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An Assessment of Canadian Corn Ethanol Life Cycle Climate Change Impacts and Potential Mitigation Pathways Including Carbon Capture and Sequestra

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An Assessment of Canadian Corn Ethanol Life Cycle Climate Change Impacts and Potential

Mitigation Pathways Including Carbon Capture and Sequestration

by

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Abstract

This thesis is an ethanol GHG life cycle assessment under several scenarios, or Cases. It also evaluates the effects of implementing CCS and biomass combustion at ethanol plants to compare it to other CO_2 reduction opportunities.

This thesis compares the 2009 CA-GREET "US Dry Mill Average" pathway with three others - an Ontario GREET case, an Ontario GHGenius case, and a site-specific case that substitutes publicly-known Suncor plant data. Life cycle emissions are compared on a "grams of CO_2 equivalent per Megajoule of fuel energy provided" basis.

Conventional corn-based ethanol can be an effective carbon mitigation strategy if the physical plant, site location and direct emissions are designed correctly. At current production levels, land use change is likely not significant in North America due to availability of sufficient fallow farmland and improving crop yields. Implementing fermentation CCS can abate almost 1 Mt in Canada and 86 Mt worldwide.

Keywords: biofuels, ethanol, greenhouse gases, carbon capture and storage, low carbon fuels, life cycle assessment

Preface

Purpose and Motivation

A life cycle assessment (LCA) of conventional corn ethanol carbon dioxide (CO_2) and other GHG emissions is evaluated under a number of scenarios. Comparison of the scenarios considered will enable readers to assess the variability of generic LCA pathways including one used to create a Low Carbon Fuel Standard (LCFS) in California in 2009. Special consideration is given to Canadian sources in Ontario due to the concentration of significant ethanol and conventional automotive fuel production in the area.

Disclosure: I am a full-time employee of Suncor Energy Inc. and have been for the entire time period in which this thesis was prepared. This document uses publically available information regarding the Suncor St. Clair ethanol plant. The research grew out of a critical comparison of LCA studies of corn ethanol, in order to gauge the true GHG benefit of bioethanol blending into automotive gasoline.

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Abbreviations and Nomenclature

Acronyms	Meanings
CAD	Canadian dollars
CARB	California Air Resources Board
CCS	Carbon Capture and Sequestration
CCGT	Combined Cycle Gas Turbine
CH_4	Methane
CO_2	Carbon dioxide
DDGS	Dry Distiller's Grains with Solids
GHGs	Greenhouse gases
Gt	Gigatonne
GWP	Global Warming Potentials
HFCs	Hydrofluorocarbons
ILUC	Indirect land use change
LCA	Life cycle assessment
LCFS	Low Carbon Fuel Standard
LUC	Land use change
kWh	Kilowatt-hours
MJ	Megajoule (million joules)
Mt	Megatonne (million tonnes)
N_2O	Nitrous oxide

Acronyms	Meanings
NF_3	Nitrogen triflouride
NGCC	Natural Gas Combined Cycle
PFCs	Perfluorocarbons
RFG	Reformulated gasoline
SF_6	Sodium hexafluoride
WDGS	Wet Distiller's Grains with Solids
WTT	Well to tank
WTW	Well to wheels

Definitions	Meanings
Bioethanol	Ethyl or grain alcohol (CH3CH2OH) that is derived from biological sources such as plants.
Co-firing	The practice of firing a slipstream of alternative fuels such as biomass along with the main fuel, usually fossil fuel, in the same heater or boiler.
Net-negative	GHG abatement technology that results in greater than 100% reduction, so that there are fewer tonnes of GHG in the atmosphere than when it started
Torrefaction	Mild pyrolysis of biomass between 200 C and 320 C to improve combustion and gasification characteristics of the fuel.

1.0 Motivation for Research

The issue of man-made or anthropogenic climate change is one that must be faced by current generations if the worst effects are to be avoided. On one hand there are the prosperity, dignity and standard of living resulting from access to affordable energy that all people deserve, but which are currently only available to developed Western countries and a select few in the developing world. On the other side of the same issue are the unintended consequences of rapid development including environmental burdens that are felt globally by all people. The problem does not seem to be one that allows for easy answers; therefore multiple technological (e.g. carbon capture, biofuels) and policy (e.g. carbon pricing, Renewable Fuel Standards) solutions must be pursued in parallel in order to bend the emissions curve downward [1] in the face of population growth and rising absolute energy use in both developed and developing nations. The use of biologically-derived automotive fuels (biofuels) is one potential solution that has already been implemented on a scale where some analysis can now be done. It is important that we assess the potential environmental effectiveness of these strategies to help shape future fuel and technology choices, as this paper attempts to do.

The purpose of this thesis is to evaluate the potential life cycle greenhouse gas performance of Canadian corn-based ethanol when blended with automotive fuel. A life cycle assessment (LCA) of conventional corn ethanol production is evaluated under a number of scenarios, or "Cases". Comparison of the scenarios considered will enable readers to understand the variability of various LCA pathways under scenarios of differing geographic areas and life cycle assessment techniques.

Once this Case study is complete, the effect of implementing relatively low-cost fermentation CO_2 Capture and Sequestration (CCS) is evaluated, as well as combustion CCS and biomass combustion at ethanol plants, in order to gauge the relative merits of this opportunity against other GHG-mitigation opportunities.

Special consideration is given to Canadian sources in Ontario due to the presence of significant corn ethanol and conventional automotive fuel production in the area. Of the 1.4 billion litres of Canadian bioethanol capacity, almost 1.2 billion are located in Ontario as is 77,300 cubic metres (490,000 barrels) per day of refining capacity out of a Canadian total of 320,500 cubic metres per day [2] of refining capacity.

Canadian corn production [3] is also concentrated in Ontario and Quebec; between 1998 and 2002 Ontario had an average of 750,000 hectares of land under corn cultivation with a yield between 5.4 – 7.2 metric tonnes (6 – 8 short tons) per hectare. Therefore, Ontario corn production was 4 to 5.4 million metric tonnes (4.5 million to 6 million short tons) at the same time that the total Canadian corn production was 7.7 million metric tonnes (8.5 million short tons). This unique combination of existing resources has allowed the Province of Ontario to achieve the goals of a Renewable Fuels Standard (RFS) in 2007 that required 5% bioethanol blending in all gasoline sold within the province [4].

Following the LCA Case study, the effects of implementing carbon dioxide reduction technologies on the biofuel production process are evaluated in order to gauge the relative merits of these opportunities.

1.1 Introduction

Since the Industrial Revolution, rising fossil fuel use has made abundant energy affordable and accessible to an increasing number of people, and vastly improved the standard of living in the developed world. However, large volumes of substances known as "greenhouse gases" (GHGs) such as carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) are generated and released to the atmosphere during the combustion of these fuels. Atmospheric and oceanic CO_2 levels have increased accordingly and scientific predictions point to dramatic changes in weather and biosystems on a time scale far quicker than anything ever seen before. While the future is difficult to predict with any precision, credible scenarios have been postulated that show the potential for massive upheavals in natural and human systems [5].

The absolute value of global CO_2 emissions is huge - global CO_2 emissions of 30,000 megatonnes (Mt) in 2009 [6] dwarf other industrial waste streams such as sulphur dioxide (SO2). For example, in 2008 the United States had SO_2 emissions of 9.7 metric Mt or 10.7 million short tons [7]. In the same year, the US emitted metric 5,657 metric Mt of CO_2 [8] or 581 times as much CO_2 as SO_2. Put another way, in the United States SO_2 emissions are only

0.2% as large as CO_2 emissions, therefore technical approaches to the CO_2 problems will face challenges of scale not seen by most other pollutants.

1.2 Basics of Climate Change

Before proceeding, it is useful to review the basic science behind the theory of climate change, thus the following section deals with the basics of the theory and the credibility of the risk.

In 1896, Arrhenius investigated the basic laws of radiative atmospheric heat transfer, and postulated the existence of what we now call the greenhouse effect. For instance, in Table VII of his paper [9], for a doubling of CO_2 the temperature would increase from 4.95 degrees Celsius at lower latitudes to 6.05 degrees Celsius at higher latitudes. Arrhenius also introduced the concept that not only was the amount of CO_2 important, but also the extremely short time frame over which changes occurred. This is a chief concern of global climate change – that changes will occur so rapidly that human and environmental systems will not have time to adapt.

It is interesting to note that his early calculations fall very close to the range of empirical evidence for past years and predicted ranges for future warming behaviour. Since 1950, we have seen an increase of global CO_2 concentrations from 310 ppm-v to 379 ppm-v in 2005, a 23% increase. Other greenhouse gas concentrations show similar exponential increases [10].

Correspondingly, we have seen an increase in global average temperature of 0.76 degrees Celsius [11].

It is risky to imply causation from correlation, but the correlation between emissions, concentrations and mean global temperatures is unmistakeable. As always, care must be taken when extrapolating behaviour beyond the range of the actual data. However, outside of some unanticipated and unknown counter-balancing effect it is clear that further climate change / global warming can be anticipated as atmospheric CO_2 levels continue to rise.

However, picking an inefficient solution or restricting access to energy and development may cause or perpetuate the same suffering from disease, famine, or population displacement that climate change reduction efforts are trying to prevent. Committing significant limited resources to the wrong solution creates inefficiency while wasting valuable time and missed opportunities to implement the best solutions. Current populations in the developing world have the same right to development and prosperity as future generations. Many people in the Western world can afford increased energy costs resulting from ineffective GHG solutions and energy policy, but the developing world cannot. As in all things, a fine balance must be struck between action and consequence, and all the benefits of our actions current and future must be weighed against all of the costs. Current poverty and suffering must count for at least as much as the potential for future suffering, and just because it is human nature to accept the status quo does not mean that we can be complacent with the disparate levels in standard of living currently seen today [12]. Solutions must be effective, affordable, and of a scale large enough to bend the emissions curve downward in time to prevent the possibility of damage.

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1.3 Carbon Dioxide

Carbon dioxide is not a classic toxic pollutant in the traditional sense, in that it is a normal constituent of the atmosphere and in the natural respiration of almost all living organisms. In pure form it is added to beverages and used in food packaging (so-called food-grade CO_2) and there are no toxicity effects associated with its use even at these moderately high concentrations. The toxic limit for CO_2 exposure is well above 1% (10,000 ppm) [13], which is much higher than seen on the atmosphere. In fact, CO_2 is even used during certain invasive medical procedures such as "Intra-abdominal insufflation during medical procedures to expand the space around organs or tissues for better visualization. [14]"

Rather, CO_2 is best thought of as an industrial waste stream where the adverse effects are not caused by its mere presence but by its rapidly increasing global concentration and large volumetric flow rate. This is not to minimize the potential for damage and need to act to prevent it; but the way one effectively treats an industrial waste stream of normally benign material will be different than how one addresses a toxic pollutant, i.e. the choice between carbon pricing versus command-and-control legislation.

The atmospheric damage from CO_2 concentration depends on the amount of CO_2 already in the air but any mitigation measures must address the large amounts still being emitted annually. Thus greenhouse gases or GHGs must be thought of as both a stock and a flow

problem, so that we must reduce the amount being added and perhaps also remove some CO_2 from the atmospheric "stock" if current levels are thought to be too high already.

There are several other important greenhouse gases besides CO_2, including CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogen triflouride (NF_3) and sodium hexafluoride (SF_6). To compare the heat trapping effects of different gases, "Global Warming Potentials" (GWP) have been introduced [15]. All GHGs are compared to an equivalent volume of CO_2 that gives the same radiative forcing over the same time span. Using CO_2 as a reference basis (GWP = 1), the values for the other GHGs are as follows:

- GREET uses the 100 year values in the 2007 IPCC AR4 [16] (25 for CH_4, 298 for N_2O)

- GHGenius also defaults to the 2007 IPCC AR4 values, although it is possible to select another basis.

The GWP assumptions used in the four Cases were consistently applied throughout this thesis. Actual St. Clair emissions are nearly 100% CO2 with no methane and negligible N2O, so results are not sensitive to the IPCC version selected.

1.4 Canadian Greenhouse Gas Volumes

In 2009, Canadian GHG emissions were 692 Mt of carbon dioxide equivalent (CO_2e) [17]. While Canada's emissions are relatively small on an absolute basis, we are by far one of the highest per capita emitters [18]. In order to do our share, Canadians must understand which

sectors of the Canadian economy contribute to this high consumption, and eliminate any areas of obvious waste. Energy efficiency is one "no regrets" policy which is beneficial to the economy, environment, and human health, and thus should be pursued as part of any GHG abatement strategy. This applies to the industrial production of goods, the personal consumption of these same goods and services, and also to how these goods are distributed and disposed.

As shown in Figure 1 below, transportation and associated fuels represent 28% of the Canadian GHG footprint [19], and rationalizing this sector's GHG emissions might go a long way towards meeting Canada's goals. Examples are the use of heavy rail for moving freight versus conventional trucking (fewer tonnes of GHG per cargo tonne-mile), or biofuels, commuter trains, hybrid or plug-in electric vehicles instead of conventional vehicles (less tonnes of GHG per person-mile).

Canada's Emissions Breakdown by Sector

Energy - Stationary Combustion Sources, 46%

Energy - Transport, 28%

Agriculture, 8%

Energy - Fugitive Sources, 9%

Waste, 3%

Solvent and Other Product Use, 0%

Industrial Processes, 7%
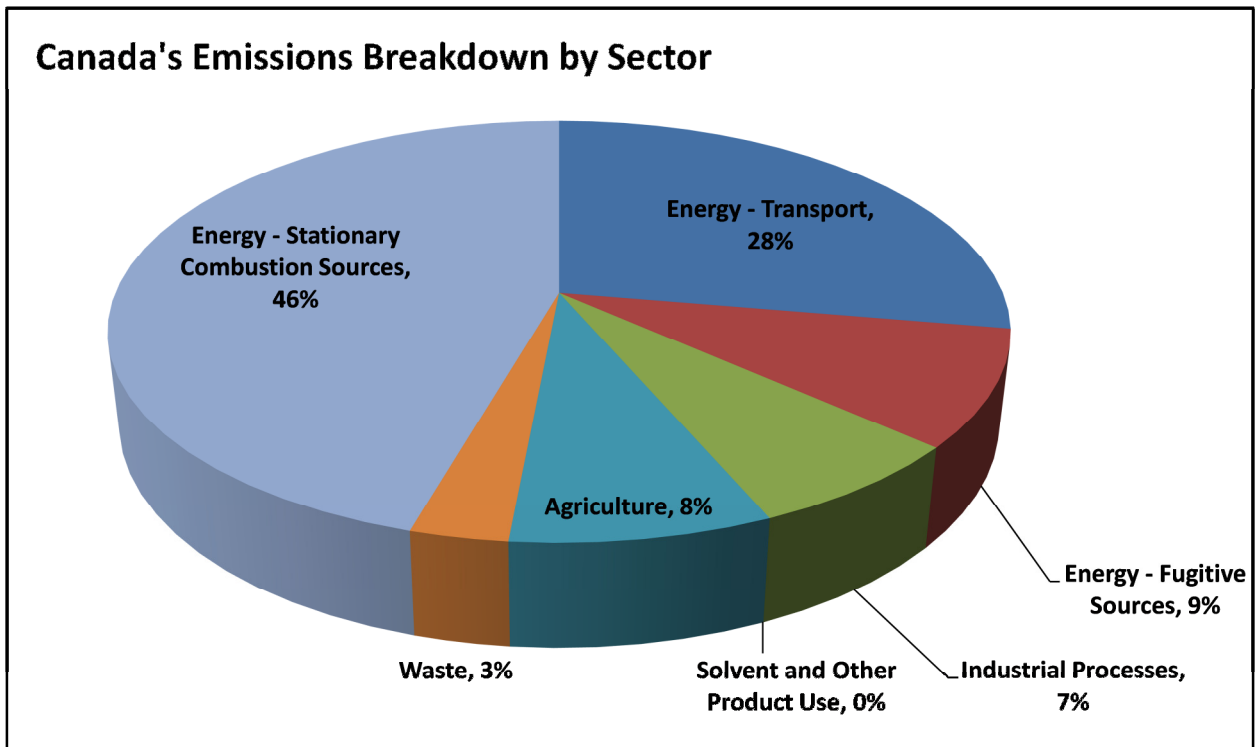
Figure 1: Canada's Emissions Breakdown by Sector, 2011

Figure 1 [1] above shows the major sectors of the Canadian GHG footprint in 2011. From looking at this Figure, policy makers can help to prioritize the mitigation opportunities available from some high impact GHG reduction pathways such as in transportation fuels, fugitive energy losses, or stationary combustion sources. It would also be beneficial for governments, corporations and consumers to explore as many efficiency and renewable energy initiatives as are currently economic, while developing new technologies to lower the price and move the economics of some reduction opportunities from marginal to profitable.

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[1] Adapted from Environment Canada, *National Inventory Report*, 1990–2009; http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=83A34A7A-1.

1.5 Technical Assessment and Economic Analysis

Contemporary renewable energy technologies consist mainly of hydroelectricity, solar electricity, solar thermal, wind electricity, biofuels, and geothermal heat and power. Each of these technologies is a subsector of its own, and they have been covered extensively in popular and academic literature [20]. Renewable biofuels pathways are the scope of this thesis, so the rest of these renewable technologies will not be covered here.

Biofuels are currently used as transportation and power generation fuels and are derived from biological sources. The direct GHG reduction potential comes from displacing traditional fossil fuels and the CO_2 release that occurs when they are burned. Instead of burning only fossil fuels such as coal or gasoline, the consumer burns an ethanol – gasoline mixture, so a share of the required energy is supplied by non-fossil fuels, and less gasoline is burned. Since the carbon in biological sources is atmospheric in origin, direct emissions from the combustion of biofuels are normally considered to be CO_2 neutral since carbon taken from the air by plants is simply returned by combustion in a closed cycle (please see Figure 2 for reference). The assumption of direct emissions neutrality requires the annual re-growth of an equivalent amount of biomass in order to be valid. Full neutrality would require the rest of the life cycle to have zero emissions, which is difficult to achieve.

In practice, biofuels production requires other activities and inputs that render them to be less than neutral on a "cradle to grave" or "wells to wheels" (WTW) life cycle basis, such as farming to grow the corn, production of and application of fertilizers, corn and fuel

transportation, and process combustion fuels. However, there can still be significant net benefits from using biofuels to displace at least a fraction of current fossil fuel consumption. Some examples of common biofuels are automotive bioethanol and biodiesel, woody waste biomass for heating [21], and synthetic "syngas" for power generation [22]. Bioethanol is pure ethanol that is indistinguishable from chemically produced ethanol; what makes it different are the feedstocks which are biological in origin.

Carbon Capture and Sequestration (CCS) is not a new concept but it has recently gained prominence in the discussions and planning for overall GHG abatement [23] in several jurisdictions. In classical CCS schemes, the CO_2 is captured from a stream such as the exhaust gas from a fossil-fuel fired heater by chemical adsorption or absorption, and then stripped from the solvent by a thermal regenerator. The concentrated CO_2 is then compressed into a dense phase liquid and transported via pipeline to an injection well where it is sequestered in a geological formation deep enough and with enough impermeable seals that it will not escape back to the surface. This works as well for biomass fuels as for fossil fuels, since the main variable determining efficiency and cost is the partial pressure of the CO_2 in the stream, regardless of fuel source. Similarly, there are other non-combustion streams in chemical processes such as ethanol production plants that contain CO_2, and CCS will work for these as well.

If CO_2 from biological activity can be captured and injected in a CCS scheme, it may be possible to have a net-negative process whereby not only are we avoiding putting more CO_2 into the atmosphere for a given volume of transportation fuel used, we are also removing

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CO$_2$ already present in the atmosphere. This is one way to reduce the existing stock of atmospheric CO$_2$ while providing for a portion of the world's energy needs. In effect, it would be "air capture" of CO$_2$ using plants as the medium and photosynthesis with fermentation and CCS as the process. Biomass with CCS is not a new concept [24] but it has not been widely adopted in North America.

Biomass combustion is the replacement of fossil fuels with combustible biomass for useful process heat. Biomass co-firing is a special application of biofuels whereby some volume of biomass, usually a waste stream, is fed into the same boiler or heater as the regular fuel to displace some of this fuel and the resulting GHG combustion emissions.

The IEA-GHG group has investigated the potential for CCS in combination with all forms of biomass energy and has estimated that there may by up to 10 Gt worth of negative CO$_2$ emissions technical potential in biomass CCS by 2050 [25]. This includes both biofuels and biomass for electrical power, and the realizable potential is less than 10 Gt although the economic potential is thought to be as much as 3.5 Gt per year. The following Figure 2 shows the IEA-GHG's vision of biomass CCS potential in graphical form:
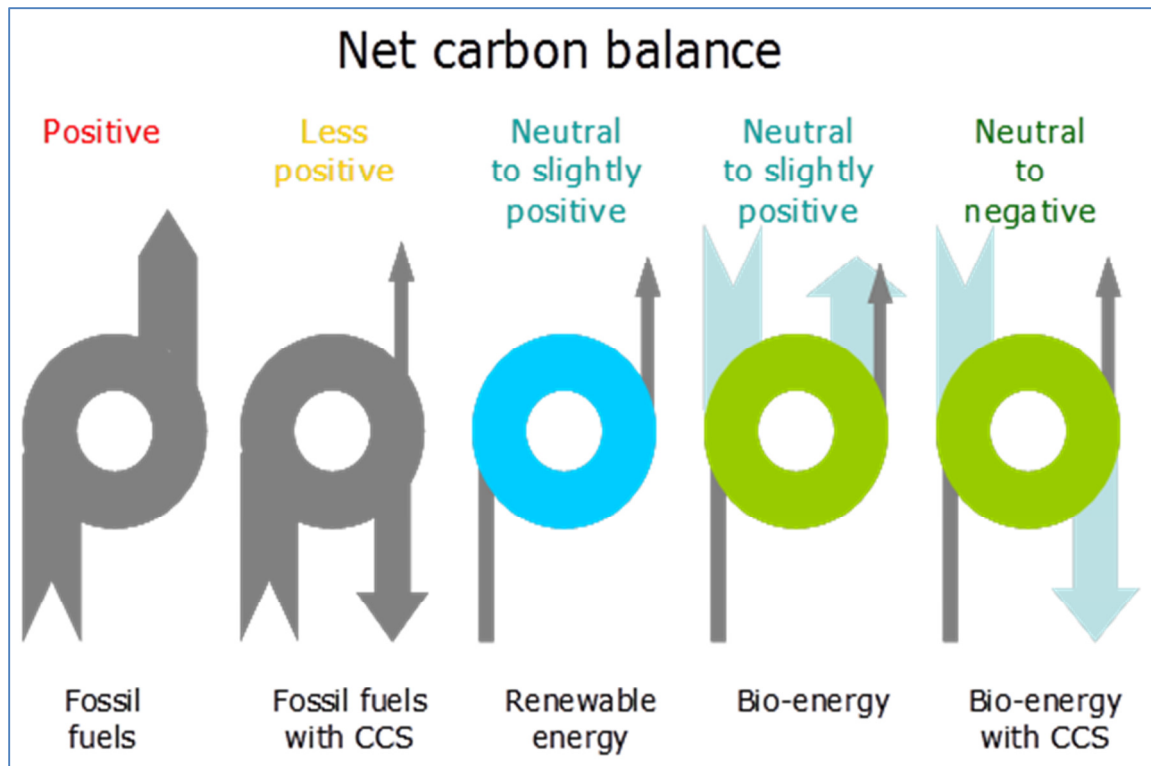
Figure 2: IEA-GHG Annual Review 2011, "Net Carbon Balance"

To put this into perspective, the world needs to cut 20.3 Gt from its current emissions to achieve cuts of 85% below 2000 levels by 2050 [26]. A recent OECD estimate of unabated Business As Usual (BAU) emissions shows emissions exceeding 80 Gt for 2050 [27]. A negative 10 Gt from biomass CCS can achieve 12% of this ambitious goal.

Chapter 1 of this document details the Motivation for Research and introduces the context of the research question. Chapter 2 is a life cycle assessment or Case study of four potential corn ethanol biofuel pathways. Chapter 3 introduces the various technologies which may lower the life cycle impact of corn-based ethanol if implemented. Chapter 4 quantifies these reductions in absolute terms and compares them to the magnitude of reductions necessary to

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reach a climate goal of restricting temperature rise to 2 degrees Celsius. Chapter 5

summarizes the Conclusions drawn on the technical and economic viability of bioethanol

GHG life cycle reduction technologies, and Chapter 6 gives recommendations for policy and

further research.

2.0 Theory and Basis of Life Cycle Footprint of Conventional Corn Ethanol

Research Questions:

How can we quantify the GHG footprint for Canadian corn-based ethanol in the face of uncertainty and an almost infinite number of site-specific factors?

Are there any potential pathways for corn-based ethanol to have a lower GHG footprint than reformulated gasoline? Are they low enough to justify policy and regulatory incentives?

Are there accounting methods that deal with the inherent uncertainties and sensitivities better than others?

What are the factors that determine if corn-based ethanol can be a low-GHG fuel?

Life Cycle Assessment or LCA is a decision support tool that is used to evaluate impacts from a product, process or service where it is "followed from its "cradle" where raw materials are extracted from natural resources through production and use to its "grave", or disposal" [28].The environmental impacts are calculated for each stage along the way; the only environmental impact studied here is GHG released to the atmosphere per functional unit of production. There are many other environmental impacts from the use of automotive fuel but the purpose of this LCA study is to evaluate the carbon intensity of ethanol fuel against the framework of a Low Carbon Fuel Standard, or LCFS. This study explores multiple Cases of the ethanol fuel pathway because in addition to estimating the average value for Ontario bioethanol, we also explore variability across models in order to make recommendations for future modelling.

The models used here are GREET, California-Modified GREET (CA-GREET), and GHGenius, as they are either the most common model used for fuel pathway studies in the US and Canada (GREET and GHGenius, respectively) or the model used to craft the first Low Carbon Fuel Standard (CA-GREET). For more information on the components and assumptions embedded in each model, please refer to the Unnasch et al 2011 report to the Coordinating Research Council, especially Chapter 3 starting on page 48 [29].

The GREET model was developed by Argonne National Laboratory for widespread use in calculating the environmental impacts of automotive fuel including the three principal GHG's (CO_2, CH_4, and N_2O). It is freely available but not transparent or easy to use; therefore corroboration of results with other independent models is valuable. The CA-GREET model is a modified version of GREET developed by Life Cycle Associates for the California Air Resources Board to model fuel pathways in a California-specific context, using regional data rather than US averages. The GHGenius model is based on the LEM 1998 model developed by $(S\&T)^2$ Consultants for Natural Resources Canada. It has been tailored to Canadian inputs, data and pathways making it useful and appropriate when discussing Canadian and Ontario bioethanol pathways as we do here in this thesis. All three models use different assumptions and base data, but each claims to give an accurate representation of the true life cycle footprint of fuels. It is valuable to compare all three side-by-side in order to assess variability caused by differing assumptions.

This Chapter compares the generic 2009 CA-GREET US Dry Mill Average ethanol pathway used in the CARB LCFS with three others - a GREET case for Ontario, a GHGenius case for

Ontario, and a site-specific case that substitutes publically-known direct emissions from the Suncor St. Clair ethanol plant. Life cycle emissions are compared on a "grams of CO_2 equivalent emissions per Megajoule of fuel energy provided" basis. The life cycle "Activities" (sectors that contribute to the total life cycle) considered in the CA-GREET LCFS case were kept throughout in order to allow for side-by-side comparisons. This required some aggregation of the GHGenius results in order to create comparative Activities.

As one potential mitigation option for transportation emissions, biofuels have immediate potential to displace some gasoline volumes especially if they can be burned in existing conventional internal combustion engine vehicles without expensive modifications. Ethanol is one such fuel which can be mixed with regular reformulated gasoline (RFG) in concentrations up to 10% with no detrimental effects seen on the vehicle's reliability and maintenance costs [30]. Specially built so-called "flex-fuel" and E85 vehicles can go to much higher ethanol concentrations, but at higher purchase price. The purpose of this LCA study is to identify the factors that determine if corn-based bioethanol can be considered a low-GHG emission fuel.

2.1 Methods

Radiative energy from the sun and naturally occurring CO_2 from the atmosphere are converted to chemical energy (sugars) by photosynthesis in a well-understood process. Biofuels convert that energy into forms that can be used for human economic activity, such as transportation and industrial or residential heating. Conventional corn ethanol technology extracts the starch from the corn kernel and converts it first to sugar, then ethanol through

traditional fermentation processes. Cellulosic ethanol is a second-generation biofuel which involves another step to break down cellulose from agricultural or wood waste to an ethanol product and by-products including industrial-grade molasses syrup and fuel-grade lignin. Opportunities exist to improve the economics of both first-generation corn ethanol and second-generation cellulosic waste ethanol through co-location and heat integration, since cellulosic ethanol produces surplus lignin biofuel that can be used in first-generation corn ethanol processing through a combined heat and power (CHP) co-generation scheme. This and other co-products can significantly improve both project economics and life cycle allocations of environmental impacts. Potential feedstocks for the cellulosic ethanol process include wheat straw, corn stover, wood waste, switchgrass, and miscanthus grasses.

The GHG benefit comes from displacing traditional fossil fuels such as petroleum and coal, and the CO_2 releases that occur when they are burned. In practice, biofuels production require other inputs such as fertilizer and other agricultural chemicals that render them to be less than neutral on a "cradle to grave" life cycle basis. For petroleum-based automotive fuels this is often referred to as "wells to wheels" (WTW) analysis. However, there can still be significant net benefits from using biofuels to displace at least a fraction of the current fossil fuel consumption. One major issue with biomass is "scale-up", or the maximum amount of biofuel production that can be sustained before biomass waste input transportation costs become too expensive or adverse effects on agriculture, food prices, or other land uses occur to negate their benefits.

Care must be taken when extrapolating the results of this research to any other plant or pathway besides the ones studied here, as local and site-specific factors have a large impact on the outcome. Site-specific factors such as transportation distances (distance from farm to ethanol plant, and ethanol plant to refinery blending terminal) and LUC resulting from site selection, as well as plant process design from technology selection, will all have a direct impact on the life cycle impacts of the plant. Life cycle assessment studies are inherently limited by the nature of the research question, assumptions, choice of boundaries, and the commissioner of the study. Comparison of LCA studies is complex and should not be attempted without in-depth knowledge of the sector and the underlying assumptions behind each study.

2.1.1 Case Study - GHG Scenarios

This study investigates the life cycle carbon intensity of 100% pure biofuels, although occasionally properties of blended fuels are mentioned when discussing real-world benefits. The impact indicator for this study is characterized by the value of the CO_2e emissions from the production and combustion of ethanol fuel; in this study those values were modeled using 4 Cases in order to focus on ethanol produced in Canada (primarily Ontario):

1. CARB modified CA-GREET US Dry Mill Average ethanol pathway numbers used to construct the 2009 California LCFS, used as the initial reference Case. Subsequent Cases use the same Activity classes in order to allow for comparisons. This was chosen as the

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base case since all ethanol fuel must be assessed against it when entering the California fuel market, the first to legislate an LCFS in North America.

2. An independent GREET model adapted to Ontario values (ie. electric grid mix, transportation distances, primary fuel types, etc.), where available. Many GREET defaults and assumptions are not transparent, meaning that other independent models should be investigated to increase the certainty of the estimates.

3. A GHGenius run using Southern Ontario values and defaults. GHGenius has multiple variable which can be tailored to Ontario and Eastern Canada data values such as refinery inlet crude streams, corn agriculture, and transportation and distribution distances, making it an appropriate model for Canadian ethanol production.

4. A model where selected Southern Ontario GHGenius activity data were replaced with Suncor St. Clair Site-Specific public data, including production / processing emissions, estimated energy-based co-products credit and an updated land use change (LUC) value. Actual operating data has much less uncertainty and does not rely on assumptions or defaults.

The Case 1 CA-GREET model created by CARB assumes data inputs are from the American midwest including agricultural practices, fertilizer use levels, primary energy types and electrical grid mix, dry versus wet mill market shares, as well as transportation distances to the ethanol plant and distribution distances to California markets. The Case 2 GREET model created for this thesis uses the Case 1 values for most Activities except for Processing / Production emissions calculated in GREET and Ontario-specific Corn Transport and Ethanol Transport / Blending emissions calculated via spreadsheet using

CA-GREET methods. The Case 3 GHGenius model created for this thesis has independently calculated values for all Activities, and inputs are from the Ontario and eastern Canada databases for electrical grid mix, primary fuels available, petroleum extraction, and transportation distances. The St. Clair ethanol plant has site-specific operating data for Process / Production emissions, Credit for Co-Products and Land Use Change; these are calculated directly in Case 4. Where St. Clair site-specific operating data is unavailable for an Activity, Case 3 GHGenius values are used for Case 4.

2.1.2   Goal and Scope Definition

From 2007 to 2010, several regulators such as the California Air Resources Board (CARB) proposed Low-Carbon Fuel Standards (LCFS) or Renewable Fuel Standards (RFS) as potential solutions to the issue of anthropogenic climate change. Low Carbon Fuel Standards such as the one adopted by the State of California have the goal of reducing the life cycle carbon intensity of transportation fuels; for California, their goal is a 10% reduction by the year 2020 [31]. Renewable Fuel Standards adopted in jurisdictions such as Canada (e.g. federally [32], Ontario [33], and Alberta [34]) dictate that 5% of the primary gasoline supplier's fuel volume be made up of biomass-based ethanol in order to reduce direct GHG emissions from internal combustion engine personal motor vehicles.

One way to meet these regulations with current technologies is the use of bio-fuels, specifically corn-based bioethanol which can be blended with Reformulated Gasoline

(RFG) and burned in standard internal combustion engines. As discussed in further detail in Section 2.1.4, there are numerous ethanol LCA studies in the literature but most have been done for "average" US or North American cases or are not detailed enough to understand the effects of site-specific factors on individual life cycle activities (e.g. CARB LCFS 2009, Cheminfo 2009, Babcock 2007, Coad 2011, Liska 2008). Large LCA models do not fully account for the variability of potential pathways, whereas in reality the specific details of ethanol production activities and factors such as site selection and transportation distances matter greatly to the final result.

The purpose of this study is to evaluate the life cycle "seed to wheels" greenhouse gas emissions of corn ethanol produced at an Activity level specifically for Southern Ontario, to see if some ethanol production pathways can have a net life cycle GHG reduction benefit as a gasoline additive over pure RFG. If so, and depending on the size of that benefit, this information can be used to inform regulatory and / or investment decisions on whether to expand ethanol production in the geographical area under study. In the future this study should be able to form the basis of a comparison of potential further carbon mitigation options.

2.1.3   Statement of Work

The material contributors to the life-cycle GHG emissions of corn-based ethanol produced in southern Ontario were calculated and compared to regular reformulated gasoline life-cycle emissions to estimate the net life cycle GHG benefit. The GHG

indicator was characterized by carbon-dioxide equivalent, or CO_2e, where other significant GHG volumes are converted to CO_2 based on their relative global warming potential due to radiative forcing. The main target audience for this work are regulators, executives and business development managers in the biofuels industry. The extended audience would be for anyone who needs to decide on the value of supplying or otherwise promoting the use of corn-based ethanol, such as other energy companies, NGOs, other researchers, and the general public.

The 2009 CARB "Detailed California-Modified GREET Pathway for Corn Ethanol Version 2.1" [35] US Dry Mill Average ethanol was used as a reference Case. While this study is deeply flawed by its lack of transparency, uncertainty analysis, explanation and justification of assumptions, data sources and mixed functional units to be considered a complete and definitive LCA study [36], it does include a great deal of data and was used to create actual real-world LCFS legislation. For comparison, a more applicable model for Ontario is used in this study - the GHGenius model from Natural Resources Canada, since the CARB study did not include pathways for Canadian ethanol. Much shorter transportation distances for corn feedstocks and products, different transportation modes, primary fuel types and electrical grid mixes ensure that unless Ontario is explicitly modelled, results for other jurisdictions will not apply. For comparison purposes, the main CARB activity classes (Activities) are kept for the GHGenius calculations.

The EIO-LCA database [37] was investigated to see if there were any notable omissions from the scope, since the CARB basis for which Activities to include were not available.

While the US agriculture and organic chemical sector data cannot be explicitly disaggregated for corn ethanol production, investigating these sectors can tell us which are the most important activities. The sector model results were reviewed to see which were the top Activities for each sector to get 95% coverage of overall emissions, and where the common activities are. When both these sectors were reviewed, the top 8 Activities were sufficient to give 95% coverage and it is clear that the CARB study should have included the Power Generation and Supply, Oil and Gas Extraction, and Petroleum Refineries activities as discrete entities. These are material sources, ranking 3, 5, and 6 out of the top 8 Activities required to get 95% coverage. Due to lack of transparency it is not obvious whether these emissions were included in other activities although it is likely that they were given their magnitude, therefore adding in an estimate of the emissions is not attempted to avoid double-counting. However they were added to the Flowchart as out-of-scope activities as their impacts cannot be ignored.

Another important component of the flowchart and model is allocation of impacts to co-products, namely Dried Distillers Grains with Solubles (DDGS) and Wet Distillers Grains with Solubles (WDGS). In a life cycle assessment, the impacts are allocated all products either by displacement (what is the impact of the material the co-product is replacing in the marketplace) or direct allocation of the impacts, if these impacts can be measured or reliably calculated using engineering calculations. When the starch is removed from the corn kernels to make the ethanol, the remaining biomass is a highly nutritious livestock feed that displaces other livestock feeds, preventing more GHG emissions from extra farming. The CARB 2009 Ethanol Pathway study using CA-

GREET and this present LCA's Cases 2 and 3 all calculate a credit for co-products like DDGS in their models. A Site-Specific simple allocation formula developed for Case 4, based on the difference in the input (corn) and output (ethanol) "metabolizable" or food energy contents [38] gives reasonably similar results. The energy content of corn and ethanol are known with relatively high accuracy, and the only output streams possible for the energy are bioethanol and DDGS. At St. Clair 72% of the input corn energy leaves as bioethanol, so the DDGS leaving the plant contains the remaining 28%. Therefore 28% of emissions can be allocated to co-products instead of ethanol. For Case 4 at St. Clair, some CO_2 is occasionally sold to the local food-beverage market, but this amount is small, still ultimately vented (by others) and often zero for an entire calendar year, therefore this co-product stream has not been included in the scope.

Practically, indirect sectors where the bioethanol supply chain is too small to affect the behaviour of the market (i.e. annual production levels) are not investigated. Since corn-based ethanol is still a relatively small market, many of these so-called Tier 2 or "supplier-to-supplier" [39] support sectors (i.e. the "pens on the desks") are not increased materially by our activities, and therefore are not quantified within the scope and budget of this study. If a separate EIO-LCA study were to be done for ethanol, these could be quantified but they did not show up in the "top 8 to get 95% coverage" EIO-LCA investigation mentioned above. They will either be immaterial or else require assumptions and allocation procedures that introduce so much uncertainty as to be of little value to the final decision. Also outside the scope of this study are the combustion of the reformulated gasoline with which the ethanol is blended (since it does not affect

our final decision), and impacts on food-grade corn since the feedstock here is solely livestock-grade corn.

The time range selected for the study data (2007 and later, if possible) corresponds with the application of updated ethanol technology, LCFS and RFS regulations, and Canadian federal GHG reporting requirements for facilities over 50,000 tonnes of CO_2e per year.

The southern Ontario geographical area has been chosen for Cases 2 to 4 for the following reasons:

a.   Existing Renewable Fuels Standard ON 535/05 require 5% ethanol by volume in Ontario.

b.   Agriculture is a mature, established and well-documented industry in the area, therefore direct and indirect land use change (LUC / ILUC) should be minimal. No new farmland is being cleared from forest in Ontario for this production or any other expanding crops.

c.   Existing local Canadian ethanol plants have provided recent data to the GHGenius model average inputs.

d.   Site-Specific publicly-available production information from the Suncor St. Clair Ethanol Plant commissioned in 2007 is available and can provide hard technical data which is preferable to engineering estimates.

If others wish to generalize this study, the factors they would have to vary would include:

a.   Primary fuel used - natural gas, fuel oil, or coal.

b. Electrical grid power supply mix.

c. Local LUC values for the area under consideration.

d. Agricultural inputs and practices in the geographic area under study.

e. Transportation distances and modes for both feedstock and products.

These were some of the factors that were investigated in the Variation Analysis and Sensitivity Analysis between Cases 1 to 4 carried out later in this study.

2.1.4   LCA Literature Review

For the purposes of this study, only corn ethanol life cycle emissions from livestock grade corn will be studied in detail so that the additional benefits of CCS can be isolated and clearly demonstrated against the base case of existing first-generation biofuel technology. Follow-up studies may be able to apply the same methodology to second-generation biofuels and see how CCS can improve GHG abatement performance.

The 2009 CARB "Detailed California-Modified GREET Pathway for Corn Ethanol Version 2.1" [40] is used as a reference Case and complemented mainly by the addition of the California Environmental Protection Agency, Air Resources Board "Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I Staff Report: Initial Statement of Reasons" [41], "Greenhouse Gas Emissions From Indirect Land Use Change" [42] by the CARB LCFS Working Group 3 and "Climate Analysis Indicators Tool (CAIT) Version 7.0." [43].

The Inventory Assessment Literature Study list has been augmented by the addition of the MIT "Review of Corn Based Ethanol Energy Use and Greenhouse Gas Emissions" [44], the "User Manual for Stochastic Simulation Capability in GREET" [45] and the "Documentation for Natural Resources Canada's GHGenius Model 3.0" [46] uncertainty documents.

Studies that gave information on Canadian or Ontario circumstances [47] or ILUC [48] have been considered. Also retained for general information were studies that examined the impact of LCFS and RFS legislation [49], EPA life cycle studies [50] and general background on ethanol biofuel [51]. The full Bibliography list can be found at the end of this document before the Appendices.

The CARB 2009 Case has been chosen as the base Case for this evaluation as it was used to implement a real-world GHG regulation [52]. Subsequent Cases 2 – 4 are attempts to model the same sequence of life cycle Activities in a Canadian and Ontario-specific context, in order to be able to directly compare Canadian life cycle impacts with the CARB assumptions.

There are a great deal of other bio-ethanol life cycle studies in the current literature (see below), and many have final results that are comparable to the Cases in this thesis. Some endeavor to arrive at a "national average" impact value, others attempt to guide environmental or agricultural policy, and the main purpose of some is to inform the basis of regulation. The methods or activities included in the other bioethanol LCA literature

are different enough from the Cases evaluated in this thesis that it is difficult to do a side-by-side comparison at a high enough level of detail to point out where and why they differ, and there are few that address Canadian or Ontario-specific circumstances.

Due to the high volume of bioethanol literature available, an exhaustive list is not included here. However some of the more applicable and insightful studies are:

1. Cheminfo Services Inc. "Life Cycle Assessment of Renewable Fuel Production from Canadian Biofuel Plants 2008 – 2009", prepared for the Canadian Renewable Fuels Association, November 25, 2009. The main conclusion was that Canadian bio-ethanol had an average fuel cycle GHG impact that was 62% lower than RFG on an energy content (g CO_2e / MJ) basis, similar to Case 4 results later in this paper. It used detailed activity classes but used only one model (GHGenius) and the bulk of the analysis was done on a volumetric g CO_2e / litre basis. As we have said elsewhere in this thesis, a multi-model approach is required in order to deal with inherent variability and uncertainty, and the energy impact metric g CO_2e / MJ is the most appropriate measure of GHG reductions from bioethanol fuel.

2. Len Coad and Marta Bristow, "Ethanol's Potential Contribution to Canada's Transportation Sector", Conference Board of Canada, November 2011. Its main conclusion is that bio-ethanol fuels have a GHG reduction of 40% – 62% over RFG, in line with our findings here. They cover more impacts than just GHG's, and the GHG section is relatively small compared with the overall length of the report. It is well documented but the actual data is not given in the report, making it difficult to

judge the suitability of underlying assumptions which have a significant outcome on results.

3. S. Unnasch et al (Life Cycle Associates), "Review of Transportation Fuel Life Cycle Analysis", prepared for Coordinating Research Council, February 2011. The main findings for bio-ethanol in this multi-model paper range from 40 g CO_2e / MJ from GHGenius (58% reduction over RFG) to 105 g CO_2e / MJ from GREET ver. 1.8b. While the data used in this study was not Canadian but from the US and EU, the Activities modeled are similar enough that comparison with our study is possible if the authors can confirm their assumptions and boundaries.

4. McCulloch et al (Pembina Institute), "Ethanol GHG Life-Cycle Assessment An Update for Suncor's Sarnia Facility", prepared for Suncor Energy Inc., July 2007. While the methods used in this study differ completely from those of the Pembina 2007 study, the Pembina result for the St. Clair (Sarnia) ethanol plant is a 4.6% CO_2e reduction for a 10% volumetric (per litre, not per MJ) blend. Assumptions are clearly documented and impartiality is assured, but the methods used are not easy to follow, and the activities are not immediately comparable to other studies.

5. Babcock et al, "Is Corn Ethanol a Low Carbon Fuel?", Iowa Ag Review, Fall 2007 which found an 11% to 39% life cycle GHG reduction for corn-based ethanol depending on process design chosen and primary fuel type. It is also volumetric and does not include the data in the text, although assumptions are well documented.

6. Liska et al, "Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn Ethanol", Journal of Industrial Ecology, 2008 which found 48% to 59% life cycle GHG reduction for corn-based ethanol with the potential for more

depending on advanced process design or agricultural practices. The assumptions, methods and methodology are well explained and source data are given, however the study is for US facilities only.

7. Don O'Connor, "GHG Emission Reductions From World Biofuel Production and Use", prepared for the Global Renewable Fuels Alliance, November 23, 2009. This study found a life cycle impact for Canadian corn ethanol of 44 g CO_2e / MJ which is between the results of Cases 3 and 4 in our study here. The study scope includes all biofuels produced globally but is disaggregated to show individual countries including Canada. The assumptions, methods and methodology are also well explained and but only one model is used (GHGenius) and source data and activity breakdowns are not given.

2.1.5   Detailed Flow Chart

The stages included in this study start with growing the corn (including producing agricultural chemicals and fertilizer), harvesting and transporting corn to the ethanol production facility, processing, shipping to the refinery for blending with gasoline, disposal of residuals and waste, and combustion in the vehicle engine. Direct and indirect emissions are counted as well as some so-called Scope 3 (indirect emissions other than energy) supplier and consumer emissions; however the Tier 2 suppliers (suppliers to suppliers) are not generally included.

Indirect land use changes (ILUC) are a poorly understood field of study but we will try to estimate them here to some degree, as it has become a central issue in the corn ethanol life cycle debate. Similarly food-grade corn production is not included within the boundaries of this study since the primary feedstock is livestock-grade corn.

The CARB study used the following main Activities [53]:

a)   Agricultural Chemical Production - chemical inputs including fertilizer (nitrogen, phosphate, potash, and lime), herbicides and pesticides; includes energy inputs and production, process and transportation emissions.

b)   Corn Farming - direct farming energy inputs and GHG emissions from each component in the corn farming pathway. The CARB study Case used here assumed average US Midwest corn production for their model.

c)   Corn Transport - moving the corn feedstock from the field to the stack to the ethanol plant, assumed to be done entirely using diesel trucks. There are default distance travel distances in the CARB study that are not applicable to many real world plants; these defaults are varied for the other 3 Cases investigated in this LCA. All corn for the St. Clair plant is sourced from brokers operating in a 100 km radius from the plant.

d)   Processing / Production - calculates the total energy required to deliver each primary energy input, using the direct primary energy inputs for ethanol production. Dry mills using natural gas and electricity are much less GHG intensive than west mills using a high proportion of coal, therefore the results are very sensitive to the assumed wet mill share, coal proportion, and electric grid mix. Cases 2 through 4 use dry mill, no coal and the actual Ontario electrical grid mix in their calculations.

e)   Ethanol Transport / Blending - transporting ethanol product from the production facility to bulk storage and blending terminals. CARB assumed 2,240 km (1,400 miles) by rail whereas the actual Southern Ontario number is much lower, and more likely to use trucks than railcars.

f)   Credits for Co-Products - energy and emissions credits using the displacement method, where 1 lb of DDGS or WDGS replaces 1 lb of feed corn; DDGS has lower starch but higher nutritional content than corn.

g)   "Well to Tank" subtotal - all the emissions from the LCA activities that go into producing and delivering the fuel to the fuel tank, before combustion.

h)   Combustion / End Use - the carbon emitted from the tailpipes of the vehicles burning the fuel; since the carbon in the corm ethanol originated from atmospheric CO_2, most studies correctly assume ethanol combustion emissions to be zero on a net basis assuming crops are re-grown annually.

i)   "Well to Wheels" total - the Well to Tank emissions plus the emissions from combustion / end use.

j)   Land Use Change - emissions caused by deforestation on forest cleared to make new farmland, or on existing farmland that would have otherwise lain fallow for that growing year.

The GHGenius model also includes the indirect emissions from Materials in Vehicles, and Vehicle Transport. These have been consolidated to fit the same Activity classes as the GREET model without losing the total emissions intensity.

Please see the Appendices for the full-sized flowchart including material flows, but a

smaller version of the materials flows is as follows in Figure 3 below:
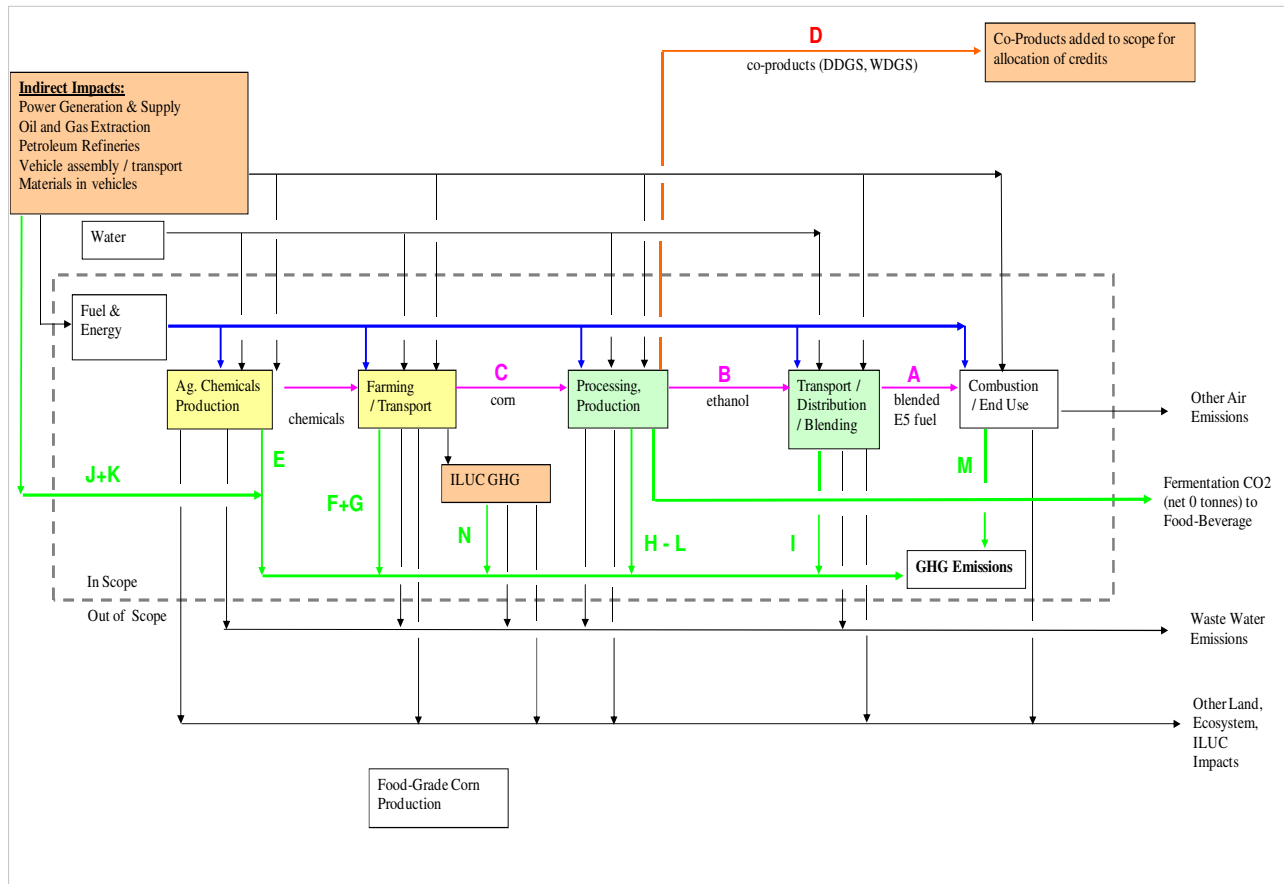
Figure 3: Detailed Corn-Based Bio-ethanol Flowchart (see Appendix 1)

The volume-based functional unit of "per million litres of ethanol" was chosen in order to

allow researchers to follow the input and output material flows through the process and

scale up the impacts for any size of ethanol facility. However, since ethanol has roughly

two-thirds the energy content of gasoline, a million litres of ethanol does not provide the

same services as a million litres of gasoline. Therefore an environmental impact

evaluation metric of "emissions per Megajoule of fuel energy used" is also used for the

majority of the analysis and comparisons with other fuels in this thesis. This also allows

us to compare impacts directly with the CARB 2009 LCFS assessments which assign a

"grams of CO_2-equivalent per Megajoule of fuel energy provided" (g CO_2e / MJ) to every

fuel type on an energy, not volume, basis.

Table 1: LCA Material Flows

Stream	A	B	C	D	
Activity Name	Blended E95 Fuel	Denatured Ethanol	Corn	Co-Products	
Units	litres	litres	kg	kg	
Common Values	20,000,000	1,000,000	2,300,000	743,000	
Stream	E	F	G	H	I
Activity Name	Ag. Chemical Production	Corn Farming	Corn Transport	Processing Production	Ethanol Transport /Blending
Units	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e
Reformulated Gasoline	0	0	0	816	0
Case 1: CARB LCFS	712	133	52	903	64
Case 2: GREET	712	133	62	267	2
Case 3: GHGenius	119	133	82	569	35
Case 4: St. Clair	119	133	82	481	35

Stream	J	K	L	M	N	
Activity Name	Vehicle assembly transport	Materials in vehicles	Credits for Co-Products	Combustion / End Use	Land Use Change	Total Net GHG to Atm.
Units	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e
Reformulated Gasoline	30	289	-6	2210	0	3340
Case 1: CARB LCFS	0	0	-271	0	707	2300
Case 2: GREET	0	0	-271	0	354	1260
Case 3: GHGenius	22	208	-390	49	481	1300
Case 4: St. Clair	22	208	-327	49	71	870

Table 1 values above are environmental impacts (for most streams tonnes of CO_2e) per

million litres of ethanol, the functional unit chosen to evaluate the material flows in this

study. This table shows that key activities contributing to emissions in this pathway include the Co-Products material stream for energy allocation purposes (Stream D) as well as the Credits for Co-Products (Stream L). The reformulated gasoline (RFG) stream shows a minor credit for co-products since the GHGenius model uses the older formulation of conventional gasoline as a base case for all fuel comparisons, and GHGenius allocates higher impacts to co-products from RFG refining than conventional gasoline refining.

Another common unit used in personal transportation impact studies is "per person-kilometre", since ultimately that is the service being provided by the fuel, to move a person or persons over some distance. This is a common and popular metric used to compare mobility studies done on different modes of travel. In order to convert from "g CO_2e / MJ" units to "g CO_2e / person kilometre", several assumptions must be made:

1. Fuel efficiency in litres per hundred kilometres
2. Number of people in the vehicle per trip

The conversion calculation is as follows:

(environmental impact load in g / MJ) x (energy content in MJ / L) x (fuel efficiency in L / km) / (number of passengers) = (impact in g / passenger – kilometres), or

$$\frac{g}{MJ} * \frac{MJ}{L} * \frac{\frac{L}{km}}{no.\,of\,passengers} = \frac{g}{passenger * km}$$

This environmental impact load can be literally any substance released by burning the fuel; for this thesis we are only concerned with GHG emissions in g CO_2e. For example, if we assume a "typical" fuel efficiency number of 10 litres per 100 kilometres with only one person in the car, then 1 g CO_2e / MJ of ethanol is equal to 2.36 g CO_2e / person-kilometres, and 1 g CO_2e / MJ of gasoline is equal to 3.47 g CO_2e / person-kilometres. If we increase the passengers up to 2 people per trip, then 1 g CO_2e / MJ of ethanol is equal to 1.18 g CO_2e / person-kilometres, and 1 g CO_2e / MJ of gasoline is equal to 1.73 g CO_2e / person-kilometres. Using 1 – 2 passengers in the car is likely a valid assumption for the United States since the number of registered vehicles has exceeded the number of licenced drivers for the past several decades [54], and is consistently approximately 80% 0f the total population of the United States.

While "per passenger-kilometre" impacts are interesting and potentially useful for comparing these types of life cycle assessments to traditional mobility studies using transportation modes other than passenger vehicles, or for comparing transportation policy alternatives, for the scope of the study done here the functional units of "per million litres" and "per MJ of fuel" are used instead for the reasons given above.

2.1.6   Classification

The study only looks at a single mid-point indicator, Global Warming Potential from greenhouse gases. This impact indicator falls into the impact category of "ecological

consequences" with secondary impacts on "human health" and is a direct result of "resource use".

2.1.7 Characterisation and Impact Assessment

The impact indicator is characterized by the value of the CO_2e emissions from the production and combustion of ethanol fuel; in this study those values were modeled using four Cases:

1.   CARB 2009 modified CA-GREET US Dry Mill Average ethanol pathway numbers used to construct the California LCFS, used as the initial reference Case. Subsequent Cases use the same Activities in order to facilitate comparisons.

2. An independent GREET model adapted to Ontario-specific values, where available.

3. A GHGenius model run using Southern Ontario values and defaults.

4. A spreadsheet model where selected Southern Ontario GHGenius activities were replaced with Suncor St. Clair site-specific public data, including production / processing emissions, estimated energy-based co-products credit and an updated LUC value from renewable fuels consultant Don O'Connor.

2.2 Life Cycle Assessment Results

Once the modelling was completed, the quantitative results of the LCA study were discussed below for each fuel pathway Case.

2.2.1   LCA Outcomes

Quantitative Results

Numerically the results are summarized in the following chart and table. The functional

unit chosen for this study is "tonnes of CO_2e per million litres of ethanol produced"

volumetric basis comparison metric, in order to track the material flows through the

process. However, calculations using energy content of ethanol, which is only 68% of

RFG, are a more important metric as it implicitly includes the vehicle performance which

is the ultimate service being provided by the fuel product. For this reason, most fuel

pathway LCA studies use the "g CO_2e / MJ fuel energy" energy basis metric. Therefore,

the results discussed below use the "g CO_2e / MJ fuel energy" energy basis impact

evaluation metric and not the "tonnes of CO_2e per million litres of ethanol produced"

volumetric basis functional unit upon which this LCA is based. Some discussion of

volumetric (per litre) results can be found in Section 2.3.1.

Graphically, the contributions of each component to the overall total GHG emissions can

be shown as follows in Figure 4:
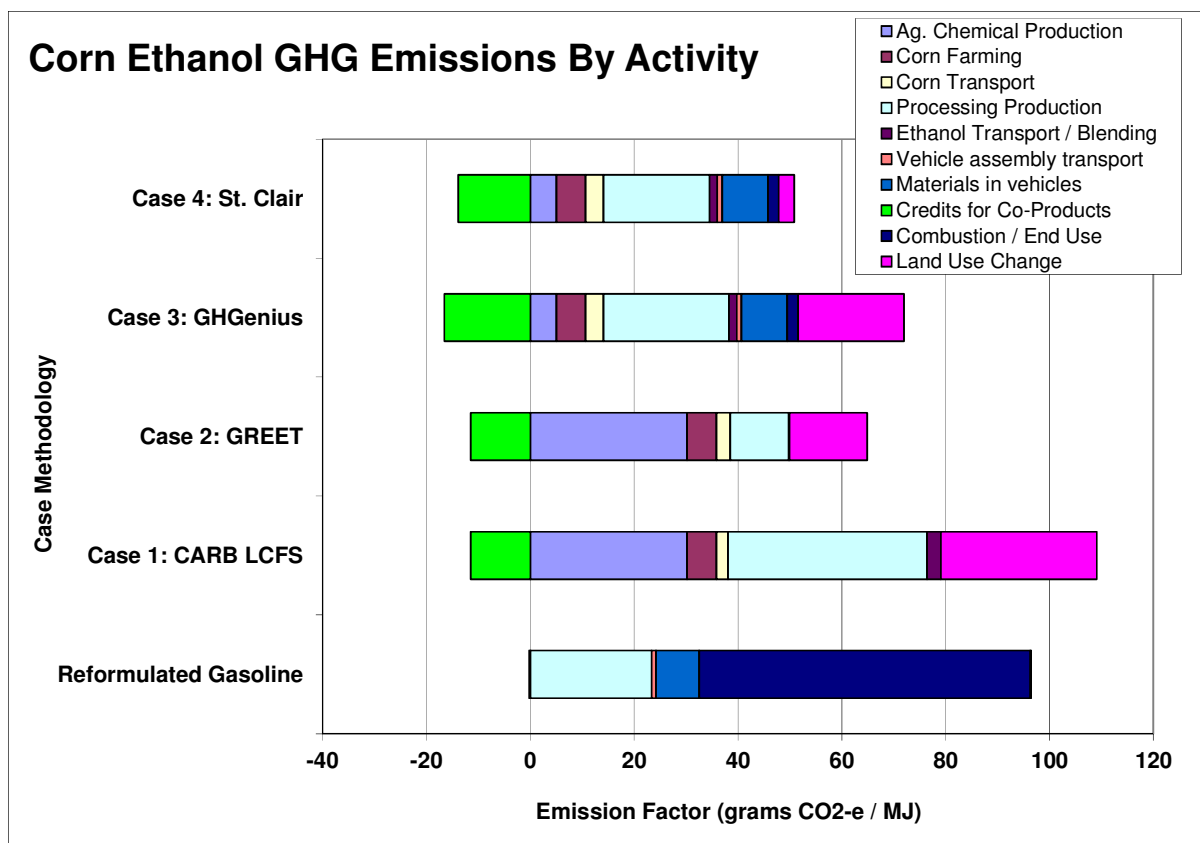
Figure 4: Corn Ethanol GHG Emissions per Volume by Activity

On an energy basis, the results range from a 1.5 gram CO2e per Megajoule (g CO2e /MJ) increase for the CARB Case, to a roughly 40 g CO2e /MJ (42 - 44%) decrease for the GREET and GHGenius Ontario results, to a 60 g CO2e /MJ (62%) reduction for the St. Clair Site-Specific Case. The net emissions can be calculated by subtracting the co-product credit (negative value in green) from the total increases (all the positive values). The activities that stand out as major contributors are Credits for Co-Products, Ag. Chemicals, Processing / Production, and ILUC. The Combustion / End Use emissions dominate the impacts of RFG, but as noted previously the combustion emissions for ethanol are assumed to be essentially zero on a net basis.

Table 2 shows the numerical material flow values for the CO_2 intensities associated with the ethanol stream Activities.

Table 2: Inventory / Impact Assessment Calculation Material Flow Results

Activity	Ontario RF Gasoline* (gCO2-e/MJ)	Case 1: CARB Dry Mill (gCO2-e/MJ)	Case 2: GREET Ont. (gCO2-e/MJ)	Case 3: GHGenius Ont. (gCO2-e/MJ)	Case 4: Site-Specific (gCO2-e/MJ)
Ag. Chemical Production	0.0	30.2	30.2	5.0	5.0
Corn Farming	0.0	5.7	5.7	5.6	5.6
Corn Transport	0.0	2.2	**2.6**	3.5	3.5
Processing / Production	23.3	38.3	**11.3**	24.1	**20.4**
Ethanol Transport / Blending	0.0	2.7	**0.1**	1.5	1.5
Vehicle Assembly & Transport	0.9			0.9	0.9
Materials in Vehicles	8.3			8.8	8.8
Credits for Co-Products	-0.2	-11.5	-11.5	-16.6	**-13.9**
"Well to tank" subtotal	32.3	67.6	38.4	32.9	31.9
Combustion / End Use	63.8	0.0	0.0	2.1	2.1
"Well to Wheels" total	96.1	67.6	38.4	35.0	34.0
Land Use Change	0.2	30.0	15.0	20.4	**3.0**
Total	96.3	97.6	53.4	55.4	37.0

In Case 1, results show that assumptions on Co-Product credits, LUC values, primary fuel use and electrical grid mix make a huge difference in the final outcome, and assumptions that are valid for certain geographical areas should not be extrapolated to others. The CARB data for average US dry mill and some California ethanol plants actually show essentially no GHG benefit to using ethanol, calculating almost 98 g CO_2e / MJ of ethanol versus their 2009 stated value of 95.86 g CO_2e / MJ for gasoline, or a net *increase* of just under 2%. This is due mainly to an assumption of 30 g CO_2e / MJ for Land Use Change, but this value is based on an assumption that for every acre of land

devoted to ethanol feedstock, there is a proportion of 1 unit of forest cleared for every 2 units of fallow farmland or pasture converted to corn ethanol feedstock [55]. This has been subsequently revised to 15 g CO_2e / MJ by CARB [56] since the underlying assumptions have shown to be overly conservative - while bio-ethanol farming has increased over the past 20 years, the actual amount of land farmed in the US actually decreased 5% from 987 million acres in 1990 to 943 million acres in 2000 [57]. The real ratio is believed to be 1/30 forest versus 29/30 existing farmland and the eventual impact number closer to 3 g CO_2e / MJ [58].

For Case 2, the GREET program is run using as much Ontario-specific data as possible, such as the actual electric grid mix, to give the expected "fuel-cycle" GHG reductions, although many of the built-in defaults could not be changed due to lack of better available data, or transparency in the original data used by CARB. The CARB LCFS study [59] methodologies in Appendix 2 for corn and ethanol transport were also modified to calculate the values for 100 km corn transport and 22 km ethanol transport by heavy duty diesel trucks which are more representative of local conditions than the values assumed by CARB. This independent GREET model plus a new LUC value of 15 g CO_2e / MJ shows a life cycle emissions of roughly 54 g CO_2e / MJ versus a value of 96.3 g CO_2e / MJ for gasoline, a 44% improvement.

The GHGenius model Case 3 for Southern Ontario shows a similar reduction in emissions, calculating 54 g CO_2e / MJ versus a calculated GHGenius value of 97 g CO_2e / MJ for Ontario gasoline, or a 42% improvement which measures up well with the

previous Case 2. This is due mainly to greatly reduced values over the initial CARB Case

for agricultural chemical production, ethanol processing / production (predominantly

natural gas in Ontario), ethanol transport / blending (less than 100 km from farming

region to the Ontario refining corridor), and a greater credit for co-products. Due to the

fossil fuel inputs to other ethanol life cycle activities, there is a slight (~3%) impact from

end-use combustion which CARB assumed to be zero on a net carbon-cycle basis.

The Site-Specific Case 4 replaces the processing / production emissions, credit for co-

products, and LUC values with numbers unique to the Suncor St. Clair Ethanol Plant to

give 37 g CO_2e / MJ versus a calculated value of 96.3 g CO_2e / MJ for Ontario gasoline,

or a 62% improvement. This agrees well with the results of a confidential 2007 report by

an external third party [60]. The actual processing emissions for St. Clair are lower than

GHGenius and much lower than CARB due to the natural gas feedstock and efficient

process design. The credit for co-products is estimated by subtracting the known energy

content of the output (ethanol) from the known food energy content of the plant input

(corn), which leaves a residual of about 28% of the "metabolizable" energy from the

feedstock corn in the DDGS. The value is slightly less but still close to the GHGenius

value, which helps to reinforce the validity of this approach. The LUC is chosen to be the

lowest of the values given by Don O'Connor [61] since the Southern Ontario area is a

mature agricultural area with no new farmland being cleared, and all St. Clair feedstock

corn being sourced from within a 100 km radius through local brokers.

Beyond the GHG / GWP reduction benefits, the economics of ethanol projects are difficult to quantify, and have not been included in Chapter 2 but are investigated to some extent in later Chapters. The costs of and forecasts for ethanol and gasoline production are typically not available as they are often classified as Confidential Business Information. Also, the market price at which fuel companies can sell blended ethanol is limited to the market price for the gasoline with which it is blended - the ability of companies to pass along any price increases is minimal in a highly competitive fuel market. However, production costs per Megajoule of ethanol can be assumed to be greater than RFG, or else we would not need an RFS regulation to promote them. Therefore, companies will only blend what is required by legislation unless a carbon price is imposed or production costs decreases to narrow the cost differential, making ethanol economically competitive with gasoline.

Qualitative Results

Since this study addresses only the Global Warming Potential of the GHG's emitted in the ethanol life cycle, all aspects can be quantified and therefore there is no need for qualitative results discussion.

2.2.2   Inventory / Impact Assessment Results

This impact assessment and interpretation includes an estimate of the emissions saved for gasoline production in grams of CO_2e per MJ of fuel. This will help us to demonstrate whether it is suitable to include corn-based ethanol as part of the LCFS framework, and

also if there is a significant global GHG benefit from blending 5% ethanol into all commercial gasoline.

2.3 Interpretation and Discussion

The main interpretations and conclusions to be drawn from the LCA Case study are detailed in the sections that follow.

2.3.1   Findings

Generally speaking, there is strong evidence of a significant life cycle GHG benefit to blending reformulated gasoline with Southern Ontario ethanol. Continued investment in the corn-based ethanol business is justified in the context of reducing overall transportation GHG emissions. The ethanol option should be promoted by regulators and groups seeking to reduce national GHG emissions wherever it can be demonstrated that their specific circumstances lead to a positive net benefit. The eventual limiting factor for scale-up will likely be direct and indirect land use change, although it is hard to say with certainty when this may be reached.

If the comparison were done on a volumetric basis it would appear that all Cases including CARB Case 1 are lower than RFG. The per-litre GHG reduction for ethanol fuel on a volumetric basis ranges from -300 to 2470 tonnes per million litres. However the energy content of ethanol is only two-thirds that of gasoline, therefore comparing

ethanol to Ontario reformulated gasoline on a volume basis can be misleading. This is why the analysis in this thesis uses the impact metric of g CO_2e / MJ instead of the functional unit "per million litres of ethanol" used to create the material flows; it is important that LCA fuels analysis is done on an energy basis and not on a volumetric one even if volume is the material flow functional unit. Compare Figure 5 below for volumetric basis comparison to Figure 4 for energy basis comparison in Section 2.2.1.
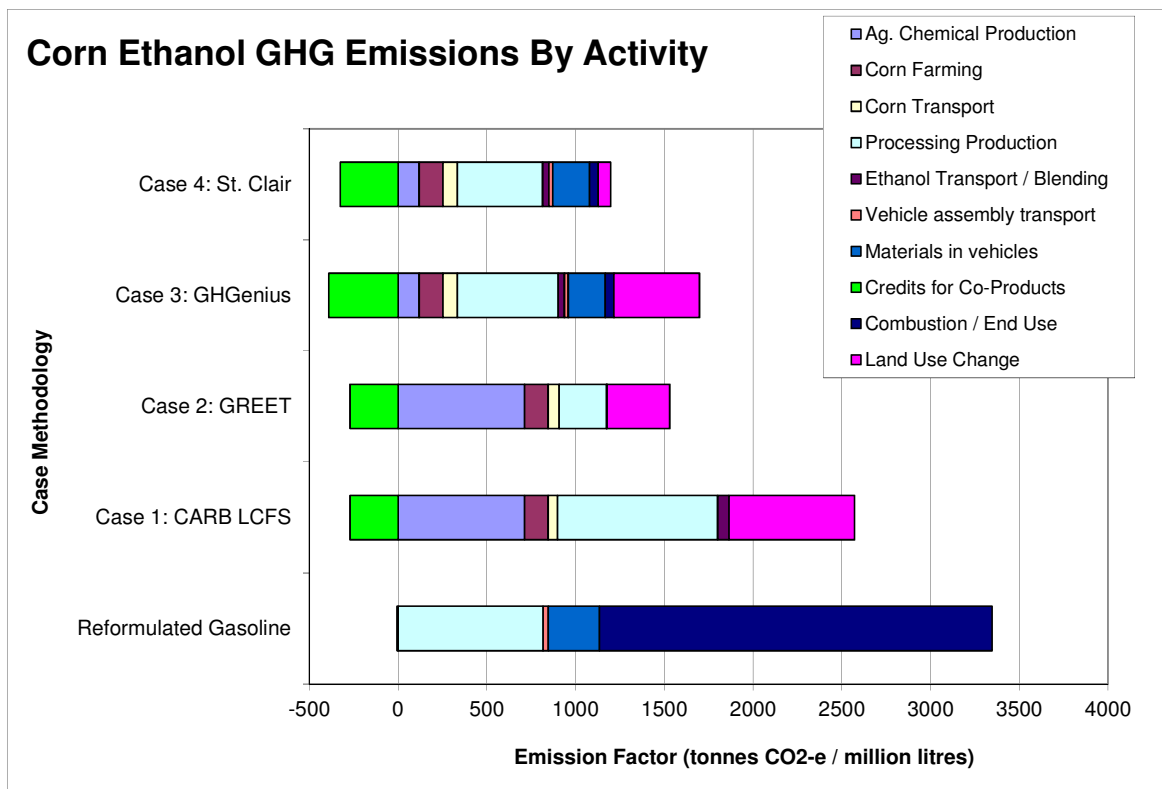
Figure 5: Corn Ethanol GHG Emissions per Volume by Activity

A volumetric per litre unit may be useful when performing analysis of fuel economics or market studies of consumer demand, but is not suitable for energy evaluations.

2.3.2   Analysis and Data Quality

The uncertainty of the models used can be checked for appropriateness where possible.

Any values that have been estimated outside of the GREET and GHGenius models,

especially the LUC value, were varied in a sensitivity analysis to check the robustness of

our conclusions. The @RISK Excel plug-in tool is applied using triangle distributions of

minimum, maximum and most-likely. Already it is fairly obvious that LUC values can tip

the scales into a negative impact for cases with WTW emissions above 60 g CO_2e / MJ,

so particular attention should be spent here.

There are several methods of analyzing LCA data. Below are several types of analysis

and their results if applicable, and the reasoning if they were judged not applicable to the

current LCA.

Dominance Analysis

From Figure 5 below for the Site-Specific Case, it is obvious that the dominant activities

are Processing / Production at 55% and Credit for Co-Products at -37% contributions to

the total. Most other activities are under 20% except for Materials in Vehicles which is

well outside the control of the ethanol producer.
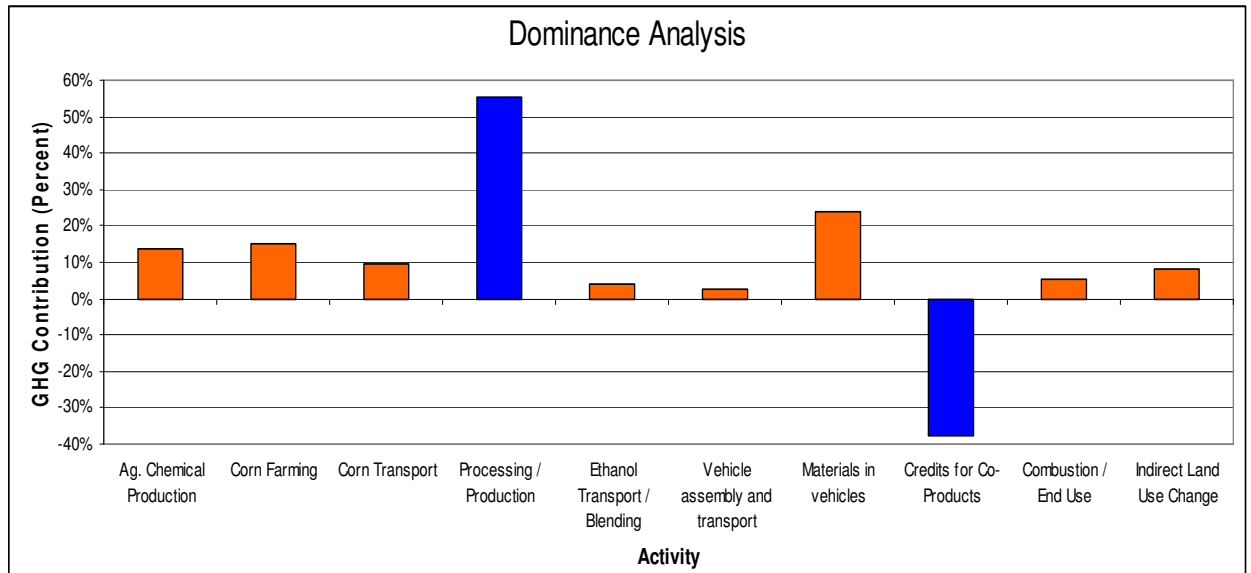
Figure 6: Dominance Analysis by Activity for Case 4: St. Clair Site Specific

Decision Maker Analysis

There are three levels of influence in the activities included here:

1. Direct Control - Processing / Production and Ethanol Transport / Blending (light green in the Fig. 3 flowchart). Here the ethanol producer directly controls the factors that determine performance for the activity. Natural gas and other fuel / energy inputs, as well as transportation distances and product distribution, are factors that are selected or designed by the producer. This is an important observation since Processing / Production is the dominant activity for GHG impact in the ethanol life cycle.

2. Financial Control / Influence - Ag. Chemical Production, Corn Farming, Corn Transport (light yellow in the Flowchart). The ethanol producer does not directly control these activities, but they can choose which suppliers and locations they deal with, and GHG performance can be an evaluation criteria when choosing between suppliers.

3. No Control / Some Influence - Vehicle Assembly and Transport, Materials in Vehicles, Credits for Co-Products, Indirect Land Use Change (light tan in the Flowchart). Here the producer has no control, since these activities are completely external to their manufacturing process. However, since some of them are critical and have a relatively large impact, efforts must be made to understand them well and advocate for reductions where possible.

Contribution Analysis

Contribution analysis is not applicable as we are only looking at one environmental load or indicator, namely GHG Global Warming Potential (GWP). Although generally combustion is dominated by CO_2, future studies may wish to disaggregate the GHG's into CO_2, CH_4, and N_2O to see where the best reduction opportunities lie.

Variation Analysis

This is done implicitly when we compared the 2009 CARB study for US Dry Mill ethanol plants with the GREET, GHGenius and Site-Specific Cases for Ontario. The biggest differences were the transportation distances for corn and ethanol, and primary source fuel for the local electric grid mix. As we saw, this makes a large difference as the CARB Case had a well-to-tank subtotal that is almost double the average of the other Cases (68 g CO_2e / MJ versus 32 - 39 g CO_2e / MJ). This is done before LUC is taken into consideration, which is highly location-dependent as well.

The four Cases investigated here were a form of variation analysis since we varied the inputs for primary fuel type, electric grid power supply mix, LUC values, and transportation distances and modes. The results of the four Cases produced a range of values for each activity that will be used as inputs to the following sensitivity analysis. The four activities that changed the most over the four Cases were LUC, Production / Processing, Ag. Chemical Production, and Credits for Co-Products. These were varied in the Sensitivity Analysis that follows.

Break-Even Analysis

It is often valuable to investigate trade-offs in parameters to see if a "break point" or threshold value can be reached that would change our decisions. In this Case, LUC seems to be an interesting activity but it takes the absolute worst Case of the CARB study plus an LUC value of 30 to just barely exceed the life cycle emissions of gasoline, therefore we can safely determine that LUC alone should not be a tipping point.

Uncertainty Analysis

As the GREET and GHGenius models have a large number of inputs and calculation methodologies, it is difficult to determine a predefined "uncertainty range" and therefore check the upper and lower bounds of a single activity or the entire life cycle. Likely for this reason the CARB reference Case does not mention uncertainty and gives only single-point estimates. The GREET model has a built-in stochastic simulation tool that allows you to statistically analyze the results as long as you have data to specify the input probability distribution functions [62]. The GHGenius model has a tool for Sensitivity

Analysis but it requires prior knowledge of the input ranges, which is the main point of uncertainty analysis [63].

Qualitatively much of the data that is used to populate the model defaults, as well as the Site-Specific Case, are based on actual operating data which have relatively low uncertainty, including Production / Processing which is the dominant activity. A better tool for this data is a Sensitivity Analysis as we have multiple estimates for every Activity.

Sensitivity Analysis

The life cycle models used here are linear and sum the activities arithmetically so there is not one activity that has a disproportionate impact based on a non-linear relationship (i.e. exponential or hyperbolic change, etc.). As well, the corn-ethanol production process is itself very linear and depends on only one input stream (corn) to produce a one primary product (ethanol). Varying inputs will not lead to any surprise results since their impacts depend only on their relative contribution to the total, so that a 10% variation in a 10% contribution Activity will always produce a 1% change in the total.

The sector with the most uncertainty here is LUC although the reasonable range is likely well-covered by the 3 to 30 g CO_2e / MJ used in the various Cases. Within this range, closer study or better data are definitely required but they are outside the scope of this report; an expert panel working group is currently looking to improve this estimate for CARB. Besides LUC, the biggest difference between the Cases is the Production /

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Processing Activity; however each Activity changes to some degree and the totals for each Case are quite different.

It is possible that one Case contains the "best" estimate for a particular activity or set of activities, but not all of them. One way to investigate this is to simulate a probability distribution function for the total life cycle emissions, using the @RISK plug-in for Excel.

As statistical studies of large numbers of actual ethanol plants are not available in the literature, the actual distribution of ethanol plant GHG performance is unknown. Here, the @RISK input parameters are Ag. Chemical Production, Processing / Production, Credit for Co-Products, and Land Use Change. These Activities are modelled with assumed triangular distributions for the minimum, maximum and most-likely values given by the minimum, maximum and average activity value from the 4 Cases, assuming the Cases are representative. Triangular distributions are commonly used for assessments where the range is known, data points are few, and the mean and mode may not necessarily be equal. Only these four input Activities were modelled in @RISK as the other Activities did not differ materially between their minimum, maximum and average values. The 95% confidence interval for the total life cycle GHG intensity can be estimated from this probability distribution as well as the minimum and maximum values. The results of the @RISK simulation are shown in Figures 6 and 7 below:
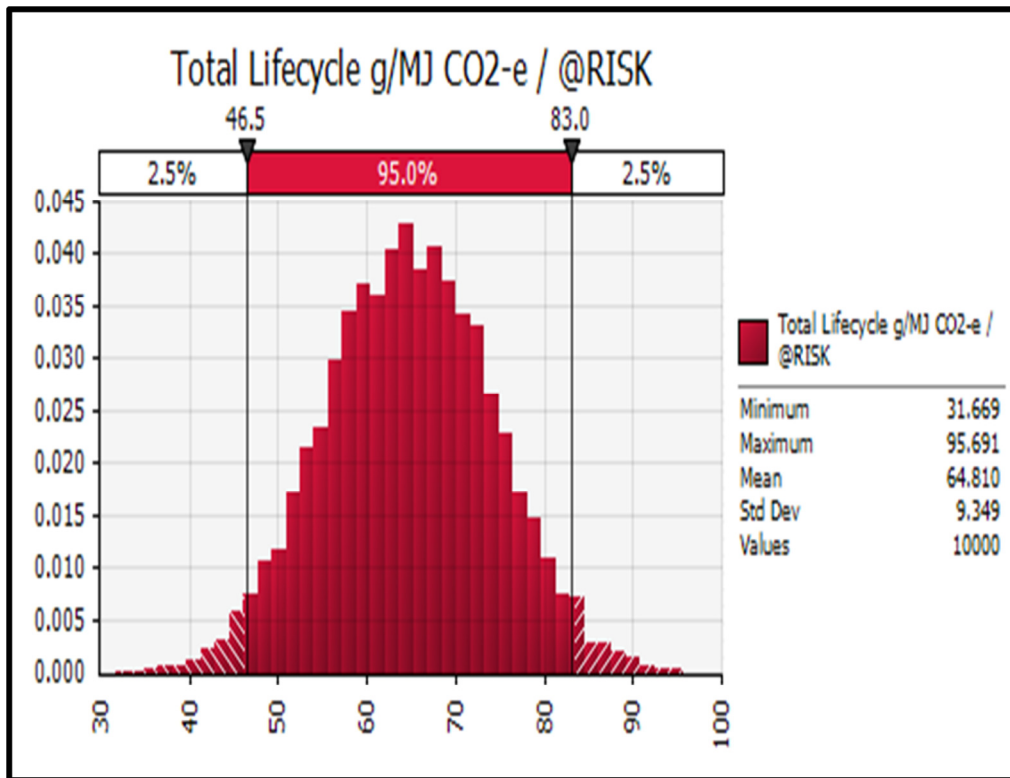
Figure 7: Total Ethanol Life Cycle Probability Distribution Function
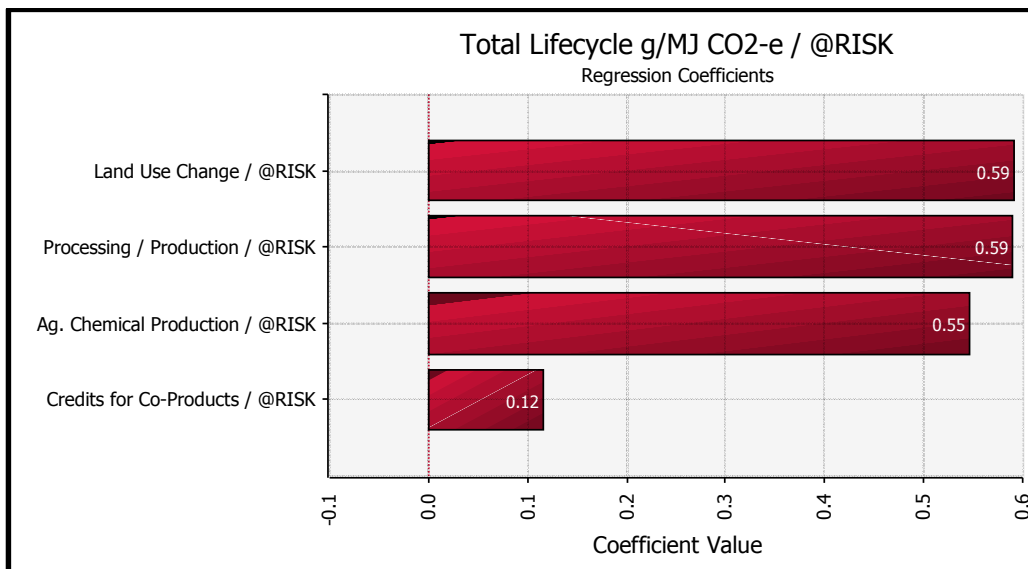
Figure 8: Life Cycle GHG Impact Regression Coefficients

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The resulting distribution is roughly Normal around a mean of 65 g CO_2e / MJ, Standard Deviation of 9 g CO_2e / MJ, and a 95% Confidence Interval between 47 and 83 g CO_2e / MJ. The minimum and maximum values were 32 and 96 g CO_2e / MJ, respectively. This can give us further confidence that the life cycle emissions of dry-mill ethanol are indeed lower than the 97.6 g CO_2e / MJ calculated by CARB.

To give more confidence that the range covered by the assumed distribution is accurate, additional Cases from other studies (i.e. Unnasch et al 2011) can be added to the @RISK evaluation, or other distributions can be modelled. For example, if the four input distributions are assumed to be Normal instead of Triangular, the output is slightly Lognormal with a mean of 66 g CO_2e / MJ, a mode of 65 g CO_2e / MJ and 95% confidence interval between 59 g CO_2e / MJ and 72 g CO_2e / MJ. Lognormal input distributions give a mean and mode of 65 g CO_2e / MJ and a 95% confidence interval that the true value is less than 75 g CO_2e / MJ.

The regression coefficients from the Sensitivity Analysis show that the impacts of varying the LUC and Processing / Production emissions are approximately equal and Ag. Chemical Production is not far behind. These Activities have the most significant impact on the overall total GHG footprint, so more attention should be paid to these activities in future studies.

2.3.3   LCA Insights and Recommendations

Simply by displacement of conventional transportation fuel such as modern Reformulated Gasoline (RFG), bioethanol fuel can reduce life cycle CO_2e emissions by $40 - 60$ g CO_2e / MJ depending on the agricultural practices used, credits assigned to co-products, production facility energy sources, and the direct and indirect land use changes caused by the additional farming.

Using pre-built models like GREET and GHGenius are useful for finding and applying large amounts of pre-gathered data quickly, but often this comes at the cost of transparency. The evaluator is not as intimately familiar with every data point as they are when they gather all the data themselves. Also, the structure of the programs tends to limit the scope of the study; the maxims "you don't know what you don't know" and "when you have a hammer, every problem is a nail" definitely apply. However, using two independently-developed models helps to limit the possibility of common errors or unreasonable data that can impact the final outcome.

Any future iterations of this study need to take the time to fully understand the root source of all inherent assumptions and default values that influence the final results. Future studies may also wish to separate each activity emissions into CO_2, CH_4 and N_2O species (and others if significant) to see if there are any species-specific opportunities for improved GHG performance.

Using EIO-LCA, future studies may want to investigate the Power Generation and Supply, Oil and Gas Extraction, and Petroleum Refineries activities since they show up as numbers 3, 5, and 6 out of the top 8 activities in the EIO-LCA database, and should be disaggregated for clarity.

The regression coefficients from the Sensitivity Analysis show that the impacts of varying the LUC and Processing / Production emissions are approximately equal and Ag. Chemical Production is not far behind. More attention needs to be paid to these activities in future studies. Site-specific factors such as transportation distances (distance from farm to ethanol plant, and ethanol plant to refinery blending terminal) and LUC resulting from site selection, as well as plant process design from technology selection, will all have a direct impact on the life cycle impacts of the plant.

2.3.4 Conventional Corn Ethanol Policy Recommendations

Governments and regulators should allow corn-based ethanol as an acceptable means to comply with Low Carbon Fuel Standards, and encourage further development of this alternative fuel source.

Suppliers of corn-based ethanol could seek to have their products certified as a "net life cycle GHG reduction product" by an external auditor or verification body, and perhaps create an industry standard for "low-GHG ethanol" to ensure fair treatment of their product by jurisdictions implementing an LCFS, RFS or similar legislation. It is already

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possible to apply individually for a CARB modified or new fuels pathway, but this is very specific to the individual fuel producer [64].

2.3.5   Qualitative Discussion of Land Use Impacts

Direct Land Use Impacts are reasonably easy to calculate and are included in most LCA software databases. These include carbon released from native vegetation and soil when forest or other undisturbed land is cleared for new farm land meant to grow corn for ethanol. However, Indirect Land Use Changes (ILUC) are due to impacts outside of the project boundaries when land is used to grow corn and the services that the land used to provide (ie. agriculture, recreation, forest, etc.) are displaced to another external location, which causes direct impacts at the external third-party location. Ranges and uncertainties for ILUC are wide and therefore accurate, precise measurements are not impossible. Evaluation of ILUC is an exercise in estimating what someone else has *probably* done because of your actions compared to what they *might have* done if you had not acted, and is inherently subjective. Nonetheless it is possible to discuss some guiding principles to help decide which end of the range should be used, and when.

As with all impacts, the actual ILUC impact will vary from site to site and project to project. Displacing rainforest or old-growth temperate forest to create new farmland for food crops displaced by corn for ethanol will have high impacts. Increasing the yield on existing fallow or marginal farmland will have almost no land use impact. Any attempt to quantify ILUC in a broader, more general way will come up with a range than

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encompasses both minimal and highly negative impacts. Which end of the range a study

chooses should be based on site-specific factors and not personal opinion.

Recent policy papers do a good job of quantifying "potential" agricultural impacts [65],

but this cannot be extrapolated to all ethanol operations everywhere. For example, some

studies state that "Based on this assessment, *and the assumptions adopted*[2], use of

additional conventional biofuels up to 2020 on the scale anticipated in the 27 NREAPs

would lead to between 81% and 167% more GHG emissions than meeting the same need

through fossil fuel use" [66] . However, care must be taken to note when a paper is

referring to the extreme upper and lower boundaries of the results, and the entire study

needs to be investigated in depth in order to deduce the most likely outcomes. Authors

often aim to be thorough to cover the entire possible range of a problem; just because a

paper contains a scenario does not mean that the author endorses that scenario as likely or

even plausible. Like all technologies, if executed poorly biofuels have the potential for

negative consequences but that does not mean that negative consequences are the norm.

The assumptions embedded in the analysis have a great deal of influence on the results of

an ILUC analysis.

While it is true that "According to the International Energy Agency (IEA), most

conventional liquid biofuels such as ethanol produced from purpose-grown corn and

biodiesel made from oilseed crops will have to significantly improve the efficiency of

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[2] Emphasis is mine.

land use and ramp up the processing efficiency to achieve any substantial reduction in greenhouse gas emissions." [67], it can be shown that this is actually occurring, at least in North America.

Actual land used for farming has gone down in the US between 1990 and 2000; according to the EPA, "In 1990, there were almost 987 million acres in farms in the U.S., that number had been reduced to just under 943 million acres by 2000." [68], so any contention that additional corn farming has removed farmland from the production of human food is incorrect, as well as the idea that new farmland must be cleared from existing forest. Total farm acreage peaked at just under 1.2 billion acres around 1950, and has decreased every decade since as per Figure 8 below:
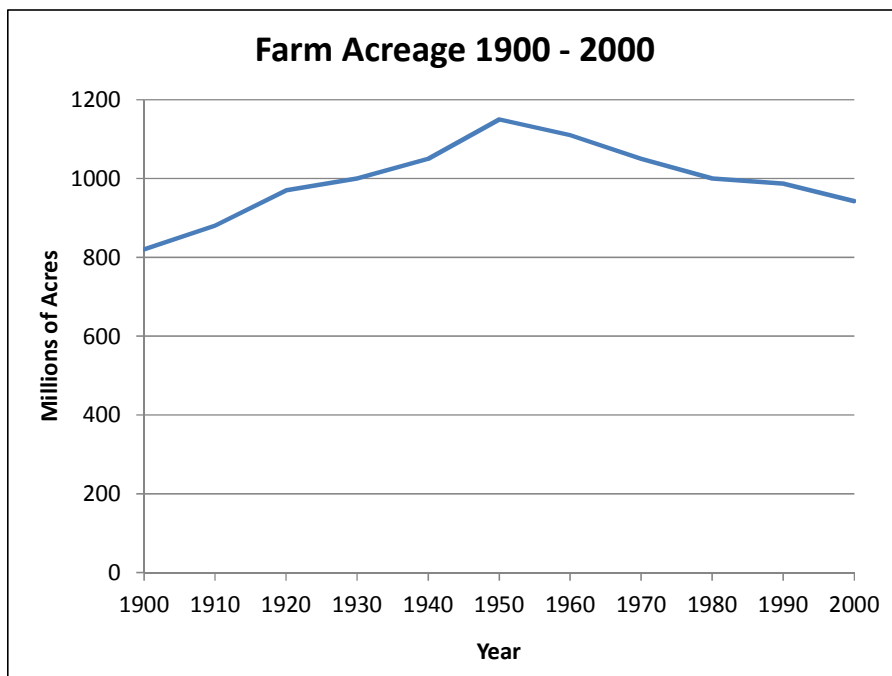
Figure 9: Farm Acreage 1900-2000 [69]

Instead, the additional corn supply has come mainly from an increase in yearly average yield, from 127 bushels per acre in 1997 to 151 bushels per acre in 2007, and has the potential to double to 300 bushels per acre before 2030 [70]. This is due to improvements in farm management of insect stress, prevalence of disease, invasive plants, and "optimum cultivar nutrition" [71].

Because ethanol production uses livestock-grade corn, it does not lower the supply or increase the cost of corn for human consumption. Food grade corn is high-grade corn meant for human consumption and has always been uneconomical to feed to livestock. The key differences are texture and flavour, but livestock grade corn is very nutritious for animals even though it does not appeal to the human palate.

Livestock grade corn is not offered for sale for consumption by humans, so they trade on separate markets and the prices are not directly linked, other than being susceptible to the same growing conditions such as rainfall and sunlight. The St. Clair plant in Case 4 uses a variety of livestock grade corn sourced through a broker from an area within a 100 mile radius around the plant. A farmer may decide to grow more of one grade than the other, but if sufficient farmland is available then on average enough of each grade will be grown to supply both markets.

It may have some impact on cattle prices due to increased feed costs, but as most of the nutrition and 28% of the food energy stays in the DDGS by-product, this may not be

significant. Beef prices have increased 26% over the past 10 years [72] which may sound high but this represents an annual price increase of only 2.3%. Over the same period, the base Canadian Consumer Price Index (CPI) has risen by a cumulative 23% and is currently tracking at 2.54% for 2012 [73]. The majority, some 65 to 80%, of the consumer retail costs for beef are in the processing, transport and marketing of the final retail product and not in cattle farming [74]. The life cycle impact will be further reduced for second-generation biofuels that use none-edible plants and waste from food crops such as corn-stover and wheat straw. Such uses should make food farming more profitable and potentially reduce the cost of food for human consumption.

We have been able to quantify the GHG footprint for corn-based ethanol by developing four Cases for possible ethanol fuel pathways. It appears that there are potential bioethanol pathways that have a lower GHG footprint than RFG, and they may be low enough to justify policy and regulatory incentives. Sufficient accounting methods and databases exist to deal with the gaps encountered while doing site-specific studies. The key factors that determine if corn-based ethanol can be a low-GHG fuel are Land Use, Processing / Production emissions and Ag. Chemical Production.

3.0 Technological Assessment and Life Cycle Impact Discussion

Research Question:

What improvements can be made to the life cycle performance of biofuels?

This Chapter gives the background and attributes of each of the technologies included in this analysis as well as the methods used to assess them. It is a qualitative discussion of the technology opportunities to improve the life cycle GHG footprint of corn based ethanol. Some numbers are given for context, but most scaled up macro numerical analysis results are found in the following Chapter. The last section compares net-negative GHG ethanol with other fuel pathways in order to gauge the relative attractiveness of the net-negative ethanol opportunity.

3.1 Methods

There are only a small number of commercial technologies currently available to reduce GHG emissions, although there are many more under development [75]. Some technologies displace high-CO_2 fuels with lower or zero net carbon alternatives, while some technologies capture the CO_2 from conventional fuels either before or after combustion. It is important that the life cycle GHG impact is considered and not just the direct emissions. For example, hydrogen produced from natural gas feedstock has zero tailpipe emissions but produces large amounts of CO_2 during the typical conversion processes from CH_4.

There are a number of technologies which have the potential to reduce the life cycle GHG footprint of biofuels during their production process. The ones being assessed in this Chapter are included in Table 3 below:

Table 3: GHG Reduction Technologies for Ethanol Plants

Technology	*Key Attributes*
Fermentation CCS	Capture and geological sequestration of the pure CO_2 off-gas stream which results from the fermentation process. Since it starts with pure CO_2, capture facilities are simple and inexpensive.
Combustion CCS	Capture and geological sequestration of the dilute CO_2 stream in the fired heaters flue gas exhaust. The primary fuel can be fossil fuels, biomass or a mixture. The diluted nature of the CO_2 stream means that additional complex and expensive equipment is required.
Biomass Combustion for Process Heat at Ethanol Plants	Burning either 100% biomass in a new boiler or a slip-stream of up to 10% along with the main (usually fossil) fuel in an existing boiler. The boilers themselves may not require capital upgrades for partial co-firing although some equipment is needed for solids biomass fuel handling, conditioning and delivery to the burner.

For specific reduction technologies, it is useful to see their impacts on a single specific area or facility such as the St. Clair facility studied in Chapter 2; this will serve as our base case. Potential improvements will be compared both on relative carbon intensities in "g CO_2e / MJ" and also an absolute basis when comparing to GHG targets and national or provincial

potentials. Caution must be taken when extrapolating to other facilities in other locations – site specific results are just that, specific to the site under study. With that said, a site specific study can show that a certain pathway is possible under a given set of conditions. From the data available, overall carbon intensities for large Canadian ethanol plants are approximately the same as what is seen at St. Clair[3].

3.2 Background and Introduction of Mitigation Technologies

Besides the GHG avoided by burning bioethanol in place of regular reformulated gasoline, there are other opportunities to reduce the GHG footprint of biofuels for every MJ of energy provided.

If more CO_2 from biofuel Activities can be either avoided or captured before they enter the atmosphere, it may be possible to have a net-negative process whereby not only are we avoiding putting more CO_2 into the atmosphere for a given amount of energy used, we would also be removing CO_2 already present in the atmosphere. This is one way to reduce the existing stock of atmospheric CO_2 while providing for the energy needs of society. In effect, it would be "air capture" of CO_2 using plants as the medium and photosynthesis with fermentation and CCS as the process.

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[3] Please see Table 8 in Chapter 4.4. Adapted from CRFA Canadian Renewable Fuels Alliance, Nov. 2010; http://www.greenfuels.org/en/industry-information/plants.aspx; and Environment Canada, GHG Reporting 2010; http://www.ec.gc.ca/pdb/ghg/onlineData/dataSearch_e.cfm.

Chapter 2 shows that the 2009 CARB LCFS results found their Dry Mill ethanol LCA Case to be slightly worse than regular reformulated gasoline (RFG). However the Chapter 2 GREET and GHGenius results show 44% and 42% life cycle GHG reductions, respectively, for Southern Ontario while the St. Clair results shows an approximately 60% GHG reduction, in line with the results of a confidential third party evaluation done in 2007 using a different method [76]. As much as 10% ethanol can be burned in conventional internal combustion engines without damage, which allowed Low Carbon and Renewable Fuel Standards to achieve their mandates in several jurisdictions.

Once fermentation CCS is implemented, St. Clair bioethanol becomes a nearly-neutral fuel with a life cycle footprint of approximately 4 g CO_2e/MJ. Combustion emissions are a smaller and more expensive opportunity; at St. Clair about 19 g CO_2e / MJ are available for capture. Thus, 100% combustion emission CCS could remove another 19 g CO_2e / MJ of pure ethanol (1 g CO_2e / MJ for 5% ethanol blends) but at a much higher cost per tonne. If both fermentation and combustion CCS are implemented, St. Clair ethanol would become a net-negative fuel (-15 g CO_2e / MJ) that removes CO_2 from the atmosphere for every litre of ethanol burned.

Biomass combustion for process heat at ethanol plants is an application of biofuels whereby some volume of biomass, usually a waste stream such as wheat straw, corn stover, or sawdust is fed into the same boiler or heater as the regular fuel (e.g. coal) to displace some of this fuel and the resulting GHG emissions. Many studies have shown that a significant

fraction of fuel can be displaced by co-firing in existing large facilities [77] without the need for capital upgrades, making this not only beneficial for GHG emissions reduction but often economical as well [78]. Biomass co-firing can easily be done at bioethanol plants which require significant heat inputs to drive the process; 10% co-firing with biomass or other renewable fuels could make a 1 to 2% improvement per litre of pure ethanol burned, which translates to only 0.1 to 0.2% improvement for a 5% ethanol / gasoline blend. Burning 100% biomass would require a purpose-made boiler and displace 90% of the combustion emissions on a life cycle basis, or another 17 g CO_2e / MJ of ethanol.

The results of this study show that it is possible for at least some ethanol production pathways to show significant GHG reductions over regular reformulated gasoline, and even reach net-negative status with the help of CCS.

3.3 Suitable CO_2 Reduction Technologies

Below are further details on the three GHG reduction technologies which may help to reduce the GHG intensity footprint of corn based ethanol – fermentation CCS, combustion CCS, and biomass combustion at ethanol plants.

3.3.1 Carbon Capture at Ethanol Plants

Fermentation CO_2 captured and stored in a CCS scheme can remove a large portion of the life cycle CO_2 footprint of corn ethanol. For every million litres of ethanol

(23,580,000 MJ of energy) produced, 750 tonnes of pure CO_2 from fermentation is returned to the atmosphere under ideal molar stoichiometric conditions [79], but this can vary due to the biological nature of the yeast cultures involved. At St. Clair, actual observed fermentation CO_2 is typically 780 tonnes per million litres of ethanol. If this CO_2 could be captured and sequestered, it would remove another 33 g/MJ from the life cycle footprint. Together with combustion CCS reductions of 19 g CO_2e / MJ, the total possible reduction is 52 g CO_2e / MJ which is 15 g CO_2e / MJ more than the total net LCA value in the St. Clair Case 4 in Chapter 2. This is a "net negative" scenario whereby we are actually removing 15 grams of CO_2 from the atmosphere for every MJ of energy consumed, thus the total CO_2 reduction in this scheme is greater than 100%.

For fermentation emissions, there is no requirement for capture process equipment like amine contactors, rich solution regenerators, heaters / boilers or solvent pumps, since the stream is already pure CO_2. However, as with all CCS schemes energy is required to compress the CO_2 into a dense phase liquid and sequester it at reservoir pressure. It is useful to put the energy loss in terms of an energy penalty in GJ/GJ and also GJ/tonne in order to compare it to other CCS schemes. For fermentation CO_2 injection, the only energy required is to dehydrate and compress the CO_2 to a dense phase liquid. The critical point for CO_2 phase behaviour is around 7,400 kPa-a at 30 C [80] but injection pressures are typically maintained over 8,274 kPa-a (1,200 psi-a) [81] to provide for a safety margin and prevent two-phase flow.

From the Life Cycle Cases in Chapter 2 above, in order to produce a million litres of ethanol between 270 and 900 tonnes of Processing / Production CO_2 emissions are created, the vast majority of which come from combustion of fossil fuels for process heat or a small amount of electrical generation. The St. Clair ethanol plant is in the middle of this range at 480 tonnes of Processing / Production CO_2e emissions, including 440 tonnes of combustion CO_2 emissions per million litres of ethanol which equates to approximately 19 g CO_2e / MJ of fuel produced. These combustion CO_2 emissions are generated in combustion devices like heaters and boilers. A traditional first-generation bioethanol plant typically has one large direct-fired heater called a Heat Recovery Steam Generator, or HRSG.

In order to capture CO_2 from the heater and boiler flue gas, and regardless of the input fuel type, combustion CO_2 emissions must be separated from the other components in combustion air or exhaust in order to meet CO_2 purity specifications. The two main options are to separate the components either pre-combustion (oxy-firing, chemical looping combustion, gasification, etc.) in the fuel or air stream or post-combustion (amine solvents, solid sorbents, membranes, etc.).

Capture technologies for combustion CO_2 include developing pre-combustion technologies such as chemical looping combustion, or else proven but expensive post-combustion technologies like liquid solvents or solid sorbents for fossil or co-fired biofuels. Post-combustion capture of the natural gas heater flue gas stream using traditional amines or carbonates is energy-intensive due to the low concentration of CO_2

in the flue gas (4 – 6%), and improvements are expected to be incremental rather than step-change due to the maturity of the technology.

The surface and downhole equipment used in general CCS applications are already well-understood in the process industry – contactors, regenerators, heaters, compressors, pipelines, and injection wells have all been in use for nearly 100 years in the petroleum and chemical processing industries. In fact, the practice of pure CO_2 injection into depleted oil reservoirs for enhanced oil recovery (EOR) has been used for at least 35 years [82] and offers a promising early opportunity to sequester CO_2 quickly and economically before CCS for sequestration becomes economical. Most EOR CO_2 is produced from natural CO_2 reservoirs specifically for this purpose, as it is currently much less expensive that capturing anthropogenic CO_2.

Acid Gas Injection (AGI) is another technology that is analogous to general CCS in many ways, in that it uses the same types of process equipment, pipelines and compressors to inject mixtures of hydrogen sulphide and CO_2 into geological formations. This is done to natural gas processing plant "acid gas" from the amine unit as an alternative to sulphur recovery, due to the low and volatile sulphur price seen in North America over the past 15 years. In Alberta, acid gas injection [83] has been done for over 40 years despite the presence of highly toxic and corrosive H2S which makes this a much more challenging application than CCS.

Economically, typical combustion CCS applications have been estimated to be a relatively high-cost but high-volume CO_2 reduction technology, with estimates ranging from $85.00 - $150.00 per tonne or more for post-combustion capture. However, it has also been estimated that CCS will lower the cost of global GHG abatement by 70% over the base case where CCS is not used [84]. A great deal of research is underway into novel CO_2 capture technologies with the goal of drastically reducing the cost of CCS [85,86]. In any case, CCS is a legitimate reduction opportunity that should be considered.

A better combustion CO_2 CCS opportunity for a large biofuel plant may be to use oxy-fired natural gas burners whereby the single large process heater fuel is combusted using pure oxygen instead of air. The resulting flue gas stream is pure CO_2 and water vapour which would only require filtration, dehydration and compression which could be shared with a fermentation CO_2 stream.

The mass flow and heat transfer rates are obviously much different when the other atmospheric components are removed including nitrogen which makes up 79% of the combustion air flow. Therefore oxy-firing requires either a new purpose-built heater or else significant exhaust gas recycle volumes to maintain heat transfer rates and temperatures.

The major costs are the capital cost of the front-end air separation plant and electrical energy cost required to run the plant, although that could be improved with further optimization and energy integration with the rest of the facility.

3.3.2   Biomass Combustion at Ethanol Production Plants

Biomass combustion may also have a role to play in displacing emissions from fossil fuels burned during bioethanol plant combustion. This could help to lower the overall life cycle footprint of an ethanol production pathway, passing the benefit on to the blended automotive fuel. Many papers have been written on the use of biomass co-firing for other fuels such as coal in power generation [87,88], and it will not be addressed in detail here. However the use of biomass for ethanol plant process heat is a much more specialized opportunity, although it has been the subject of some study [89]. There are also mechanical issues with co-firing solid fuels with liquid or gaseous fuels, so gasification may have to be considered even though it would add complexity and cost.

Agricultural residues such as corn stover (cobs, husks, stalks and leaves) are an interesting opportunity as they are the co-product of the main feedstock to the corn ethanol plant. Canada produces 3.5 million tonnes [90] or 62 – 67 million GJ (at a higher Heating Value of 17.57 - 19.02 GJ/tonne [91]) of harvestable corn stover biomass per year.

Wood pellets can be ground up and fed into ethanol plant boilers that can also handle solid fuels like coal or petroleum coke. In particular, torrefaction[4] produces wood pellets

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[4] See definition on Page xiii of this document.

that can be pulverized like coal and has the same heat content (20-24 GJ/tonne versus 17-28 GJ/tonne for coal [92]). Canada has the capacity to produce 2.9 million tonnes [93] or 58 - 70 million GJ of wood pellets per year, although actual output will vary from year to year.

Lignin is a by-product of second-generation cellulosic biofuels plants which use agricultural wastes to make bio-ethanol. Typically the cellulosic biofuels plant can produce enough lignin to fuel its own needs plus export a surplus amount for external users. A second-generation biofuels plant co-located with a first-generation biofuels plant could help reduce the combustion emissions of both plants by using lignin fuel with 13.21 GJ / tonne [94] heat content. Currently Canada does not produce commercial quantities of lignin from cellulosic biofuels plants but it may be an interesting topic for future research.

St. Clair's combustion emissions of 440 tonnes of CO_2 equates to 235,000 m^3 of natural gas fuel used or 8,000 GJ of process heat required to produce a million litres of ethanol. To replace this fuel gas with 100% biomass, St. Clair would need 300 – 400 tonnes of torrefied wood pellets, 610 tonnes of lignin or 420 – 460 tonnes of corn stover for each million litres of product. However, the ash from 100% biomass combustion is reactive and the heater will have to be designed to that specific fuel only. This is often not economic due to higher capital costs, lack of fuel flexibility, and fuel availability concerns. It is possible to design, build and operate a boiler that runs exclusively on 100% biomass, but the metallurgy will have to be specific to that particular feedstock

leaving it susceptible to supply disruption risk if that feedstock is not available [95]. This lack of fuel flexibility can seriously harm the economics of any biomass combustion facility.

Often 10% biomass co-firing is economic since it can usually be done without expensive capital upgrades to existing equipment. Biomass could conceivably displace 10% of the ethanol plant heater and dryer fuel inputs if a co-firing scheme is implemented, depending on the biomass species, ash chemistry and specific boiler metallurgy. At higher percentages the alkali content of the ash may cause excessive corrosion and premature failure of the boiler. Any plant that takes delivery of feed-grade corn would be able to take delivery of the associated waste biomass, known as corn stover. After some conditioning, corn stover can be co-fired alongside fossil fuels in existing combustion equipment. Corn stover co-firing could use the same transportation and receiving infrastructure as corn inputs, so impact on cost and the environment could be minimal.

Obviously the economics depend on the price for the biomass when in turn depends on what type of biomass is available, how much preparation it needs, capital required to purchase equipment, and how far it has to be shipped to get to the boiler or heater.

3.3.3   Comparison with Alternative Net-Negative Mitigation Options

Direct capture of CO_2 from ambient air is another technology that can be used to actually lower the concentration of CO_2 in a net-negative manner. While it is already possible to

physically capture CO_2 from ambient air using existing technology, research is ongoing to find technologies and niches where the economics are favourable and the energy penalty not prohibitive [96,97]. If the captured CO_2 can be used for valuable products or services like EOR, chemicals or synthetic fuels, or the energy inputs are inexpensive and environmentally benign, there may be a market opportunity for successful air capture schemes. However biomass CCS actually produces fuel energy for every gram of CO_2 sequestered, so in addition to having a net-negative carbon balance it has a negative energy penalty as well. Issues of scale-up are applicable to both technologies, and not enough is known about future process design to know if significant material volumes can be obtained and sequestered via bulk air capture.

Current estimates for air capture range from $600 per tonne [98] to $1,000 per tonne [99], although recent work has shown that the cost for contacting, which is normally half the cost, could only be $60 to $95 per tonne [100]. If the regeneration cost is assumed to be $300 to $500 per tonne as per above, then the total cost could be between $360 and as high $600 per tonne using current technology, with the potential for improvements inherent in all immature technologies.

Conversion of atmospheric CO_2 to biomass using algae may prove to be both beneficial for climate change considerations and economics, but it is still unproven and will not be net-negative unless some of the captured carbon is left unburned. Using biochar as a soil amendment will prevent organic carbon from re-entering the carbon cycle, but no-one has

yet built a profitable commercial operation at significant scale, so more work is required to further investigate this opportunity.

3.4 Analysis of Reduction Technology Maximum Life Cycle Impact

This section contains further analysis of the life cycle impacts of the three GHG reduction technologies discussed earlier. Fermentation CO_2 CCS can remove 33 g CO_2e / MJ, while combustion emissions of 19 g CO_2e / MJ can be offset in one of two ways – either with combustion CO_2 CCS, or else with 100% biomass combustion. It is also possible to do both and install CCS on a GHG-neutral biomass combustion stream, thereby removing even more biological CO_2 from the existing atmospheric stock. Therefore in order to estimate the maximum potential reductions, combustion CO_2 CCS and biomass combustion are shown as additive even though they are deployed on the same process unit.

The 100% biomass combustion case is shown here to demonstrate the maximum life cycle potential of biomass, even though the 10% co-firing case is most likely to be implemented – it is discussed more fully in Chapter 4. Full 100% biomass combustion is only calculated to be 17 g CO_2e / MJ or a 90% reduction over the full 19 g CO_2 / MJ, reflecting the fact that the biomass fuel life cycle is not completely GHG neutral. The net total from the LCA Case 4 (St. Clair site-specific) is only 37 g CO_2e / MJ, so fermentation CO_2 gets the footprint to nearly neutral, and the combustion CO_2 stream technologies can carry it quite far into a net-negative position.

Below in Figure 9 is a modified version of Figure 4 from Chapter 2 wherein the St. Clair base case (Case 4) is shown next to the abated base case, which is St. Clair minus the reductions listed in the paragraph above. Regular reformulated gasoline (RFG) is also shown for context. The emissions in g CO_2e / MJ of bioethanol produced are given for each main Activity, and the abated Case also adds in the emissions reductions for the three technologies under study.
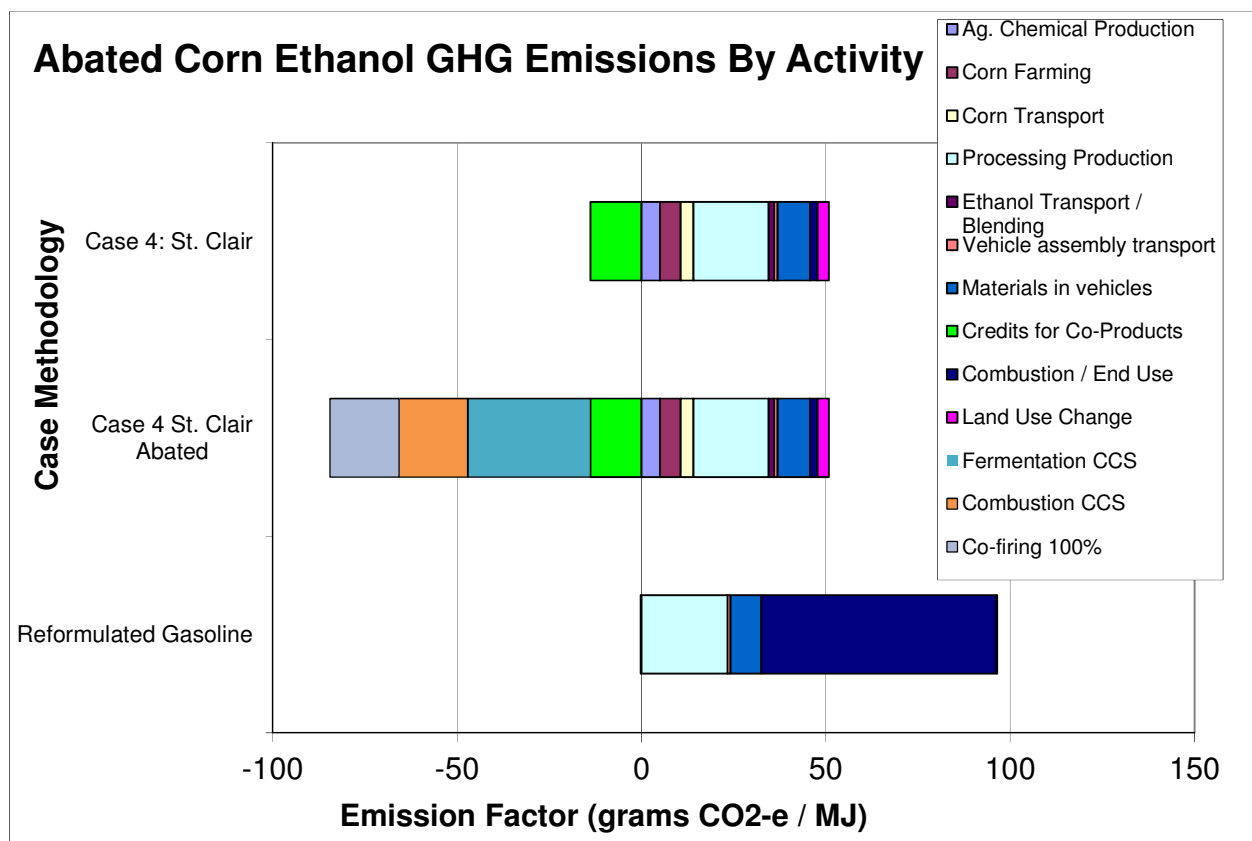
Figure 10: Abated Corn Ethanol Emissions by Activity

The numerical values in tonnes per million litres of ethanol can be found in Table 4:

Table 4: Abated LCA Material Flows

Stream	A	B	C	D	
Activity Name	Blended E95 Fuel	Denatured Ethanol	Corn	Co-Products	
Units	litres	litres	kg	kg	
Common Values	20,000,000	1,000,000	2,266,026	742,911	

Stream	E	F	G	H	I
Activity Name	Ag. Chemical Production	Corn Farming	Corn Transport	Processing Production	Ethanol Transport /Blending
Units	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e
Reformulated Gasoline	0	0	0	816	0
Case 4 St. Clair Abated	119	133	82	481	35
Case 4: St. Clair	119	133	82	481	35

Stream	J	K	L	M	N
Activity Name	Vehicle assembly transport	Materials in vehicles	Credits for Co-Products	Combustion / End Use	Land Use Change
Units	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e
Reformulated Gasoline	30	289	-6	2212	0
Case 4 St. Clair Abated	22	208	-327	49	71
Case 4: St. Clair	22	208	-327	49	71

Activity Name	Fermentation CCS	Combustion CCS	Co-firing 100%	Total Net GHG to Atm.
Units	t CO_2e	t CO_2e	t CO_2e	t CO_2e
Reformulated Gasoline	0	0	0	3340
Case 4 St. Clair Abated	-783	-440	-396	-748
Case 4: St. Clair	0	0	0	872

For Stream definitions, please refer to the flow sheet in Appendix 1.

In order to show more visually the different Activities that contribute to the footprint of abated St. Clair ethanol, the Activities are arranged in order of decreasing absolute value and plotted on a tornado diagram in Figure 10 below. It is possible to see at a glance that the magnitudes of the reduction technologies are large enough to counter-balance the emissions from producing the ethanol. Even with a worst-case scenario land use change value of 30 CO_2e / MJ instead of 3 g CO_2e / MJ, it is still possible to get to a net-negative state.
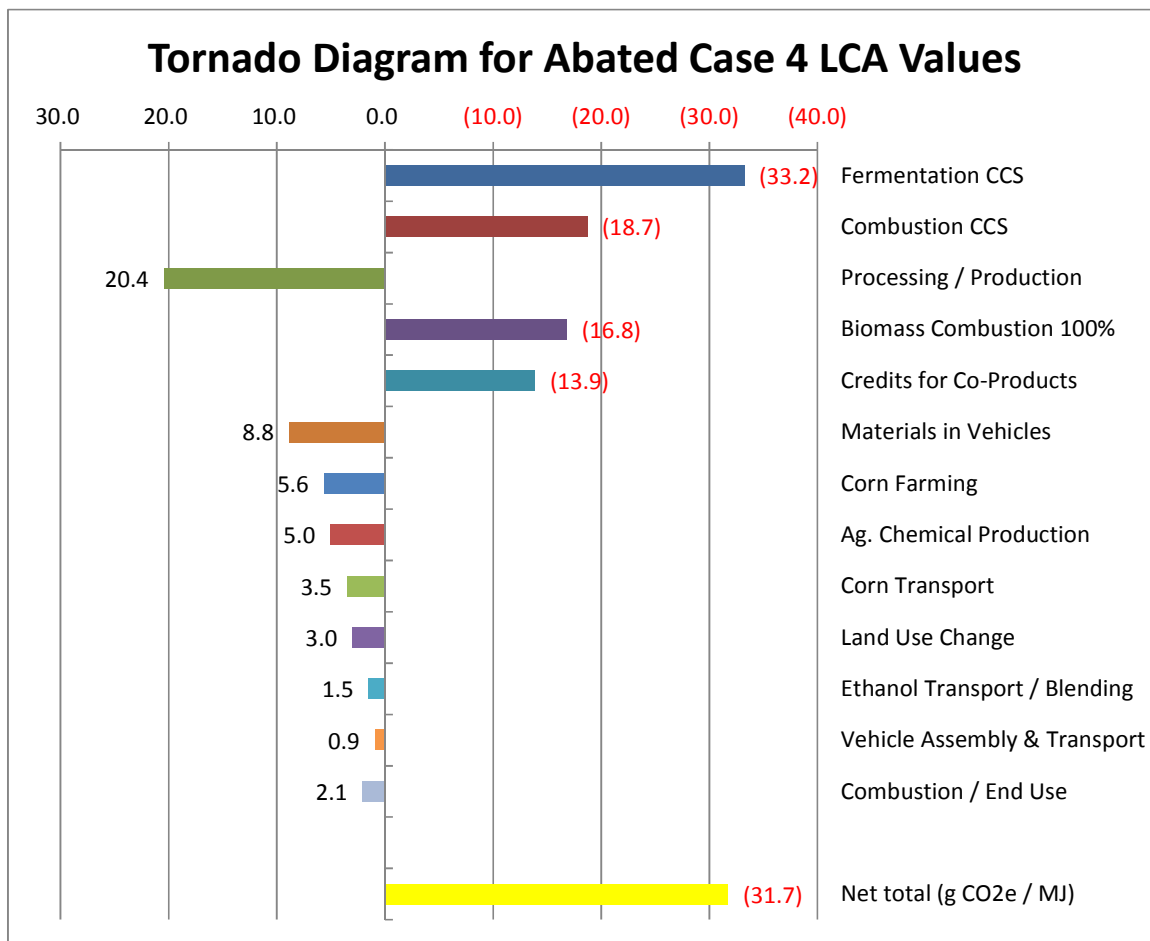
Figure 11: Tornado Diagram for Abated Case 4 LCA Values

Numerical values for the tornado diagram are given in Table 5 below:

Table 5: Abated Case 4 Life Cycle Activities

Activities	*CO$_2$e intensity*
Fermentation CCS	(-33.2)
Combustion CCS	(-18.7)
Processing / Production	20.4
Biomass Combustion 100%	(-16.8)
Credits for Co-Products	(-13.9)
Materials in Vehicles	8.8
Corn Farming	5.6
Ag. Chemical Production	5.0
Corn Transport	3.5
Land Use Change	3.0
Ethanol Transport / Blending	1.5
Vehicle Assembly & Transport	0.9
Combustion / End Use	2.1
Net total (g CO$_2$e / MJ)	(-31.7)

The strong potential for net-negative ethanol fuel is apparent here, but we now have to

estimate the costs of these technologies as well as their absolute reduction opportunity

compared to relevant reduction targets, or at the very least notional reduction aspirations where no targets exist.

4.0 Potential Impacts of Low GHG Footprint Corn Ethanol

Research Question:

What are the potential life cycle GHG reductions over business as usual, specifically in Ontario?

How does this compare to their short and long term reduction goals?

What are the costs, trade-offs, and competitive position of biofuel carbon abatement?

In this Chapter, the broad results of the numerical analysis are scaled up to a macro level and given in both GHG reduction and economic impact terms for all three technologies included in this analysis – bioethanol combustion (blending), bioethanol plant CCS, and bioethanol plant biomass combustion. The absolute and life cycle GHG reductions are given in Mt of CO_2e and g CO_2e / MJ, and the economics are shown in terms of $ per tonne and as a cost burden per litre and kilometre driven.

4.1 Methods

The technologies introduced in Chapter 3 are quantified and compared to the magnitude of the available CO_2 storage area in selected locations. The opportunities are also compared on an economic basis to determine how they rank with other GHG reduction opportunities.

GHG reductions from bioethanol combustion (blending with gasoline) are calculated as the amount of gasoline vehicle emissions avoided by burning the current production of ethanol on a global, Canadian and Ontario provincial basis. Economic factors for bioethanol

combustion are the incremental cost to produce fuel on a GJ of transportation energy basis, translated to a cost per tonne of CO_2 avoided.

GHG reductions from bioethanol CCS are estimated by approximating the proportions of fermentation and combustion CO_2, and discussing the possible Canadian and Ontario locations for bioethanol (and other nearby high-CO_2 concentration streams) CCS. Economic factors for bioethanol CCS are shown for capture, transport and storage costs for both fermentation and combustion CO_2 CCS.

GHG reductions from biomass combustion at ethanol plants are estimated using existing Canadian corn stover and wood pellet volumes. Here, only the impact of 10% co-firing is calculated and not 100% combustion, as 10% is the most economical and therefore the most likely to actually be implemented [101]. Economic factors for biomass combustion CO_2 include a cost per tonne of CO_2e avoided value using the current wood pellet export market price.

4.2 GHG Reductions from Bioethanol Combustion

In the US it takes over 300 hectares (800 acres) of farm land to produce 2.6 MM kb (5.7 MM lb) of livestock-grade corn in one year, which is sufficient to produce 1 million litres of bioethanol [102]. Displacing world-wide gasoline consumption of 22 million barrels per day of gasoline [103] would entail 32 million barrels (5.2 billion litres) of ethanol per day, because of the lower energy content of ethanol compared to petroleum liquids. This would

require 620 MM hectares (1500 MM acres) of land to produce, which is over 100% of the total land under cultivation in the United States and nearly 13% of the total agricultural land in the world in 2008 [104]. In the US alone, gasoline demand of 8.74 MM barrels per day would require 750 billion litres per year of ethanol and 240 million hectares (600 million acres) devoted to growing high-yield corn, or 64% of the total US farm land available in 2000. The conversion of this much farm land to high-yield corn would cause massive indirect land use impacts, and is obviously impossible.

According to Chapter 2, US farm land peaked around 465 million hectares (1150 million acres) in 1990 and dropped to 380 million hectares (943 million acres) by the year 2000. This extra 84 million hectares (200 million acres) could be used to produce another 250,000 million litres of ethanol per year, or 700 million litres of ethanol per day equivalent to almost 3 million barrels of gasoline per day, without causing a net increase in the historical total land use due to farming. The true number depends on yield productivity which in turn depends on land quality and agricultural practices, but it is an interesting order of magnitude comparison.

According to Statistics Canada, in 2011 the Canadian consumption of gasoline was over 700,000 barrels (110 million litres) per day [105], or 3.9 billion MJ per day. Replacing 5% of that energy with energy from ethanol fuel would avoid almost 4.1 Mt of GHG per year at 60 g CO_2e / MJ (Case 4) decrease, or a 2.9 Mt of GHG at a 40 g CO_2e /MJ (Cases 2 and 3 average) decrease. These amounts are relatively significant and could offset the emissions of

3 to 4 Canadian large industrial site emitters, or up to 1 million passenger vehicles at 4 tonnes of CO_2e per vehicle per year.

In 2011, US gasoline consumption of 8.74 barrels (almost 1.4 billion litres) per day [106] of gasoline with a 5% ethanol blend would have an impact of over 51 Mt at 60 g/MJ reduction or 36 MT at 40 g/MJ reduction.

Globally 22 million barrels (over 3.5 billion litres) per day [107] of gasoline was consumed in 2010 with a potential 5% ethanol impact of almost 130 Mt at 60 g/MJ reduction or 91 Mt at 40 g/MJ reduction. These were roughly equal to the total GHG emissions of Algeria and Greece, respectively, in 2009 [108].

4.3 Economic Factors for Bioethanol Combustion

The cost to produce both biofuel and regular reformulated gasoline is confidential business information and not generally made public. However, there are some approximate numbers which we can investigate to estimate the cost of abating CO_2 using ethanol-blended gasoline. In 2007, the estimated net production cost (break-even price) for corn-based ethanol was approximately $1.58 USD per gallon [109]. This works out to $0.42 USD per litre of ethanol and $17.65 USD per GJ of ethanol fuel energy. The average USD – CAD currency conversion rate was 1.075 in 2007, so the cost to produce ethanol in Iowa in 2007 was approximately $19 CAD per GJ of energy produced.

For reformulated gasoline, the components of gasoline pumps prices are:

1. Crude costs

2. Refining and marketing costs

3. Taxes

4. Profit

The "base price" is comprised of crude costs, refining and marketing costs, and profit. In 2007, the average base price in Canada was $0.65 CAD per litre [110]. Profit is typically 1-3 cents per litre [111], so the gasoline production cost (crude costs plus refining and marketing costs) was therefore $0.62 CAD per litre. This works out to about $18 per GJ of gasoline fuel energy, so on average in 2007 it cost an extra $1.00 CAD to provide a GJ of energy using ethanol instead of gasoline.

For a million GJ of gasoline, the life cycle CO_2 emission savings are 59,000 tonnes of CO_2e at 95.86 g CO_2e / MJ (CARB 2009 assumed value) and 37 g CO_2e / MJ for Case 4 St. Clair ethanol; at an incremental cost of $l CAD per GJ or $1 million CAD per million GJ, the avoided cost is only $18 per tonne of CO_2e.

If we use 2007 ethanol market prices instead of break-even prices, the average is now $1.94 USD per gallon [112], with a premium of $5.50 CAD per million GJ, and an avoided GHG cost of $93 per tonne of CO_2e. This is getting close to the range of post-combustion capture and higher than any global carbon price yet seen.

4.4 GHG Reductions from Bioethanol CCS

Translating the quantity of pure fermentation CO_2 available for CCS to units of grams per MJ, it appears that the lowest-emission intensity ethanol pathway (Case 4) in Chapter 2 can achieve nearly neutral GHG footprint for pure ethanol. Including other higher-cost, lower concentration combustion CO_2 streams could improve the absolute and life cycle net-negative effects but worsen the economics by increasing the cost per tonne of CO_2 abated.

There are 23,580 GJ of transportation fuel energy in each million litres of ethanol produced. To compress the 780 tonnes or 420,000 m^3 of fermentation CO_2 from every million litres of ethanol up to a pressure of 8,274 kPa-a (1,200 psi-a [113]) injection pressure requires 18 kW (24 hP) of compression power or 570 GJ (159 MWh) of compression energy, for a GJ/GJ energy penalty of 2.4%, or 0.73 GJ / tonne CO_2 captured. If the reservoir requires a higher injection pressure such as 15,100 kPa-a (2,200 psi-a) the penalties only increase slightly to 2.8% or 0.85 GJ / tonne CO_2. This compares very favourably to CCS at a coal-fired power plant where the CCS energy penalty is typically 35-40% and the best achievable goal is thought to be 8% for economic utilization of CCS in this application [114]. Filtration, dehydration and compression are proven, low-risk and low cost technologies making this is an attractive capture opportunity.

From Table 8, there are almost 1.6 Mt of fermentation and combustion CO_2 emissions available for CCS in Canada, and Chapter 4.11.3 identifies over 150 Mt of ethanol emissions globally from current ethanol production levels. While these are not immaterial – each

megatonne represents the equivalent of a large industrial facility like a refinery or small electrical generation site, or 250,000 passenger cars – this is not enough at current bioethanol production levels to bend the global emissions profile down noticeably in the long term although it can help meet near-term 2020 goals.

4.5 Possible Locations for Bioethanol CO_2 Capture

Traditional first-generation corn ethanol plants in Canada are located in the locations shown in Table 6 [115], with capacities given in "millions of litres per year". Fermentation and combustion emissions are estimated based on proportions and energy requirements for the St. Clair ethanol plant. It is apparent that Ontario is by far the largest corn growing biofuel area in Canada. This is likely due to the simultaneous presence of significant automotive fuel refining activity and a mature healthy agricultural sector, as well as a response to Ontario's early adoption of a Renewable Fuels standard [116].

Table 6: Canadian Corn Ethanol Plants

Plant	City	Province	Feedstock	Emissions (t CO_2e/y)	Capacity (Million L/y)
GreenField Ethanol Inc.	Chatham / Tiverton	Ontario	Corn	297,000	222
Collingwood Ethanol LP	Collingwood	Ontario	Corn	67,000	58

Plant	City	Province	Feedstock	Emissions (t CO_2e/y)	Capacity (Million L/y)
GreenField Ethanol Inc.	Johnstown	Ontario	Corn	261,000	230
GreenField Ethanol Inc.	Varennes	Quebec	Corn	99,000	155
IGPC Ethanol Inc.	Aylmer	Ontario	Corn	65,000	162
Kawartha Ethanol.	Havelock	Ontario	Corn	*110,000* [5]	80
Suncor St. Clair Ethanol Plant	Sarnia	Ontario	Corn	*474,000* [6]	400
Husky Energy Inc.	Minnedosa	Manitoba	Wheat & Corn	195,000	130
		Totals	t CO_2e	1,570,000	1437
		Estimated	fermentation emissions	923,000	t CO_2e/year
		Estimated	combustion emissions	647,000	t CO_2e/year

The single largest plant in Canada is the Suncor St. Clair ethanol plant, which comprises 28%

of the total Canadian capacity and 30% of the associated emissions. By virtue of the

[5] Estimated from full plant ethanol production capacity, no emissions reported to Environment Canada in 2010.

[6] Updated to include fermentation emissions and the impact of twinning the plant in 2007.

fermentation process, St. Clair emits 300,000 tonnes per year of pure fermentation CO_2 that did not have to be reported under Environment Canada guidelines because of its biological origin. Earlier in this study, the St. Clair plant was chosen due to the public availability of recent operating data. For these additional reasons, this plant should be an acceptable proxy for an evaluation of the opportunities for fermentation and combustion CCS on life cycle emissions of corn ethanol automotive fuel, in particular the allocation:

- The St. Clair plant is almost 30% of Canadian capacity and will have an oversized impact on national averages.

- Plants with similar total CO_2e emissions per litre of ethanol make up over 80% of Canadian ethanol capacity.

- The Canadian bioethanol industry is recent and commercial technologies are standardized. There are few places where plants can deviate in performance due to design, only operationally. St. Clair uses the Phoenix / ICM [117] dry mill process to produce ethanol.

- The process is fairly linear with only one process feedstock and one main product. The main input variable – amount of corn purchased – is within the control of the plant, and the outputs flow from the input in predictable proportions.

From the Table above there is an obvious cluster of these plants in Ontario. As a member of the Western Climate Initiative [118], Ontario is expected to take steps to cap their provincial emissions although they have not yet announced firm plans to do so. This makes Ontario an obvious location for a bio-CCS offset project, if all the related issues can be addressed.

4.6 Available Ontario CO_2 Storage Potential

If Ontario contains a large concentration of CO_2 emissions sources, can we be sure that there is sufficient geological sequestration capacity within economic pipeline range? Local geology in southern Ontario is not as well characterized as the Western Canada Sedimentary Basin underlying most of Alberta, Saskatchewan, and British Columbia. It does however have a long history of petroleum production, and in fact the Canadian oil industry had its start in the year 1858 in nearby Oil Springs [119], only 35 km away from the St. Clair Ethanol Plant. The shallow reservoirs involved in the early days of petroleum production are likely not suitable for CO_2 sequestration, but their existence does indicate the presence of sedimentary rock formations with sufficient trapping mechanisms to accumulate oil deposits.

Ontario is at the eastern edge of the Michigan Basin and the northern edge of the Appalachian Basin [120]. Zones of interest include the Mt. Simon Formation, the St. Peter formation, and possibly Michigan gas storage salt caverns although caverns would have unique storage challenges that might render them unsuitable. More information on Ontario geology can be found below.

The sedimentary basins in the Southern Ontario area are not as thick and extensive as in Western Canada, but they are still present and thought to have significant CO_2 storage potential. The Mt. Simon formation ranges from Ontario through Indiana, Michigan, Illinois and Ohio, and is believed to have as much as 11-151 Gt of CO_2 storage capability in the US [121] and 731 Mt in Ontario [122].

In nearby Michigan, the St. Peter formation may have up to 88 Gt of capacity and the state is the site of existing CO_2 EOR sites and pilots [123]. The Sarnia industrial area is approximately 200 km from the US Department of Energy CCS test site at Otsego County, Michigan.

One of the best locations for CO_2 storage in the Canadian portion of the Mt. Simon formation is actually under Lake Erie [124]. This and other sites in southern Ontario have been considered for potential CO_2 EOR or storage projects due to the presence of legacy oil production in the area [125]. Geologically speaking it could be fairly low-risk to inject CO_2 into a structural trap that previously held oil and gas as long as existing wellbores have been properly abandoned, and an onshore pipeline route could be fairly straightforward since it is far from population centres. However, although the region is historically familiar with oil and gas operations, there may be resistance to injecting a new fluid such as CO_2 into the reservoir under a large source of fresh water. Also, due to the proximity of the US border and Lake Erie being international waters, cross-border agreements would have to be necessary.

The risks to a successful CCS project in this area can be divided up into three main categories:

1. Geological – the storage site must have a suitable geological rock formation with favourable permeability, porosity, injectivity, volumetric capacity (thickness times surface area extent) and sufficient primary and secondary sealing mechanisms such as multiple layers of impermeable caprock. These formations

must also occur at sufficient depth that the CO_2 stays in the dense-phase fluid state which is better for efficient storage and secondary trapping mechanisms.

2. Integrity – if the reservoir seals and caprock zones have been penetrated by previous oil and gas production wellbores or known geological faults, these represent potential leak pathways for the CO_2 to migrate back to surface. Older wellbores with unknown abandonment histories are especially problematic because proper records often do not exist. Proper seismic data and well bore records by themselves may not be sufficient for assuring public and regulatory confidence in the safety of the CCS project design, but without them projects will find it difficult to proceed. The inverse of this risk is that existing wellbore files often provide good geological knowledge of the penetrated zones, including known structural traps and caprocks.

3. Political / stakeholder – political challenges stem from the proximity to the US border and a large cross-border freshwater lake, and also the appetite of the current Ontario and federal Canadian governments for CCS schemes in a highly visible area. Local municipalities will also want and deserve a say in any developments that occur within their jurisdictions.

Without further study, the current probability of success for southern Ontario CCS is hard to quantify. In order to improve this probability to a level where a potential project could be feasible, further geological potential evaluations should be done. The ultimate sequestration potential parameters for southern Ontario need to be confirmed, including volumetric capacity, geological formation depth, and injectivity.

4.7 Ontario, Canadian and Global Bioethanol CCS Reduction Potential

As can be seen in Table 8, in 2010 there were enough corn biofuel facilities in Canadian to produce 1437 million litres of bioethanol per year, and nearly 1.6 Mt of associated CO_2e emissions. If St. Clair proportions can be assumed to be consistent for first-generation corn ethanol, this means almost 1 million tonnes of CO_2e per year of pure fermentation CO_2 emissions, and another 650,000 tonnes (11.5 million GJ of natural gas) of associated low-concentration combustion emissions. For context and relative scale, this is equivalent to the emissions from two small petroleum refineries or electrical generating stations, or 400,000 passenger cars. If these emissions can be abated, it would be as effective for the climate as shutting down those installations but with the economic benefits of keeping them open.

For context, in The United States in 2011, there were 53 million litres (13,900,000 US gallons) [126] of bioethanol production which corresponds to 41 Mt of ethanol fermentation emissions and likely 23 Mt of associated combustion emissions if the St. Clair proportions of fermentation and combustion emissions per volume of ethanol are representative of the wider North American industry.

Globally in 2011, there are currently about 86 Mt of corn ethanol fermentation emissions and approximately 48 Mt of associated combustion emissions [127] from global ethanol production of 110 billion litres, if fermentation and combustion emission proportions are also assumed to be represented by conventional first-generation corn ethanol technology. This is

not likely accurate if the feedstock is something other than corn, but it is a good first approximation when estimating the magnitude of the opportunity. Other sources have calculated fermentation CO_2 volumes of 52 Mt in 2009 [128], a more conservative estimate.

In 2010, Ontario had over 56 Mt of CO_2e emissions from large reportable facilities [129], and nearly 57 Mt once the St. Clair expansion and fermentation CO_2 are added. As shown in Table 7, the southern Ontario Sarnia-Lambton industrial area near St. Clair itself had 7.4 Mt of CO_2e emissions (7.8 Mt once the St. Clair expansion and fermentation CO_2 are added) including 0.3 Mt per year of fermentation CO_2 emissions, 0.2 Mt of ethanol plant combustion emissions, and almost 0.5 tonnes of hydrogen plant emissions. Hydrogen plant CO_2 emissions are often essentially pure, especially if the Catacarb or Benfield purification processes are used. A PSA purification process produces a CO_2 stream of lower purity but it is still a much higher concentration and therefore lower capture costs that a combustion exhaust gas stream, as long as the PSA off-gas is treated before it is commingled with other refinery gas streams.

Table 7: Sarnia Area Industrial CCS Potential, adapted from Environment Canada

Facility (2010)	Reporting Company	City	Total CO_2e (tonnes)
Cabot Canada Limited	Cabot Canada Limited	Sarnia	201,000
Clean Harbors Canada, Inc	Clean Harbors Canada, Inc.	Corunna	61,000
Corunna Hydrogen Facility	Air Products Canada Ltd.	Corunna	391,000

Facility (2010)	Reporting Company	City	Total CO_2e (tonnes)
Corunna Site	NOVA Chemicals (Canada)	Corunna	1,462,000
Moore Site	NOVA Chemicals (Canada)	Mooretown	57,000
Sarnia Chemical Plant	Imperial Oil	Sarnia	256,000
Sarnia Cogen Plant	Imperial Oil	Sarnia	366,000
Sarnia Fractionation Plant	BP Canada Energy Company	Sarnia	140,000
Sarnia Manufacturing Centre	Shell Canada Products	Corunna	690,000
Sarnia Refinery	Suncor Energy Products Inc.	Sarnia	612,000
Sarnia Refinery Plant	Imperial Oil	Sarnia	1,288,000
Sarnia Regional Cogeneration Facility	TransAlta Generation Partnership	Sarnia	1,206,000
Sarnia Site	INEOS Styrenics Ltd.	Sarnia	159,000
St. Clair Energy Center	St. Clair Power, LP	Corunna	362,000
St. Clair Ethanol Plant	Suncor Energy Products Inc.	Mooretown	82,000
St. Clair River Site	NOVA Chemicals Corporation	Corunna	73,000
Total	Sarnia Lambton area		7,400,000

If a bioethanol CCS scheme is implemented in the Sarnia area, capturing pure CO_2 streams from other neighbouring facilities may improve the economies of scale and provincial per tonne unit capture costs by using a common regional network of CCS infrastructure. From Table 7 above, Ontario has 0.75 Mt of corn ethanol fermentation emissions and

approximately 0.5 Mt of associated combustion emissions. Nearly half of these emissions are at the Suncor St. Clair and Greenfield Chatham plants in the southern Ontario region.

In the wider southern Ontario area within a 200 km (125 mile) radius of Sarnia, including the Nanticoke, Chatham, and London areas, the total emissions are 19 Mt including 0.5 Mt of CO_2 from hydrogen plants and almost 0.50 Mt of CO_2e from ethanol fermentation (as mentioned above, the St. Clair ethanol plant had 175,000 tonnes of fermentation CO_2 to go along with 82,000 tonnes of combustion CO_2; since the plant capacity was doubled in early 2011, it now produces 300,000 tonnes of fermentation emissions and 174,000 tonnes of combustion emissions). The facility emissions are shown in Table 8 below:

Table 8: Southern Ontario Industrial CCS Potential, from Environment Canada (2010)

Facility	*Reporting Company*	*City*	*Total CO₂e (tonnes)*
Cabot Canada Limited	Cabot Canada Limited	Sarnia	201,000
Casco Inc. - London Plant	Canada Starch Operating Company Inc.	London	124,000
Chatham Plant	Greenfield Ethanol Inc.	Chatham	297,000
Clean Harbors Canada	Clean Harbors Canada, Inc.	Corunna	61,000
Corunna Hydrogen Fac.	Air Products Canada Ltd.	Corunna	391,000
Corunna Site	NOVA Chemicals (Canada) Ltd.	Corunna	1,462,254

Facility	Reporting Company	City	Total CO_2e (tonnes)
London District Energy	Fort Chicago District Energy Ltd.	London	40,000
Main Campus	The University of Western Ontario	London	53,000
Moore Site	NOVA Chemicals (Canada) Ltd.	Mooretown	57,000
Nanticoke Generating Station	Ontario Power Generation Inc.	Nanticoke	8,601,000
Nanticoke Refinery	Imperial Oil	Nanticoke	1,067,000
Natural Gas Transmission & Dist.	Union Gas Limited	Chatham	812,000
Sarnia Chemical Plant	Imperial Oil	Sarnia	256,000
Sarnia Cogen Plant	Imperial Oil	Sarnia	366,000
Sarnia Fractionation Plant	BP Canada Energy Company	Sarnia	140,000
Sarnia Manufacturing Centre	Shell Canada Products	Corunna	690,000
Sarnia Refinery	Suncor Energy Products Inc.	Sarnia	612,000
Sarnia Refinery Plant	Imperial Oil	Sarnia	1,288,000
Sarnia Regional Cogeneration Facility	TransAlta Generation Partnership	Sarnia	1,206,000
Sarnia Site	INEOS Styrenics Ltd.	Sarnia	159,000

Facility	Reporting Company	City	Total CO_2e (tonnes)
St. Clair Energy Center	St. Clair Power, LP	Corunna	362,000
St. Clair Ethanol Plant	Suncor Energy Products Inc.	Mooretown	82,000
St. Clair River Site	NOVA Chemicals Corporation	Corunna	73,000
St. Mary's Cement Plant	St. Mary's Cement Inc.	St. Mary's	545,000
W12A Landfill	Corporation of the City of London	London	135,000
Total	Southern Ontario		19,000,000

Another possible CCS opportunity is the high-concentration CO_2 emission stream from calcination at the St. Mary's Cement Plant. Typically the flue gas stream contains 14 to 33% CO_2 from calcination and fossil fuel combustion [130]. At this high concentration, either post-combustion capture or pure oxygen-firing with exhaust gas recycle could be implemented. That means another 0.5 MT of high-concentration CO_2 might be available to a regional CCS development. Total pure and high-concentration CO_2 streams from hydrogen plants, fermentation and cement production are therefore approximately 1.5 Mt of CO_2e. Please refer to Chapter 4.9 for comparison of available volumes to overall targets.

4.8 Economic Factors for Bioethanol CCS

The cost variability of different CCS technologies and applications are dependent mainly on capture costs. Capture cost is typically 60 - 80% of the overall project cost per tonne CO_2, and the only part that is technology dependent. Once the nearly-pure CO_2 stream is created,

the compression, transport, and sequestration facilities and costs are the same regardless of CO_2 source or capture technology.

4.8.1 Transport and Disposal Costs per Tonne

Storage and transport costs are independent of the upstream capture processes as long as the CO_2 stream reaches acceptable purity specifications.

Transport costs for pipelining CO_2 have been estimated at 5.4 Euros ($7.00 CAD at 1.3 CAD per Euro) per tonne of CO_2 [131] for a 180 km onshore pipeline. Compression energy costs are included in the upstream capture costs, as well as the energy penalty calculated earlier.

There is much more variability in the storage cost estimates as measurement, monitoring and verification (MMV) as well as injection well drilling and completion costs are highly site-specific. However, costs have been estimated to be between 2 to 12 Euros ($2.60 to $15.60) per tonne of CO_2 for storage in onshore saline aquifers [132].

4.8.2 Fermentation and Combustion CO_2 Capture Costs per Tonne

It is valuable here to compare the cost of fermentation CCS to combustion CCS in order to assess the desirability of the opportunity.

As discussed above, one inexpensive opportunity is CCS on the fermentation CO_2 stream. For every million litres of corn ethanol produced, there is approximately 780 tonnes of CO_2 produced by the fermentation process. This CO_2 is pure and only requires filtering to be used in food-grade applications. The reason this is such an attractive option is that in classical amine-based CCS, the capture costs are typically 60-80% of the full CCS cost, but fermentation CO_2 has very low capture cost since it is already pure. The only remaining costs are compression, dehydration, pipelining, injection and monitoring.

Compression and dehydration costs can be estimated from typical petroleum industry projects. A plant to capture 150,000 tonnes of fermentation CO_2 per year would require 1750 kW (2400 metric horsepower) of compression. Here it is assumed that the compressor would be electrically driven since this is quieter and more likely to be installed in an urban or suburban setting. This size of compressor station would cost roughly in the order of $40 million Canadian dollars[7], and use around 15 million kWh of electricity per year. Since it would be integrated with the host facility, incremental operating costs would be minimal except for the cost of the compression energy. At an

[7] Personal experience – From June 1997 to October 2006 I worked as an Operations Support small project engineer, and from October 2006 to September 2009 I worked as a Facilities Project Team Lead, executing medium to large upstream oil and gas projects for several major Canadian petroleum producers. During this time, I either led or participated in the installation of 20 new compressors and 2 new or refurbished dehydrators, as well as numerous modifications to existing units. This includes an acid gas injection project, analogous to CCS. Therefore, I have professional knowledge and experience that I have used here to estimate the cost per horsepower for compression and the cost per volume throughput for dehydration.

assumed $0.10 per kWh over 25 years, the NPV of the electricity cost is $16 million

CAD at an assumed discount rate of 8%. At a flow rate of 220,000 standard m^3 of CO_2

per day, the installed dehydrator cost will be approximately $10 million CAD bringing

the total project cost NPV up to $66 million CAD.

Another potentially economic source of electricity could be natural gas fired onsite

generation with heat recovery (i.e. combined heat and power). However this would add

significant capital expense to the project and since Ontario's electricity is a mixture of

nuclear, wind, coal and imported hydroelectricity the grid intensity factor is already quite

low (Ontario's value was 0.17 tonnes / MWh in 2008 [133]) and the GHG reduction

benefits would be minor even with heat recovery.

Over 25 years the project would capture 3.8 Mt of CO_2 at a rate of 150,000 tonnes per

year. This equates to a captured CO_2 cost of $17.50 CAD per tonne if the total project

cost NPV is $66 million CAD, and electricity price is $0.10 / kWh. However, we have to

factor in the emissions from extra electrical generation caused by this facility in order to

get the cost for the net CO_2 emissions avoided by the facility. At a grid intensity factor of

0.17 tonnes / MWh this equals 2,600 tonnes per year of CO_2e or 65,000 tonnes over 25

years of emissions from electricity.

This decreases the avoided CO_2 volumes to 3.7 Mt and increases the avoided CO_2e cost

to almost $18 CAD per tonne, still very low compared to other technologies. Adding

fermentation CO_2 capture cost of $18 per avoided tonne of CO_2e to the transport and

disposal costs in the previous section, the total fermentation CCS project cost is therefore $27 to $41 per tonne which is a comparatively attractive CO_2 abatement cost.

A capture cost this low compares favourably with conventional CCS costs which are estimated to be $85.00 to $160.00 CAD (65.9 to 125 Euros) per tonne at natural gas fired installations in Europe [134].

Sensitivity Analysis of Capital and Operating Cost on Abatement Cost

The cost advantage of fermentation CCS over combustion CCS is not very sensitive to the cost. In fact, at a compression electricity price of $0.10 / kWh, the total compression and dehydrator facilities capital cost would have exceed $270 million CAD for the unit costs to exceed $100.00 per tonne of CO_2, which is highly unlikely. Similarly, at $50 million CAD fermentation CO_2 facility capital cost, the avoided cost per tonne is still only $51 even if the electricity cost increases by 500% to $0.60 / kWh.

As per Table 9 and Figures 11, 12 and 13 below, the sensitivities to capital and operating costs are linear over the ranges shown, which were chosen to cover current norms up to highly unlikely maximum costs.

Table 9: Two-Dimensional Sensitivity of Avoided Cost to OPEX and CAPEX

Capital $ million CAD	Low	Medium	High	OPEX
Power price $ / kWh	$50.00	$175.00	$300.00	600%
$0.10	$40.43	$73.95	$107.48	266%
$0.35	$51.43	$84.96	$118.48	230%
$0.60	$62.43	$95.96	$129.48	207%
600%	154%	130%	120%	CAPEX

At $50 million capital, a six-fold increase in power price causes a 54% increase in avoided cost per tonne.
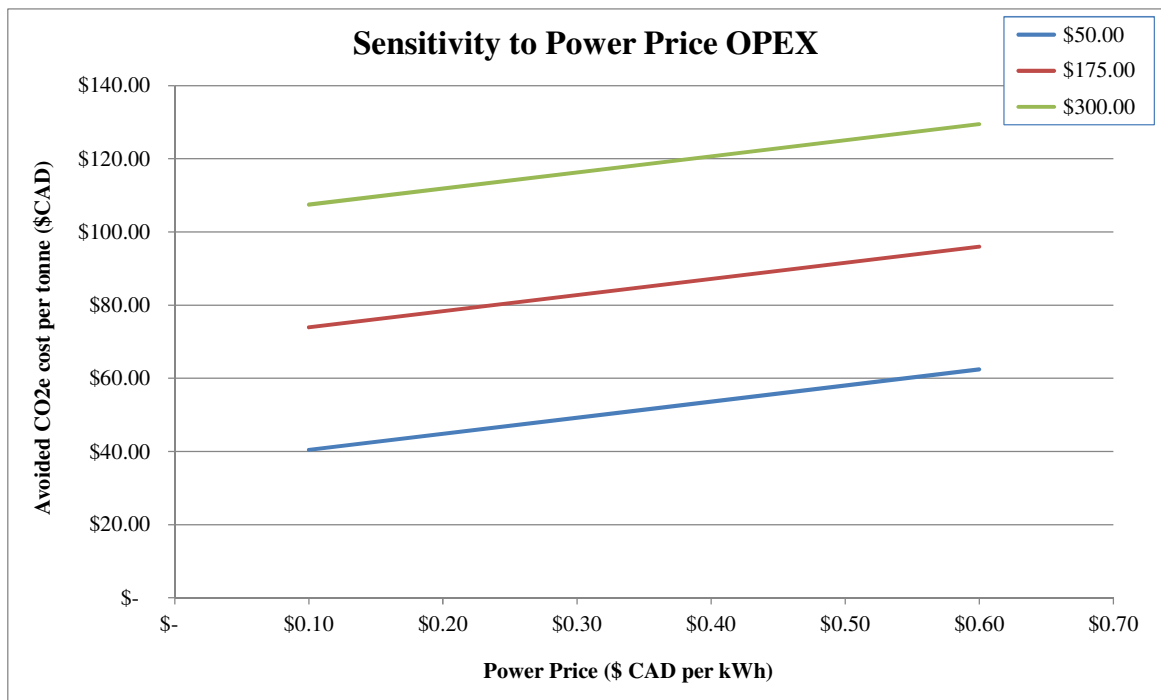
Figure 12: Sensitivity to Power Price OPEX at Various Capital Costs

Similarly, at $0.10 / kWh, a six-fold increase in capital causes a 166% increase in avoided cost.
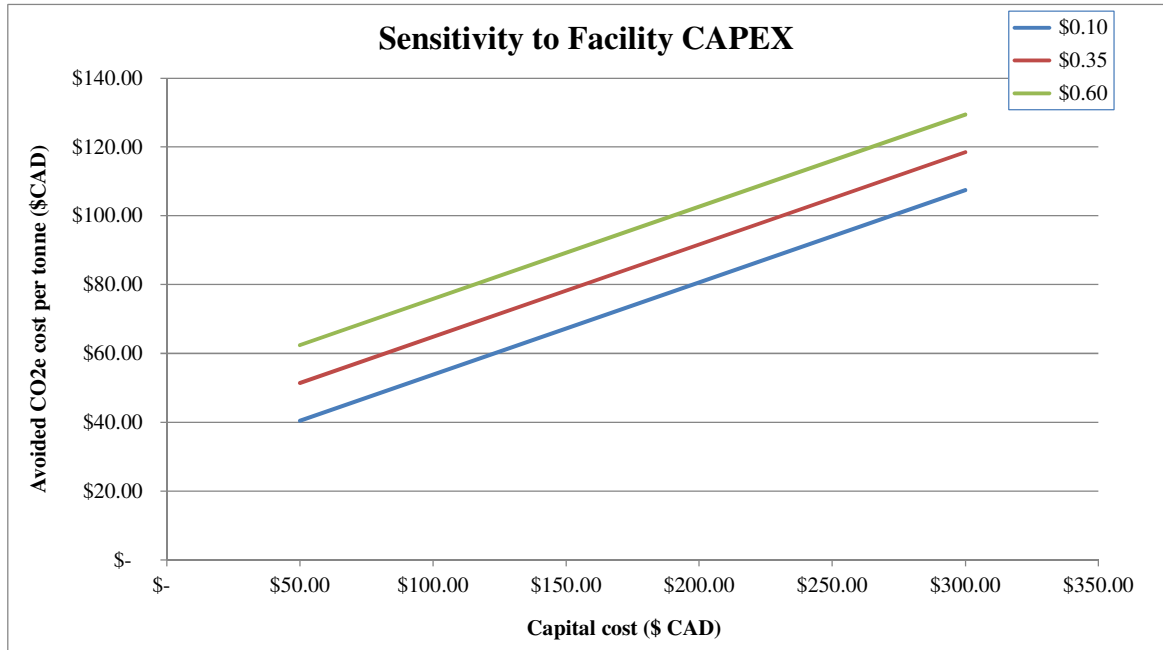
Figure 13: Sensitivity to Facility CAPEX at Low, Medium and High Power Price

It takes the simultaneous occurrence of a very unlikely capital cost and a highly-inflated electricity cost to reach the $160.00 per tonne level of combustion CCS.
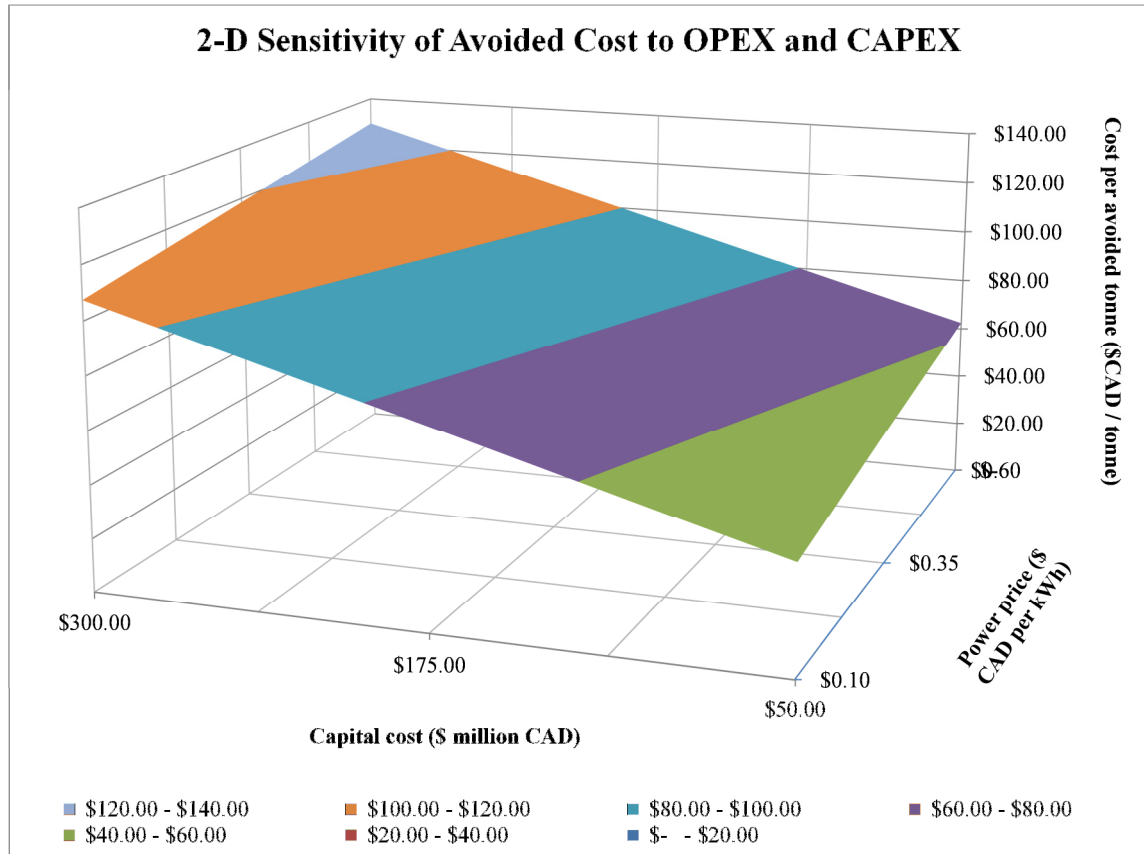
Figure 14: Two-Dimensional Sensitivity of Avoided Cost to OPEX and CAPEX

This low likely capture and sequestration cost is much less than conventional CCS capture plus transport and storage opportunities which cost $175.00 to $250 CAD [135] in Alberta as discussed elsewhere in this thesis.

For reference, the Alberta SGER cost per tonne of CO_2 is $15.00 CAD [136], while the BC carbon tax on commercial fuels is $30.00 CAD per tonne [137] and the current EU ETS carbon cost is currently ~6.00 Euros [138] ($10 CAD at approximately 1.3 Euros per CAD) although it has been as high as 13 Euros ($17 CAD) in the past year. Norway has recently announced an increase in its oil and gas carbon tax, up to a new value of 410

Norwegian kroner [139] or about $70 CAD per tonne, therefore it seems as if a fermentation CCS offset project would be economical in Norway.

Another interesting comparison is that of fuel efficiency standards that also aim to reduce automotive vehicle emissions. Under some recently modelled scenarios [140], the average cost of abating CO_2 in the US through a 5% fuel efficiency standard increase could be on the order of $131.00 per tonne in 2004 dollars ($25 billion USD per annum for 190 million metric tonnes per year).

It must be noted here that the costs quoted here do not include any potential revenue from EOR CO_2 sales or offsets under carbon pricing schemes. This is another business opportunity that can potentially lower the cost of CO_2 capture or avoidance.

Once the fermentation CO_2 has been captured using dehydration and compression, the next opportunity is capture of ethanol plant combustion emissions. Post combustion removal of CO_2 from ethanol plant combustion flue gas streams using amines would be similar to CCS at any other natural-gas fired industrial installation, with temperatures, similar pressures, and compositions (partial pressures). There has been a great deal of research into natural gas CCS applications such as Natural Gas Combined Cycle (NGCC) plants but no definitive research has been done for appropriate combustion emission capture technology selection at ethanol plants, so these other natural gas applications are used here as approximations.

Post combustion capture of fired heater emissions could be cost in the order of $175.00 - $250.00 / tonne [141] in northern Alberta and $97.00 to $185.00 CAD (74.2 to 142.4 Euros) per tonne in Europe [142], although that number may come down as the result of current research supported by groups such as the US Department of Energy, IEA-GHG, the CO_2 Capture Project, and the GCCSI. Commercial scale plants have been built using this technology, and some technology providers such as MHI offer commercial warranties on system performance.

The most advanced pre-combustion technology is oxy-firing which uses pure oxygen for combustion instead of air and produces pure CO_2 and water vapour in the exhaust stream. This could lead to CO_2 abatement costs of $125.00 - $150.00 / tonne [143] which can be further reduced by new technology development or improved process energy optimization designs. This number must be met with caution as full scale commercial CO_2 capture plants using oxy-firing have yet to be built. Demo and first commercial plant costs are expected to be higher. Once the pure CO_2 is produced from ethanol plant combustion, it could be run through the same dehy, compression and pipeline infrastructure as the fermentation CO_2 discussed above.

Hydrogen gasification and firing with CCS refers to a pre-combustion scheme where hydrogen is generated in a central plant, then sent as fuel to a distributed network of individual heaters, boilers and other combustion sources. Carbon abatement costs are expected to be in the $75.00 - $125.00 CAD per tonne CO_2e range [144] when implemented at large scale, however this scheme is better suited to a larger complex

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facility with many distributed sources like a petroleum refinery and not a relatively small and simple facility like a bioethanol plant with only a small number of combustion sources.

4.9   GHG Reductions from Biomass Combustion at Ethanol Plants

If we judge the St. Clair plant to be an acceptable proxy for the combustion emissions of the Canadian bioethanol sector, then at 8,000 GJ per million litres of ethanol the sector-wide combustion energy required is 11.5 million GJ per year for 1437 million litres of Canadian ethanol production capacity. As per above, the technical potential of both corn stover and torrefied wood pellets are high enough to meet this demand, although the economic potential will undoubtedly be lower. Corn stover may be the better opportunity since the transportation distances will be smaller in corn-growing areas where ethanol plants are located.

Either pulverized torrefied wood pellets, corn stover or lignin from a cellulosic ethanol plant represent an interesting opportunity as they can be fed into existing coal boilers, and have similar heat content as some grades of coal.

One example of this opportunity is the ability to displace up to 10% of the coal in a thermal power plant with pulverized wood or lignin pellets, with a corresponding 9% reduction [145] in GHGs. One important question to ask here is would this solution be material enough to matter - since all combustion emissions are 20 g CO_2e / MJ, then 10% co-firing would only lower the emissions by 2 g CO_2e / MJ. If a 10% ethanol blend is used then the automotive

fuel will only see a 0.2 g CO_2e / MJ reduction, slightly over 0.2% when the average fuel is around 95 g CO_2e / MJ.

From Table 8, the absolute reduction in Canadian bioethanol plant combustion emissions would only be 10% of 689,000 tonnes, or only 68,900 tonnes. Consequently the cost per tonne of CO_2 avoided may be very high unless there are other economic drivers for the project.

4.10 Economic Factors for Biomass Combustion at Ethanol Plants

Corn stover does not yet have a significant market so a price per tonne is difficult to quantify. However, Canada currently exports most of its wood pellet production overseas at an average price of $200 per tonne [146] with an average GHG reduction percentage of 90% over coal.

Coal cost an average of $115.00 USD per tonne in 2011, so wood pellets have an $85 per tonne premium and essentially the same average heat content. A tonne of coal creates 2.4 tonnes of CO_2, while a tonne of wood pellets creates only 10% as many life cycle emissions. The net cost is $85 and the net CO_2e savings is 2.2 tonnes, for an avoided CO_2e cost of $40 for wood pellets.

According to the Third Argus Biomass Trading Conference, the "CIF Amsterdam Rotterdam, Antwerp (ARA) price" was as low as $148 CAD (116 Euros) per tonne in August 2010 and

as high as $175 CAD (137 Euros) per tonne in February 2012 [147]. At $148 CAD per tonne, the CO_2 avoided cost drops to only $16 per tonne.

4.11 Analysis of Macro Effects

The economic impacts of the various technologies to reduce the GHG footprint of biofuels are summarized in the following Table 10. To judge the sensitivity to abatement costs, each technology is evaluated at the low and high range of the per tonne abatement costs estimated earlier in the paper.

Table 10: Economic Impact Metrics

Technology	*$ / tonne*	*$ / litre*[8]	*$ / km*[9]
Bioethanol combustion	$19.00	$0.04	$0.00
Bioethanol combustion	$93.00	$0.22	$0.02
Fermentation CCS	$18.00	$0.04	$0.00
Fermentation CCS	$41.00	$0.10	$0.01
Combustion CCS	$97.00	$0.23	$0.02
Combustion CCS	$250.00	$0.59	$0.06
Biomass combustion	$16.00	$0.04	$0.00

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[8] Assumes 0.003325 tonnes of CO_2e per litre of gasoline (96 g CO_2e / MJ).

[9] Assumes 10 km per 100 litres of gasoline.

Technology	$ / tonne	$ / litre[8]	$ / km[9]
Biomass combustion	$40.00	$0.09	$0.01
Fuel efficiency [148]	$131.58	$0.31	$0.03
Air capture	$360.00	$0.85	$0.08
Air capture	$1,000.00	$2.36	$0.24

From this Table, it appears that the lowest cost opportunities to achieve deep and potentially negative ethanol life cycle GHG reductions are fermentation CO_2 CCS and biomass combustion, as the costs compare very well with other current and developing technologies.

In light of the previous section, it is desirable to put the available reductions in the perspective of local, Canadian and global reduction targets. Each area has existing short-term reduction goals or aspirations in order to spur technological innovation and early action to lower current emissions. However, to limit the worst effects of climate change, it is thought that cuts of up to 85 % will ultimately be necessary to keep the average temperature rise under 2 – 2.5 degrees C [149]. While no jurisdiction has adopted regulations enforcing targets as stringent as 85%, it is worth looking into this number as an upper bound for the eventual GHG cuts required for Canada and globally. However, Ontario has set an aspirational target of 80% from 1990 levels by 2050, so that target is evaluated for that particular jurisdiction.

4.11.1 Ontario GHG Targets

As per their "2007 Ontario Climate Change Action Plan", Ontario reduction targets are
15% or 26 Mt by 2020 and 80% or 141 Mt by 2050 [150] from a 1990 baseline of 176.2
Mt [151]. The 15% target for 2020 is 99 Mt under the no-action Business As Usual
scenario.

Biofuel consumption can reduce Ontario emissions by 1.1 to 1.6 Mt by displacing
conventional reformulated gasoline, since 2011 gasoline sales in Ontario were
approximately 15 million cubic metres [152].

Meanwhile, 10% biomass co-firing at ethanol facilities could avoid another 0.05 Mt of
combustion emissions relatively cheaply. Biofuel CCS can reduce the Ontario GHG
footprint by another 0.8 Mt from fermentation and 0.5 Mt from combustion. A further 0.8
Mt can be captured from other nearby pure and nearly pure GHG streams in the Sarnia –
Lambton – Chatham – London area. Graphically these 3.7 Mt of GHG emissions can be
shown in a waterfall diagram in Figure 14 to show their magnitudes compared to
provincial targets:
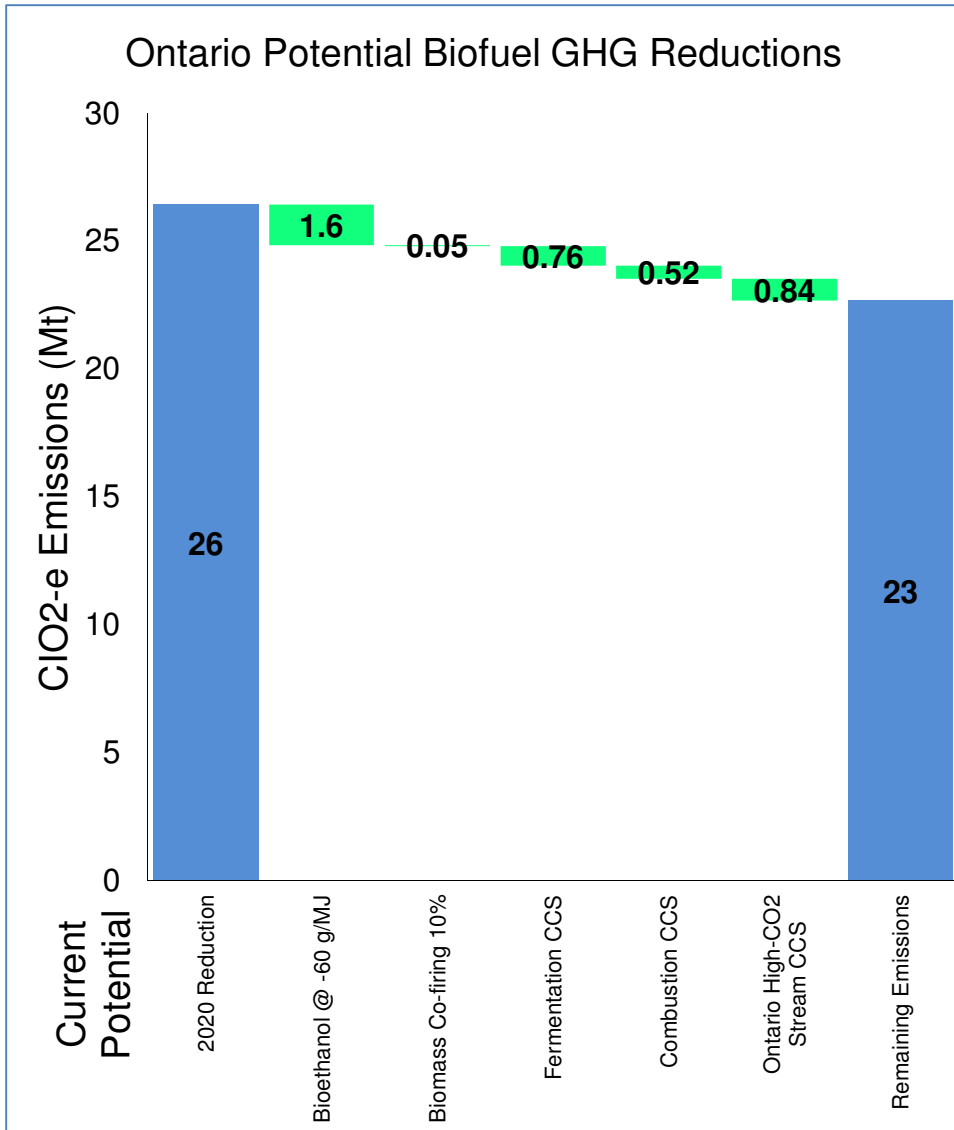
Figure 15: Waterfall Diagram for Ontario 2020 Reductions

4.11.2 Canadian Target Emissions Reduction Fraction

As stated under the Copenhagen Accord, Canada's current absolute GHG reduction goal

is 17% below 2005 levels by 2020 [153]. It is not a legally binding treaty and has not

been translated into actual federal regulations, and therefore actual legislation and

subsequent reductions will likely look much different. However, it is the only Canadian

reduction goal currently in place, even if it lacks the force of law behind it, so it will be

used here.

Translated into tonnes of GHG, this means we have to be 123 Mt below our 2005

emissions of 731 Mt for an absolute emissions level of 607 Mt. From another perspective,

we must cut 243 Mt (29%) from our projected Business as Usual 2020 GHG emissions of

850 Mt [154]. This is an ambitious goal which will take both consumer and industrial

efforts to meet. Canadian historical trends and forecasts can be found in the following

Figure 15 [155] using data from Environment Canada's National Inventory Reports and

projections.
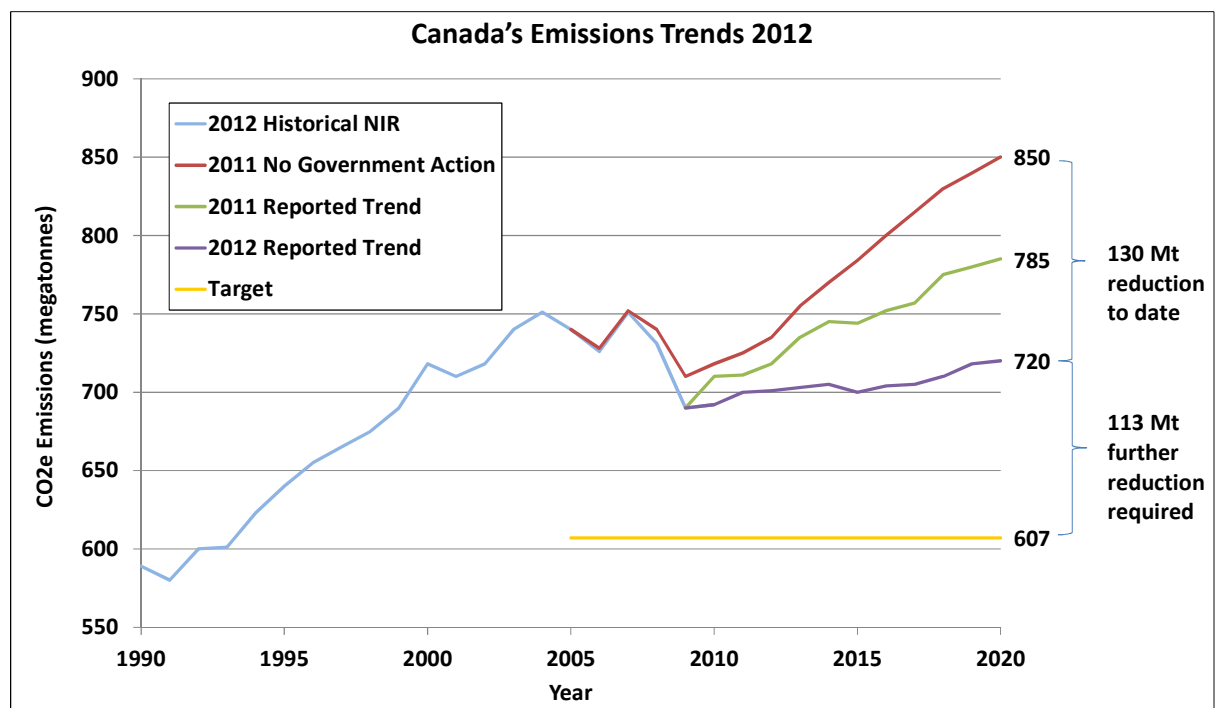
Figure 16: Canada's Emissions Trends

Canada's national emissions peaked at 751 Mt in 2004 [156] and an 85% reduction from that amount would be a drop of 638 Mt down to 113 Mt annually, equal to 90% of the entire country's GHG emissions in the year 2010 [157].

Displacing 5% of Canadian gasoline volumes with current bioethanol will avoid nearly 4.1 Mt of GHG per year at 60 g CO_2e / MJ (Case 4) decrease, or 2.9 Mt of GHG at a 40 g CO_2e /MJ (Cases 2 and 3 average) decrease. Fermentation and combustion CO_2 CCS at existing bioethanol plants can reduce emissions up to 1.6 Mt of CO_2 plus 0.80 Mt from southern Ontario high-concentration CO_2 streams. The impact of 10% biomass co-firing at ethanol facilities could be inexpensive but is relatively minor at 0.06 Mt. Added together, these amounts are reasonably significant at 6.6 Mt and could offset the emissions of 1 million passenger cars, or 4 to 5 large emitters such as petroleum refineries or small electrical generating sites, or 1.6 million cars. The waterfall diagram for available Canadian biofuel GHG reductions is shown as follows in Figure 16:
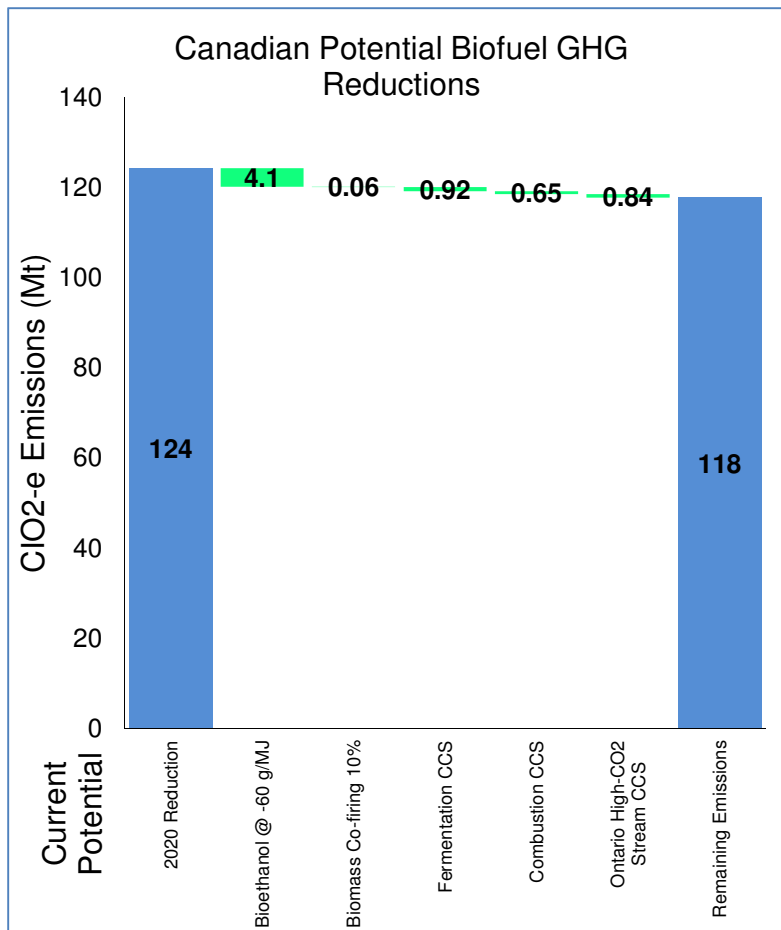
Figure 17: Waterfall Diagram for Canadian 2020 Reductions

4.11.3 Global Atmospheric Effects

According to the Carbon Tracker Initiative [158], the atmosphere can hold another just under 600 Gt of CO_2 before it exceeds the 2 C temperature rise threshold. This point estimate is overly simplistic since it glosses over the uncertainty in the CO_2 sensitivity of the global ecosystem, and variables such as ocean, soil and biomass CO_2 uptake. Any attempt to calculate a precise number will only show the order of magnitude of the tonnes remaining, but not with any certainty or reliable precision. However it agrees

directionally with analysis done by the IEA [159] who state "No more than one-third of proven reserves of fossil fuels can be consumed prior to 2050 if the world is to achieve the 2 °C goal, unless carbon capture and storage (CCS) technology is widely deployed". According to BP [160], current booked fossil fuel reserves are 263 billion cubic metres of oil, 208 trillion cubic metres of gas, and 861 billion tonnes of coal. The total CO_2 represented by these reserves is 2800 Gt so 1/3 of this represents over 900 Gt of CO_2. This number is higher than the Carbon Tracker number of 600 Gt, likely due to more rigorous climate modelling, but close enough to show some validity of approach.

Directionally it is an interesting example of the "stock" nature of the problem, and in the absence of better data it can at least inform us of the shape of the likely reduction profile, if not an accurate magnitude. At current rates of approximately 30 Gt per year, society will reach 1140 cumulative Gt by 2050, and 900 cumulative Gt by 2042 – only 30 years from now. Average rates over the next 38 years (until 2050) need to be 24 Gt per year to stay under 900 Gt, meaning steep cuts will be required, and since the emissions rate in 2051 will have to be essentially zero, a linear average is not realistic.

Global GHG emissions were 17 Gt in 1990 and 23.7 Mt in 2000 [161], therefore global reduction target of 17% below 1990 by 2020 and 85% below 2000 by 2050 correspond to reductions of 2.9 and 20.3 Gt, respectively. Biofuel displacement of current levels of global ethanol production at a 5% ethanol concentration will have an impact of almost 130 Mt at 60 g/MJ reduction or 91 Mt at 40 g/MJ reduction. Chapter 4.7 estimates potential for 86 Mt corn ethanol fermentation emissions and approximately 48 Mt of

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associated combustion emissions globally; therefore biofuel CCS can remove 134 Mt
from fermentation and combustion, and 10% biomass co-firing can displace another 4.8
Mt of CO_2 emissions for a total of 230 – 270 Mt of potential GHG reductions. The
waterfall diagram for available global biofuel GHG reductions, at current gasoline
volumes and 5% blending is shown as follows in Figure 17:
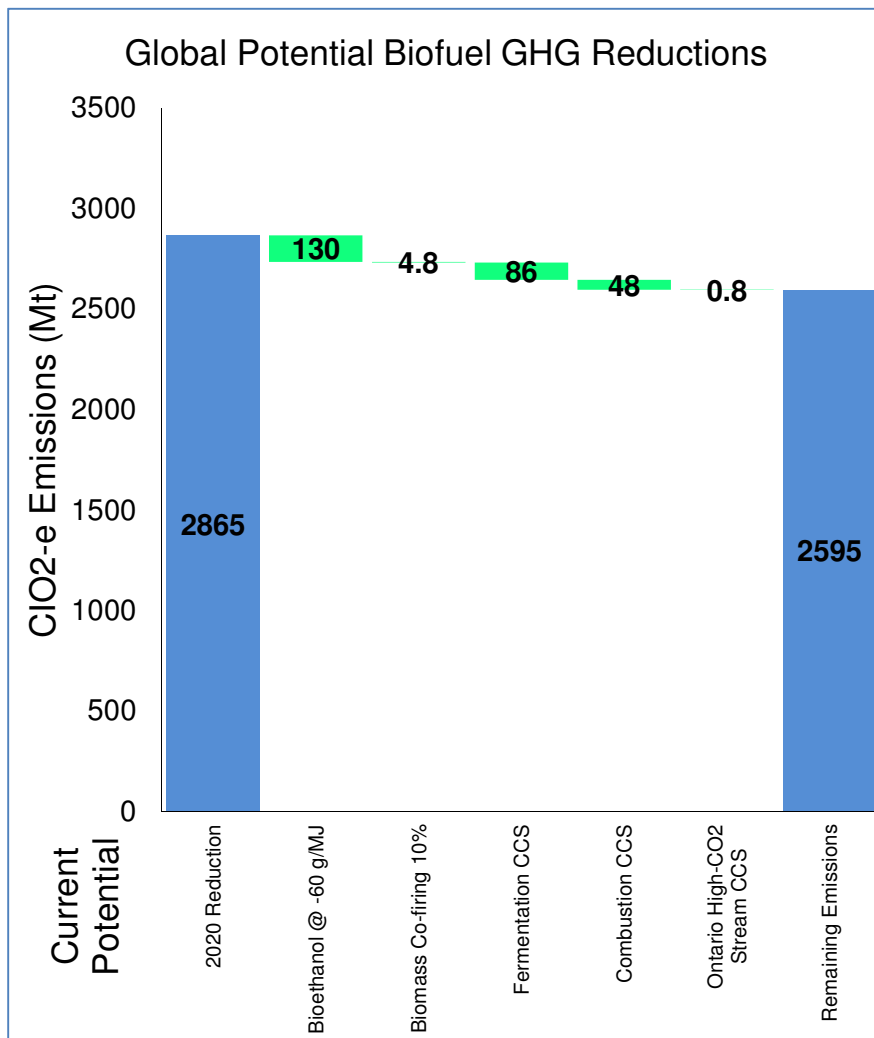
Figure 18: Waterfall Diagram for Global 2020 Reductions

To summarize the main results of this study and compare them to overall GHG cuts
required, the relevant values are repeated in the following Table 11:

Table 11: Summary of Macro Effects

Technology	Ontario	Canada	Global
Bioethanol @ -40 g CO_2e /MJ	1.1	2.9	91
Bioethanol @ -60 g CO_2e /MJ	1.6	4.1	130
Biomass Co-firing 10%	0.05	0.06	4.8
Fermentation CCS	0.76	0.92	86
Combustion CCS	0.52	0.65	48
S. Ontario High-CO_2 Stream CCS	0.84	0.84	0.84
Total Reductions (Mt) -40 g/MJ	3.3	5.3	231
Total Reductions (Mt) -60 g/MJ	3.7	6.6	270
2020 Reduction Target	26 Mt (15%, 1990)	124 Mt (17%, 2005)	2,865 Mt (17%, 2005)
2050 Reduction Target	141 Mt (80%, 1990)	638 Mt (85%, 2007)	20,268 Mt (85%, 1990)

Therefore, it seems that current levels of biofuel production can have a material impact
on Ontario's near-term targets and a smaller but still noticeable effect on longer term
goals. From a Canada-wide perspective, the average effect is not as large, which is
logical since most biofuel production and potential GHG reductions are concentrated in
Ontario. Globally, current levels of biofuel production and CCS potential are material at

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just over 9% of the 2020 reduction and 1% of the 2050 reduction. If bioethanol is to make a serious dent in future global emission, both biofuel production and CCS volumes would have to be increased by 2050.

5.0 Conclusions

Conventional corn-based ethanol can be an effective carbon mitigation strategy if the plant design, site selection and direct emissions are designed and managed correctly. The dominant Activities included Processing / Production (direct emissions), Credit for Co-Products (plant design), Corn Transportation, Ethanol Transportation and Indirect Land Use Change (site selection). Choosing the lowest-impact and most efficient technology, and placing the production facility in an area with nearby fallow or under-utilized farmland, existing corn production and close proximity to petroleum refineries for blending can lead to a fuel that has a much lower GHG footprint than conventional automotive fuels. Policies such as Renewable or Low Carbon Fuel Standards can be effective as long as they incent the maximum reduction in emissions without exceeding the capacity of the agricultural sector to provide for both food and fuel.

At currently levels of bioethanol use, indirect land use change does not seem to be a significant issue in North America due to availability of sufficient fallow farmland and improving crop yields globally [162]. However, these non-linear factors will reach a practical limit before considerably higher volumes of RFG can be replaced by biofuels, and evaluation of LUC will be critical to the analysis while remaining highly site- and project-specific.

At avoided prices less than about $19 CO_2e per tonne, the effect of 5% bioethanol blending on gasoline prices in terms of $ per litre and also kilometre driven are negligible at $0.04 per litre, and within the range of normal variability. The cost of abating CO_2 by fermentation CO_2 CCS and biomass combustion at ethanol plants are both in the order of $40 per tonne CO_2e and will

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cause a noticeable fuel price increase in the order of $0.10 per litre. While noticeable, fuel prices in North America are still far lower at around $1.00 per litre than prices found in other regions such as Europe [163] which are currently $ 2.40 CAD (1.5 British pounds) per litre.

5.1 Technical Feasibility of Biomass CCS

Biomass CCS is not only technically feasible, it is straightforward and uses proven technology. In fact, it is easier, simpler and less risky than conventional CCS using amine-based capture processes. The biggest risk to a biomass CCS project is not technical; it lies with finding favourable economic conditions, regulatory regimes, suitable geology and stakeholder acceptance. Combining CCS with current levels of biofuels is a material opportunity to meet close to 10% of near-term (e.g. 2020) goals.

5.2 Economic Desirability of Biomass CCS

Conventional fossil-fuelled power plant CCS is quite expensive on a cost-per-tonne basis, typically $100.00 to $250.00 CAD per tonne or more of CO_2e. Biofuel plant fermentation CCS is in theory much cheaper, on the order of $30.00 to $45.00 CAD per tonne. There are very few other GHG reduction opportunities at this cost with the exception of profitable energy efficiency initiatives and some alternative fuels technology. Biofuel plant combustion CCS is as expensive as conventional fossil-fuelled CCS but may be able to share infrastructure with fermentation CCS to lower the cost. Combustion CCS will increase the

overall cost of combustion plus fermentation CCS, but could add up to 50% more CO_2 captured volume.

Biomass supply scale-up issues are the one potential economic stumbling block to expansion of biomass combustion. If agricultural productivity gains cannot keep pace with demand for biofuels, and enough additional farmland is required for bioethanol to put pressure on food production, corn input prices may make biofuel production uneconomic or unpopular and stop any expansion plans beyond levels dictated by regulations.

6.0 Recommendations and Further Research

In order to investigate more ways to reduce the GHG footprint of automotive biofuels, future research into this topic may wish to focus on the proper selection of post-combustion technologies for combustion fuel flue gas streams at ethanol plants, in order to take advantage of the specific equipment in place at these facilities. Statistical evaluation of a large population of operating ethanol plants should be done to confirm the true distribution of their GHG performance results. Also, research should be done on the impacts of CCS on a standalone second-generation cellulosic ethanol plant to see how much improvement can be obtained in CO_2 abatement and atmospheric CO_2 removal. An alternative is to investigate a second-generation plant integrated with a conventional first-generation plant to evaluate the benefits of co-location such as co-firing with lignin, energy efficiency and heat integration, once sound economic second-generation technologies are developed.

It would be valuable to investigate the maximum amount of feedstock farming scale-up that could occur before indirect land use change pushes the life cycle GHG footprint past the 40 – 60 g CO_2e / MJ tipping point where it would be higher than reformulated gasoline.

6.1 Biofuel and Biomass CCS Policy Recommendations

Credit must be given to the additional benefits of combining CCS with biofuel production. When evaluating GHG reduction policies, Renewable and Low Carbon Fuel Standards need to be compared to the entire portfolio of potential approaches. Once the decision has been

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made to enact a Renewable or Low Carbon Fuel Standard, then recognition of GHG reduction benefits from using both very low and net-negative CCS-aided CO_2 footprint fuels should be considered as a possible policy approach. If a fair and equitable valuation of their true GHG reduction can be obtained, this will allow biofuels to be compared on a fair basis with other general carbon pricing and mitigation technologies. Lower-carbon ethanol should achieve more recognized GHG reductions for the blended automotive fuel than regular bioethanol, and the lower-carbon ethanol should therefore be able to fetch a higher price (or lower penalty) thus providing a payback for the CCS investment.

It may be possible to obtain an external certification by an accredited outside party for the actual GHG performance of a particular facility or fuel stream, describing their specific circumstances including the presence or absence of CCS. For example, the CARB LCFS allows for producers to submit fuel pathway applications for specific fuel streams [164], where individual fuel carbon intensities are calculated using the LCA models such as CA-GREET and later OPGEE. It is important that these models allow for credits from both conventional and biomass CCS, in order to incent the right behaviors and get the large-scale reductions required. The OPGEE v1.0 model [165] does have a place for "Gas sequestration credit (CO_2 flood)" in the Model Organization worksheet, but it is not immediately obvious how it impacts the final carbon intensity calculations.

As an alternative, offset protocols can be written so that the biomass CCS volumes generate offset credits not only for both the net CO_2 that they displace from avoided gasoline

combustion, but also the biological CO_2 that is removed from the atmosphere and

sequestered using CCS.

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Appendix 1: Detailed LCA Flowchart
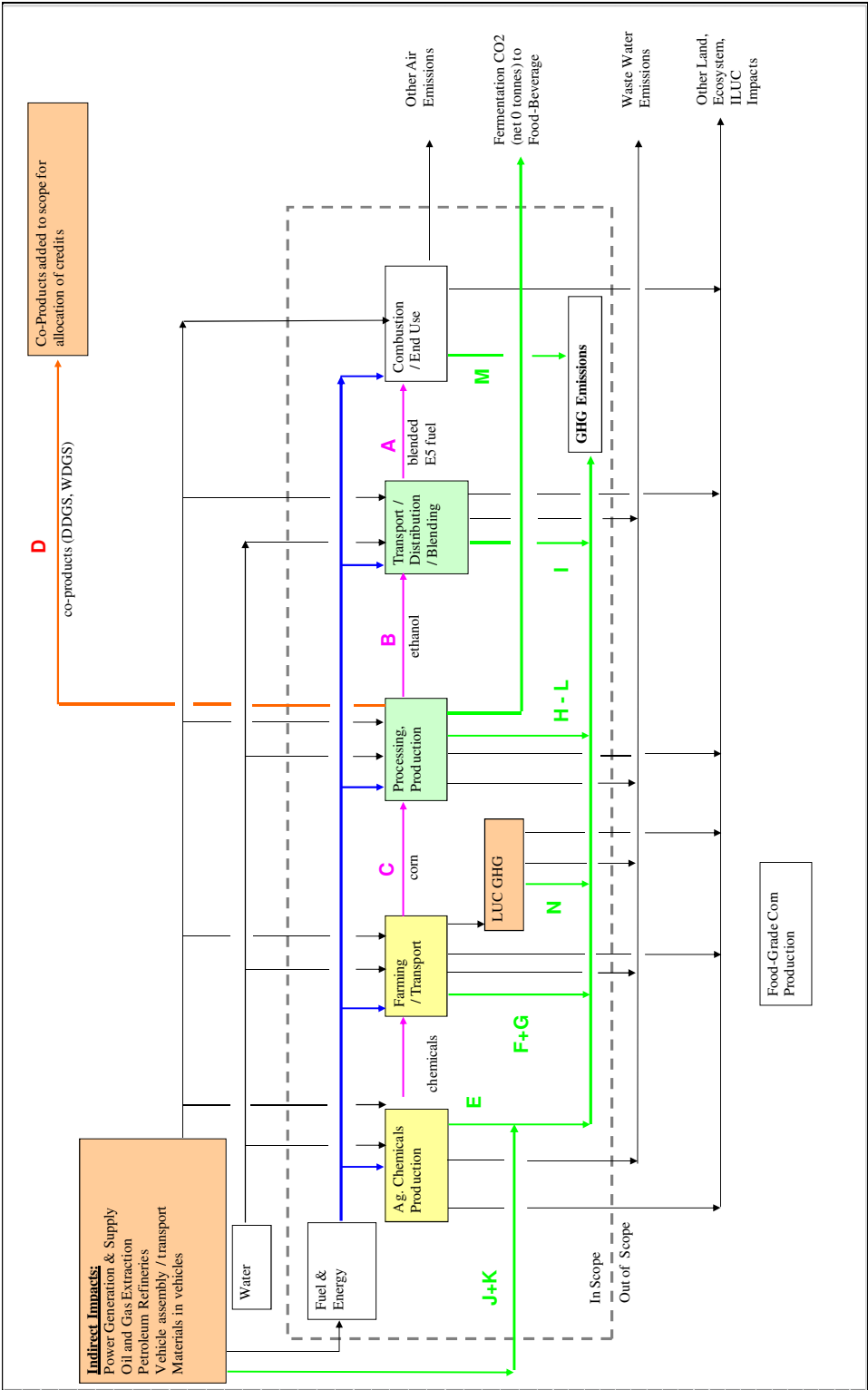
Appendix 2: LCA Calculations

Case 4 St. Clair site-specific data:

Litres of ethanol produced	193,744,506	L ethanol =	4,568,495	GJ of ethanol energy produced	
Functional unit	1,000,000	L ethanol =	23,580,000	MJ of ethanol energy produced	
Scaling factor (1 million L)	193.74				
Energy Content EtOH	23.58	MJ/L	68%		32.7 MM bpd ethanol
Energy Content RFG	34.69	MJ/L			12.9 MM bpd ethanol
MJ energy in 1 MM L EtOH	23,580,000	MJ ethanol energy			22 MMbd gasoline global 2013 forecast
Direct + indirect emissions	93,197.07	tonnes CO2-e in 2009 (constant)			8.74 MMbd gasoline global 2013 forecast
Emissions intensity	481.03	tonnes CO2-e / million litres			
Processing / Production	20.40	gCO2-e/MJ			
Agricultural:	2009				
Corn Received - kg	439,030,080				
Corn Received - lb	967,895,812				
DE, kcal/lb - Corn	1,550	University of Kentucky - digestible energy			
Energy content of corn - kcal	1,500,238,508,693				
Energy content of corn - GJ	6,281,499				
Litres of ethanol produced	193,744,506				
GJ of ethanol produced	4,568,495				
KG of corn per litre of EtOH	2.27				
Proportion of energy into EtOH	72.7%				
Gasoline weight	6.25	lb/gallon	Clean Air Conservancy NETZERO calculator		
Composition C8H18	114.22	g/mol	(100% octane)		
Weight of CO2	44.01	g/mol			
Products (1 C8H18 -> 8 CO2)	352.08	g/mol	assume 100% combustion		
Pounds of CO2 / gallon	19.27	pounds per gallon of gasoline			
Pounds of CO2 / litre	5.10	pounds per litre of gasoline			
Kilograms of CO2 / litre	2.31	kg per litre of gasoline			
Grams of CO2 / litre	2,311.79	g per litre of gasoline	117,236,797	litres / day	
Grams of CO2 / MJ	66.64	g per MJ of gasoline			

Gasoline Consumption	Canadian Gasoline Use 2011	Ontario 2011	US Gasoline Use 2011	Global Gasoline Use 2010	Units
Source: EIA					
	696,419	269,059	8,740,000	22,226,300	bbl / day =
	110,718	42,776	1,389,507	3,533,593	m3 / day =
	110,718,386	42,775,718	1,389,507,154	3,533,593,005	litres / day / litres/day gasoline
	3,840,820,821	1,483,889,651	48,202,003,180	122,580,341,335	MJ / day
Bioethanol required for blending					
	5%	5%	5%	5%	replaced by ethanol
	192,041,041	74,194,483	2,410,100,159	6,129,017,067	MJ / day ethanol
	23.58	23.58	23.58	23.58	MJ/L
	8,144,234	3,146,501	102,209,506	259,924,388	L/day required
	2,973	1,148	37,306	94,872	million L required
Case 4 CO2 savings	ethanol 5%	Case 4 ethanol 5%	Case 4 ethanol 5%	Case 4 ethanol 5%	
	11,199,667,675	4,326,958,151	140,554,960,017	357,438,982,589	g CO2-e/ day
	11,200	4,327	140,555	357,439	tonnes / day
	4,087,879	1,579,340	51,302,560	130,465,229	tonnes / year
Cases 2 & 3 CO2 savings		Cases 2 & 3	Cases 2 & 3	Cases 2 & 3	
	7,850,617,251	3,033,062,524	98,524,637,143	250,553,563,220	g CO2-e/ day
	7,851	3,033	98,525	250,554	tonnes / day
	2,865,475	1,107,068	35,961,493	91,452,051	tonnes / year

Combustion emissions at corn ethanol plants	Value	Units	Note
	440.37	tonnes CO2-e / million litres	
	18.68	g CO2e / MJ direct combustion emissions only	
	85,319.13	tonnes CO2-e total direct	
	0.6728	kg NG / m3	API 2009 Table 3.8 76% carbon
	76%	carbon	
	0.5113	kg C / m3	
	12.0107	MW carbon	
	44.0100	MW CO2	
	1.8736	kg C02 / m3 NG	
	0.0018736	tonnes CO2 / m3	
	235,036.01	m3 NG / million litres	
	0.0342	GJ/m3	API 2009 Table 3.8 LHV
	8,038	GJ / million litres	

2009 combustion energy	1,557,363	GJ	
at corn ethanol plants	8,038	GJ / million L	
	1,437	million L / year	
	11.6	million GJ / year	Requied combustion energy from all Canadian ethanol plants
corn stover	17.57	GJ / tonne	
	457.5	tonnes per million L	
	19.02	GJ / tonne	
	422.6	tonnes per million L	
	3.5	million tonnes per year in Canada	
	61.5	million GJ / year low estimate	
	66.6	million GJ / year high estimate	
torrefied wood pellets			http://www.pellet.org/home/35-serving-the-pellet-industry
	20	GJ / tonne	$ 200.00 CAD per tonne of wood pellets WPAC
116 Euros per tonne	401.9	tonnes per million L	$ 115.04 USD coal price per tonne BP SRWE 2012
137 Euros per tonne	24	GJ / tonne	$ 84.96 CAD price difference
Canadian price per tonne	334.9	tonnes per million L	2.355 tonnes CO2 / tonne coal
$ 148.16	2.9	million tonnes per year in Canada	0.2355 tonnes CO2 / tonne wood pellets
$ 174.98	58.0	million GJ / year low estimate	2.1195 tonnes CO2 saved
	69.6	million GJ / year high estimate	$ 40.08 abatement cost using wood pellets
lignin	13.21	GJ / tonne	http://www.biotechnologyforbiofuels.com/content/4/1/27/table/T7
	608.5	tonnes per million L	

BP Statistical Review of World Energy June 2012
http://www.bp.com/assets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2011/

			emission factor		Gt tonnes C	Gt tonnes CO2	
	B tonnes	B m3	kg C / m3				
oil	234.3	262.73	740.69408		195	714	API 2009 Table 3-8
	Mt A+B	Mt S+L	tonne CO2/tonne	tonne C02/tonne			
coal	404762	456176	2.355	1.643	464	1703	Env. Canada 2009
	TCF	tcm	kg / m3				
gas	7360.9	208.4	0.511328		107	391	API 2009 Table 3-8
					total	2807 Gt CO2	
					one-third	936 Gt CO2	

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Reduction Targets for GHG's

Canada	Baseline	731	Mt (2005)
	Target	17%	
	Reduction	606.73	Mt (2020)
	BAU	124.27	Mt
		850	Mt (2020)
		243.27	Mt (2020)
	Peak	751	Mt (2004)
	Long term	85%	
		112.65	Mt (2050)
	Reduction	638.35	Mt
Ontario	Baseline	176.2	Mt (1990)
	Target	15%	
	Reduction	149.77	Mt (2020)
	BAU	26.43	Mt
		248.77	Mt (2020)
		99	Mt (2020) 99 Mt
	Peak	176.2	Mt (1990)
	Long term	80%	
		35.24	Mt (2050)
	Reduction	140.96	Mt
Global	Baseline	16,855	Mt (1990)
	Target	17%	
	Reduction	13,990	Mt (2020)
	Reduction	2,865	Mt
	Baseline 2	23,845	Mt (2000)
	Long term	85%	
	Target	3,577	Mt (2050)
	Reduction	20,268	Mt

Biofuel combustion

Iowa State

Month	Break-even			Ethanol Price
7-Jan	$1.57			$2.15
7-Feb	$1.70			$1.90
7-Mar	$1.66			$2.19
7-Apr	$1.54			$2.16
7-May	$1.59			$2.17
7-Jun	$1.70			$2.09
7-Jul	$1.48			$1.97
7-Aug	$1.48			$1.86
7-Sep	$1.48			$1.58
7-Oct	$1.45			$1.52
7-Nov	$1.56			$1.74
7-Dec	$1.69			$1.94

Break-even value	Description		Ethanol Price value	Description
$ 1.58	USD per gallon of ethanol		$ 1.94	USD per gallon of ethanol
3.79	litres per gallon		3.79	litres per gallon
$ 0.42	USD per litre of ethanol		$ 0.51	USD per litre of ethanol
23.58	MJ/L ethanol energy content		23.58	MJ/L ethanol energy content
$ 17.65	USD per GJ of ethanol		$ 21.72	USD per GJ of ethanol
2007	reference year		2007	reference year
2%	inflation rate		2%	inflation rate
-	years to reference year		-	years to reference year
1.00	inflation factor 2007		1.00	inflation factor 2007
$ 17.65	USD inflation-adjusted cost in 2007		$ 21.72	USD inflation-adjusted cost in 2007
1.075	2007 CAD / USD conversion rate		1.075	2007 CAD / USD conversion rate
$ 18.97	CAD ethanol production costs		$ 23.35	CAD ethanol production costs

Petro-Canada

Break-even value	Description		Ethanol Price value	Description
2007	reference year		2007	reference year
$ 0.62	CAD per litre of gasoline		$ 0.62	CAD per litre of gasoline
34.69	MJ/L gasoline energy content		34.69	MJ/L gasoline energy content
$ 17.87	CAD per GJ of gasoline		$ 17.87	CAD per GJ of gasoline
$1.10	per GJ ethanol production premium		$5.48	per GJ ethanol production premium
$ 1,095,884	per million GJ		$ 5,481,715	per million GJ
58.9	g CO2e / MJ savings		58.9	g CO2e / MJ savings
58,895	tonnes CO2e per million GJ		58,895	tonnes CO2e per million GJ
$ 18.61	per tonne of CO2e avoided		$ 93.08	per tonne of CO2e avoided

Technology	$ / tonne	$ / litre	$ / km	$ / litre (direct)	% reduction
Bioethanol blending low	$ 19.00	$ 0.06	$ 0.01	$ 0.04	60%
Bioethanol blending high	$ 93.00	$ 0.31	$ 0.05	$ 0.22	60%
Fermentation CCS low	$ 18.00	$ 0.06	$ 0.01	$ 0.04	40%
Fermentation CCS high	$ 41.00	$ 0.14	$ 0.02	$ 0.10	40%
Combustion CCS low	$ 97.00	$ 0.32	$ 0.05	$ 0.23	20%
Combustion CCS high	$ 250.00	$ 0.83	$ 0.12	$ 0.59	20%
Biomass combustion low	$ 16.00	$ 0.05	$ 0.01	$ 0.04	19%
Biomass combustion high	$ 40.00	$ 0.13	$ 0.02	$ 0.09	19%
Fuel efficiency standards	$ 131.58	$ 0.44	$ 0.06	$ 0.31	5%
Air capture low	$ 360.00	$ 1.20	$ 0.18	$ 0.85	100%
Air capture high	$ 1,000.00	$ 3.33	$ 0.49	$ 2.36	100%

[1] Assumes 10 km per 100 litres of gasoline.

0.1	litres per km		
2,357.34	kg CO2 / m3	API 2009 GHG compendium	
0.0024	tonnes / litre	motor gasoline	32% engine efficiency loss from ethanol
0.003325	tonnes / litre		1.41

Passenger - kilometre conversion

	ethanol	gasoline		ethanol	gasoline
passengers / trip	1			2	
fuel type	ethanol	gasoline		ethanol	gasoline
fuel content MJ / L	23.58	34.69		23.58	34.69
fuel efficiency L / km	0.1	0.1		0.1	0.1
g / MJ of fuel energy	1	1		1	1
g / L	23.58	34.69		23.58	34.69
g / km	2.36	3.47		2.36	3.47
g / passenger-km	2.36	3.47		1.18	1.73

Canadian inflation

CPI Canada 2011	2.30%	CPI Canada 2001	0.72 %
CPI Canada 2010	2.35%	CPI Canada 2000	3.20 %
CPI Canada 2009	1.32%	CPI Canada 1999	2.63 %
CPI Canada 2008	1.16%	CPI Canada 1998	1.00 %
CPI Canada 2007	2.38%	CPI Canada 1997	0.78 %
CPI Canada 2006	1.67%	CPI Canada 1996	2.16 %
CPI Canada 2005	2.09%	CPI Canada 1995	1.74 %
CPI Canada 2004	2.13%	CPI Canada 1994	0.23 %
CPI Canada 2003	2.08%	CPI Canada 1993	1.65 %
CPI Canada 2002	3.80%	CPI Canada 1992	2.17 %
10-year average	2.13%		
5-year average	1.90%		

Source: US EPA and RTI, Greenhouse Gas Emissions Estimation

fermentation CO2 emissions =	6.29 lb CO_2 /gallon EtOH
	2.85 kg CO_2 /gallon EtOH
	0.75 kg CO_2 /litre EtOH
	754 tonnes CO_2 / million litres EtOH

CCS data

	Per million L scale	Full plant	
Litres of ethanol produced	193744506 L ethanol = 4.57E+09 MJ of ethanol energy produced		
Energy Content EtOH	23.58 MJ/L		2011
fermentation CO2 =	151,766.16 tonnes =	151,766,163,754 grams	303,532 tonnes
fermentation CO2 intensity =	33.22 g CO2 / MJ		
	783.33 g CO2 / L		
Functional unit	1000000 L ethanol = 23580000 MJ of ethanol energy produced		
Scaling factor (1 million L)	193.744506		
fermentation CO2 mass =	783.33 tonnes / million L ethanol		
	783,331.44 kg CO2 / million L ethanol		
	0.53726 m3 / kg		
		Full plant fermentation emissions	
fermentation CO2 volume =	420,853 m3 CO2 / year	81,537,889 m3 CO2 / year	
	48.04 m3 CO2 / hour	9,307.98 m3 CO2 / hour	
initial pressure	101.33 kPa-a	101.33 kPa-a	
discharge pressure	1200 psi-a	1200 psi-a	
	8,273.71 kPa-a	8,273.71 kPa-a	
compression ratio	81.66	81.66	
per stage CR	3.01	3.01	
	4.00 four stage compressor	4.00 four stage compressor	
F =	1.12 Eq. 13.4 GPSA	1.12 Eq. 13.4 GPSA	
	0.014	0.014	
power requirement	9.06 kW	1,754.92 kW	2386.0 metric horsepower
	12.15 horsepower		
	8,760.00 hours per year	8,760.00 hours per year	
compression energy	79,347.28 kWh / year	15,373,099 kWh / year	
	285.65 GJ / year	55,343.16 GJ / year	
	79.35 MWh / year	223,391.48 m3 CO2 / day	
	23,580 GJ of energy / million litres EtOH	4,568,495 GJ of energy	193.74 million litres EtOH
	1.2% GJ / GJ energy penalty	1.2% GJ / GJ energy penalty	
	0.36 GJ / tonne sequestered	0.36 GJ / tonne sequestered	
		81,537,889 m3 CO2 / year	
$	7.02 per tonne estimated transport cost	223,391 m3 CO2 / day	
$	13.07 per e3m3	28.3 e3m3/mmscf	223 e3m3 CO2 / day
	0.46 cents per mmscf **Reasonable**	151,766.16 t/y fermentation CO2	

CCS Costs from ZEP	Natural gas-fired single-shaft F-class CCGT with post-combustion capture, based on an advanced amine							
Capture	Optimized	Base	EUR/$CAN	$CAN	Optimized	Base		
low fuel price	65.9	91.80	1.3		$ 85.67	$ 119.34		
medium fuel price	79	109.70	1.3		$ 102.70	$ 142.61	$ 121.68	90%
high fuel price	90.2	125.00	1.3		$ 117.26	$ 162.50		
Transport cost								
onshore pipeline, 180 km	1.5	5.40	1.3		$ 7.02		$ 7.02	5%
Storage - onshore								
DOGF, legacy wells	1.00	3.00	7.00	1.30 $	$ 3.90	$ 9.10		
DOGF, no legacy wells	1.00	4.00	10.00	1.30 $	$ 5.20	$ 13.00	$ 6.50	5%
SA, no legacy wells	2.00	5.00	12.00	2.60 $	$ 6.50	$ 15.60		
					average		$ 135.20	
	$ 74.30	$ 104.20			$ 96.59	$ 135.46		
	$ 88.40	$ 125.10			$ 114.92	$ 162.63		
	$ 100.60	$ 142.40			$ 130.78	$ 185.12		

EU ETS allowances	Euros			CAD	
24-Aug-12	6	52 week low		$	7.80
	8	current		$	10.40
	13.1	52 week high		$	17.03

Block 1

	25 years	Life of Facility
	3,794,154	total captured tonnes
$	40,000,000.00	compressor capital cost
$	10,000,000.00	dehy capital cost
	8%	discount factor
$	0.10	per kWh
$	1,537,309.88	per year electricity
	$16,410,438.88	NPV electrical costs
	$66,410,438.88	total project cost
$	$17.50	per captured tonne
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$17.81	per avoided tonne

Total Project Cost

$	17.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	27.43	
$	17.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	40.43	

Block 2

	25 years	Life of Facility
	3,794,154	total captured tonnes
$	140,000,000	compressor capital cost
$	35,000,000	dehy capital cost
	8%	discount factor
$	0.10	per kWh
$	1,537,309.88	per year electricity
	$16,410,438.88	NPV electrical costs
	$191,410,438.88	total project cost
$	50.45	per captured tonne
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$51.33	per avoided tonne

Total Project Cost

$	51.33	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	60.95	
$	51.33	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	73.95	

Block 3

	25 years	Life of Facility
	3,794,154	total captured tonnes
$	240,000,000.00	compressor capital cost
$	60,000,000.00	dehy capital cost
	8%	discount factor
$	0.10	per kWh
$	1,537,309.88	per year electricity
	$16,410,438.88	NPV electrical costs
	$316,410,438.88	total project cost
$	83.39	per captured tonne
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$84.86	per avoided tonne

Total Project Cost

$	84.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	94.48	
$	84.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	107.48	

Scenario 1

		25 years
	3,794,154	total captured tonnes
$	40,000,000.00	compressor capital cost
$	10,000,000.00	dehy capital cost
	8%	discount factor
$	0.35	per kWh
$	5,380,584.57	per year electricity
	$57,436,536.09	NPV electrical costs
	$107,436,536.09	total project cost
$	28.32	**per captured tonne**
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$28.81	**per avoided tonne**
Total Project Cost		
$	28.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	38.43	
$	28.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	51.43	

Scenario 2

		25 years
	3,794,154	total captured tonnes
$	140,000,000.00	compressor capital cost
$	35,000,000.00	dehy capital cost
	8%	discount factor
$	0.35	per kWh
$	5,380,584.57	per year electricity
	$57,436,536.09	NPV electrical costs
	$232,436,536.09	total project cost
$	61.26	**per captured tonne**
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$62.34	**per avoided tonne**
Total Project Cost		
$	62.34	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	71.96	
$	62.34	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	84.96	

Scenario 3

		25 years
	3,794,154	total captured tonnes
$	240,000,000.00	compressor capital cost
$	60,000,000.00	dehy capital cost
	8%	discount factor
$	0.35	per kWh
$	5,380,584.57	per year electricity
	$57,436,536.09	NPV electrical costs
	$357,436,536.09	total project cost
$	94.21	**per captured tonne**
	0.17	tonnes/MWh grid intensity
	15,373	MWh / year
	2,613	tonnes per year from electricity indirects
	65,336	total tonnes from electricity
	3,728,818	total avoided tonnes
	$95.86	**per avoided tonne**
Total Project Cost		
$	95.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	105.48	
$	95.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	118.48	

Scenario 1

Value	Description
	25 years
3,794,154	total captured tonnes
$ 40,000,000.00	compressor capital cost
$ 10,000,000.00	dehy capital cost
8%	discount factor
$ 0.60	per kWh
$ 9,223,859.27	per year electricity
$98,462,633.29	NPV electrical costs
$148,462,633.29	total project cost
$ $39.13	per captured tonne
0.17	tonnes/MWh grid intensity
15,373	MWh / year
2,613	tonnes per year from electricity indirects
65,336	total tonnes from electricity
3,728,818	total avoided tonnes
$39.81	per avoided tonne

Total Project Cost

	Value	Description
$	39.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	49.43	
$	39.81	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	62.43	

Scenario 2

Value	Description
	25 years
3,794,154	total captured tonnes
$ 140,000,000.00	compressor capital cost
$ 35,000,000.00	dehy capital cost
8%	discount factor
$ 0.60	per kWh
$ 9,223,859.27	per year electricity
$98,462,633.29	NPV electrical costs
$273,462,633.29	total project cost
$ 72.07	per captured tonne
0.17	tonnes/MWh grid intensity
15,373	MWh / year
2,613	tonnes per year from electricity indirects
65,336	total tonnes from electricity
3,728,818	total avoided tonnes
$73.34	per avoided tonne

Total Project Cost

	Value	Description
$	73.34	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	82.96	
$	73.34	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	95.96	

Scenario 3

Value	Description
	25 years
3,794,154	total captured tonnes
$ 240,000,000.00	compressor capital cost
$ 60,000,000.00	dehy capital cost
8%	discount factor
$ 0.60	per kWh
$ 9,223,859.27	per year electricity
$98,462,633.29	NPV electrical costs
$398,462,633.29	total project cost
$ 105.02	per captured tonne
0.17	tonnes/MWh grid intensity
15,373	MWh / year
2,613	tonnes per year from electricity indirects
65,336	total tonnes from electricity
3,728,818	total avoided tonnes
$106.86	per avoided tonne

Total Project Cost

	Value	Description
$	106.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	2.60	per tonne avoided Storage Cost
$	116.48	
$	106.86	per tonne avoided Capture Cost
$	7.02	per tonne avoided Transport Cost
$	15.60	per tonne avoided Storage Cost
$	129.48	

Current Reductions

Current Reductions	Ontario	Canada	Global		
Bioethanol -40 g/MJ	1.1	2.9	91	Mt	
Bioethanol -60 g/MJ	1.6	4.1	130	Mt	
Biomass Co-firing 10%	0.05	0.06	4.8	Mt	
Fermentation CCS	0.76	0.92	86	Mt	
Combustion CCS	0.52	0.65	48	Mt	
Ontario High-CO2 Stream CCS	0.84	0.84	0.84	Mt	
Total	3.3	5.3	231	Mt	
	3.7	6.6	270	Mt	9%
	26	124	2,865	Mt	
2020 Reduction	Mt (15%, 1990)	Mt (17%, 2005)	Mt (17%, 1990)		
	141	638	20,268	Mt	1%
2050 Reduction	Mt (80%, 1990)	Mt (85%, 2007)	Mt (85%, 2000)		

Ethanol Production

Ontario Plants	City	Province	Feedstock	Emissions (t/y)	Capacity (Mmly)	t/litre	
29 GreenField Ethanol Inc.	Chatham / Tiverton	Ontario	Corn	297,427	222	1,340	
24 Amaizeingly Green Products	Collingwood	Ontario	Corn	67,179	58	1,158	
30 GreenField Ethanol Inc.	Johnstown	Ontario	Corn	261,392	230	1,136	Prescott
36 IGPC Ethanol Inc.	Aylmer	Ontario	Corn	64,636	162	399	
38 Kawartha Ethanol Inc.	Havelock	Ontario	Corn	110,400	80	1,380	Estimate
43 Suncor St. Clair Ethanol Plant	Sarnia	Ontario	Corn	474,171	400	1,224	Suncor
			total	1,275,205	1152	1,107	35%

656.82

			t CO2-e/year fermentation emissions	756,657	1152		
			t CO2-e/year combustion emissions	518,547	56	kg / GJ	
					8,038	GJ/Mmly	
					9,259,776	GJ	

Canada Plants	City	Province	Feedstock	Emissions (t/y)	Capacity (Mmly)	t/litre	
29 GreenField Ethanol Inc.	Chatham / Tiverton	Ontario	Corn	297,427	222	1,340	
24 Amaizeingly Green Products	Collingwood	Ontario	Corn	67,179	58	1,158	
30 GreenField Ethanol Inc.	Johnstown	Ontario	Corn	261,392	230	1,136	Prescott
32 GreenField Ethanol Inc.	Varennes	Quebec	Corn	99,090	155	639	dry / wet
36 IGPC Ethanol Inc.	Aylmer	Ontario	Corn	64,636	162	399	
38 Kawartha Ethanol Inc.	Havelock	Ontario	Corn	110,400	80	1,380	Estimate
43 Suncor St. Clair Ethanol Plant	Sarnia	Ontario	Corn	474,171	400	1,224	Suncor
35 Husky Energy Inc.	Minnedosa	Manitoba	Wheat & Corn	194,837	130	1,499	28%
			total	1,569,132	1437	1,092	30%

641.81

			t CO2-e/year fermentation emissions	922,279	1152		
			t CO2-e/year combustion emissions	646,853	56	kg / GJ	
					8,038	GJ/Mmly	
					11,550,939	GJ	

United States

Year	Millions of Gallons	Millions of Litres	Year	Millions of Gallons	Millions of Litres
1980	175	662	1996	1100	4,164
1981	215	814	1997	1300	4,921
1982	350	1,325	1998	1400	5,300
1983	375	1,420	1999	1470	5,565
1984	430	1,628	2000	1630	6,170
1985	610	2,309	2001	1770	6,700
1986	710	2,688	2002	2130	8,063
1987	830	3,142	2003	2800	10,599
1988	845	3,199	2004	3400	12,870
1989	870	3,293	2005	3904	14,778
1990	900	3,407	2006	4855	18,378
1991	950	3,596	2007	6500	24,605
1992	1100	4,164	2008	9000	34,069
1993	1200	4,542	2009	10600	40,125
1994	1350	5,110	2010	13230	50,081
1995	1400	5,300	2011	13900	52,617
			t CO_2-e/year fermentation emissions	41,216,726	
			t CO_2-e/year combustion emissions	23,171,009	
			total	64,387,735	

2011 Global

Ethanol

Continent	Millions of Gallons	Millions of Litres	
North & Central America	14,401	54,515	
South America	5,772	21,849	
Brazil	5,573	21,097	
Europe	1,168	4,420	
Asia	890	3,368	
China	555	2,100	
Canada	462	1,750	
Australia	87	330	
Africa	38	145	
Total Ethanol	28,946	109,574	
Total CO_2	85,832,764	t CO_2-e/year fermentation emissions	
	48,253,027	t CO_2-e/year combustion emissions	
	134,085,791	t CO_2-e/year combustion emissions	

	2009	2001		
	U. Kentucky	Cornell	Penn State	
Corn Received - kg	439,030,080	136,133	439,030,080	kg
Corn Received - lb	967,895,812	136,132	967,895,812	lb
DE, kcal/lb - Corn	1,550		6810	Btu/lb *	http://energy.cas.psu.edu/energycontent.html
Energy content of corn - kcal	1,500,238,508,693		6,591,370,480,127.51	Btu
Energy content of corn - GJ	6,281,499		6,954,264	GJ
Litres of ethanol produced	193,744,506			
GJ of ethanol produced	4,568,495		4,568,495	
KG of corn per litre of EtOH	2.27			
Proportion of energy into EtOH	72.7%		65.7%	

* "Coping with High Energy Prices - Heat Energy Content of Shelled Corn", Penn State College of Agricultural Sciences, February 25, 2009

Use the U Kentucky data as it is more recent and conservative.

	DDGS			
Hudson	Atchison	average	WDGS	Feoli et al 2007
1,646	1,333	1,490	*1702.285714*	

University of Kentucky - ME	1550 kcal/lb	http://www.uky.edu/Ag/AnimalSciences/pubs/highoilcornbenefitsforswine.pdf
Penn State - CAS	6,810 BTUs per pound of shelled corn	
	1,716 kcal per pound of shelled corn	
Jacela et al 2007	1855 kcal/lb for corn distillers meal, as-is (wet 12.31%) gross energy	

DDGS Production - kg	138,024,000	
	lb	303,652,800
	516,903,823,542.86	
WDGS Production - kg	5,911,000	
	lb	13,004,200
	19,369,755,900	
	536,273,579,443	
	35.7%	

Ethanol Across America "Food, Feed and Fuel", 2008

1997	126.7	bushels / acre
2007	151.1	bushels / acre
	13,100,000,000	bushels total
	86,697,551	acres under corn cultivation
2002	2.3%	
	10	years
2012	126%	

Inflation in Canada 2002 to 2011

2002	2.26%	1.02
2003	2.77%	1.05
2004	1.86%	1.07
2005	2.21%	1.09
2006	2.01%	1.12
2007	2.14%	1.14
2008	2.37%	1.17
2009	0.31%	1.17
2010	1.78%	1.19
2011	2.91%	1.23

• Through research performed at Cornell University, we know that 1 acre of land can yield about 7,110 pounds (3,225 kg) of corn, which can be processed into 328 gallons (1240.61 liters) of ethanol. That is about 26.1 pounds (11.84 kg) of corn per gallon

| 1 acre to produce | 7110 | pounds of corn = | 3225 | kg of corn |
| 0.404685642 hectare | 328 | gallons of ethanol = | 1240.61 | litres of ethanol |

| 806 | acres to produce | 5,731,051.66 | pounds of corn = | 2,599,528 | kg of corn |
| 326.2 hectares | | | 1,000,000 | litres of ethanol | 7969.149 kg/ha |

Abusing our precious croplands to grow corn for an energy-inefficient process that yields low-grade automobile fuel amounts to unsustainable, subsidized food burning, says the Cornell professor in the College of Agriculture and Life Sciences. Pimentel, who chaired a U.S. Department of Energy panel that investigated the energetics, economics and environmental aspects of ethanol production several years ago, subsequently conducted a detailed analysis of the corn-to-car fuel process. His findings will be published in September, 2001 in the forthcoming Encyclopedia of Physical Sciences and Technology .

Global gasoline use

32.70	MM bpd =	5.198	MM m3/d
		5,198	MM litres / day
		1,897,448.03	MM litres / year
326.2	hectares for	1	MM litres
618,945,499	hectares for	1,897,448	MM litres
1,529,447,636	acres for		

Global agricultural land 2008

48,836,976	km²		FAO Resources page". FAO.org. 2010.
4,883,697,570.00	hectares		
12.7%			

http://www.fao.org/economic/ess/ess-publications/ess-yearbook/ess-yearbook2010/yearbook2010-reources/en/

US gasoline use

12.86	MM bpd =	2.044	MM m3/d
		2,044	MM litres / day
		746,129	MM litres / year
326.2	hectares for	1	MM litres
243,386,603	hectares for	746,129	MM litres
601,421,394	acres for		

US agricultural land 2000

943,000,000.00		EPA AG 101
63.8%		

peak US farm land 1990 =	1150	million acres
US farm land use 2000 =	943	million acres
	207	million acres
	256,806.27	million litres of ethanol per year
	703.58	million litres of ethanol per day
	478.25	million litres of gasoline per day
	0.48	million m3 of gasoline per day
	2.97	million barrels of gasoline per day