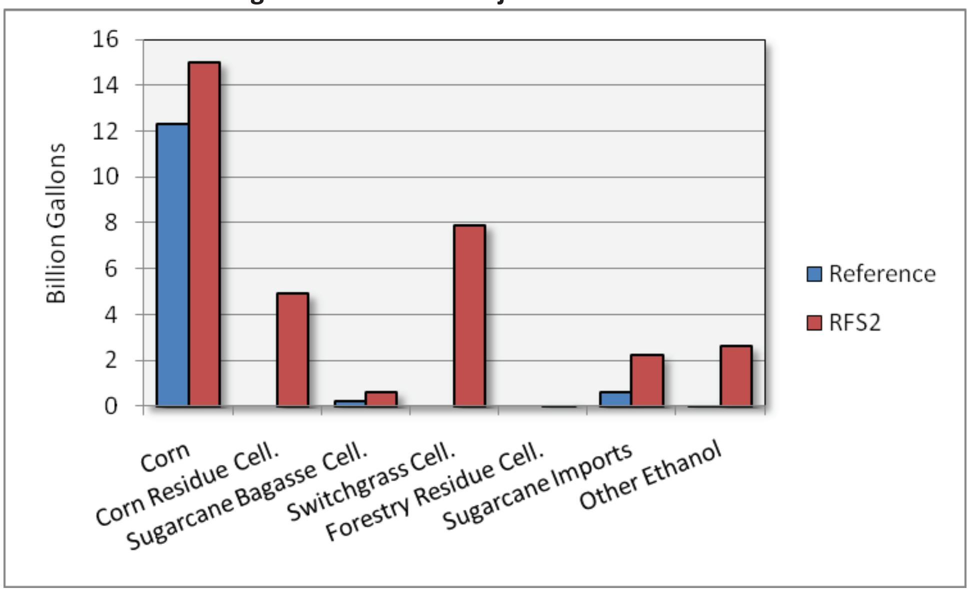
Table 5.1 GHG Thresholds Specified in EISA (percent reduction from 2005 baseline)[a]

Renewable fuel	20%
Advanced biofuel	50%
Biomass-based diesel	50%
Cellulosic biofuel	60%

[a] For new facilities after December 19, 2007
Source: EPA

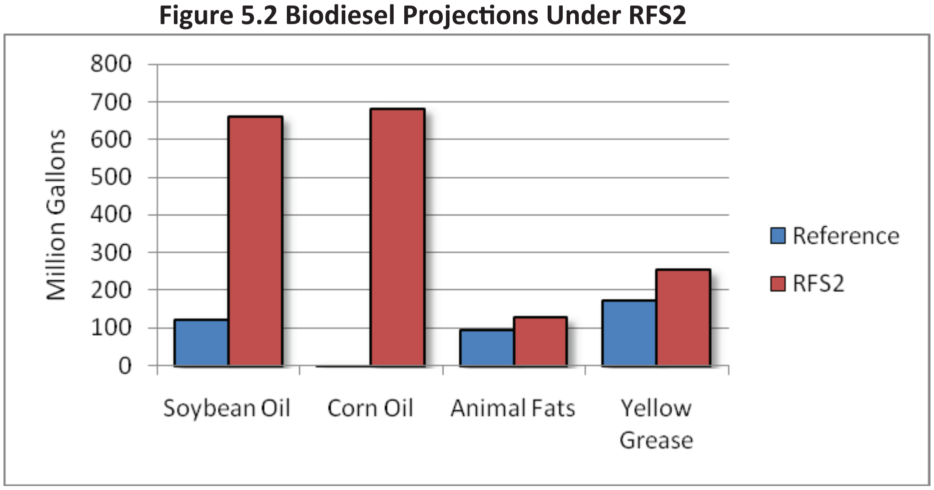
Although the RFS2 requires volumetric increases in biofuel production and does not set greenhouse gas (GHG) reduction standards aside from its threshold criteria, the increased use of lower-carbon fuels will likely influence the carbon intensity[5] of the nation's fuel blend. According to the EPA, the RFS2 will displace approximately 7 percent of the nation's total gasoline and diesel consumption in 2022. It is not immediately clear what magnitude of carbon intensity reduction this might achieve, but a look at the EPA's projections is elucidating.

Figure 5.1 Ethanol Projections Under RFS2[a]



[a] Cellulosic ethanol (cell.)

Figure 5.2 Biodiesel Projections Under RFS2



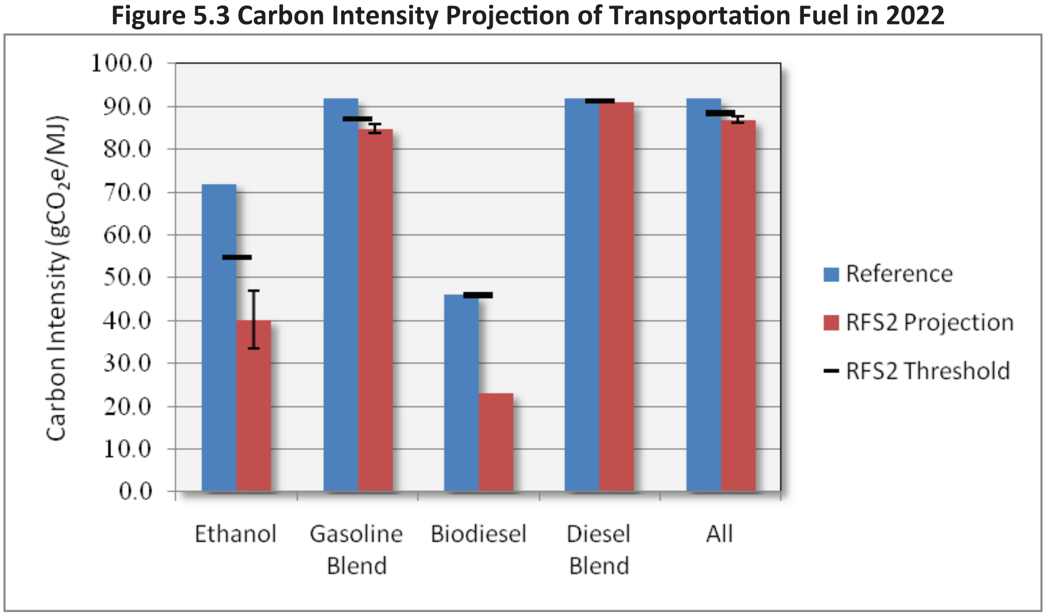
[5] In this report, the carbon intensity of a fuel includes other greenhouse gases (GHG) in terms of their carbon dioxide equivalency (CO_2e). Common GHGs used in CO_2e accounting are methane, nitrous oxide and hydrofluorocarbons.

The EPA's projections are based on the U.S. Department of Energy (DOE), Energy Information Administration's (EIA) Annual Energy Outlook. As explained in the EPA's regulatory impact analysis, projections of biofuel production before RFS2 implementation were based on the 2007 outlook; projections for oil consumption under EISA and proposed RFS2 volume requirements were based on the 2008 and 2009 outlooks. As shown in figures 5.1 and 5.2, the RFS2 results in a very significant increase in a variety of biofuels, requiring at least 21 billion gallons of advanced biofuels, and a total of 36 billion gallons of biofuel by 2022.

According to the projections, it appears that, without the RFS2, many next generation biofuels would not be produced in significant levels by 2022. Cellulosic ethanol from corn residue, switchgrass, and sugarcane bagasse, as well as diesel substitutes from crop oil, animal fats and yellow grease, will receive significant boosts in production from the RFS2. These fuels have much lower GHG emission intensities than the current generation of fuels and will help reduce the carbon intensity of the total gasoline and diesel fuel blend.

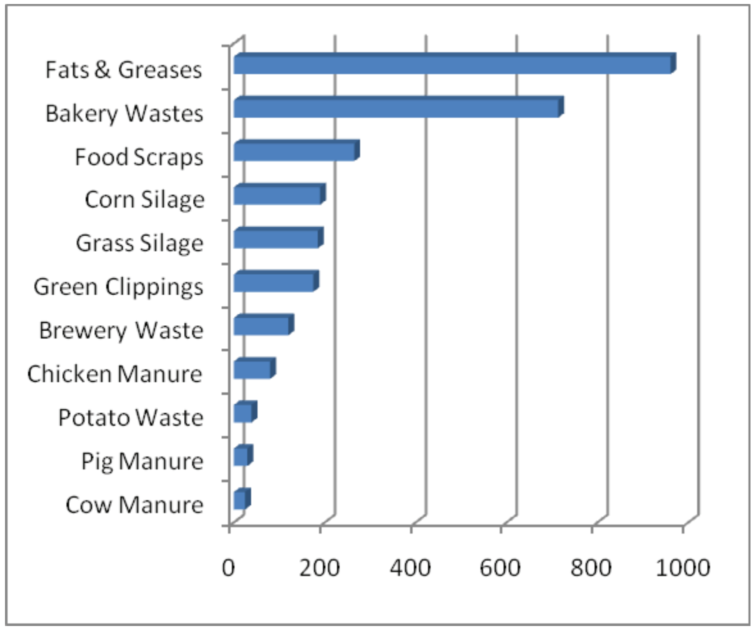
As part of its analysis, the EPA collected LCAs for a variety of biofuel production pathways to gauge the feasibility GHG thresholds under the RFS2. According to the EPA, corn ethanol provides a mean lifecycle GHG emission reduction of 21 percent from a gasoline baseline, while cellulosic ethanol can offer reductions of between 72 and 110 percent. Meanwhile, biodiesel might provide reductions of between 57 and 86 percent from the diesel baseline, and next generation diesel made from the Fischer-Tropsch biomass conversion processes can provide a 70 to 91 percent reduction. The EPA reported a carbon intensity of 93.08 gCO_2e/MJ for gasoline, and 91.94 gCO_2e/MJ for diesel.

Figure 5.3 Carbon Intensity Projection of Transportation Fuel in 2022



Projections by the EPA signal that the RFS2 will incentivize the production of higher-performing biofuels so that, by 2022, the total carbon intensity of ethanol will be reduced approximately 44 percent to an average of 40 gCO_2e/MJ, while the carbon intensity of biodiesel and renewable diesel will be reduced approximately 50 percent to an average of 23 gCO_2e/MJ. This assumes that all new biofuels are produced with GHG intensities around the mean scores found in the EPA's LCA studies and, perhaps more importantly, that the carbon intensity of gasoline and diesel remains the same (meaning that the ratio between fuel production from sweet crude and heavier crudes like bitumen would remain the same). For the gasoline blend, this amounts to a carbon intensity reduction of about 7.59 percent, and for the diesel blend, a reduction in carbon intensity of about 0.99 percent. Overall, the carbon intensity of the gasoline and diesel blend may be reduced by 5.32 percent to an average of 87 gCO_2e/MJ by 2022. If the slate of crude oil utilized by the U.S. for gasoline and diesel production trends toward heavier crudes, however, this effect may be greatly diminished.

Figure 5.4 Biogas Generation Potential of Substrates



Cubic meters of biogas per ton of substrate

NATURAL GAS AND BIOGAS

Natural gas can be used as compressed natural gas (CNG) or liquefied natural gas (LNG) to supply fuel for vehicles. The Honda Civic GX Sedan is the only light-duty vehicle available to run on CNG or LNG.[6] One benefit to using natural gas to fuel vehicles is that there already is a natural gas distribution infrastructure in place to deliver the fuel. However, a supporting infrastructure to allow vehicle owners to refuel would need to be developed. Biogas, as described below, could be a source of renewable natural gas that could be fed into the existing natural gas distribution infrastructure or used by vehicle fleets to supply additional fuel for CNG or LNG vehicles.

Biogas is a mixture of approximately 60 percent methane and 40 percent CO_2 along with other trace gases. In the Midwest, biogas production has been derived from agricultural wastes, mostly dairy manure, using anaerobic digestion to produce the gas and generate electricity. There are currently 55 on-farm anaerobic digestion projects in the ten MGA states producing approximately 21 megawatts of electricity.[7] This potential resource could be much larger by adding organic substrates to be co-digested with animal manure such as food waste, milk processing waste, fats, oils, greases and crop residues. Adding substrates to animal manure would not only produce more gas at existing or planned facilities, but would expand the number of potential projects at farms with medium-sized herds.

[6] U.S. Department of Energy. Alternative Fuels & Advanced Vehicles Data Center.

[7] AgStar Program, U.S. Environmental Protection Agency.

Biogas can also be produced at municipal wastewater treatment facilities. Additionally, new technologies are emerging to capture biogas from mostly solid feedstocks (poultry litter and dry feedlot manure). Another development in the industry is the emergence of new ownership models focused on centralized systems where manure and substrate feedstocks are brought to a central facility instead of having biogas-to-energy systems at individual farms. All of these advancements could lead to significant growth in the biogas-to-energy market.

The majority of operational biogas-to-energy projects are currently producing electricity. Two farm-based anaerobic digesters in the Midwest, Scenic View Dairy in Michigan and Emerald Dairy[8] in Wisconsin, have upgraded biogas produced from farm-based anaerobic digesters for injection into the natural gas pipeline, with a number of additional projects in the proposal stage. Upgraded biogas that is injected into natural gas pipelines is referred to as biomethane, or renewable natural gas, and is a direct substitute for pipeline natural gas, including for use as a transportation fuel. Upgraded biogas can also be used directly as a vehicle fuel without meeting pipeline natural gas pressure and interconnection standards. New technologies are emerging that can take a slipstream of biogas from new or existing biogas sources and provide fuel for individual vehicle or CNG fleets.

Challenges and Barriers

- CNG vehicles available in the market;
- CNG fueling infrastructure;
- Technical management for on-farm projects;
- New development models other than farm ownership;
- Permitting obstacles for mixing of multiple feedstocks at project sites; and
- Determining appropriate feedstock mixes to optimize biogas production.

Assuming that the utilization of new substrates will allow smaller farms to operate anaerobic digesters, the Midwest has the potential to produce a significant amount of biogas. By adding up the estimated biogas output of cattle and dairy farms above 500 head, swine farms above 100 head and chicken farms above 20,000 head, the Midwest could produce up to 130 billion cubic feet each year.[9] In 2009, the Midwest produced about 652 million megajoules (MJ) of the fuel. If it is assumed that 75 percent of the region's farms feed their livestock waste into a digester, approximately 45 billion MJ of biogas could be produced. This would imply an annual growth or adoption rate of 39 percent. While an adoption assumption of 75 percent may seem high, the region's currently low production level provides an opportunity for large increase in anaerobic digester policies or incentives over 10 years.

Table 5.2 Results: 75% of Biogas Potential by 2022	
Annual Growth Rate	39%
2009 Capacity (MJ)	662 million
2022 Capacity (MJ)	46 billion
2022 Capacity (scf)	98 billion
% GHG Reduction	1.17%

8 At the time of this writing, Emerald Dairy was no longer injecting upgraded biogas into the natural gas pipeline.

9 National Agriculture Statistics Service. U.S. Census of Agriculture 2007.

Given a carbon intensity of about 13.45 g/MJ, the combustion of 45 billion MJ of biogas in the year 2022 would result in 618 thousand tons of CO_2 emissions, but would prevent approximately 3.66 million tons of CO_2 emissions by displacing gasoline. **This would result in a 1.17 percent reduction in carbon intensity over 10 years.**

This analysis does not take into account many factors that can expand the opportunities for biogas production. These factors include technology advancements to utilize additional manure feedstocks and substrates, as well as the gasification of biomass feedstocks. In addition, other countries have experienced rapid expansion of anaerobic digesters under favorable economic and policy conditions. For example, at the end of 2008, Germany had approximately 4,100 anaerobic digesters.[10] Putting in place the right mix of economic and policy conditions could result in similar success in the Midwest.

ELECTRICITY

Electric vehicles (EV) use an onboard battery to power the motor. Battery power can be replenished by plugging the vehicle into a power source, either at the home or at a public charging station, to draw electricity from the power grid.[11] The Midwest's heavy reliance on coal powered electricity will be a consideration in determining carbon emissions associated with EV use. The Midwest also has rich renewable electricity resources, including significant wind potential, that could help meet the increased demand from EVs.

While availability and demand for EVs remains low, a number of factors might play a role in reversing that trend in coming years. High gas prices, government incentives, stronger Corporate Average Fuel Economy (CAFE) standards and a large increase in hybrid vehicle sales in 2007 and 2008 spurred announcements by leading U.S. car manufactures to introduce EV models starting in 2010 and 2011.[12] The Nissan Leaf and Chevy Volt are set to be debuted on the market at the end of 2010, and some cities are announcing initiatives to construct public charging stations for EVs. The DOE's Alternative Fuels and Advanced Vehicles Data Center has a searchable map of charging stations in individual states.[13] As demonstrated by the map, the EV charging infrastructure will need to be strengthened in order for EVs to achieve greater market penetration. In the Midwest, Iowa and Michigan, along with other states throughout the nation, have plans to install public charging stations.[14]

Electric utilities must determine how best to manage and update an electric grid that provides power to homes, businesses and transportation. Increased electric demand from the transportation sector may result in an additional increment of power generation depending on the number of EV's and whether they must serve this incremental load during off-peak or on-

[10] Federal Ministry of the Environment, Nature Conservation and Reactor Safety.

[11] U.S. Department of Energy. Alternative Fuels & Advanced Vehicles Data Center.

[12] Bailey, J., Morris, D. "Electric Vehicle Policy for the Midwest—A Scoping Document." Institute for Local Self-Reliance.

[13] U.S. Department of Energy, Alternative Fuels & Advanced Vehicles Data Center.

[14] Gonzalez, A. "Charging Ahead, Cities are working with car companies to prepare for the arrival of electric vehicles." *Wall Street Journal*. May 10, 2010.

peak demand periods. If a relatively small number of EVs were added to the fleet with charging done off-peak, then the incremental load could be met with the existing mix of generators and their associated carbon profile. If sufficiently large numbers of EVs are charged off-peak or on-peak, then the electric supply moves to a different mix of generating units depending on the region of the country. Marginal generators are the last plants brought online to satisfy increased demand and are generally more expensive, and less efficient, than base load plants.[15] However, the higher-marginal-cost units typically include more natural gas-fired units with lower carbon intensity profiles. As more EVs enter the market, electric utilities will need to plan and properly account for the increase in demand to satisfy demand increases in order to improve the carbon profile of EV use.

Table 5.3 Results: Optimistic electric growth	
Electric consumption - Gallons of Gasoline Equivalent	
2005	625,000
2022	690 million
Carbon intensity (g/MJ)	222.72
Drive train adjustment Energy Economy Ratio	3.0
GHG Reduction (%)	**0.50%**

In 2005, the electricity used for EVs equated to approximately 625,000 gallons of gasoline equivalent. This is a relatively small number, given that total gasoline use in 2005 was on the order of billions of gallons. Therefore, even high annual growth rates for electricity demand from the transportation sector would result in a relatively small, but significant, penetration rate for EVs. An optimistic scenario, displayed in Table 5.3, factors in EV usage growing by 25 percent a year until of 2012, and then accelerating to 75 percent to 80 percent growth a year due to policy incentives. This is similar to the growth assumed for the biogas scenario mentioned earlier. This optimistic assumption could result in approximately 690 million gallons of gasoline being displaced by electricity within 10 years (only about 2 percent of total gasoline consumption in the Midwest). This could be achieved by the sale of only 150,000 EVs over 10 years.[16] Given an average carbon emission intensity of 222.72 g/MJ for the Midwest's electric grid[17], as well as an energy-economy ratio adjustment factor of 3:1 to account for the increased efficiency of EV drive trains, this would prevent about 1.6 million tons of CO_2e emissions. Given EIA projections for gasoline consumption over the next decade, **this could equate to a carbon intensity reduction of about 0.50 percent.**

HYDROGEN

There is significant potential for the use of hydrogen as a transportation fuel in the Midwest. Because hydrogen is an energy carrier, not an energy source, it is produced from one of three main sources: fossil fuels, nuclear electricity and renewables such as wind, biomass, and urban-waste resources.[18] Though there are several pathways for producing and extracting hydrogen,

[15] McCarthy, R., Yang, Christopher. "Determining marginal electricity for near-term plug-in and fuel cell vehicle demands in California; Impacts on vehicle greenhouse gas emissions." *Journal of Power Sources*. 2009.

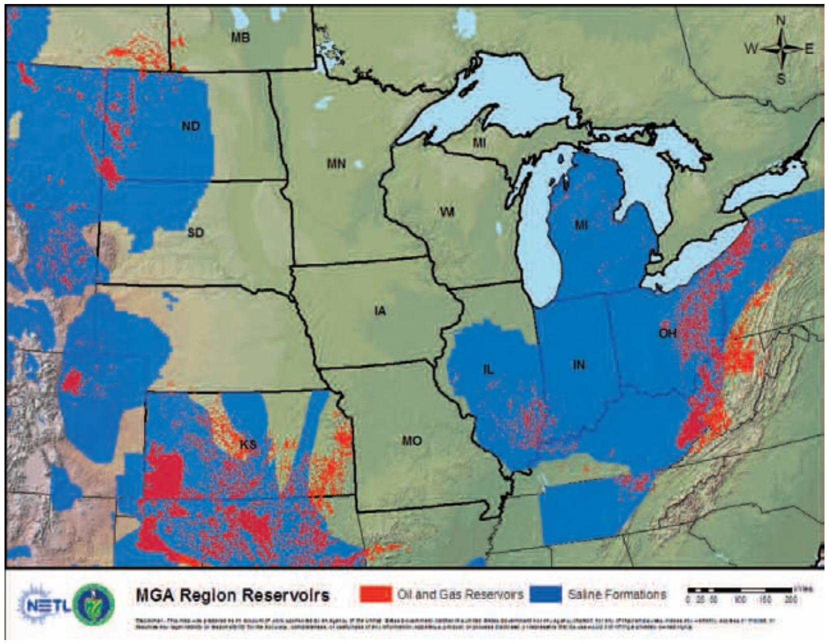
[16] According to the Energy Information Administration, there were 3,393 electric vehicles in the Midwest in 2005.

[17] U.S. Environmental Protection Agency. eGRID.

[18] U.S. Department of Energy. Energy Efficiency & Renewable Energy: Hydrogen Production.

[19] Florida Solar Energy Center. Hydrogen Basics- Production. University of Central Florida.

Figure 5.5 Geologic Storage Potential in the MGA



steam reforming accounts for 95 percent of the U.S. production and electrolysis.[19] Since the region is rich in renewable energy sources, specifically biomass and wind, hydrogen production has significant potential.

There are challenges and barriers to using hydrogen as a transportation fuel. The transition to a hydrogen economy will require several solutions to technologically challenging problems: increasing renewable resources as an energy source; the development of a distribution infrastructure for the nation's more than 160,000 filling stations;[20] the development and supply of vehicles from auto manufacturers to meet demand; and reducing the cost of fuel cells. Many practical considerations stem from targeting the challenges that face hydrogen today for tomorrow's implementation and solutions. Figuring out how to separate hydrogen from the other naturally occurring compounds in an efficient and economically viable process will allow production to reach the necessary capacity for transportation use. Whether hydrogen will be produced at centralized production plants and distributed to refueling stations or produced onsite, the infrastructure costs will likely be significant.[21] Hydrogen can be stored as a compressed gas, liquid, or solid, but requires rigorous standards for high-pressure tanks. Hydrogen vehicles must become more readily available, and the cost of fuel cells will need to decrease.

Table 5.4 Results: Optimistic H2 Growth

Hydrogen consumption (Gallons of Gasoline Equivalent)	
2010	69 thousand
2022	63 million
Carbon intensity (g/MJ)	98.3
Drive train adjustment (Energy Economy Ration)	3.0
GHG Reduction (%)	**0.15%**

At the time of this writing, the Midwest had a production capacity of about 70 thousand kilograms of hydrogen per year.[22] This equates to about 8.4 million MJ, or 69,000 gallons of gasoline equivalent. Assuming optimistic annual growth rates similar to those used in the electricity and biogas scenarios, the Midwest could produce about 63 million kilograms of hydrogen by 2022, enough to displace about 63 million gallons of gasoline. Assuming an average carbon intensity of 98.3 gCO_2e/MJ and a drive train adjustment factor equivalent to that used

[20] Ibid.

[21] Ibid.

[22] National Hydrogen Association. Merchant Hydrogen Production.

for EVs (3.0 energy economy ratio), this would prevent about 458,000 tons of CO_2 equivalent (CO_2e) and **result in a .15 percent reduction of the gasoline baseline carbon intensity.**

CARBON DIOXIDE ENHANCED OIL RECOVERY WITH CARBON CAPTURE AND STORAGE IN THE MGA REGION

The Midwest has the potential to increase regional oil production while simultaneously reducing the carbon footprint of the region's energy production through carbon dioxide-based enhanced oil recovery (CO_2-EOR) with carbon capture and storage (CCS).

CO_2-EOR is an established commercial practice and has been used for decades in the U.S. to increase production of oil beyond primary and secondary methods. Oil recovery is enhanced through the injection of CO_2 into depleted oil and gas formations. These formations are also potentially suitable for storing the CO_2 over the long-term. Current EOR practices store the injected CO_2 that is not recycled for other projects (assuming that the well is properly plugged and abandoned).[23]

Some oil and gas formations in the Midwest and other regions of the U.S.[24] are 'stacked' (as in the two types of formations are located in a similar location at different depths) with saline formations that have greater capacity for long-term CO_2 storage. These and other formations in close proximity provide an opportunity to maximize investment in infrastructure and minimize land-use impacts for both oil production and CO_2 storage by using the same project footprint (such as pipeline rights-of-way, injection and monitoring areas) for both oil production and the storage of CO_2. Furthermore, establishment of a pipeline for CO_2-EOR can be used to transport CO_2 to saline formations over the long-term that have larger storage-capacity potential.

The DOE's 2007 *Carbon Sequestration Atlas* estimated that depleted oil and gas formations have the capacity to store 91 billion tons of CO_2. Recent estimates by Advanced Resources International[25] (ARI) of U.S. oil reserves in the lower 48 states show that there are 72 billion barrels of oil that are technically recoverable using "best practices" and more than 106 billion barrels of oil are available using "next generation" technologies. The U.S. currently produces about 250,000 barrels of oil per day from more than 105 active CO_2-EOR projects. Analysis by ARI prepared for the Natural Resources Defense Council estimates that oil produced through CO_2-EOR could displace 33 percent to 40 percent of net crude imports in 2009 and between 43 percent and 52 percent of net crude oil imports projected by the EIA in 2030. The ARI estimated that this increased domestic oil production would improve the U.S. trade balance by nearly $700 billion and would result in an increase of between $190 billion and $210 billion dollars in state and federal revenues.

According to analysis completed by ARI for the MGA in 2009, the MGA region has a technically recoverable resource of 4.0 to 7.5 billion barrels of oil through CO_2-EOR depending on the

23 U.S. Dept of Energy, National Energy Technology Lab (March 2010). "Carbon Dioxide Enhanced Oil Recovery, *Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*."

24 Southeast Regional Carbon Sequestration Partnership Gulf Coast Stacked Storage Project.

25 Advanced Resources International is a research and consulting firm with several clients who are involved in the MGA process including Exxon Mobil, BP, ConocoPhillips, Marathon, Duke Energy, the American Petroleum Institute, the Pew Charitable Trusts and Natural Resources Defense Council.

technology applied. There are proposed and active projects, both commercial and demonstration projects, in the Midwest for EOR using captured CO_2 from coal-fired power plants, ethanol plants and other industrial projects. In one scenario,[26] ARI conservatively estimates that 6 billion to 7 billion barrels of oil could be produced from 2012 to 2030, resulting in 1.6 billion to 1.8 billion tons of stored CO_2. ARI's calculation assumes that, on average, a quarter ton of CO_2 is used to produce each incremental barrel of oil. The MGA region could store 1.0 billion to 1.9 billion tons of CO_2 as a result of recovering its estimated technically recoverable resource based on the ARI calculation.

The practice of coupling CO_2-EOR with the long-term geologic storage of the CO_2 would reduce the carbon footprint of a barrel of oil over an equivalent barrel imported to the U.S. Several Midwestern states have significant potential for geologic storage of CO_2 in depleted oil and gas formations, saline formations, and unmineable coal seams. There are several active storage demonstration projects across the Midwest. Core Energy, for example, has been recovering oil through CO_2-EOR using anthropogenic CO_2 from the Antrim gas stripping plant in Michigan. Core Energy is also using the CO_2 for EOR and storage as one of the DOE's regional sequestration demonstration projects. Core Energy produced its one-millionth barrel of oil in 2008 through CO_2-EOR.[27] Other examples of established commercial projects include North Dakota's Dakota Gasification Company project, which transports captured CO_2 via a 205-mile pipeline to the Weyburn oil fields in Canada for CO_2-EOR and long-term storage.[28] Exxon Mobil's project in La Barge, Wyoming captures 4 million tons of CO_2 per year from a natural gas processing plant and markets the CO_2 in part to nearby oil operations for CO_2-EOR.

Table 5.5 Technical Potential for CO2-EOR in the MGA Region

State	# Reservoirs Amenable for EOR	Favorable Oil in Place (MM Bbls)	State of the Art Technically Recoverable (MM Bbls)	Next Generation Technically Recoverable (MM Bbls)
Illinois	75	5,260	494	2,276
Kansas	25	5,149	1,272	1,748
North Dakota	34	3,703	1,060	1,548
Ohio	19	3,906	853	1,495
Michigan	11	1,033	230	320
Nebraska	3	276	44	109
South Dakota	1	93	23	30
Indiana	7	241	18	19
Total	**175**	**19,661**	**3,994**	**7,545**

Table developed by Advanced Resources International for the MGA (2009).[30]

Technologies to increase the recovery rate of CO_2-EOR continue to advance, but the real challenge to increasing the recovery of oil through CO_2-EOR is the availability of CO_2. Other

[26] Advanced Resources Institute (2010). "Assuming that about 300,000 barrels per day can be produced using CO_2 from these (predominately) natural sources, and that CO_2-EOR production ramps up uniformly over 18 years (from 2012 to 2030), 6 billion to 7 billion barrels of incremental oil could be produced using captured CO_2 from industrial sources, *assuming all of this CO_2 is utilized for CO_2-EOR.*"

[27] Core Energy. "CO_2-EOR Green Oil."

[28] Dakota Gasification Company. "Carbon Capture and Storage."

[29] ExxonMobil. "The Promise of Carbon Capture and Storage."

[30] Ferguson, Robert (June 22, 2009). "CO_2-Enhanced Oil Recovery Potential for the MGA Region," prepared for the MGA by Robert Ferguson, Advanced Resources International.

challenges to expanding CO_2-EOR include the capacity of the pipeline infrastructure, further advancement of technology to increase production with CO_2, and a stable regulatory framework that provides incentives for CO_2-EOR projects with long-term CO_2 storage. CO_2-EOR operations have traditionally extracted CO_2 from naturally occurring deposits such as the Jackson Dome in Mississippi. These deposits are not sufficient to provide future operations with supplies of CO_2 to take advantage of the significant oil recovery opportunities.

ARI's 2010 report states that the availability of large volumes of reliable and affordable CO_2 is the "single largest deterrent" to expanding CO_2-EOR. CO_2-EOR operations are structured to efficiently use CO_2 to enhance the recovery of oil. Policy mechanisms could provide incentives for CO_2-EOR projects to inject larger volumes of CO_2 for the purpose of both EOR and CO_2 storage.[31] A clearly defined regulatory framework for long-term storage of CO_2 versus incidental storage will also foster project development.[32] A policy framework that supports CO_2 capture projects to develop reliable sources and storage values of CO_2 will accelerate and promote the development of CO_2-EOR as a means to increase domestic production of oil and to reduce the carbon footprint of domestic energy production.

According to ARI analysis, there are between 2.17 billion and 3.86 billion barrels of crude oil that could be economically recovered through CO_2-EOR in the MGA region.[33] For each barrel that is produced, 0.26 tons of CO_2 are sequestered, thus reducing the carbon intensity of gasoline and diesel fuels that are refined from this source.[34] In the Midwest, a barrel of oil generally produces 21.3 gallons of gasoline and 13.5 gallons of diesel (the remaining 17 percent of each barrel produces other petroleum products).[35] If the sequestered CO_2 is accounted for in proportion to the amount of gasoline and diesel that is produced from each barrel, then 0.13 tons of CO_2 are sequestered for each gallon of gasoline, while 0.08 tons are sequestered for each gallon of diesel. This results in a carbon intensity reduction of about 51 g/MJ and 46 g/MJ for gasoline and diesel, respectively.

ARI estimates that up to 19 percent of economically recoverable oil resources in the lower-48 states could be recovered through CO_2-EOR by 2030. Therefore, it is reasonable to assume that 10 percent of it may be extracted by 2022. In the MGA region, this translates into a total of between 4.6 billion and 8.2 billion gallons of gasoline, and 2.9 billion to 5.2 billion gallons of diesel fuel, assumed to be extracted over a period of 10 years. For consistency with the other calculations in this section, fuel consumption projections from the EPA's RFS2 impact analysis[36] were used in conjunction with region-specific consumption baseline data on highway statistics from the U.S. Department of Transportation, Federal Highway Administration.

[31] U.S. Department of Energy, National Energy Technology Lab (March 2010).

[32] For an extensive analysis of the issues involved with developing a framework from an EOR context to the CCS context, see Philip M. Marston and Patricia A. Moore, "From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage," *Energy Law Journal,* Vol. 29, no.2 (2008): 448 – 465.

[33] Ferguson (2009). The economic potential uses a base case scenario of 70 dollars per barrel of oil and 45 dollars per metric ton of CO_2. The range of oil recovery potential between 2.17 to 3.86 depends on using State of the Art Technology or Next Generation Technology.

[34] Advanced Resources Institute (March 10, 2010).

[35] Consultation with representative from Marathon Oil Corporation, May 10, 2010.

[36] Final Regulatory Impact Analysis. U.S. Environmental Protection Agency.

By 2022, between 842 million and 1,497 million gallons of gasoline can be produced in the MGA region using CO_2-EOR. This results in a carbon intensity reduction of the gasoline blend of between 1.7 percent and 3.0 percent. Between about 534 million and 949 million gallons of diesel can be produced alongside this gasoline, resulting in a carbon intensity reduction of between 1.8 percent and 3.2 percent. If added together to calculate the reduction upon a combined gasoline and diesel baseline, **CO_2-EOR offers the potential for carbon intensity reductions of between 1.7 percent and 3.0 percent over 10 years.**

Table 5.6 CO_2 - EOR Economically Feasible Scenario

	State of the Art	Next Generation
Economically Feasible (billion barrels)	2.17	3.86
Sequestration Rate (tons CO_2 per barrel)	0.26	
By 2022		
Gasoline produced (million gallons)	842	1,497
Gasoline GHG Reduction	1.7%	3.0%
Diesel produced (million gallons)	534	949
Diesel GHG Reduction	1.8%	3.2%
Total GHG Reduction	**1.7%**	**3.0%**

DIESELIZATION

Increasing the use of diesel for road transportation (and reducing the use of gasoline), known as dieselization, may be one way to improve the overall efficiency of oil consumption and reduce GHG emissions. A study by the Argonne National Laboratory suggests that the U.S. could have saved half a quadrillion British thermal units of petroleum per year in 1992 (3.7 percent of energy consumed by light-duty vehicles) had it pursued a dieselization strategy starting in 1970, and could have reduced CO_2 emissions by 45.7 million metric tons.[37]

A "matched pair" analysis of similar cars with diesel and gasoline engines suggests that diesel cars have 15 percent to 20 percent better fuel economy, and a roughly 15 percent CO_2/km advantage when divided out by vehicle class.

Diesel vehicles remain a small proportion of the U.S. automotive market, despite dominating the heavy vehicle market. A few automakers do offer diesel passenger vehicles, including Volkswagen, Audi, Mercedes Benz and BMW.[38] Chrysler, Ford, and General Motors offer diesel-powered full-sized heavy trucks in the U.S. market, but not passenger vehicles.[39] There are many more diesel vehicles offered in Europe, including by U.S. manufacturers.

Because the U.S. transportation system has favored gasoline, many refineries are not equipped to dramatically increase their diesel production. The ability of refineries to increase their diesel production depends on the technology used by the refinery, the type of crude oil used and other factors. In the summer of 2008, when diesel fuel had high profit margins and gasoline had low profit margins, many refineries began to increase their production of diesel. The average diesel

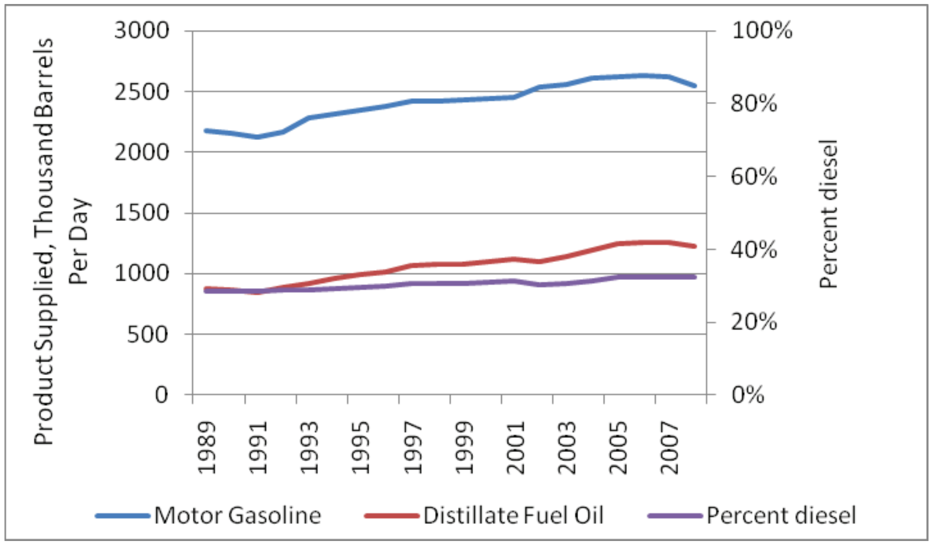
[37] Stork, K., M. Mintz, A. Vyas, F. Stodolsky, R. Cuenca. "Another way to go? Some implications of a diesel light duty vehicle strategy." Conference paper. 76th Annual Meeting of the Transportation Research Board. January 1997.

[38] www.fueleconomy.gov.

[39] Kaho, T. "Clean Diesel: A New Era of Green Cars". Mother Earth News February/March 2010.

yield increased by 3 percent relative to 2007. An EIA study determined that nearly all types of refineries were able to increase their diesel production, with some individual refineries increasing their diesel yield by up to 12 percent.[40] Thus, altering the diesel yield by an average of 3 percent to 5 percent would seem reasonable over a relatively short timeframe, larger shifts might require capital investments.

Figure 5.6 Share of Gasoline and Diesel Fuel



Any dieselization strategy would require a coordinated effort between refineries, automakers, consumers, fuel retailers and government to assure that the fuels, vehicles and refueling infrastructure were available.

Table 5.7 Results: 4% Annual Growth in Diesel Share

	billion gallons	%
Gasoline	25.1	56%
Diesel*	17.4	44%
Gasoline displaced:	2.7 billion gallons	
GHG Reduction:	**1.7%**	

*Only 2.7 billion gallons of this is used to displace gasoline in light-duty passenger vehicles

The percentage of diesel-to-gasoline use has increased about 4 percent over the past 20 years from around 29 percent to around 33 percent of total fuel. According to EIA projections, the Midwest will consume 27.8 billion gallons of gasoline and 14.9 billion gallons of diesel by 2022. However, if a 4 percent annual growth rate for the share of diesel continues over the next 10 to 12 years, the Midwest could increase the share of diesel from 38 percent to 44 percent of total transportation fuel consumption. This would displace about 2.7 billion gallons of gasoline and prevent about 5.4 million tons of CO_2e due to the higher energy content and the efficiency of diesel fuels and vehicles. As a result, **the carbon intensity of the Midwest's transportation fuel baseline could be reduced by about 1.7 percent.**

[40] Presentation. Joanne Shore and John Hackworth, Energy Information Administration. "Trends, Cycles and Kinks." OPIS 11th Annual National Supply Summit. October 19, 2009.

IV: TECHNICAL REPORT

As part of the advisory group process, the data, modeling and analysis subgroup met regularly from the winter of 2009 through the spring of 2010 to perform research and make recommendations regarding the technical considerations of implementing an LCFP in the Midwest. This report incorporates many of the technical considerations and analysis determined by the subgroup for the advisory group process.

An LCFP/LCFS sets a limit on the carbon intensity of liquid transportation fuels in order to curb GHG emissions from automobiles, regardless of the level of driving or fuel consumption. Defined as the amount of GHG emissions per unit of energy (generally, grams of CO_2 equivalent per megajoule, or gCO_2e/MJ), the carbon intensity[41] of a liquid transportation fuel represents the carbon and other gases embedded in a certain amount of the fuel that is released either through combustion in an engine (direct emission), or through the extraction, production, transportation and refining of the fuel (upstream emissions). An LCFP can target direct emissions only, or the entire lifecycle of emissions (direct and upstream emissions).

While the level of direct emissions can vary widely between types of transportation fuels, there are many variations in the production of fuel that are not accounted for on a direct emission basis. For each type of fuel, there are multiple production pathways that affect the amount of total carbon emissions produced through feedstock extraction, fuel production, refining and other upstream processes. Each production pathway results in a unique level of carbon emissions based on the total amount and type of energy used throughout a fuel's full lifecycle. An LCA accounts for the variations in production pathways by conducting a "cradle-to-grave" or "wells-to-wheels" analysis.

To enact a carbon intensity based fuels policy, an LCFP framework needs to have a consistent methodology for determining the LCA carbon intensity of each fuel pathway. A number of existing LCA models offer a consistent approach for a range of fuels. This report will compare the LCA carbon scores produced by each of these models, and discuss the variation of inputs, assumptions and lifecycle methodologies of each. An LCFP program can use existing models, conduct analysis to internally determine carbon scores, or engage with a third party consultant to perform LCAs. For the purposes of these recommendations, no new LCA analyses were performed; only scores from existing models and other LCAs were used (models are discussed later in this section).

An LCFP requires annual percentage reductions from a baseline average fuel carbon intensity (AFCI). The first working group's recommendations called for a policy that results in a 10 percent reduction from a 2005 baseline AFCI. To determine the Midwest's 2005 baseline AFCI,

[41] In this report, the carbon intensity of a fuel includes other GHGs in terms of their carbon dioxide equivalency (CO_2e). Common GHGs used in CO_2e accounting are methane (CH_4), nitrous oxide (N_2O) and hydrofluorocarbons (HFCs).

the subgroup conducted a review of fuel-consumption data from federal and industry sources. For some fuels, public data did not exist on the appropriate level of specificity to calculate an exact AFCI. In these cases, estimates were made based on the judgment of industry experts in the advisory group. Additionally, as an internal LCA was not conducted due to timeline and resource constraints, LCA carbon scores were chosen based on existing models.

There are a number of alternatives to achieve reductions in the carbon intensity of liquid transportation fuels. A very common approach is to increase the blending of biofuels such as ethanol and biodiesel into conventional fuels like gasoline and diesel. The resulting intensity reduction is then based on the amount of alternative fuel and its carbon score. Other compliance strategies include efficiency improvements in production, feedstock switching, and other process changes that reduce the upstream emissions of a fuel pathway. Alternatively, an obligated party may choose to purchase credits from a trading system (if one exists). An LCFP that considers the full LCA of a fuel pathway would count any verified combination of these compliance strategies toward a required annual reduction.

Just as there are multiple compliance strategies associated with an LCFP, there are multiple existing or proposed policies that may result in similar strategies being undertaken by obligated parties. For example, many states in the Midwest have existing biofuel mandates that may be strengthened in the next decade. Additionally, in February 2010, the EPA announced its final ruling on updating the federal RFS, thus RFS2. While approaching carbon emissions from transportation fuels through different means, some of these policies may achieve a portion of the intensity reductions required by an LCFP.

BASELINE FUEL USE

In order for an LCFP to set regional carbon intensity standards and annual reduction targets, a baseline carbon intensity for the region must be established. The baseline is an average carbon intensity of all transportation fuel consumed in the region. It is calculated from the carbon intensity and the total amount of consumption of each fuel. As mentioned in the introduction, the carbon intensity of each fuel relies on the LCA score given to the fuel by an existing model or applicable analysis. To determine the total amount of consumption, it is possible to construct an estimate based on public data collected by governmental agencies. Some state revenue departments track gasoline and diesel sales for tax purposes. The U.S. Department of Transportation's Federal Highway Administration collects this information from states and industry to compile annual reports on its website. The EIA has a variety of information on petroleum production.

While a wealth of transportation fuel data does exist, the data are often tailor-made for existing policies and regulations. In most areas, an LCFP is a new policy that may require new types of data. Specifically, while existing reporting frameworks track the amount of the end product used in a region, they often do not track the production pathway used to create that fuel. Under an LCFP, it is necessary to track which pathways are used in order to determine a carbon score. In general, the research conducted for this LCFP process found that this information is primarily privately held by fuel producers as a trade secret and that current state and federal reporting requirements are insufficient to make truly accurate calculations. Consequently, the advisory group constructed a best estimate based on existing data.

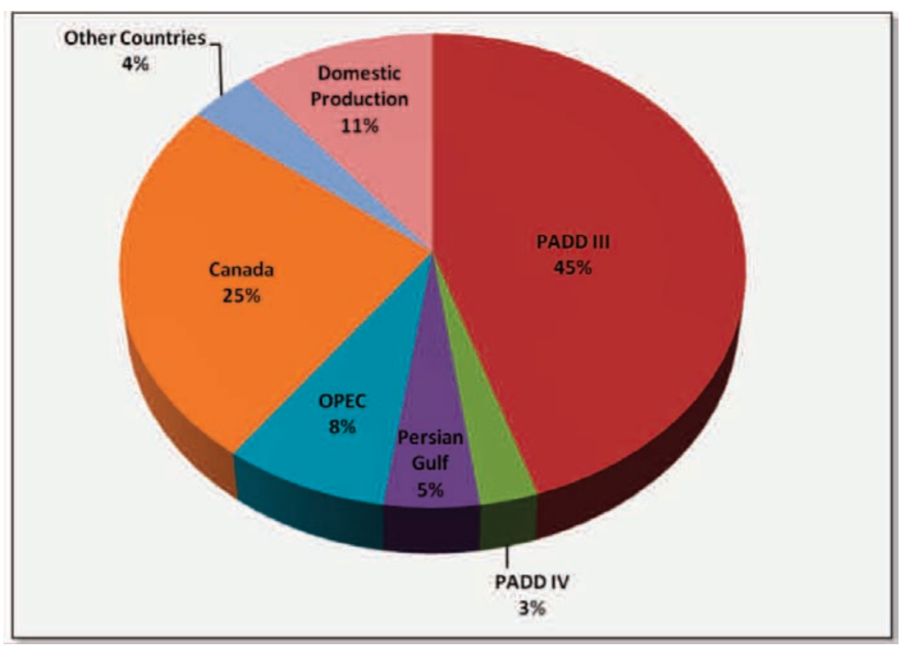
Petroleum information collected by the EIA is aggregated and sorted into five Petroleum Administration for Defense Districts (PADDs). The Midwest is located in PADD II, which also contains the states of Kentucky, Oklahoma and Tennessee. While this analysis was conducted for the MGA, an LCFP could be adopted in any state that chooses to do so. Additionally, it would be difficult to break down much of the data used for this analysis in order to omit specific states. Therefore, this analysis used data sorted by either the Midwest region or PADD II.

PETROLEUM PRODUCTION AND IMPORTS

According to the EIA, the PADD II (Midwestern) region imported or produced a total of about 1.5 billion barrels of crude oil in 2005.[42] Of this amount, approximately 674 million barrels, or 45 percent of total crude oil, were shipped into the Midwestern region from PADD III (the Gulf Coast region), and approximately 379 million barrels, or 25 percent, were imported from Canada. Approximately 11 percent of total crude consumed in PADD II, or 161 million barrels, was produced within the region (12 of the 15 states in PADD II produce oil; see Table 6.1 for state production levels). Figure 6.1 displays the sources of crude oil in PADD II in 2005.

It is important to note that, while these recommendations refer to the year 2005 for a fuel volume and carbon intensity baseline, production and import levels have changed in the five years between the baseline and the time of this study. Complete data for the years 2009 and 2010 are not yet available. But, in 2008, imports from PADD III into PADD II fell 19 percent, from 674 million barrels to about 546 million barrels. Meanwhile, imports from Canada grew 13 percent, from 379 million barrels to 430 million barrels, as did imports from PADD IV (Rocky Mountain states), from about 42 million to 61 million. Domestic production in PADD II also grew 22 percent, from approximately 162 million to 197 million barrels.

Figure 6.1 PADD II Crude Oil Sources 2005



[42] The quantities listed in this section do not include petroleum products such as liquefied petroleum gases, kerosene, and lubricants, etc., though Energy Information Administration does track this information.

Table 6.1 State Crude Oil Production (thousand barrels)

	2005	2006	2007	2008
Illinois	10,207	10,323	9,609	9,423
Indiana	1,727	1,731	1,727	1,858
Kansas	33,823	35,651	36,490	39,582
Kentucky	2,535	2,340	2,666	2,645
Michigan	5,549	5,093	5,201	6,223
Missouri	85	87	80	99
Nebraska	2,413	2,313	2,334	2,394
North Dakota	35,660	39,911	45,058	62,776
Ohio	5,652	5,422	5,455	5,715
Oklahoma	62,142	62,841	60,952	64,065
South Dakota	1,469	1,394	1,665	1,697
Tennessee	324	192	284	344

Source: Energy Information Administration

Therefore, while the share of Gulf Coast oil shrunk from 45 percent to 38 percent of PADD II's total oil supply, Canadian imports grew from 25 percent to 30 percent and domestic production from 11 percent to 14 percent.

Although imports from PADD III did shrink between 2005 and 2008, the Gulf Coast remains the largest single provider of oil to PADD II. It is hard to determine whether this is true only for Kentucky, Oklahoma, Tennessee and other states located in the southern portion of PADD II, and not for states considered part of the Midwest. Generally, states in the northern part of PADD II, such as Illinois, Michigan, Minnesota and Wisconsin, receive higher levels of petroleum from Canada than from the Gulf Coast.

Additionally, while the data shows the most immediate sources of oil flowing across the PADD II boundary, data identifying the ultimate origin of each barrel of oil was not available. As a result, much of the oil coming into the Midwest from the PADD III may actually be from foreign countries. EIA data on PADD III reveal that 31 percent of Gulf Coast oil originated from Organization of Petroleum Exporting Countries (OPEC) countries, 14 percent from the Persian Gulf and 15 percent from Mexico. Only 28 percent of Gulf Coast oil came from domestic production.

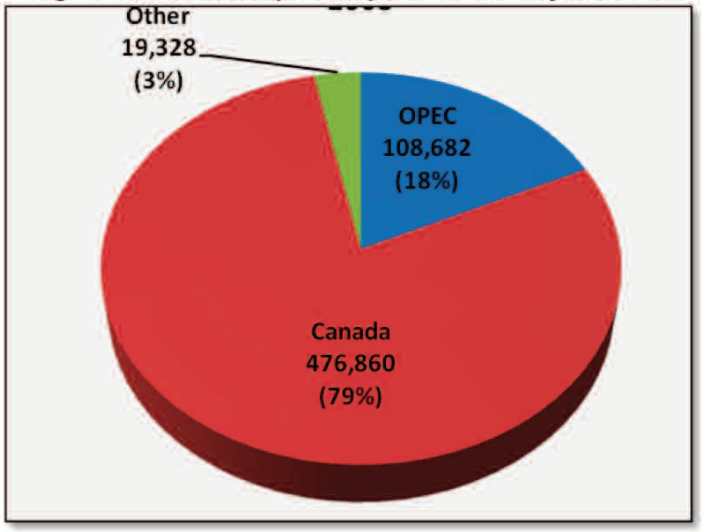
The data for PADD II are consistent with industry statements contending that the Midwest is moving toward Canadian and domestically refined petroleum, while imports are diminishing from Gulf Coast states and offshore refineries. Canada offers a secure source of crude oil to the U.S., and its close proximity enables a mutually beneficial trade partnership with the Midwest. In recent years, however, environmental groups have grown concerned about the increasing production of bitumen, or oil sands, from Alberta, much of which ends up in the Midwest.

CANADIAN CONVENTIONAL AND HEAVY CRUDE IN THE MIDWEST

Conventional means of oil extraction cannot be applied due to bitumen's heavy density and high viscosity, so additional energy-intensive extraction and refining processes must be used to turn oil sands into usable crude oil. This additional energy use results in a higher level of production phase emissions that can put the fuel at a disadvantage when compared with lighter crudes on a lifecycle basis.[43] A comparison of crude types and LCA models is provided later in this section. Canada is the largest single provider of oil imports into the Midwest. According to the EIA, in

[43] Alberta Energy Research Institute & Jacobs Consultancy. Lifecycle Assessment of American Imported Crudes.

Figure 6.2 Midwest (PADDII) Petroleum Imports 2008

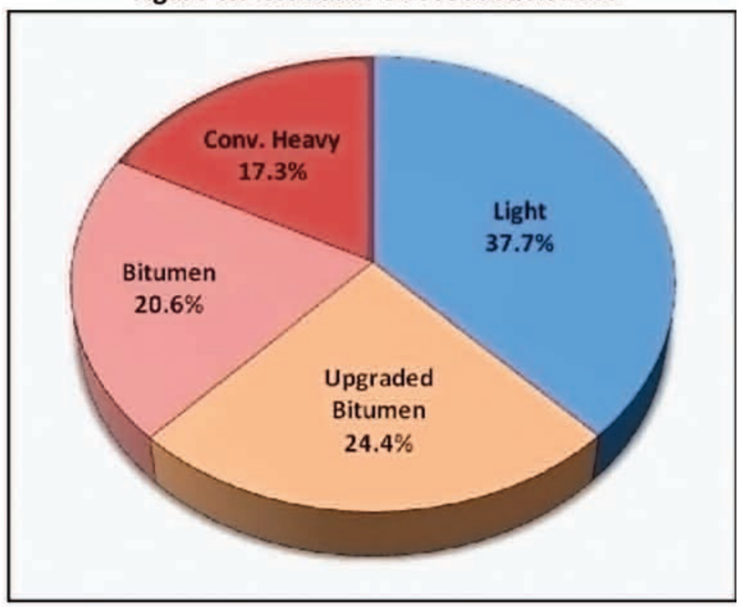


Source: Energy Information Administration

2008, PADD II imported approximately 477 million barrels of crude oil, or 79 percent of total imports, from Canada, approximately 109 million barrels (18 percent) from OPEC nations, and 19 million (3 percent) from non-OPEC nations.

The Canadian National Energy Board (NEB) also breaks down its production info by province and type. Alberta is Canada's largest oil producing province by far, with an average daily production of 1.8 million barrels per day,

Figure 6.3 Canadian Oil Production 2008

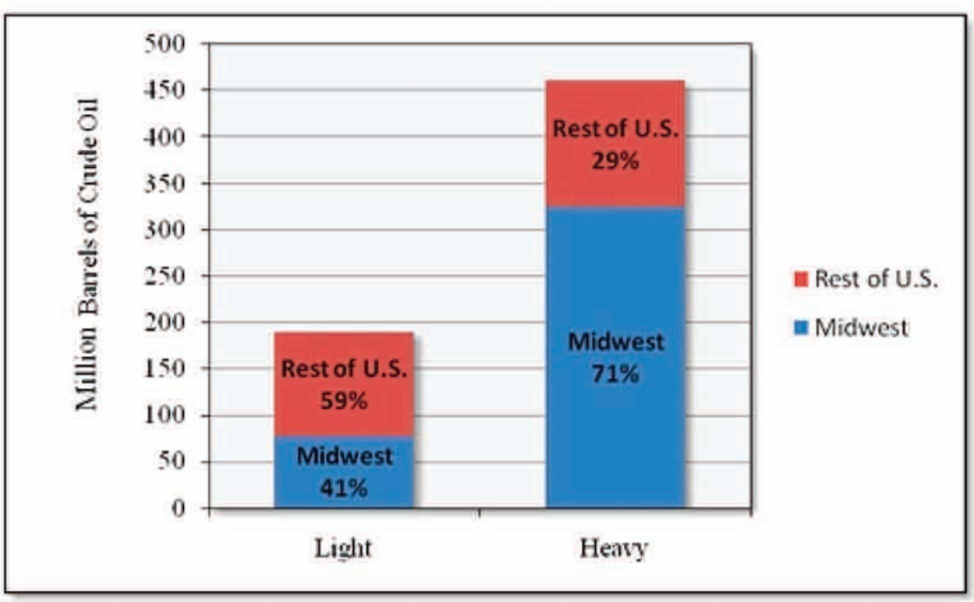


Source: Canadian National Energy Board

compared to Saskatchewan's 440 thousand barrels per day and Newfoundland's 308 thousand barrels per day. Alberta's lead is almost entirely due to bitumen and heavy oil extraction, as 65 percent of its total production originates from bitumen.

Finally, it is important to consider how much of Canada's bitumen and heavy oil ends up in the Midwest. According to the NEB, 41 percent of Canada's total exports of conventional light crude oil to the United States were processed in the Midwest (78 million barrels). In contrast, the Midwest received 71 percent of Canada's total exports of heavy crude (325 million barrels). Additionally, up to 40 percent of Canada's light crude comes from upgraded bitumen (NEB differentiates between light crude and synthetic light for exports). In other words, heavy crude imports into the Midwest outnumber light crude imports by well 4:1.

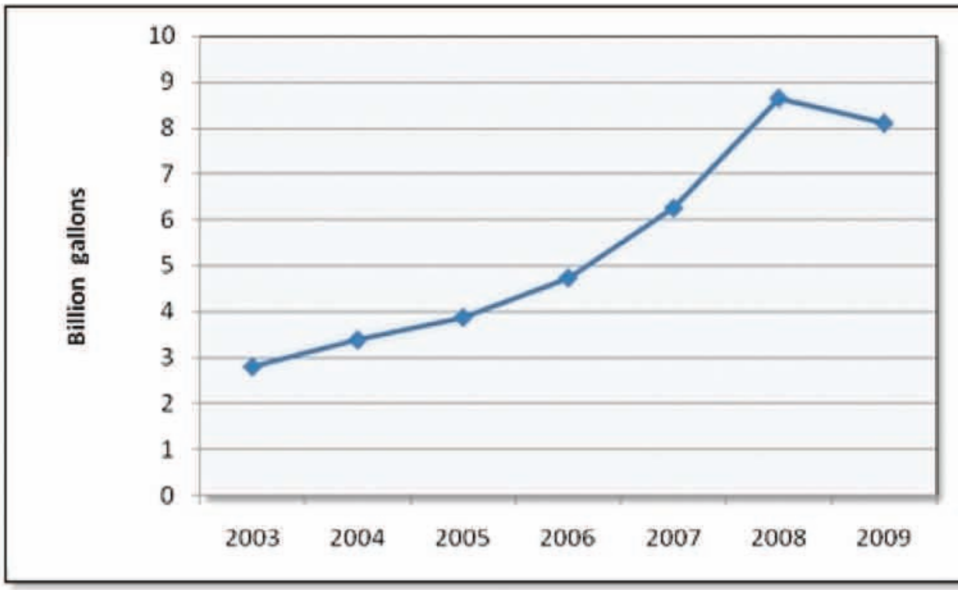
Figure 6.4 Canadian Heavy Crude Oil Exports



GASOLINE AND ETHANOL CONSUMPTION

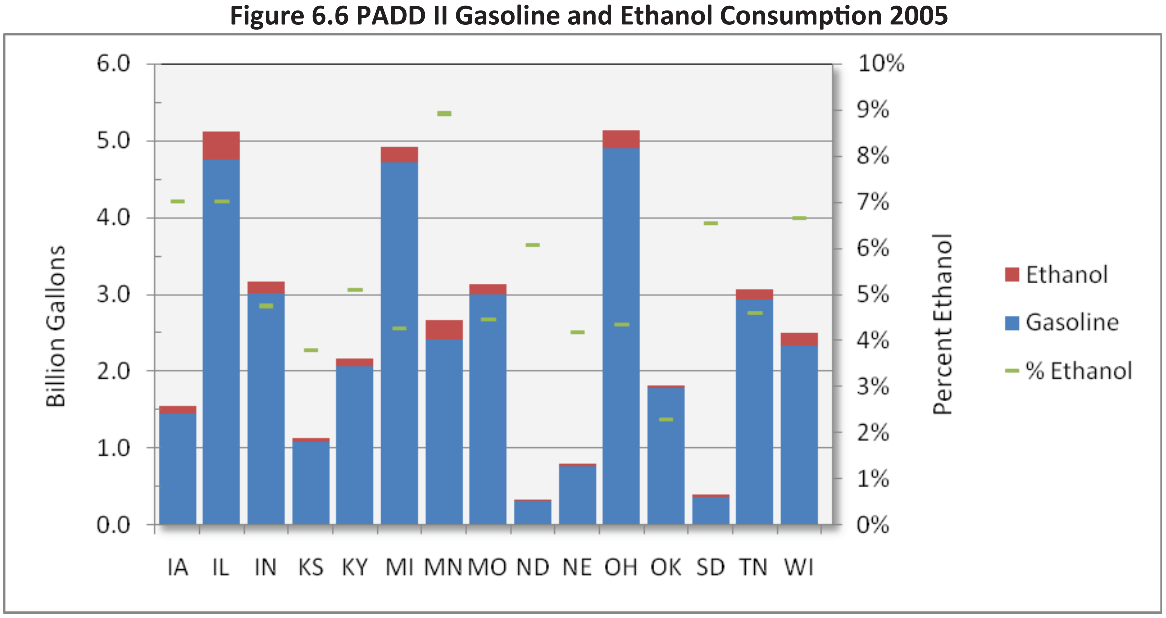
The Midwest consumed 32 billion gallons of gasoline in 2005.[44] Much of this was gasoline blended with ethanol. Several Midwestern states have ethanol mandates and other policies that encourage, or require, ethanol to make up a certain percentage of gasoline sold within each state. Based on reports by the EIA and the Renewable Fuels Association, ethanol accounted for 5.6 percent of the gasoline sold in the Midwest in 2005. In some states, the blend rate was as high as 7 percent and 8.9 percent.[45] Ethanol production in PADD II has increased from 2.8 billion gallons in 2003 to 8.1 billion gallons in 2009. In 2005, the Midwest was a net exporter of ethanol, consuming only 2 billion of the 3.8 billion gallons it produced.

Figure 6.5 PADD II Ethanol Production



Source: Renewable Fuels Association

Figure 6.6 PADD II Gasoline and Ethanol Consumption 2005



Source: Energy Information Administration and the Renewable Fuels Association

[44] Federal Highway Administration Monthly Motor Fuel Reported by States.

[45] While some states have ethanol mandates at or above 10 percent, this often applies only to gasoline sold at the pump for on-road passenger vehicles. The policies may not apply to off-road or aquatic recreational vehicles, among others. Ten percent is maximum legal ethanol content by federal law except for flexible fuel vehicles, which can utilize blends up to E85.

DIESEL AND BIODIESEL

Used less commonly than gasoline in the U.S., diesel provides fuel for large trucks, industrial equipment and agricultural vehicles, among others. In 2005, the Midwest consumed about 9.6 billion gallons of diesel. According to the National Biodiesel Board, the Midwest produced approximately 43 million gallons of biodiesel in the 2005 fiscal year (FY). Since then, production levels have fluctuated quite dramatically. The Midwest produced almost 421 million gallons of biodiesel in the FY 2008, but only about 265 million gallons in fiscal year 2009. According to the National Biodiesel Board, there are a number of reasons for this recent fluctuation. In 2009, for example, diesel prices fell while soy prices remained high, two factors that hamper the economic benefit of biodiesel blending. [46]

ALTERNATIVE FUELS

Aside from blending conventional biofuels into gasoline or diesel, a number of alternative fuels are currently utilized on a small scale in the Midwest. Although some of the fuels are fossil fuel based, they tend to have a lower carbon intensity than conventional gasoline or diesel. These fuels include compressed natural gas (CNG), liquefied natural gas (LNG), liquefied petroleum gases (LPG), an 85 percent ethanol blend (E85), electricity and hydrogen. Table 6.2 lists the consumption of these fuels in PADD II and the Midwest in gallons of gasoline equivalent.

Table 6.2 Alternative Fuel Use in the Midwest*

Region	CNG	LNG	Electric	E85	Hydrogen	LPG
PADD 2	12,224	33	625	10,933	0	51,409
Midwest	9,981	28	467	9,045	0	38,132
US Total	166,878	22,409	5,219	38,074	25	188,171

*Gasoline gallon equivalent – approximately 121 MG
Source: Energy Information Administration, 2005

According to the EIA, alternative fuels displaced approximately 57,000 gallons of gasoline in 2005 (75,000 gallons for PADD II). If the region consumed a total of almost 31 billion gallons of gasoline in 2005,[47] then alternative fuels accounted for less than two ten-thousandths of a percent of the Midwest's total transportation fuel use. This is partially due to the need for specialized vehicles and filling-station equipment to use these fuels. In addition, each fuel type requires unique types of engines, many of which are not readily available to consumers or are still in development (hydrogen fuel cell engines, for example). See Table 6.3 for a list of alternative fuel vehicles by type in the Midwest.

Table 6.3 Alternative Fuel Vehicles in the Midwest*

Region	CNG	LNG	Electric	E85	Hydrogen	LPG
PADD 2	13,762	19	3,680	68,398	0	32,899
Midwest	10,014	8	3,393	55,295	0	23,851
US Total	117,699	2,748	51,398	246,363	119	173,795

*Number of vehicles
Source: Energy Information Administration, 2005

[46] National Biodiesel Board. 2010.

[47] Energy Information Administration and the Renewable Fuels Association.

LIFECYCLE ASSESSMENT MODELS

To perform a more complete estimate of the amount of carbon emissions that result from consuming a volume of transportation fuel, attention must be paid not only to the emissions that result from combustion in a vehicle's engine, but also to the emissions that are a result of a fuel's full production cycle. The production cycle may include extraction of the fuel feedstock (oil drilling or corn harvesting, for example), transportation of the feedstock to a production facility (such as through a pipeline), converting the feedstock to a fuel (for example oil refining or biorefining), and distributing the fuel to the consumer (such as from a refiner/blender to the gas station pump). This is colloquially called the well-to-tank phase. Tailpipe combustion emissions can be added to the well-to-tank emissions to from the full well-to-wheels or cradle-to-grave lifecycle. This technical report considers only direct emissions as part of the LCA of transportation fuels.

There are a variety of nationally and internationally recognized models that provide estimates of the full GHG lifecycle emissions of transportation fuels. Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model is perhaps the most widely used LCA model in the Midwest. Natural Resources Canada's GHGenius is utilized by a number of Canadian government agencies and in academic or industry studies. The University of Nebraska-Lincoln's Biofuel Energy Systems Simulator (BESS) model provides an easy-to-use interface to calculate detailed LCAs for ethanol production based on a variety of inputs. While developed for similar purposes, these models are based on unique assumptions and LCA calculation methodology. As a result, each model produces a unique result for the lifecycle emissions of each fuel.

To assess the carbon intensity of transportation fuels used in the region, a Midwestern LCFP program needs to assign carbon scores to each fuel. Therefore, regulators should choose an appropriate model to generate LCA using data inputs that reflect the Midwest's fuel production system. For this technical report, no new LCAs were conducted. Instead, a summary of existing LCAs, including those conducted by government agencies for use in transportation fuel policies, is provided in Table 6.4. The following LCA models and studies were used to compile carbon intensity scores for a variety of typical fuel pathways: California's Air Resource Board LCAs (CARB); GREET; Northeast States for Coordinated Air Use Management LCFS Report (NESCAUM); Canada's GHGenius Model; BESS; and EPA's RFS2 threshold levels. For illustration purposes, default assumption inputs were used to generate results from GREET, BESS and GHGenius. Table 6.4 summarizes the LCA scores from the following models.

Table 6.4 Lifecycle GHG Intensity Inventory

Fuel	CARB	GREET	NESCAUM	GHGenius	BESS	RFS2***
Conventional Gasoline	-	90.34	92.70	94.08	-	93.08
Reformulated Gasoline	95.86	-	96.70	94.27	-	-
Gasoline from Oil Sands Crude	107.7 – 131.5	104.07	108.00	-	-	-
Diesel	94.71	91.87	93.00	74.64	-	91.94
Diesel from Oil Sands Crude	107.7 – 131.5	104.62	105.00	-	-	-
Diesel Coal (CTL)*	153.2 – 178.7	221.04	-	147.24	-	-
Liquefied Natural Gas	72.38	74.63	78.00	-	-	-
Compressed Natural Gas	68.00	74.52	73.10	71.53 - 154.74	-	-
Liquefied Petroleum Gas	-	76.78	86.90	76.13	-	-
Oil Shale	120.9 – 256.9	-	-	-	-	-
Corn EtOH	69.40	67.31	72.60	56.68 - 91.44	45.1 - 72.1	73.53
Corn EtOH w/Stover Heat	63.60	35.96	-	-	-	-
Corn EtOH w/Biogas Heat	-	-	-	-	27.9	-
Corn Stover EtOH	-	8.37	-	-	-	6.52
Forest / Woody Biomass EtOH	-	20.69	-1.7 – 11.5	-	-	-
Grass / Cellulosic EtOH	-	10.76	-	47.02 – 57.84	-	26.06
Biodiesel	11.76 - 21.25	23.55	35.10	20.04	-	39.54
Electricity	124.10	-	0 /181/ 345**	324.03	-	-
Hydrogen	98.80 – 142.20	-	-	31.51 – 237.55	-	-
*Fischer-Tropsch ** Renewable / NG / Coal ***Includes EPA's ILUC calculations						

Total Direct CO_2e Emissions g/MJ

GASOLINE & DIESEL

The U.S. utilizes a wide variety of feedstocks to produce gasoline and diesel. Common gasoline production pathways include conventional and reformulated gasoline produced from crude oil, synthetic crude derived from oil sands or diluted bitumen. Of the LCA models and fuel policies listed earlier, five include scores for conventional gasoline, four differentiate reformulated gasoline, and four include scores for gasoline derived from oil sands. Six of them contain values for diesel from crude (ultra low-sulfur diesel), and four differentiated diesel produce from oil sands.

In general, LCA scores for gasoline were very similar to each other, with a total variation of 4 percent for conventional fuel and 3.8 percent for reformulated gasoline. Five of the six scores for diesel were very close, with the one outlier being the GHGenius model. The scores for diesel varied by only about 3.1 percent when the GHGenius value was excluded, but by 22.4 percent when it is included. Gasoline and diesel derived from oil sands presented a larger ranges of possible values due to a wider variety of extraction, upgrading and refining techniques. The scores for gasoline and diesel varied by 24.6 percent and 24.3 percent, respectively. See below for results from an in-depth study on heavy crude LCA production conducted by the Alberta Energy Research Institute.

The scores listed at right are generally for lighter grades of crude oil. According to some reports, the crude slates for U.S. refineries are trending towards heavier grades of crude.[48] In 2009, the Alberta Energy Research Institute published an LCA, conducted by Jacobs Consultancy, that compared lifecycle emission values of a large variety of crudes utilized in the U.S. In general, the gasoline and diesel produced from oil sands has a lifecycle carbon intensity score within the range of other heavy crudes (see table below). Of the heavy crudes, oil sands are the only type imported into the Midwest in significant quantities. A wide variety of heavy crudes enter the U.S. through the Gulf Coast (PADD III) and other regions, and much of the heavy crudes are eventually transported to the Midwest (PADD II). However, no public tracking mechanism currently exists that could assess the amount of each crude type that ends up within the region.

Figure 6.7 Carbon Intensity Scores of Gasoline and Diesel Pathways

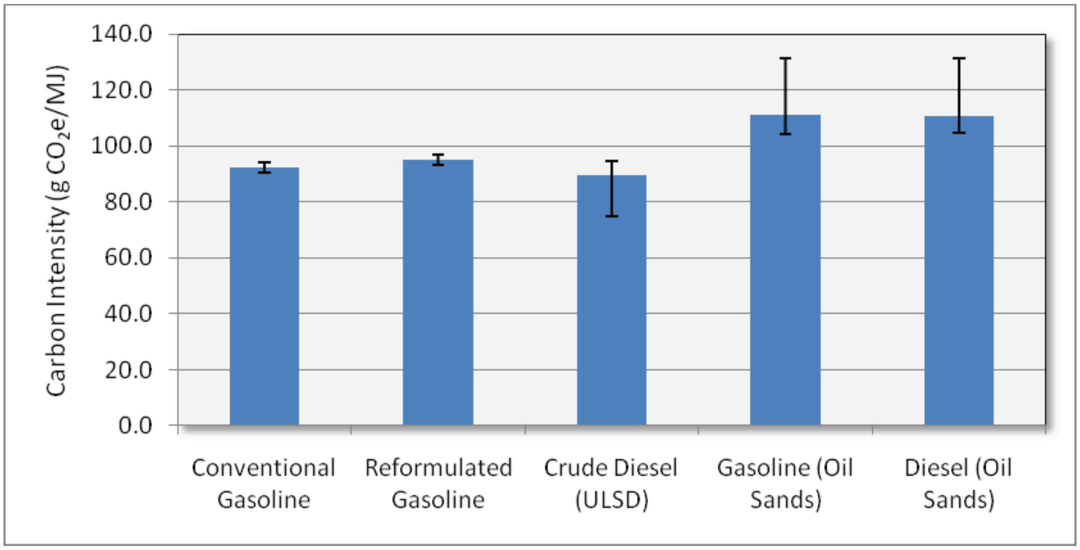


Table 6.5 Alberta Energy Research Institute & Jacobs Heavy Crude Oil LCA

Crude Type	Conventional Gasoline	Reformulated Gasoline	Diesel
SAGD Bitumen via Coking Upgrader	115.7	116.1	112.7
Bitumen via Dilbit, Diluent Return	113.3	113.1	111.2
Bachaquero	101.7	101.9	100.2
Maya	102.2	102.1	102.5
Arab Medium	98.8	98.3	98.2
Mars	103.1	103.9	103.5
Bonny Light	106.8	106.4	106.9
Kirkuk Blend	102.2	101.7	102.1
CA TEOR	113.5	114.2	112.9
SAGD SCO - coker	115.7	116.1	112.7
SAGD SCO – ebullated bed	118.5	118.9	115.6
SAGD Bitumen	113.3	113.1	111.2
Dilbit	108.1	105.4	103.4
Mining SCO - coker	107.8	108.2	104.7
Mining Bitumen	105.5	105.4	102.7

SAGD: Steam Assisted Gravity Drop (In Situ Oil Sands Extraction)
SCO: Synthetic Crude Oil (Upgraded Bitumen)

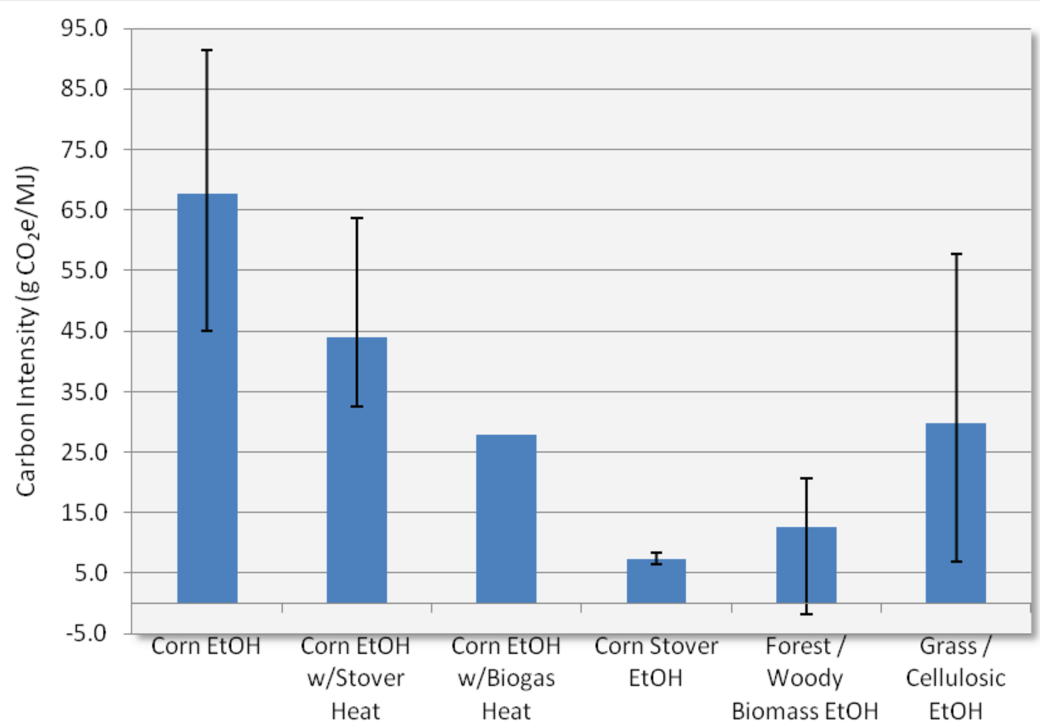
Total Direct CO_2e Emissions g/MJ

48 Alberta Energy Research Institute and Jacobs Consulting. Life Cycle Assessment Comparison of North American and Imported Crudes.

ETHANOL

Ethanol has traditionally been seen as the compliance pathway toward lower-carbon fuels. Midwestern states have a variety of state-level policies encouraging the use of ethanol including renewable fuel standards, incentives for refueling infrastructure and incentives and requirements for state fleet usage of ethanol. The EPA's RFS2 sets very substantial volume requirements for ethanol from a variety of sources. The 10 MGA states are all within the top 12 ethanol-producing states.[49] While ethanol is currently made primarily from corn grain, a variety of cellulosic and lignocellulosic feedstocks are being tested to produce next-generation ethanol. Production-scale technology for feedstocks that include corn stover, wood and grass or energy crops has yet to be achieved. Each type of feedstock results in a different carbon intensity due to unique production characteristics. Additionally, the energy source for the production plant's electricity and heat has a large impact on the LCA. A plant that uses natural gas or combined heat and power has a much lower LCA carbon intensity than one that uses coal or electricity from the grid.

Figure 6.8 Carbon Intensity Scores of Ethanol Pathways



Note: High values may include indirect land use change from U.S. Environmental Protection Agency analysis.

The average carbon intensity under the seven models and policies for corn ethanol was 67.65 g/MJ. This varied widely (by 68.5 percent), however, as each LCA assumed varying levels of coal, natural gas and other energy sources. Additionally, the EPA's modeling for the RFS2 included indirect emission values for land-use change.

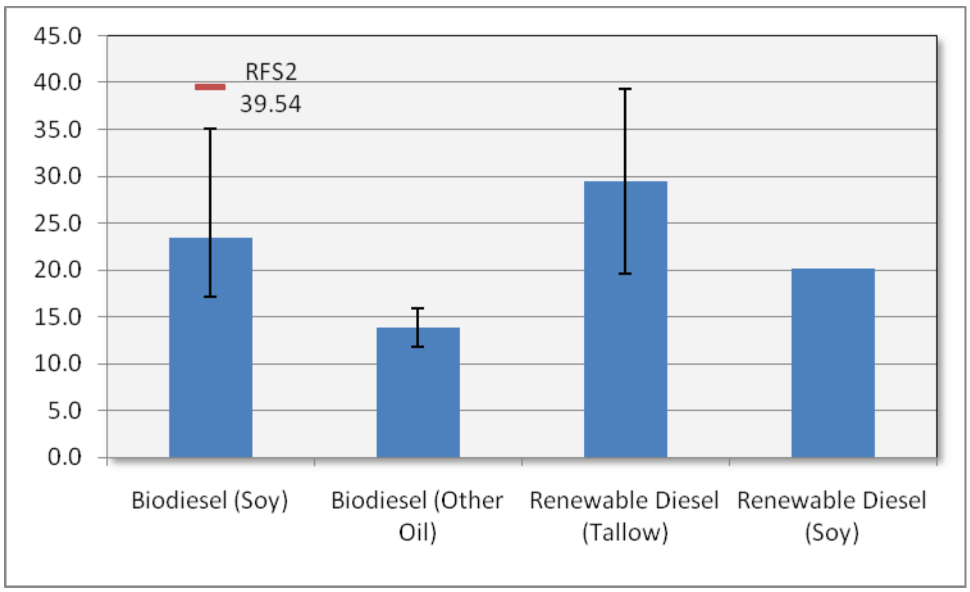
Using alternative sources of heat greatly reduced the carbon score, with three programs giving stover heat an average score of 44 g/MJ (but with a 70.8 percent variation due to one outlier). One model, BESS, scored corn ethanol with biogas heat at 27.9 g/MJ. Three models gave corn stover ethanol an average score of 7.36 g/MJ, while woody biomass ethanol received an average of 12.61 g/MJ, but with a wide variation in which one model scored woody biomass at -1.70 g/MJ (NESCAUM). Finally, grass-based or cellulosic ethanol was scored at an average of 29.72 g/MJ by four models, with a very wide variation of 171.3 percent.

[49] "A USDA Regional Roadmap to Meeting the Biofuels Goals of the Renewable Fuels Standard by 2022." USDA Biofuels Strategic Production Report. June 23, 2010.

BIODIESEL & RENEWABLE DIESEL

Diesel substitutes can be made from a variety of grease and oils, including soybean oil and animal fat or grease. Biodiesel is created from plant- and animal-derived oils using transesterification with alcohols, while renewable diesel is produced from plant oils and tallow through catalytic processes similar to those found in oil refineries. Just as the chemical production processes are unique for each fuel, so are the resulting LCA values. California's LCFS lookup table includes three values for biodiesel and three for renewable diesel. GHGenius provides a variety of scores for biodiesel and renewable diesel from many feedstocks.

Figure 6.9 Carbon Intensity Scores of Biodiesel and Renewable Diesel Pathways



Note: High values may include indirect land use change from analysis by the U.S. Environmental Protection Agency.

Average soy biodiesel scores were about 23.41 g/MJ (CO_2e), with NESCAUM and the RFS2 giving the fuel a higher carbon intensity due to land-use change (35.10 g/MJ and 39.54 g/MJ, respectively). Biodiesel from waste oil scored much lower than soy biodiesel, between 11.76 g/MJ and 15.84 g/MJ, though only CARB listed the fuel in its lookup table. Based on the level of energy used in producing renewable diesel from tallow, CARB scored the fuel at 19.65 g/MJ and 39.33 g/MJ, while renewable diesel from Midwestern soybeans were scored at 20.16 g/MJ.

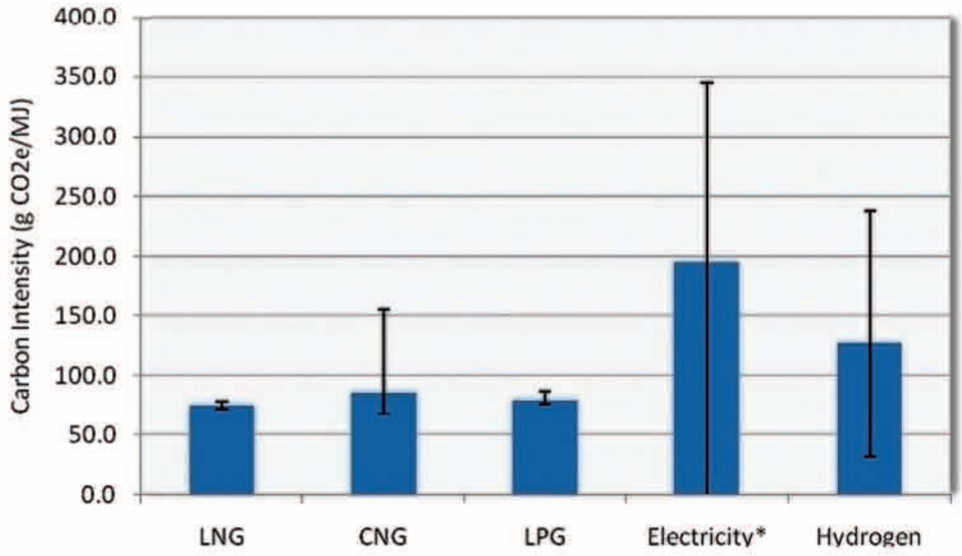
ALTERNATIVE FUELS & ELECTRICITY

A number of non-renewable alternative fuels could be used to comply with an LCFP, according to the scores assessed by multiple LCA studies. Liquefied natural gas (LNG) received an average score of 74.96 g/MJ from four models with only a 7.5 percent variation, while compressed natural gas (CNG) was given an average of 86.37 g/MJ by five models. One outlier from GHGenius scored the fuel at 154.74 g/MJ when being made with coal electricity, but at only 71.53 g/MJ when utilizing natural gas electricity. Four models scored liquefied petroleum gas (LPG) at an average of 79.21 g/MJ.

Hydrogen carbon intensity values varied widely, depending on the source of energy for production. CARB gave the fuel a range between 98.8 g/MJ and 142.2 g/MJ, while GHGenius assigns a range of 31.51 g/MJ to 237.55 g/MJ.

Thus, a number of carbon intensity scores should be made available in a lookup table for assessing hydrogen individually by a specific production pathway.

Figure 6.10 Carbon Intensity Scores of Alternative Fuel Pathways



*Electricity scores include values for wind, coal, and natural gas

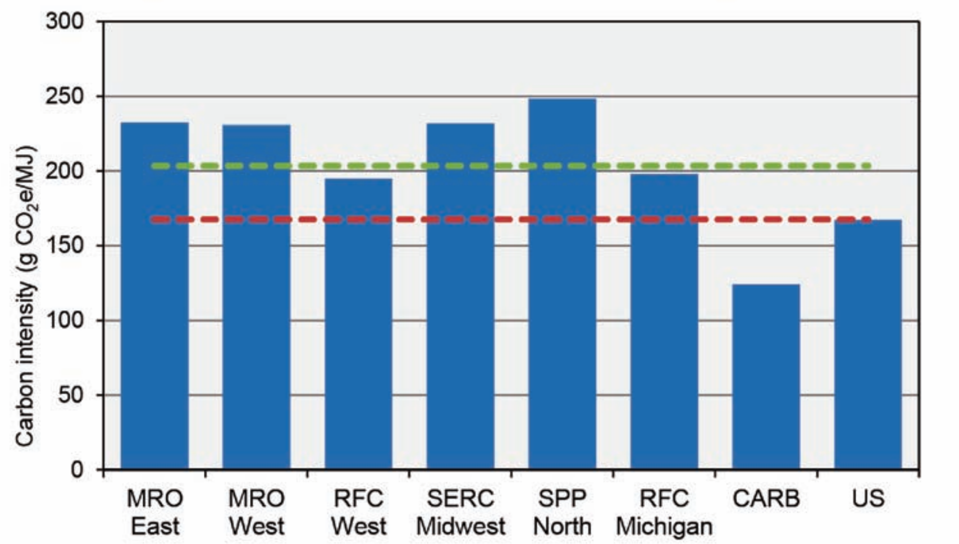
Like hydrogen, carbon intensity values for electric vehicles (EVs) can also vary widely. CARB calculated California's average electricity mix at 124.1 g/MJ. However, if marginal electricity were used to charge a vehicle, the score is reduced to 104.71 g/MJ. NESCAUM provides three scores: 0 g/MJ for renewables, 181 g/MJ for natural gas and 345 g/MJ for coal. Finally, GHGenius provides a score for the U.S. average electricity mix at 299.45 g/MJ, as well as 325.66 g/MJ for the East Central Midwest region and 322.40 g/MJ for the West Central Midwest region.

With scores near 300 g/MJ, it may seem that electricity would not comply with an LCFP when the gasoline baseline is closer to 92 g/MJ. Because the LCFP is based on the amount of conventional fuel displaced, however, the scoring of electricity must take into account the improved drive train efficiency of EVs. An electric motor is much more efficient than an internal combustion engine, so an energy economy ratio (EER) can be used to account for the actual impact of each MJ of electricity. Thus, with an EER adjustment of about 3:1, as used in California, the score for electricity from a natural gas plant is reduced from 181 g/MJ to 60.33 g/MJ. In the Northeast, NESCAUM has proposed an EER as high as 4:1 for plug-in hybrid EVs, which would allow electricity with carbon intensities as high as 300 g/MJ or more to comply with an LCFP in early years.

Technically, it is not possible to track whether electricity from the grid was generated at a coal plant, at a natural gas power plant, or by a wind turbine. Electricity generation within certain regions is coordinated by an independent system operator (ISO) or a regional transmission operator (RTO).

The EPA's eGRID model maintains frequently updated databases on sources of electric generation in each ISO or RTO. According to eGRID, the Midwest's dependence on coal power plants results in a carbon intensity that is higher than the national average. The Midwest's electricity grid, on average, has a carbon intensity of about 222.72 gCO_2e/MJ, compared to an average of 168.36 g/MJ for the entire U.S. In CARB's LCFS program, electricity generated in California is rated at 124.10 g/MJ from widespread usage of natural gas electric power plants.

Figure 6.11 Carbon intensity scores of electric regions



OPTIONS FOR REDUCING CARBON INTENSITY OF TRANSPORTATION FUELS

As discussed earlier in these recommendations, there are a number of available strategies for reducing the carbon intensity of transportation fuels in the Midwest. The most significant among these is likely the RFS2, which may reduce the carbon intensity of the nation's gasoline blend by upward of 7 percent. This, however, assumes that there are no significant increases in the importation of heavy crudes into the U.S. Regardless of the RFS2's true impact, there are a number of other available options for achieving carbon intensity reductions. These options include the anaerobic digestion of livestock waste to produce biogas (up to 1.17 percent reduction), the increased deployment of electric (0.5 percent) and hydrogen (0.15 percent) vehicles, the utilization of captured CO_2 for EOR (3.0 percent), and an increased share of diesel-based passenger vehicles (1.7 percent).

Other strategies that were not investigated but would decrease emissions of the transportation sector include efficiency improvements in the extraction and production process of fuels, mid-range ethanol blends and blender pumps, improved LCA methodology, and carbon capture and storage programs. Given the diversity of choices for carbon reduction strategies, it is clearly feasible to achieve a 10 percent reduction in the Midwest within 10 years. If an LCFP provides the flexibility to choose from a diverse menu of options, or provides an ability to propose or prove unique carbon reduction strategies, many of the Midwest's low carbon fuel resources could be further developed within a few decades.

Table 6.6 GHG Reduction Options

Pathway	GHG Reduction
RFS2	5.3 - 7.6%
Biogas	1.2%
Electricity	0.5%
Hydrogen	0.2%
EOR	1.7 - 3.0 %
Dieselization	1.7%
Total	**10.5 - 14.1%**

Appendix A.
Low Carbon Fuel Policy Advisory Group Roster[50]

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[50] The LCFP Advisory Group was tasked with developing an LCFP, rather than fundamentally revisiting, previous MGA commitments. Therefore participants were not asked whether they support an LCFP, but instead how the benefits of such a policy be maximized and the negatives minimized from their perspective. Of particular interest to the MGA is what a "Midwestern" approach to an LCFP would look like, and how this could influence federal and state policy-making efforts. **Some participants do not support an LCFP in principle and participation in this process by any participant does not imply support by any individual participants of an LCFP. Specific policy, principles and recommendations in this document reflect the opinions of the majority of participants in the process, but should not be interpreted as the positions of any individual participant or the firm they represent.**

Appendix B. Alternative Approaches to Addressing Indirect Land Use Change

INTRODUCTION

Indirect Land Use Change (ILUC) has been the subject of great academic and political debate. The MGA LCFP Advisory Group recommends that an updated ILUC be re-reviewed in 2012 after new technical reviews are completed. The advisory group also recommends consideration of alternative means of addressing ILUC at this time regarding the magnitude of impacts from ILUC. The advisory group is not recommending any one approach as they all contain some level of uncertainty, as identified below, and all of these approaches would require much more research and would need to be compared to any new ILUC specifications by 2012 before being implemented as part of a policy. The advisory group is simply recommending further consideration of these options as potentially viable alternatives.

OPTION 1: DIRECTLY INVESTING IN AVOIDING ILUC

One of the remedies that the advisory group reviewed is investing directly in avoiding ILUC, rather than assigning a numeric penalty as part of a biofuels' lifecycle assessment (LCA) score. Under this approach, biofuel producers could select from an approved list of funds and purchase offsets to supplement the LCA score. One option is in offsets that directly prevent deforestation. Although the group considered the idea of creating one unified fund that biofuel producers paid into, and which made investments as a unit, the group prefers an approach that provides guidance on where money is spent, but leaves spending decisions up to individual companies. The advisory group reviewed the following categories of funds as examples:

1. **Reducing Emissions from Deforestation and Forest Degradation (REDD)**

   REDD is an effort by the United Nations to create financial value for the carbon stored in forests, to reduce emissions from forested lands, and to invest in low-carbon paths to development. The REDD program is currently supporting programmatic efforts at the national level, helping countries access financial and technical support, and develop common approaches to issues such as measurement, reporting, remote sensing and inventories. The REDD framework would allow an industry group to independently negotiate a REDD-type offset with a participating country. Continued development of the REDD program was one of the major areas of agreement at the Copenhagen meeting in 2010. At the Copenhagen meeting, the negotiators released a four-page draft covering areas of agreement. At this point, however, no REDD mechanism is in place and no date has been set for its completion. However, private investors are still free to independently negotiate and develop REDD projects and acquire REDD credits. They would likely need to work with designated national authorities as intermediaries to ensure some level of consistent and reliable universal quality standards.

2. **Clean Development Mechanism (CDM)**

   The CDM is a mechanism for industrialized nations with GHG commitments under the Kyoto Protocol to meet their obligations. This mechanism represents the majority of global offset project transaction volumes. Although renewable energy and methane projects have been the dominate type of offset, there may be the possibility of developing offsets through the CDM that address deforestation.

3. **Voluntary Offset Standards**

   Voluntary offsets allow businesses, governments and individuals to voluntarily offset their emissions outside the context of a legally binding law or treaty. They function outside of compliance markets such as the Kyoto Protocol or Regional Greenhouse Gas Initiative (RGGI.) Although they lack universal quality standards, and are not fungible in compliance markets, which are key factors in any LCFP program, voluntary offsets do have some advantages, including allowing for experimentation and innovation and creating a niche for projects that aren't covered by existing compliance schemes. There is a long list of voluntary offset programs, including the Climate Action Reserve, Chicago Climate Exchange, Voluntary Carbon Standard, American Carbon Registry, Gold Standard, VER+, Climate Community and Biodiversity Standards, Plan Vivo and Social Carbon Methodology.

Many questions would need to be answered before offsets could be included in any LCFP program. They include:

- What is the overall magnitude of ILUC in the region, and what level of investment by fuel producers would be sufficient to offset this impact? This question is heavily dependent on continued scientific research on the magnitude of ILUC.

- Who would govern a regional offset program of this nature? Presumably a regional body would make recommendations on various aspects of the program, including:

  - What types of offsets qualify?

  - What quality standards must offsets meet?

OPTION 2: DIRECTLY INVESTING IN YIELD IMPROVEMENT

One way to minimize the indirect-land-use impact of biofuels is to maximize the output from existing agricultural lands involved in both crop and livestock production. There is enormous potential to accelerate adoption of current best practices to dramatically increase worldwide yields. For example, average maize yields in sub-Saharan Africa are around 1 tonne per hectare (ha), yet demonstration farms in the same region achieve yields of 3-6 tonnes / ha.[51] Similarly, cereal yields in sub-Saharan Africa, India and China lag behind the U.S.

The advisory group reviewed the types of programs currently investing in developing world crop agriculture. Programs tend to focus their investments in four main areas:

- Crop productivity and crop protection, including education and training, access to financing, and soil, water, weed and pest management;
- Market access, including infrastructure, securing demand and market-pricing information;
- Development of policy at the local and national level; and
- Science and technology, including crop improvements such as implementing local breeding programs, maximizing the utilization of hybrid technology, developing seeds that are disease resistant and higher yielding, and training local plant breeders.

Crop Productivity and Crop Protection

A significant fraction of crop productivity is lost due to weed, pest and disease pressure. Estimates for losses vary between countries and crops, but estimates of losses approach 30 percent to 40 percent for maize, rice and potatoes.[52] Implementing known technologies to protect crops in the field can result in significant yield improvements.

Developing countries also suffer from significant crop losses after both crop maturity as well as harvest due to pests, diseases, inadequate or poor quality storage, and physical damage.[53] Agricultural practices such as pre-harvest field drying can lead to crop losses ranging from 15 percent to 26 percent due to bird losses, insect damage and fallen plants.

Crop Improvement

Estimates of the economic return for investing in crop improvement in developing countries are quite high. An analysis of 700 research and development projects focusing on plant breeding showed a mean internal rate of return of 43 percent.[54] Implementing local crop breeding and hybrid technology can result in substantial yield improvements. Advanced technologies such as marker-assisted breeding can double the rate of genetic gain.[55] Biotechnology can provide tools that can further help to protect plants from pests and weed pressure

[51] World Bank, Annual World Development Report, 2008.

[52] Oerke, J. Agri Sci, 144, 31-43.

[53] Grollead, FAO, 2002 "Post Harvest Losses: Discovering the Full Story."

OPTION 3: CERTIFICATION OF BIOMASS AS AVOIDING INDIRECT LAND USE CHANGE

A third possible approach to the ILUC question also begins with the supposition that not all use of biomass inherently causes ILUC. The group discussed whether there would be a way to test whether ILUC is being caused at the scale of an individual plant or within a geographic area such as a state or regional grouping of states. If that plant or geographic area was demonstrated to have no ILUC impact from its biofuel production, then no ILUC penalty or other remedy would need to be applied. Notably, this approach could potentially be applied to existing programs such as the federal renewable fuels standard or state LCFP programs.

Two approaches to the question are under consideration, one that would operate at a plant-level scale, and the other that would operate at a state or regional-level scale.

The state/regional level scale is based on work done by Dr. Steffan Mueller and Ken Copenhaver of the University of Illinois- Chicago. They studied[56] whether three individual ethanol plants in Illinois and Iowa caused sufficiently large distortions in agricultural markets as to cause ILUC. The study calculated a corn supply area for each plant, and determined whether non-agricultural acreage was converted to agriculture, whether corn production at the state level changed, whether planted acres of corn changed, and whether corn exports, or exports of other commodities, changed as a result of the building of new ethanol plants. The authors concluded that there were not significant impacts on acreage, and that exports continued to grow. Their conclusion, then, was that improvements in yield were sufficient to supply growth in the ethanol industry without causing sufficient disruptions in agricultural markets as to cause indirect land use change. Based on this research, a suggested approach would be to track the relevant statistics over time (acreage in various agricultural and non-agricultural land uses, corn used for ethanol and other uses such as animal feed, changes in exports) and to develop an algorithm for determining whether ethanol production is causing disruptions in agricultural markets sufficient to cause indirect land use change. In this way, an entire state or region might be deemed not to cause indirect land-use change in a given year.

A second approach would conduct an analysis at an individual plant level. Bioenergy producers would have to show that they were maintaining the average output of food, feed and fiber from the feedstock "basin" at or near the baseline. The "basin" would be the farms or forests that supply the producers with the feedstock, or a slightly larger area. The baseline would be the average of the gross non-bioenergy farm or forest revenues for the past five years of output from the basin and would increase annually at the average regional rate of growth in agricultural productivity and the consumer price index. The escalation is critical given that with increased population and changing diets, agriculture and silviculture will need to become more productive,

[54] Alston et.al, A meta analysis of rates of return to agricultural R&D, IFPRI, 2000.

[55] Eathington, Crop Science 47:S154-S-163, 2007.

[56] Mueller, S. and K. Copenhaver. September 18, 2009 Determining the Land Use Impact of Two Midwestern Corn Ethanol Plants. Unpublished manuscript prepared for the Illinois Corn Marketing Board. AND November 6, 2009. Determining the Land Use Impact of the Absolute Energy LLC Dry Mill Corn Ethanol Plant in St. Ansgar, Iowa. Unpublished Manuscript prepared for the Illinois Corn Marketing Board.

even in the absence of biofuels. Under this baseline, degraded or abandoned land would have a zero or very low baseline, making it easier to maintain that level of output. The focus is on economic output because with or without biofuels, production of food, fiber and feed will shift over time to meet demand. Focusing on economic output allows farmers and foresters flexibility to meet this shifting demand while maintaining the same level of aggregate contribution to the aggregate food, feed and fiber markets as they would have absent producing biomass for energy.

As with all the options listed here, the advisory group recommends further development of these concepts in order to evaluate whether they could be practically implemented. The following questions need to be answered before these ideas could be translated into a practical application:

- What would be the transaction costs of implementing a system like this?
- Are there any other practical concerns (data availability, for example) that would create problems in implementing such a system?
- Will there be further replication and refinement of the Mueller and Copenhaver research?

Midwestern Governors Association

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