Evaluating the economic, environmental and policy impacts of ethanol as a transportation fuel in Pennsylvania

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Stephanie M. Seki

B.S., Civil and Environmental Engineering, Carnegie Mellon University
M.S., Engineering and Public Policy, Carnegie Mellon University

Carnegie Mellon University
Pittsburgh, Pennsylvania 15213

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To three great women:
Evelyn Yasuno Doi Seki
Mildred Sung Soon Thomas
Kathleen Ann Thomas-Sano

Abstract

Natural gas is a growing energy source in the US for various end-uses, and its potential future as a transportation fuel has been the focus of recent policy discussions. Nationally, ethanol is blended with gasoline up to 10% for conventional vehicles, and up to 85% (E85) for use in Flexible Fuel Vehicles (FFVs). Federal mandates require increasing ethanol use in the transportation sector. Meeting the mandates could mean increasing the blend in conventional gasoline, or increasing the use of E85 in FFVs. This dissertation explores the economic, environmental and policy effects from producing ethanol from natural gas, and generally expanding access to ethanol as a transportation fuel (feedstock agnostic). Three processes are considered for producing ethanol from natural gas: (1) autothermal reforming (ATR) with catalytic conversion, (2) TCX, a process that produces intermediate products of methanol and acetic acid, developed by Celanese Corp., and (3) a fermentation process developed by Coskata Inc. I first estimate the cost of producing ethanol from natural gas to power light-duty FFVs in Pennsylvania (PA). Relying on production cost estimates provided by developers and assuming recent natural gas and gasoline prices are good proxies for future prices, I conclude that the cost of producing ethanol with either the Coskata or ATR processes would more likely than not be cheaper than gasoline and corn-based ethanol. However, capital costs from these emerging processes and future natural gas and gasoline prices are highly uncertain.

The NGLF ethanol must also have acceptable greenhouse gas (GHG) emissions, for which an estimate is not currently available in the literature. I find the average life cycle GHG emissions for a 100-yr global warming potential (GWP) are 137 g CO_2-eqiuv/MJ (ATR Catalytic), 119 g CO_2-eqiuv/MJ (Celanese TCX) and 156 g CO_2-eqiuv/MJ (Coskata fermentation), given the uncertainty in some parameters the estimate could be slightly higher or lower. All processes have life cycle emissions well above gasoline, and the 20% reduction from gasoline required by the Renewable Fuel Standard (RFS2). Even in the unlikely scenario of zero emissions from the upstream processes, NGLF ethanol process and combustion emissions are still larger than gasoline, although with more overlap in the error bars. More detailed life cycle assessments with process modeling could refine the emissions estimates. Existing policies incentivize ethanol produced from renewable sources, but no current policy provisions specifically incentivize the use or production of ethanol produced from natural gas.

I conclude the dissertation with estimates of additional refueling costs for an FFV driver and infrastructure costs for expanding E85 access in Pennsylvania. The state recently received government grants for biofuels infrastructure. I find that even with a subsidy to cover average infrastructure costs of \$0.03 to \$1.48 per gasoline gallon equivalent (gge) for the retailer, the consumer would still incur additional costs for refueling more often with E85. A refueling cost subsidy of \$3.60/gge to cover the additional costs is also higher than historical ethanol subsidies. Additionally, a subsidy to encourage E85 use could reduce emissions at a cost equivalent to \$1,320/metric ton CO_2, which is approximately two orders of magnitude above the average social cost of carbon. Therefore, reducing emissions through more ethanol fuel use is not a cost-effective mitigation strategy.

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Chapter 1. Introduction

1.1 Research Motivation

In 2015, the transportation sector accounted for 28% of total energy consumption in the United States (U.S.).[1] Of that, 92% came from petroleum, 3% from natural gas, and 5% from renewable sources including biomass, as shown in Figure 1.1.[1] U.S. energy imports decreased from 30% in 2005 to 13% in 2013, as domestic production increased and energy use decreased.[2] Within that period, the US Congress also enacted the Energy Independence and Security Act (EISA) of 2007, which had the main goals to (1) encourage energy independence and security, (2) increase renewable fuel production, (3) encourage the research and use of greenhouse gas (GHG) emissions capture and storage and (4) improve Federal government energy performance.[3]

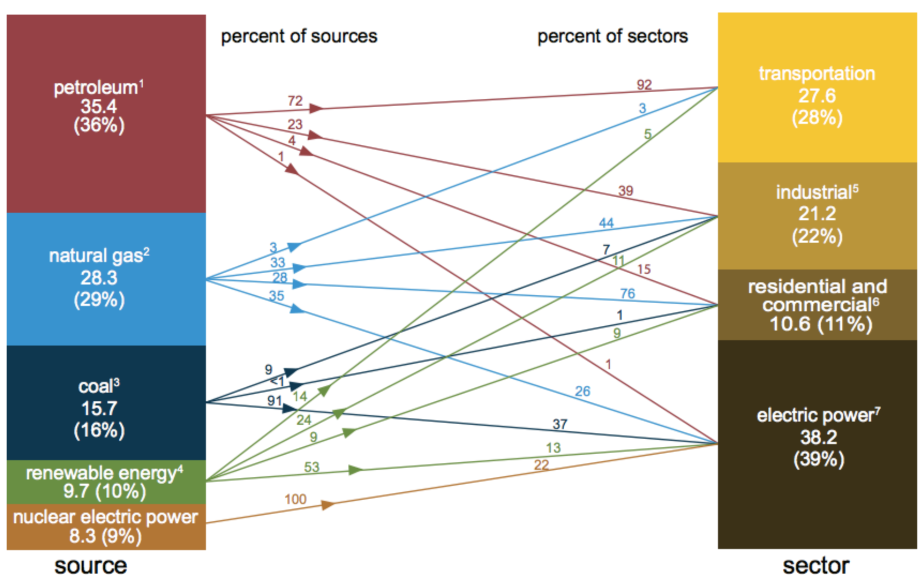


Figure 1.1. Primary Energy Consumption by Source and Sector, 2015 from the Energy Information Administration (EIA).[1]

As a part of EISA, the Renewable Fuel Standard (RFS2) was developed with one key component of mandating the volume of biomass-based, domestically produced renewable biofuels blended in transportation fuels.[3,4] As shown in Figure 1.2 the types of fuels required are renewable biofuel (corn ethanol), cellulosic biofuel, other advanced biofuel and biodiesel. Over time the renewable biofuel requirement levels off, but the other fuel requirements continue to increase. The Environmental Protection Agency (EPA) has been responsible for setting required volumes every year based on gasoline and diesel production and the growth of production technology. The EPA has adjusted the requirement volumes each year from 2011 to 2014 due to an inability to meet the proposed volumes.[4-7] The difficulty in meeting the mandates is attributed to the inability of conventional vehicles to consume more than 10 to 15% ethanol blended with gasoline, thereby hitting the ethanol "blend wall", and the lack of cellulosic and other advanced biofuel development.[7]

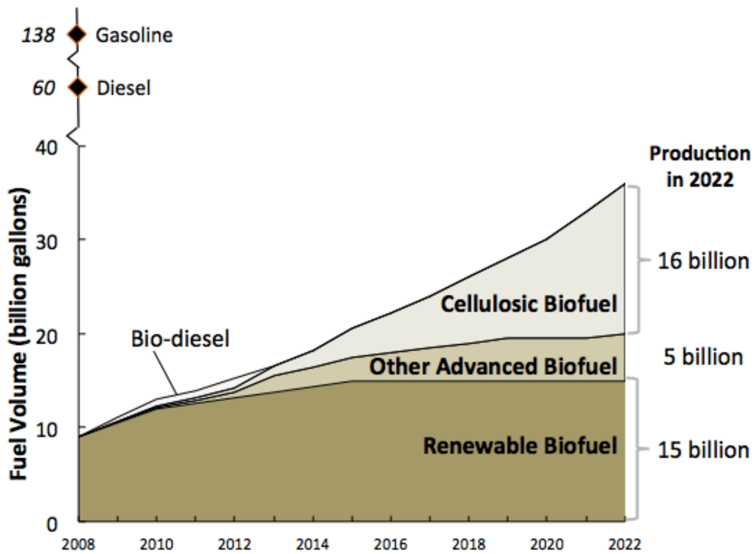


Figure 1.2. RFS2 fuel volume requirements by fuel type till year 2022.[8]

To address demand side limitations to meeting the mandates, this dissertation considers how to increase the use of ethanol in the transportation sector. One possibility is to utilize an existing vehicle fleet of Flexible Fuel Vehicles (FFVs). These FFVs can run on both conventional gasoline and E85 fuel (at most 85% ethanol, 15% gasoline). There are approximately 17 million FFVs in the US, most of which are not utilized in their flex capacity.[9] If FFVs were to use E85 instead of E10 (fuel that is 10% ethanol, 90% gasoline) additional ethanol consumption would be possible.

Since the enactment of EISA and the RFS2, there has been a major change in energy production in the U.S. In 2008, previously inaccessible and unrecoverable natural gas was produced from the Marcellus Shale Deposit in Pennsylvania, New York, Ohio and West Virginia. Dry natural gas production has increased from approximately 18 to 26 trillion cubic feet (Tcf) from 2005 to 2014 as shown in Figure 1.3.[10] During the period of 2005 to 2013, the average price of natural gas, based on Henry Hub prices, dropped from \$8.69 to \$3.73 per million Btu as shown in Figure 1.4. The large quantity and low price of natural gas make finding uses for it attractive, and the transportation sector is one area that could benefit.

Much of the attention for natural gas use in the transportation sector has been given to using compressed or liquefied natural gas (CNG/LNG) as fuel[11-13], but both approaches have substantial drawbacks, particularly for widespread adoption in light-duty vehicles.[14-16] CNG is best suited for high mileage and centrally located vehicles – typically medium and heavy-duty vehicles – as the upfront cost of purchasing or converting a vehicle is much higher than its gasoline or diesel powertrain equivalent.[17,18] CNG fuel costs are lower than petroleum-based fuels, so a sufficiently high-mileage driver can recover higher purchase costs with operation fuel cost savings.[19] Similarly, LNG is best used for heavy-duty vehicles with large tanks that attain high-mileage to offset costs.[19] The only light-duty dedicated CNG vehicle, the Honda Civic, was discontinued as of model year 2015 leaving no options for the light-duty sector besides aftermarket conversion.[20,21]

Given abundant natural gas and the underutilized FFVs, I explore if natural gas could be converted to ethanol and used in the existing FFV fleet. Although a natural gas-derived liquid fuel (NGLF) is not considered renewable it could still encourage energy security and independence, and has the potential to reduce greenhouse gas emissions and the cost of ethanol. In chapters Two and Three of this dissertation I estimate the private cost and emissions impacts of potential processes that produce a NGLF ethanol.

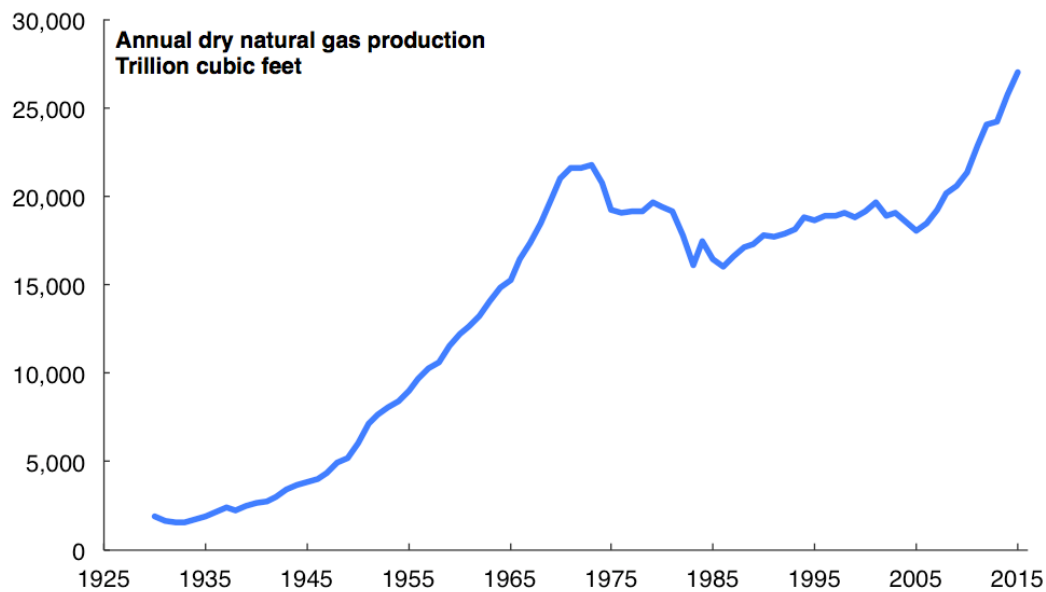


Figure 1.3. Dry natural gas production 1930 to 2014 from the Energy Information Administration (EIA).[10]

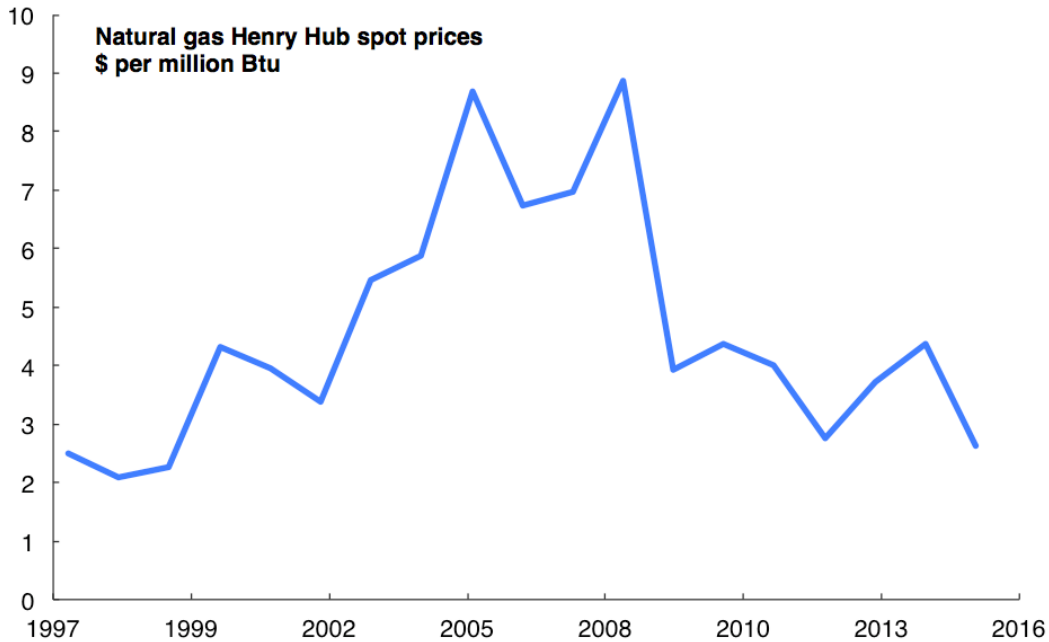


Figure 1.4. Henry Hub natural gas spot prices 1997 to 2013 from the Energy Information Administration (EIA).[22]

Whether ethanol is produced from corn or natural gas, the underutilization of E85 in existing FFVs is a critical issue in meeting the RFS2 mandates. Although there are vehicles available to use E85, there are many reasons why they may not be refueled with E85, the most important being price and convenience.[23] As of October 2015, there were 2,679 public stations that sell E85.[18] If private stations are included, there are an additional 312 stations.[18] The Bureau of Labor Statistics (BLS) estimates there are approximately 105,000 total gasoline stations in the U.S.[24], which means only 2.5% of them sell E85. Analyses have estimated that the availability of an alternative fuel is no longer an issue to drivers when availability, measured by the percent of stations in the study area selling the alternative fuel, is between 10-30%.[25,26] Understanding the cost of expanding access and use of E85 to consumers, retailers and the government is crucial to making informed transportation policy decisions.

Each of the chapters in this dissertation use Pennsylvania as a case study. Pennsylvania was selected because it is where the researchers are located, at the center of the Marcellus Shale gas development and because I had access to Pennsylvania vehicle registration, emissions and safety data all of which are used in these analyses.

1.2 Dissertation Overview and Research Questions

This dissertation assesses the impacts of ethanol use in the transportation sector using quantitative modeling methods in three separate chapters. The research questions for each chapter are listed here.

1. In the second chapter I explore if there is the potential to produce cost competitive ethanol made from natural gas. The specific research questions include:
   (a) Is there a feasible process for making ethanol from natural gas?
   (b) How do process parameter values and assumptions impact the overall costs?
   (c) Where in Pennsylvania should NGLF plants be located? How do the processing costs compare to corn ethanol and gasoline?

2. In the third chapter I will build upon the second chapter's evaluation of NGLF ethanol, and will estimate the GHG and discuss criteria air pollutant (CAP) emissions for converting natural gas to ethanol. The specific research questions include:
   (a) Are there data available for a life cycle GHG emissions estimate of an NGLF ethanol?
   (b) What are the life cycle GHG emissions for an NGLF ethanol?
   (c) How do the GHG emissions compare to gasoline, corn ethanol and other natural gas based fuels? Can a NGLF ethanol meet the RFS2 GHG emissions reduction targets?
   (d) What are the implications of the emissions results? What are the limitations in the results?

3. In the fourth chapter I will explore the issue of E85 availability. Even if ethanol could be made from natural gas cost competitively and within allowable emissions, there is still the ongoing issue of minimal E85 use in the U.S. In this chapter I use Pennsylvania as a case study to estimate the costs for increasing availability and use of E85 to the consumer, retailer and the government. The specific research questions include:
   (a) How available is E85 in Pennsylvania? How many FFVs have reasonable access?
   (b) What is the difference in cost for FFV drivers to refuel on E85 compared to E10?
   (c) What are the infrastructure costs to increase the availability of E85?
   (d) What needs to change to encourage more E85 use? What are the policy implications?

1.3 Background

The relevant background information for the thesis is included below divided into sections including ethanol, natural gas liquid fuels, natural gas emissions and E85 fuel distribution and use.

1.3.1 Ethanol and the RFS2

Ethanol is produced in the U.S. to be blended with gasoline blendstock and consumed in the transportation sector. Total ethanol consumption increased from 3.6 billion gallons in 2004 to 13.9 billion gallons in 2015[27], supported by the EISA 2007 and the RFS2. According to the U.S. Energy Information Administration, almost all of US gasoline is 10% ethanol.[28] The EPA has approved all light-duty vehicles to run on E10.[29] However, only light-duty vehicles of model year 2001 and newer are approved for E15 use, and only FFVs are approved for E85 use.[29] Given the prevalence of ethanol in the transportation sector, there is a body of previous work that has looked into the impacts from ethanol use motivated by EISA and the RFS2. The types of analyses that have been done can be divided into a few categories for which there is overlap.

The general ethanol literature related to the RFS2 involves assessments of the processes to make cellulosic and other advanced biofuels (sugarcane). Cellulosic ethanol includes feedstock such as wood, grasses or inedible plants. There are numerous studies that have evaluated thermochemical and biochemical processes for converting cellulosic feedstock to ethanol. Some studies are economically focused[30-36], and some include environmental impacts.[37-40] Whether a thermochemical or biochemical process is better depends on the type of feedstock and the model assumptions, which are not always consistent between studies.

The impact of the RFS2 mandates on ethanol prices and markets was explored in a few papers, which found that consumers can experience some fuel price benefits from ethanol production[41-43] with few long-term disturbances to the agricultural market.[44] The EPA also conducted a thorough Regulatory Impact Analysis (RIA) that covered among other issues, ethanol production, FFV and other vehicle use, fuel availability, emissions and fuel pricing.[4] Other studies and reports have built upon the RIA, and considered the blend wall limitations surrounding the RFS2.[45-49] Continual updates and waivers on some of the biofuel volume requirements, particularly cellulosic ethanol, keep this regulation continually analyzed.[4-7] A study by Meyer and Thompson (2012) discusses how cellulosic ethanol waivers from the EPA could negatively impact both overall GHG emission reductions and the cost of compliance.[50]

RFS2 mandates are managed through a Renewable Identification Number (RIN) system. Each RIN is attached to a single gallon of renewable fuel produced. Gasoline and diesel transportation fuel suppliers are required to produce a specific quantity of renewable fuels (per the RFS2), which are based on a percentage of their total annual fuel sales.[51] The company's obligatory renewable fuel quantity is referred to as the renewable volume obligation (RVO), and fuel suppliers can meet RVO's by earning (through production) or purchasing RINs.[51] A RIN is a commodity that can be bought and sold. The value of a RIN is linked to total blended ethanol, and how much non-RVO companies are participating in the market.[51] The value of a RIN can impact decisions on whether a RVO company decides to purchase a RIN or blend additional ethanol.[52] A non-RVO company could blend their own fuel, produce RINs that they are not obligated to obtain and sell RINs for profit. Studies on the impact of a RIN system have shown that the value of a RIN is dependent on the hierarchical system of the RFS2 (the tiered volume requirements), and the gap between RVOs and RIN holders who are not RVOs.[53,54]

1.3.2 Emissions from Ethanol

One major goal of the EISA 2007 is to promote energy independence and security, while also reducing GHG emissions from the transportation sector. The renewable fuels included in the RFS2 must at a minimum reduce GHG emissions by 20% from the baseline gasoline life cycle GHG emissions for corn ethanol, a 50% reduction for advanced biofuels and a 60% reduction for cellulosic biofuels.[3] Corn ethanol has been estimated to have life cycle GHG emissions less than or equal to gasoline.[55-58] However, when accounting for direct and/or indirect land use change (LUC) some studies have found that corn ethanol life cycle GHG emissions can actually be larger than gasoline.[59-61] The GREET model finds that even with land use change there are still reductions in GHG emissions with corn ethanol.[62] GHG emissions from cellulosic and other advanced ethanol are estimated to have significant reductions in GHG emissions when compared to gasoline.[40,62-65] Some of these studies also emphasize the need for stochastic modeling due to the uncertainty in the estimates that could impact policy decisions.[63,66] Posen et al. (2014) suggests that expanding the RFS2 to include some biofuel use in the chemical (plastics) industry could help to meet the mandates without compromising the GHG emission reduction goals.[66] Other consider various ethanol blends used in vehicles, and find some differences in the life cycle emissions.[67,68]

In addition to GHG emissions, CAP emissions can have an impact on the environment, and to public health. CAP estimates for ethanol (and E85) compared to gasoline have found differences in NOx that can impact both ozone and particulate matter, but also depend greatly on the source of the ethanol.[69-71] Additionally, the severity of some CAP emissions impacts can increase with colder temperatures.[72] CAP emission impacts are location dependent. Tessum et al. (2012) discuss the value in understanding both the spatial and temporal parameters in a model. The authors find that CAP emissions for ethanol are concentrated in the Midwest where it is produced, and find differences over time due to the seasonality of farm products when compared to gasoline.[73]

1.3.3 NGLF Ethanol

The use of natural gas feedstock for ethanol is not covered in the existing peer-reviewed literature, and the second and third chapters of this dissertation on NGLF ethanol costs and emissions are novel contributions. Some previous work have estimated emissions from converting ethane (a co-product of methane) to ethanol through ethane cracking and catalytic ethylene hydration.[16,66,74] Instead, I consider three processes for converting NG (methane) to ethanol, selected to represent a range of technologies under development. The processes include: (1) methane autothermal reforming (ATR) with catalytic conversion to synthesis gas (syngas) and then to ethanol, (2) the conversion of acetic acid, produced from syngas, to ethanol developed by Celanese Corp. (TCX), and (3) ethanol fermentation using syngas as the feedstock, developed by Coskata Inc.[31,75-77]

The three NGLF ethanol processes assume methane is converted into syngas through ATR or steam methane reforming. Previous studies on these processes were used to inform the work, including papers that discuss detailed processes[75,78,79], costs[75,80,81] and emissions.[16,78,82] The syngas is then processed into ethanol by catalytic conversion, acetic acid processing or fermentation. I used additional literature on the transformation of syngas into ethanol (typically biomass-based). These reports and journal articles included detailed processes[31,38,79,83-89], costs[31,80,81] and emissions.[31,40,84-86]

1.3.4 Natural Gas Upstream and Fuel Use Emissions

In addition to understanding the processes for converting natural gas into ethanol, I include natural gas feedstock considerations. The primary issue surrounding natural gas is upstream emissions including pre-production, production, processing, transmission and distribution. Natural gas upstream emissions were assumed to be from Shale Gas production, which made up over 40% of gross natural gas withdrawals in the U.S., 29% from Pennsylvania in 2014.[90] Numerous studies have estimated the GHG emissions for shale gas upstream emissions with resulting ranges from 8.3 to 26.6 g CO_2-equiv/MJ.[91] Here I use the estimates from Tong et al. (2015) of on average 17.2 (100-yr Global Warming Potential, GWP) to 30.3 (20-yr GWP) g CO_2-equiv/MJ, which have an average implicit methane leakage rate of 1.3% to 2.0%. Ongoing research continues to examine the methane emissions from natural gas production and transmission. The EPA also tracks GHG emissions, including methane leakage from the natural gas system, in its GHG inventory reports as a commitment to addressing climate change.[92] A reconciliation study to match top-down and bottom-up approaches in the Barnett Shale formation was also recently published, and provides encouragement for better emissions estimates.[93-97]

In addition to the cost differences, emissions estimates for light-duty, medium-duty and heavy-duty vehicle natural gas pathways vary. A recent study by Tong et al. found that CNG fuel could have emissions reductions of 0-6% (mean values) for medium-duty vehicles when compared to baseline petroleum fuels.[14] However, the authors also found that for Class 8 heavy-duty transit buses and trucks, CNG, GHG emissions *increase* on average when compared to conventional diesel.[14] The same study by Tong et al. similarly found that for Class 8 heavy-duty transit buses and trucks, LNG has greenhouse gas emission increases on average when compared to conventional diesel.[14] Luk et al. found that some air emission benefits are possible when comparing a gasoline vehicle to a CNG vehicle without increasing ownership costs.[98] Tong et al. report that for light-duty vehicles, CNG vehicle emissions are comparable to conventional gasoline, and ethanol made from ethane has larger emissions than conventional gasoline.[16]

1.3.5 E85 Distribution and Use

The fourth chapter in this dissertation discusses the issues surrounding the distribution and use of E85 in the transportation sector, which is relevant regardless of the ethanol feedstock type. A few reports from the National Renewable Energy Laboratory (NREL) have focused on E85 at the station.[23,99-101] Johnson and Melendez (2007) discuss the business case for selling E85, and find that converting a mid-grade tank to E85 coupled with adequate fuel sales is the most economical way to make infrastructure changes.[100] The authors suggest selling E85 is a way to differentiate a particular station from others.[100] Bromiley et al. (2008) conducted statistical analyses on nine years worth of data for E85 sales in Minnesota, and found the most important factors influencing E85 sales were price differential with gasoline and fuel availability.[23] Corts et al. (2010) suggested that starting with government fleet use of E85 could increase overall retail sales of the fuel.[102] Greene (1998 and 2008) used survey methods and economic models to analyze consumer preferences for E85.[25,103] He found that the marginal value of availability decreases as a percent of the stations offering the a fuel increases, and typically hits a plateau around 25% availability.[25,103] For E85 specifically, Greene found to meet the 2017 RFS2 goals, even with high oil prices, 30 to 80% of existing stations need to offer E85, and there need to be 125 to 200 million FFVs.[103] Even accounting for the uncertainty in the modeling, meeting the national goals for 2017 will be difficult.[103]

Westbrook et al. (2014) and Pouliot & Babcock (2014) built upon the research from Greene (1998 and 2008) regarding E85 consumption. Westbrook et al. (2014) considered the inclusion of cellulosic ethanol and alternate vehicle technologies such as hybrid and plug-in hybrid vehicles.[104] The analysis showed that an increase in E85 fuel use was more dependent on price differential between E85 and gasoline than infrastructure, and that the RFS2 may be met at extreme high values for oil prices combined with low biomass feedstock prices.[104] Westbrook et al. concluded that enforcement may be required to meet RFS2 mandates.[104] Pouliot & Babcock (2014) derive a demand model for E85, and find that existing FFV fleet could consume 15 billion gallons without a large price discount only if there is a much larger number of stations.[105] Similarly to other assessments of the state of E85, they conclude that an increase in stations selling E85 and lower E85 prices are needed to meet long term goals. The Pouliot & Babcock paper also novelly includes a "convenience cost" for using E85, which accounts for the added cost of having to drive further to get to a station that sells E85.[105] I use the concept of a convenience cost in the fourth chapter of this dissertation.

Locating alternative refueling stations has been covered in many studies, most of which use more sophisticated geographical information systems or optimization modeling.[106-110] Detailed modeling can be useful for specific station locations and incorporating street flow data, but many other station location studies have used simpler geographical location tools to perform station location analyses.[26,111-113] In this thesis I perform a broader locational analysis using ZIP code locations, while trying to maximize access to E85. Finally, when considering where to place biofuel facilities for Chapter 2, I follow a similar approach for production facility locations to prior work on biofuel facility locations and distribution optimization using linear and mixed linear integer programming models.[114-119]

Chapter 2. Assessing the Economic Viability of Ethanol Produced from Natural Gas to Power Light-Duty Vehicles in Pennsylvania.

2.1 Abstract

Natural gas has become a growing energy source in the U.S. for various end-uses, and its potential future as a transportation fuel has been the focus of recent policy discussions. I estimate the cost of producing ethanol from natural gas to power light-duty Flexible Fuel Vehicles in Pennsylvania (PA). I construct a mixed integer linear programming model to minimize annualized costs by choosing the capacities and locations of potential natural gas-derived ethanol plants in PA, satisfying a pre-specified light-duty vehicle fuel demand. Three processes are considered for producing ethanol from natural gas: (1) autothermal reforming (ATR) with catalytic conversion, (2) TCX, a process that produces intermediate products of methanol and acetic acid, developed by Celanese Corp., and (3) a fermentation process developed by Coskata Inc. If I rely on production cost estimates provided by developers and assume recent natural gas and gasoline prices are good proxies for future prices, I conclude that the cost of producing ethanol with either the Coskata or ATR processes would more likely than not be cheaper than gasoline and corn-based ethanol. However, capital costs from these emerging processes and future natural gas and gasoline prices are highly uncertain. Thus, I provide an assessment of the robustness of the processes' economic viability under different assumptions. I find that if capital costs in practice are 1.2 to 3.7 times more expensive than estimated currently, as suggested by the pioneer plant literature, it becomes more likely that the natural gas-derived ethanol will be more expensive than the existing fuels. I also identify optimal plant locations to minimize costs near the demand centers of Pittsburgh and Philadelphia, under regionally uniform natural gas feedstock prices. Existing policies incentivize ethanol produced from renewable sources, but no current policy provisions specifically incentivize the use or production of ethanol produced from natural gas.

This chapter is based on the working paper: *Seki, S. M., Griffin, W. M., Michalek, J. J., Azevedo, I. L. and Hendrickson, C. (2016) Assessing the Economic and Environmental Viability of Ethanol produced from Natural Gas to Power Light-Duty Vehicles in Pennsylvania.*

2.2 Introduction

Natural gas (NG) is a widely used energy source for heating and electricity production; however, plays only a minor role in the transportation sector. In transportation, NG is used as compressed NG (CNG) or liquefied NG (LNG) in dedicated vehicles. Alternatively, it can be converted to liquid fuels, like ethanol or methanol for use by the existing light-duty fleet. I refer to these latter fuels as natural gas-derived liquid fuels (NGLFs). NGLFs have historically been economically uncompetitive with petroleum-based fuels, but recent changes in technology, NG prices, and legislative support for alternative transportation fuels could increase the economic viability of NGLFs. In this work, I compare the costs of producing ethanol NGLF with petroleum-based fuels and corn ethanol.

Currently the U.S. renewable fuel standard (RFS2) mandates bioethanol blending. The mandate encourages domestic ethanol production from corn and cellulosic sources. The purpose of the RFS2 is to promote energy independence and security and reduced greenhouse gas emissions through increased renewable fuel use over time.[3,4] Although NG is not considered a renewable fuel, these goals could also potentially be achieved by NG use as a transportation fuel. The U.S. has abundant NG resources and recent work has demonstrated reduced emissions compared to fossil alternatives for a few pathways (though it has also shown an increase in emissions for others).[14,16]

Proposals for transportation use of NG typically focus on CNG and LNG.[11-13] However, upfront cost for NG vehicle purchase or conversion[17,18] and required high mileage use to recover fuel cost savings[19] prevent widespread adoption in light-duty vehicles[14-16]. LNG is best suited for heavy-duty vehicles with large tanks that attain high-mileage to offset costs.[19] In contrast, a NGLF could be blended with gasoline and seamlessly integrated into the current fueling infrastructure, making it readily available for use in the current light-duty conventionally fueled fleet.

I consider three processes for converting NG to ethanol, selected to represent a range of technologies under development. The processes include: (1) methane autothermal reforming (ATR) with catalytic conversion to synthesis gas (syngas) and then to ethanol, (2) the conversion of acetic acid, produced from syngas, to ethanol developed by Celanese Corp. (TCX), and (3) ethanol fermentation using syngas as the feedstock, developed by Coskata Inc.[31,75-77] Figure 2.1 provides an overview of the three processes. All processes begin with processed NG, assumed to be 100% methane. Although some intermediate steps are similar, the three processes each generate ethanol through a unique production pathway. This is not an exhaustive list of possible processes. Alternative combinations of intermediate steps could result in more efficient or cost-effective processes that are not explored here.

I construct an optimization model to estimate the least-cost plant locations and plant capacities for producing NGLF ethanol in Pennsylvania (PA) to satisfy state demand using the three processes. I consider three different demand cases: ethanol demand for E85-capable vehicles only, E10 only in light-duty vehicles, or both E85-capable and light-duty vehicles fueled with E10 in PA. I follow a similar approach to prior work on biofuel facility locations and distribution optimization.[114-118] PA was chosen as a case study, as it produces approximately 3 Tcf of NG annually, second only to Texas[120], and its location between the Midwest and the East Coast could provide access to larger demand markets for NGLF ethanol. Finally, there are over 600,000 FFVs registered in the state, which is in the top 10 for the U.S.[121,122]

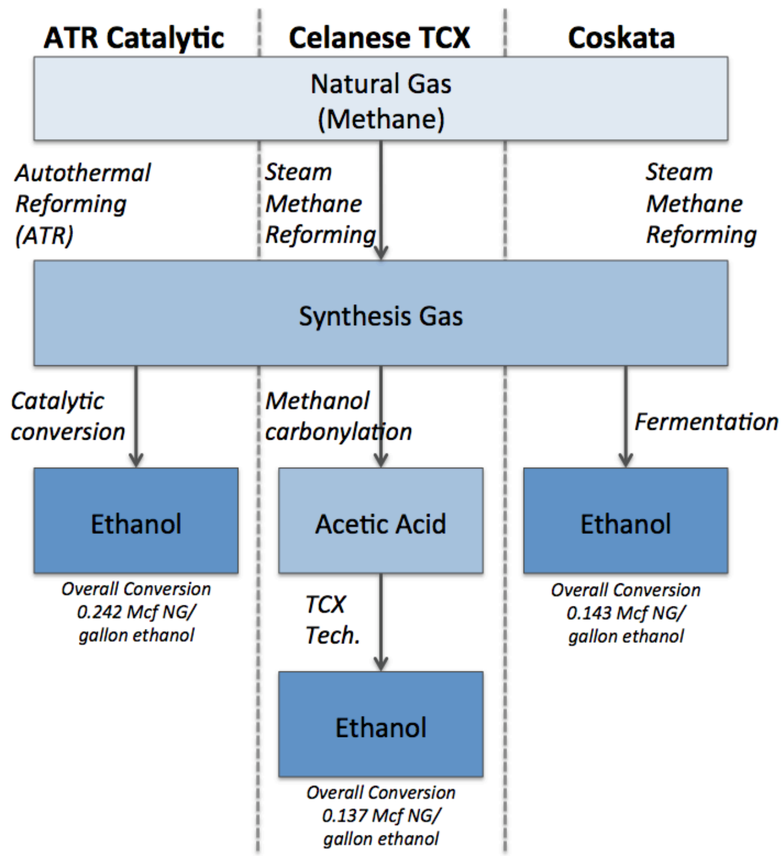


Figure 2.1. NGLF processes to make ethanol. The first columns describes the ATR catalytic process; the middle column the Celanese TCX process; and the third column the Coskata process.[31,76,77,80]

2.3 Data & Methods

I first define the mixed-integer linear programming (MILP) model used to optimize plant capacity and location for each process to satisfy demand at minimum cost, and then describe data and assumptions used for cost and ethanol demand in PA.

2.3.1 MILP Model

I constructed a MILP model to identify optimal plant location and capacity to minimize annualized costs subject to several constraints. Plant locations and demand locations were represented with county-level resolution using county centroid locations. The optimization problem is posed as:

$$\text{minimize } \sum_{i=1}^{P}\left(\underbrace{\sum_{j=1}^{J} c_j^{\mathrm{CAP}} x_{ij}^{\mathrm{CAP}} + \left(c_j^{\mathrm{CAP}} f^{\mathrm{OM}}\right)}_{\substack{\text{Annualized Plant}\\ \text{Capacity Costs}}} + \underbrace{\sum_{l=1}^{L} c^{\mathrm{NG}} \eta^{-1} x_{il}^{\mathrm{TR}}}_{\substack{\text{NG Feedstock}\\ \text{Cost}}} + \underbrace{\sum_{l=1}^{L} \left(c^{\mathrm{FT}} + c^{\mathrm{VT}} d_{il}\right) x_{il}^{\mathrm{TR}}}_{\substack{\text{EtOH Transport}\\ \text{Cost}}}\right) \tag{1}$$

with respect to

$$x_{ij}^{\mathrm{CAP}} \in \mathbb{R}, x_{il}^{\mathrm{TR}} \in \mathbb{R}, y_{ik} \in \{0,1\}$$
$$\forall i \in \{1, \dots, P\}, j \in \{1, \dots, J\}, k \in \{1, \dots, J-1\}, l \in \{1, \dots, L\}$$

subject to

$$\sum_{i=1}^{P} x_{il}^{\mathrm{TR}} = q_l \;\; \forall l \tag{2}$$
$$\sum_{j=1}^{J} \kappa_j x_{ij}^{\mathrm{CAP}} \geq \sum_{l=1}^{c} x_{il}^{\mathrm{TR}} \;\; \forall i \tag{3}$$
$$\sum_{j=1}^{J} x_{ij}^{\mathrm{CAP}} = 1 \;\; \forall i \tag{4}$$
$$\sum_{k=1}^{J-1} y_{ik} = 1 \;\; \forall i \tag{5}$$
$$x_{i1}^{\mathrm{CAP}} \leq y_{i1} \tag{6}$$
$$x_{ij}^{\mathrm{CAP}} \leq y_{ij} + y_{i(j-1)} \;\; \forall j \in \{2,3, \dots, J-1\} \tag{7}$$
$$x_{iJ}^{\mathrm{CAP}} \leq y_{i(J-1)} \tag{8}$$

where c_j^{CAP} is the annualized plant construction cost of capacity level j (i.e., the capital cost of the plant times the capital recovery factor); x_{ij}^{CAP} is the continuous component and y_{ij} is the integer component for piecewise-linear interpolation between cost point estimates c_j^{CAP} provided by the producers for costs at fixed capacity levels $j \in \{1, \dots, J\}$ for each plant $i \in \{1, \dots, P\}$; f^{OM} is the annual operation and maintenance costs expressed as a percent of total capital cost; c^{NG} is the average cost of purchasing NG per thousand cubic feet (Mcf); η is the amount of ethanol produced per unit of NG feedstock in gallons per Mcf; x_{il}^{TR} is the quantity of ethanol transported from plant i to demand location l in gallons; c^{FT} is the fixed transportation cost per gallon; c^{VT} is the variable transportation cost per gallon-mile; d_{il} is the distance from plant location i to ethanol demand location l in miles; q_l is the quantity of ethanol demanded at location l in gallons; κ_j is the capacity of a plant with capacity level j in gallons; P is the number of candidate plant locations; J is the number of plant capacity cost data points; and L is the number of county demand locations.

Equation (2) ensures that ethanol demand q_l is satisfied in each county; Equation (3) ensures that the plant capacity is sufficient to produce its output; and Equations (4-8) ensure that x_{ij}^{CAP} and y_{ij} correspond to a point on the piecewise linear curve passing through data points $\left(\kappa_j, c_j^{CAP}\right)$ for each plant i.

I computed transportation distances using the Geographical Information Systems (GIS) program ArcMap with county-to-county centroid street network distances.[26,108,111] Table 2.1 summarizes the universal parameter values assumed and their sources. Section 2.2 provides additional detail and justification for the process cost assumptions.

Table 2.1. Optimization model parameters.

Symbol	Value	Units	Description	Source / Justification
c^{VT}	\$0.02	USD / gal-mi	Variable transportation cost	Parker et al. (2008)[123]
c^{FT}	\$0.02	USD / gal	Fixed transportation cost	Parker et al. (2008)[123]
c^{NG}	~\$2 to \$8	USD / Mcf	NG price	EIA NG Prices [2,124]
P	58 or 67	#	Number of plant counties	Based on location of NG pipelines in PA. See Appendix A Section A.1 (Figure A.2).
L	67	#	Number of demand counties	Number of PA counties.
J	6	#	Number of capacity levels	Based on available data for capacities shown in Table A.1 in Appendix A.
d	0 to 380	mi	Distance from plant to demand counties. Varies by county.	Street network calculated distances using county-to-county centroids.
q	0.2 to 71	Million gal	Demand quantity per county. Varies by county.	Estimated based on the number of automobiles. See Table A.3 in the Appendix Section A.4.
η	ATR - 0.242 Celanese - 0.137 Coskata - 0.143	gal / Mcf	Conversion from Mcf to gallons of ethanol	ATR Catalytic [31,80] Celanese [80] Coskata [80]
$\boldsymbol{\nu}$	1.5	gge/gal	Conversion from gallons to gge of ethanol	

Note: Plant life is assumed to be 30 years. The dollar values are real, and I assume they do not change over time. Given that the costs are compared, I assume they are similarly inflated over time.

2.3.2 Cost Data

Capital costs, operation and maintenance (O&M) costs, feedstock costs, and transportation costs for the three NGLF processes were used in the objective function. Capital costs were annualized, and all other costs were expressed on a yearly basis. The estimates were taken from existing literature and reports, adjusted to have consistent assumptions wherever possible, as summarized in Table A.1 and Table A.2 in Appendix Section A.2.

I used the following framework to estimate capital cost curves. First, I identified total plant cost c_0^{TCAP} for a given capacity κ_0 based on available data. I then developed a power law scaling model to estimate costs of other plant capacity values κ. The power law represents the economies of scale associated with increasing production capacity:

$$c^{\text{TCAP}}(\kappa) = c_0^{\text{TCAP}} \left(\frac{\kappa}{\kappa_0}\right)^p \tag{9}$$

where p is an assumed or estimated capital scaling factor. I then computed annualized capital costs c_j^{CAP} at selected capacity levels κ_j (listed in Table A.1) as

$$c^{\text{CAP}}(\kappa) = c^{\text{TCAP}}(\kappa)\frac{r}{1-(1+r)^{-n}}$$

$$c_j^{\text{CAP}} = c^{\text{CAP}}(\kappa_j) \tag{10}$$

where r is the discount rate and n is the plant's life in years.

For ATR and catalytic conversion costs the estimates were based on Pei *et al.* (2014), who assessed the conversion of NG to syngas, and a National Renewable Energy Laboratory (NREL) study by Dutta *et al.* (2011) for the conversion of biomass to ethanol via syngas conversion (adjusting from 2007 to 2012 dollars). These sources provided an estimate of $c_0^{\text{TCAP}} = \$580$ million for a $\kappa_0 = 64$ million gallons per year plant capacity. I assumed the same base case capital scaling factor of $p = 0.6$ as in Dutta et al. (2011)[31] to compute costs at the selected capacity levels summarized in Table A.1.

For the Celanese process, only unit cost estimates were available for a 380 million gallon plant at \$1.33 per gallon, which is approximately \$510 million in annualized cost[80] (converted from 2010 to 2012 dollars per gallon). For this process, annualized cost estimates were available directly without reference to the plant life and discount rate used. I was unable to convert these figures to total cost estimates without the assumed plant life and interest rate. The annualized costs were assumed to include annualized capital and O&M costs. I assumed a base case capital scaling factor of $p = 0.6$ as in Dutta et al. (2011) to compute costs at the selected capacity levels summarized in Table A.1.

For the Coskata process, estimates were available in published reports for several plant capacities (assumed 2012 dollars).[80,81] Specifically, $c_0^{\text{TCAP}} = \{\$150, \$535, \$650\}$ million for $\kappa_0 = \{25,125,200\}$ million gallons of produced ethanol per year plant capacity, respectively. Because of the additional data points, I fit a logarithmic curve to these points rather than using the power law, and I used the resulting curve to compute cost estimates at the selected capacity levels, summarized in Table A.1.

In all cases, these costs were simulated or estimated. Deployment costs are likely to vary. There are large uncertainties in estimating capital costs, especially at early stages of plant development.[125] For pioneer plants, capital cost estimates for first-of-their kind plant processes in the research and development and project definition stage can be underestimated by a factor of 1.2 to 3.7.[125] Similarly to previous work on biofuels processing, I used the factors from the pioneer plant literature to perform a more simplified adjustment to the capital cost estimates for the processes as part of the sensitivity analysis.[35,126-128]

Feedstock costs are typically a large component of total production expense. I used a distribution of historical Pennsylvania monthly average NG prices from 2012 to 2014, which range from about $2 to $8/Mcf.[124] The NG price is assumed to include the cost of transmitting the NG to the plant by pipeline. Local/regional variations in the price of NG are not considered and could potentially impact optimal plant locations. The conversion factor from methane to ethanol, η in Table 2.1, was provided by Celanese and Coskata[80] and was calculated for ATR catalytic using the efficiencies of the conversion[31,75] (see Appendix Section A.3).

2.3.3 Ethanol Demand

The maximum ethanol consumption was determined using the number of registered light-duty vehicles in PA (henceforth referred to as "automobiles"). The 2014 PA registration database includes approximately 600,000 FFVs and 10 million total automobiles.[121] The automobiles were assigned to their registered counties (assuming all fuel demand for each automobile occurs within its registered county). The annual consumption of ethanol was calculated for each county using average annual vehicle miles travelled (VMT) per county (which ranged from 8,400 to 15,400 miles) and assuming 23 gasoline gallon equivalent (mpgge) for light-duty vehicles fueled by E10 and 13 mpgge for FFVs run on E85.[121,129,130] The ethanol consumption was estimated for three cases designed to capture three possible demand scenarios:

(1) E85 only (assuming all FFVs are fueled entirely from E85 and all other automobiles use E10);
(2) E10 only (assuming all automobiles are operated using gasoline E10); and
(3) both E85 and E10 (assuming all FFVs are fueled with E85 and all other automobiles use E10).

The three cases are optimistic estimates for ethanol demand because they assume the NGLF ethanol will fully replace corn ethanol. Additionally, they assume E85 would be 85% ethanol and 15% gasoline even though the range of commercially available E85 is 50% to 83%.[131]

2.4 Results & Discussion

2.4.1 Production Costs

Figure 2.2 summarizes unit production costs (c^{UNIT} measured in \$/gge) for the three processes at different plant capacities including capital, O&M, and feedstock costs (see Equation 11 and Tables 2.1, A.1 and A.2 for methods and assumptions).

$$c^{\mathrm{UNIT}} = \left(\frac{c^{\mathrm{CAP}}(\kappa)+\left(c^{\mathrm{TCAP}}(\kappa)f^{\mathrm{OM}}\right)+c^{\mathrm{NG}}\eta^{-1}\kappa}{\kappa}\right)\nu \tag{11}$$

Figure 2.2 shows the power law and logarithmic cost curves in dotted lines and the piecewise-linearized portions of the curves as solid lines, assuming a NG price of \$3/Mcf. The linearized portions appear to be a good fit to for the cost curves. The linear cost profiles were used in the optimization model to estimate the non-transportation costs of producing an NGLF at varying plant capacities. Costs included in Figure 2.2 are optimistic estimates, as actual capital costs are likely to be higher. Here, Coskata has the lowest cost of all of the processes for all plants sizes and Celanese the highest. These data seed the MILP model.

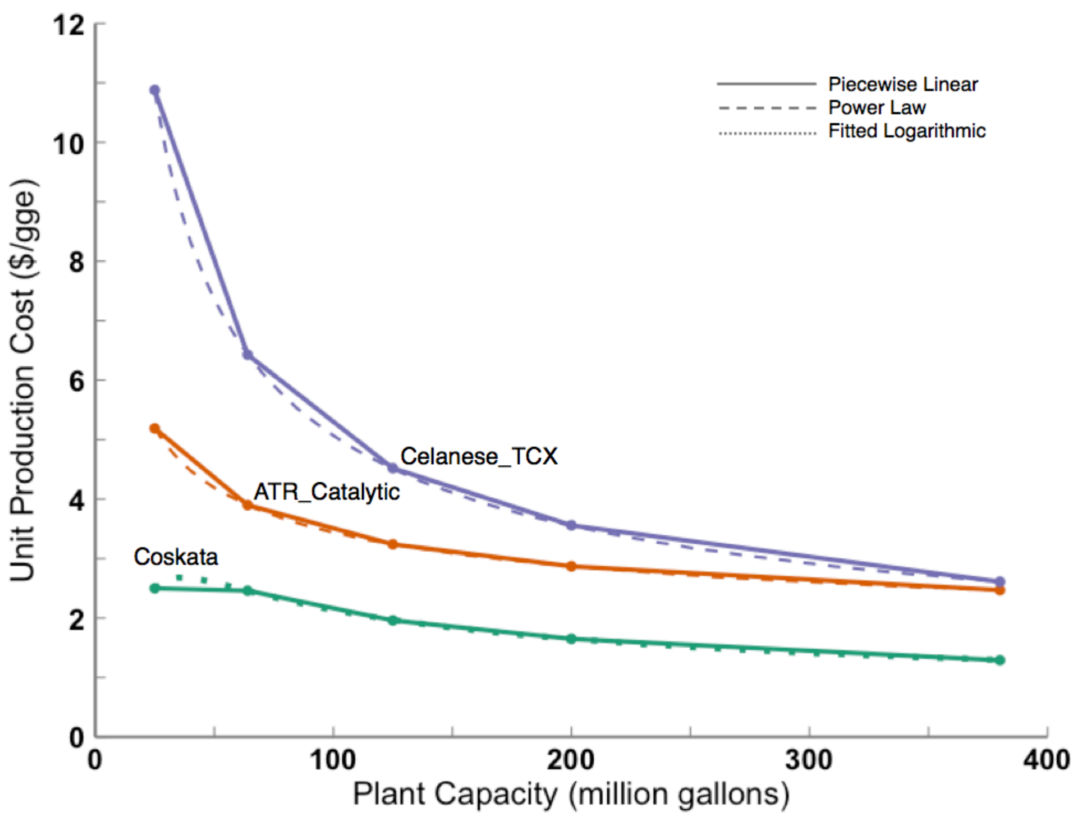
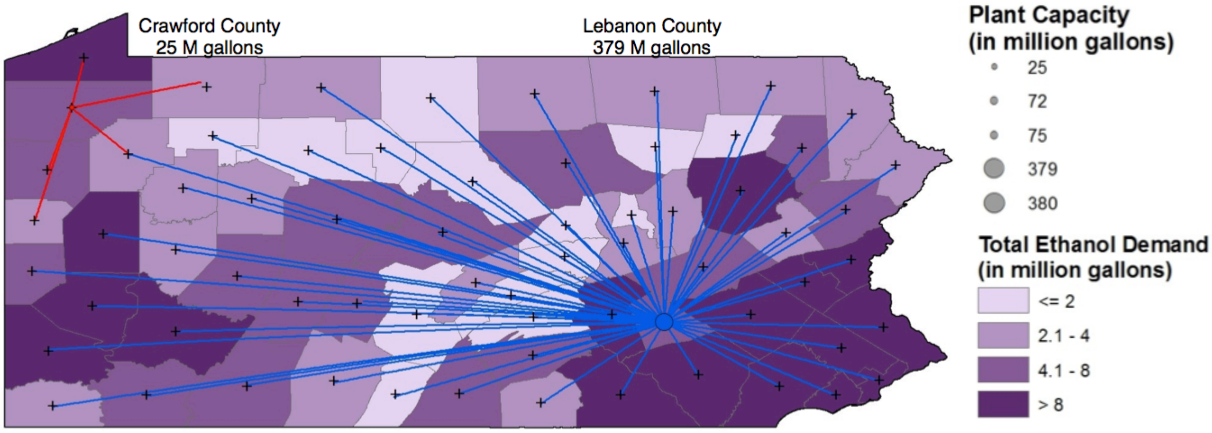


Figure 2.2. Estimated annual production costs in 2012 dollars per gasoline gallon equivalent (gge) per annual plant capacity for the three NGLF processes assuming the plants operate at full capacity. Dotted lines are the cost curves; solid lines are the piecewise-linearized cost curves, which were used in the MILP model. NG price is \$3 per Mcf.

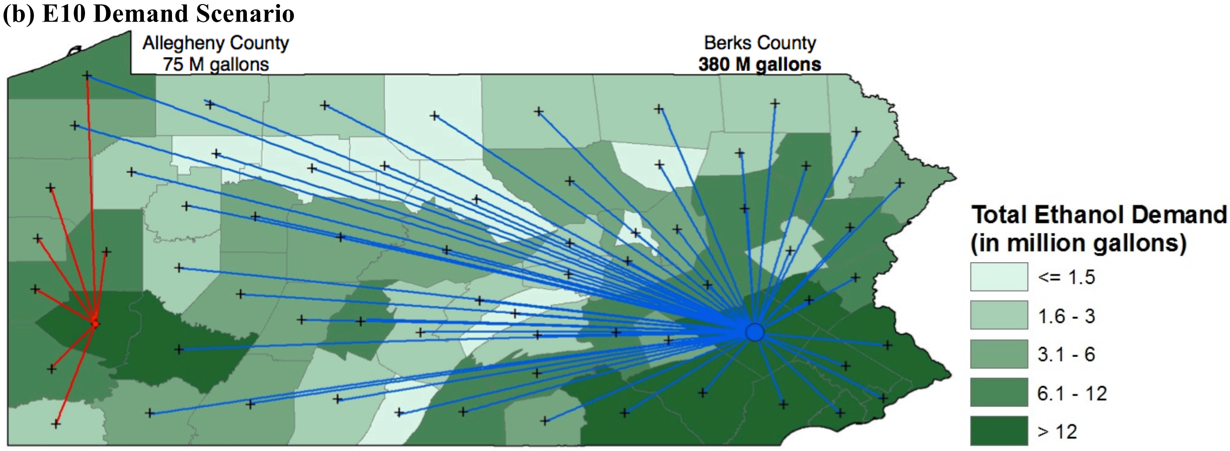
2.4.2 NGLF Ethanol Costs & Parameter Summary

I modeled potential plant locations in 58 PA counties with current natural gas transportation pipeline infrastructure (see Figure A.2). Regardless of the technology process, the model consistently selected either two or three sites located near the high demand areas of Pittsburgh and Philadelphia. The optimized plant sizes varied from 25 to 380 million gallons to maximize the benefits from the economies of scale as shown in Figure 2.3. These plant locations result in transportation costs of \$0.05 to \$0.07/gge. Transportation costs account for less than 5% of the total cost making location a non-critical component of cost; if the plants were randomly located throughout the 58 counties resulting transportation costs were generally +/-\$0.02/gge of the optimized transportation costs.

(a) E85 Demand Scenario



(b) E10 Demand Scenario



(c) E85 & E10 Demand Scenario

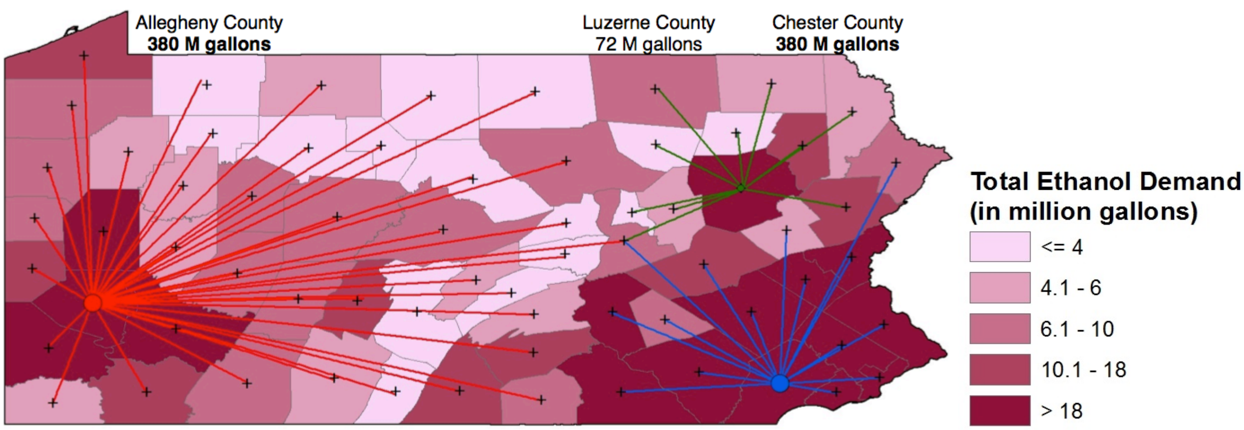


Figure 2.3. Plant locations (colored dots) and capacities for all ethanol demand scenarios. (a) Total ethanol demand from E85 only by county in gallons with the optimal plant locations in Crawford and Lebanon County. The plant capacities total 400 million gallons. (b) Total ethanol demand from E10 only by county in gallons with the optimal plant locations in Allegheny and Berks County. The plant capacities total 455 million gallons. (c) Total ethanol demand from both E85 and E10 by county in gallons with the optimal plant locations in Allegheny, Luzerne and Chester County. The plant capacities total 830 million gallons. The colored lines connect the plants to the demand counties they service. Bold plant capacities are plants that are at the maximum allowable plant capacity.

The unit costs (which include capital, O&M, feedstock and transportation costs) to meet scenario demand (E85, E10, or both) are shown in Figure 2.4 for each process. The uncertainty presented is due to NG feedstock prices. The scenarios for satisfying E10 + E85 demand have smaller overall costs than the E85 or E10 only scenarios due to economies of scale. Overall, the estimates indicate that Coskata could have the lowest costs of the three processes examined, and Celanese TCX the highest. Although costs for the Celanese TCX process are higher than the others, it is important to note it is a more mature process with potentially more accurate cost estimates at this stage of development. The company, Celanese, already produces acetic acid from natural gas, and may have a firmer handle on the design, utilities and siting costs. However, the other process are more likely closer to engineering estimates.

The costs presented in Figure 2.4 are compared to the U.S. monthly average costs from 2012 to 2014 for corn ethanol and gasoline production and transportation (box plots labeled "Existing Fuel").[132,133] Gasoline costs include crude oil acquisition, refining, and distribution; corn ethanol costs include corn feedstock and fermentation. The estimated optimal NGLF process costs fall within the ranges of gasoline and corn ethanol costs. Corn ethanol tends to be more expensive than gasoline and more comparable to the NGLF processes.

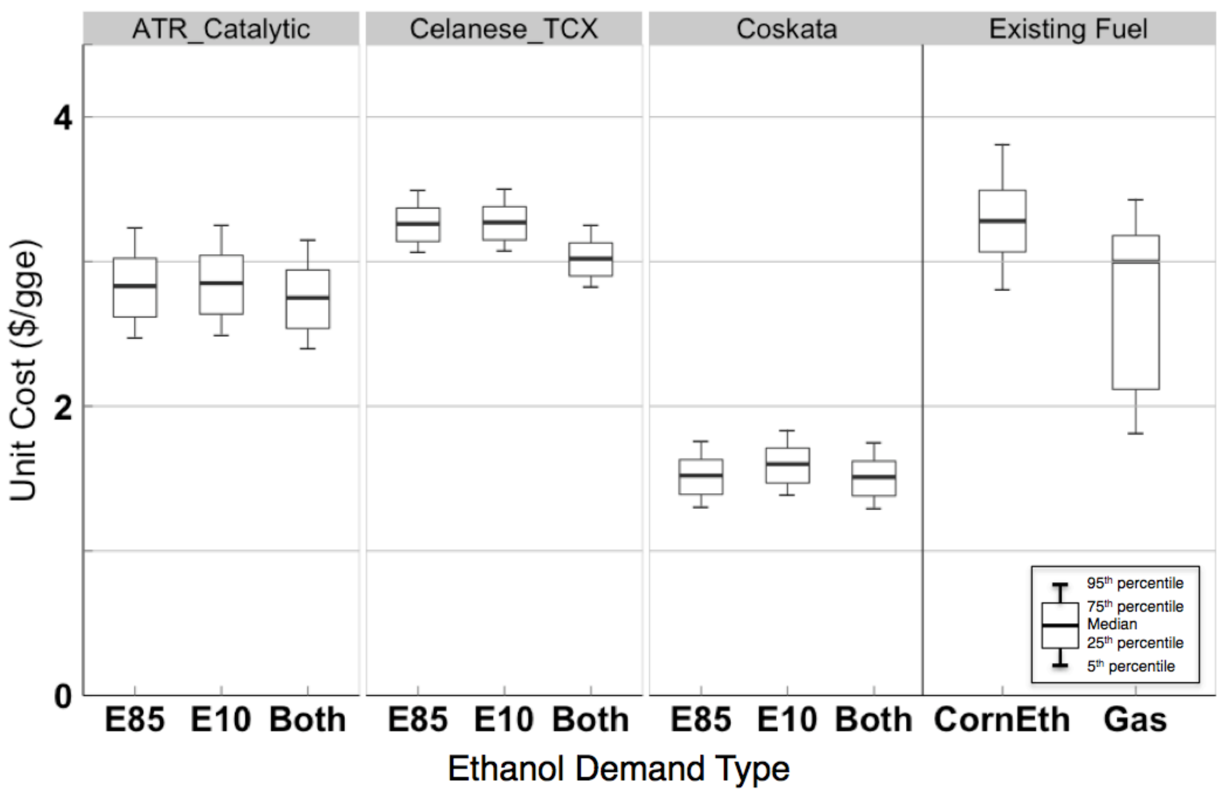


Figure 2.4. Unit costs (in $/gge) for capital, operation, maintenance, feedstock and transportation for each process and the three ethanol demand scenarios given 58 potential plant locations. Uncertainty in the costs is due to NG prices (historical monthly average NG prices in PA from 2012 to 2014.[124] Other sensitivities are discussed in later sections. The corn ethanol and gasoline costs are from 2012 to 2014.[132,133] For the NGLF processes, the 5th percentile is based on a NG feedstock price of approximately $2.45/Mcf, and the 95th percentile is a NG price of approximately $4.10/Mcf. For gasoline (Gas), the 5th percentile is approximately $1.81/gallon, and the 95th percentile is approximately $3.43/gallon. For corn ethanol (CornEth), the 5th percentile is approximately $2.81/gge, and the 95th percentile is approximately $3.81/gge.

Based on the results shown in Figure 2.4, I compare the cost of NGLF ethanol to the cost of corn ethanol and gasoline. Table 2.2 shows that NGLF ethanol made with the Coskata process has a high probability of being less expensive than gasoline or corn ethanol. The ATR catalytic process is likely less expensive than corn ethanol and gasoline costs. The Celanese TCX process is least likely of the three to be less than gasoline or corn ethanol costs.

Table 2.2. Likelihood that NGLF ethanol is less expensive than gasoline or corn ethanol. Historical NG prices and gasoline and corn ethanol costs are monthly average costs from 2012 to 2014.[124,132,133]

Cost Comparison ($/gge)	**ATR Catalytic**	**Celanese TCX**	**Coskata**
Pr(NGLF Eth < Gasoline)	56 to 61%	22 to 42%	97%
Pr(NGLF Eth < Corn Eth)	92%	53 to 83%	100%

The NGLF ethanol costs shown in Figure 2.4 are likely optimistic estimates. Actual capital costs may be higher as more detailed engineering design, site characteristics and other possible unforeseen costs are included. Also, the model was simplified in that no cost for connecting the plants to natural gas trunk lines, annual charges for obtaining pipeline capacity, or any downstream storage and blending costs were considered. These costs also exclude marketing, retail markup, taxes or tax credits that may affect the fuels differently.

To understand the effect of the cost parameter assumptions I conducted sensitivity analysis on the values assumed for natural gas price, interest rate, O&M cost percentage, plant life, plant cost scaling factor and transportation costs (Table A.2 and Table A.5). Each of these assumptions was analyzed as a one-way sensitivity holding all other assumptions constant at the base case value. Figure 2.5 shows the sensitivity results. In the figure, the high and low values for the varied parameters are listed in the ATR catalytic analysis, but reflect value ranges inputted across each of the three processes. The NG price sensitivity dominates the other parameters, which is important because future natural gas prices are highly uncertain. Other economic parameters, which are solely prospective estimates or widely accepted rules of thumb, have less impact on the final estimates. Boxplots of the plant cost parameters are included as Figure A.3 in the Appendix. Figure A.4 in the Appendix shows how the parameter assumptions could impact whether an NGLF ethanol would be less expensive than gasoline or corn ethanol.

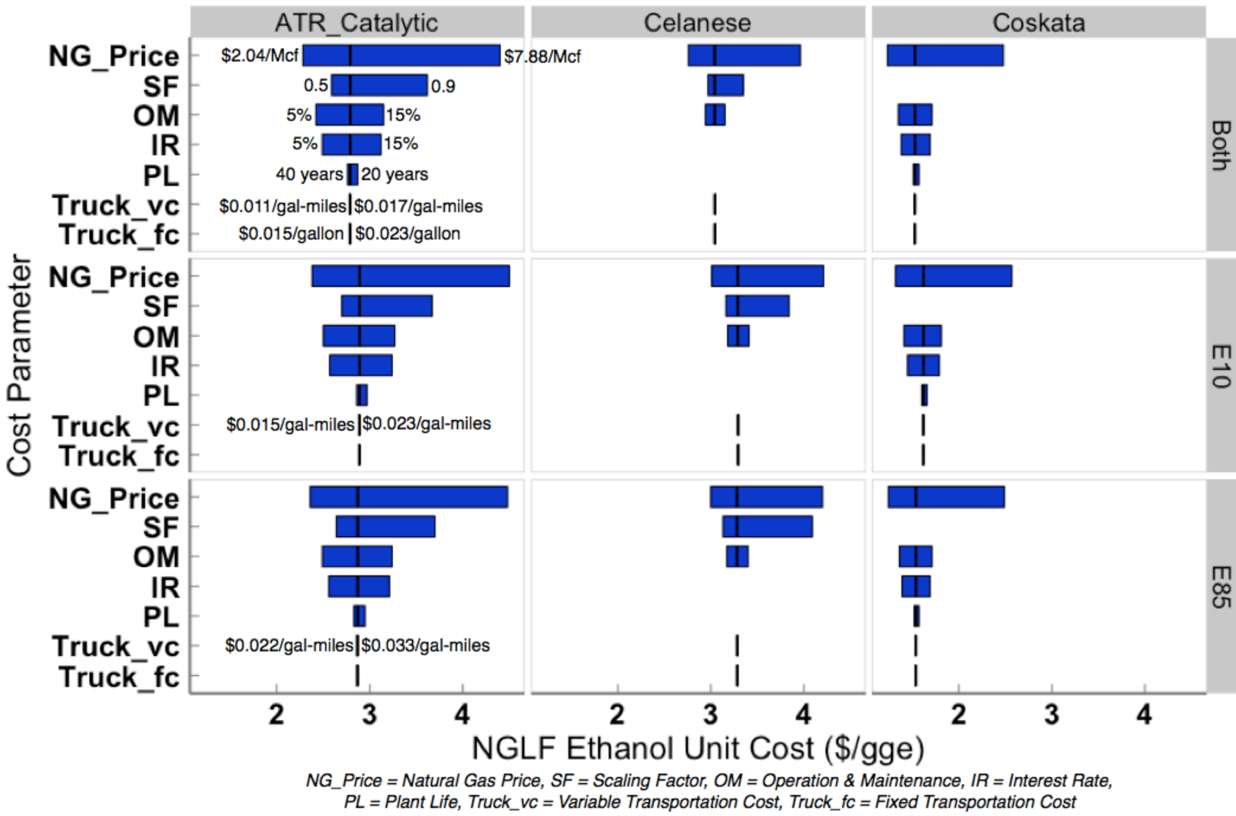


Figure 2.5. NGLF ethanol unit costs for one-way sensitivities of cost parameters. The black lines in the bar are the NGLF ethanol costs assuming the mean natural gas price from 2012 to 2014 prices. The high and low parameter values are shown for ATR catalytic, and reflect values across processes. Natural gas price is the dominant contributor to the NGLF ethanol costs.

Given the sensitivity dominance of natural gas prices, fluctuating gasoline prices and the 30-year life span of the plants, I assessed the effect of natural gas and gasoline prices on the viability of the processes. Figure 2.6 shows gasoline and NG prices, and cost curves for NGLF ethanol cost for the three processes. As an example, for the mean NG price of $3.43/Mcf (black line) gasoline prices would need to be $1.54/gallon for Coskata to be cheaper. At an average gasoline price of just under $1/gallon and less, gasoline will be less expensive than all of the NGLF processes.

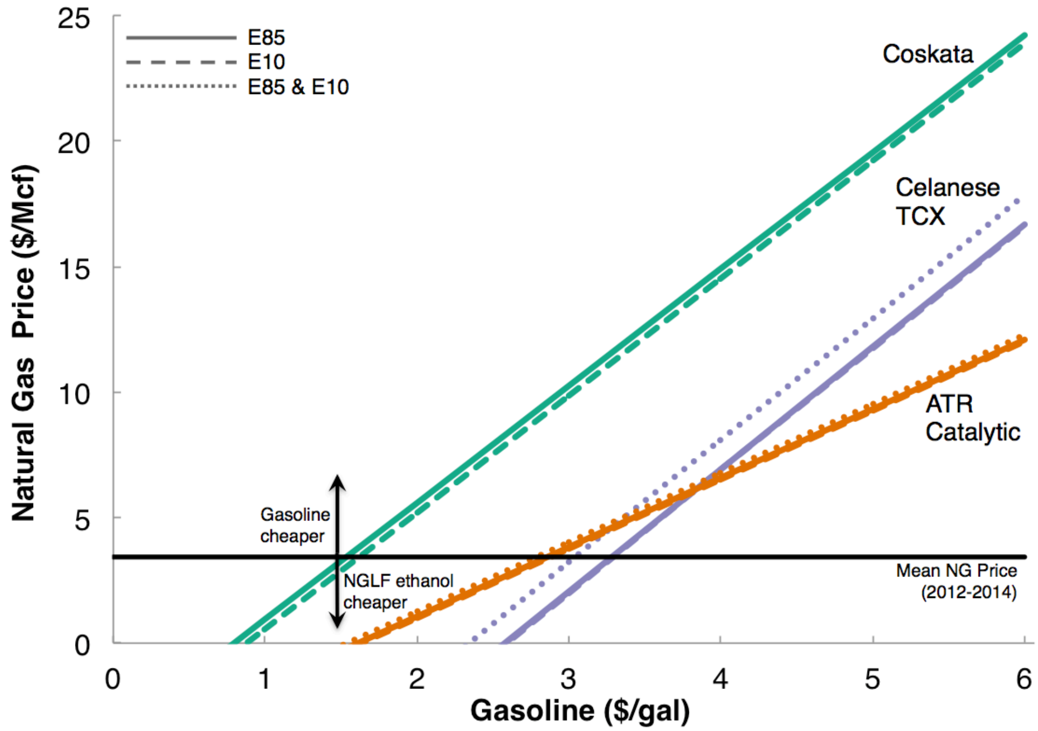


Figure 2.6. Comparison of gasoline and NG prices. The lines indicate the costs at which gasoline and a NGLF ethanol costs are equivalent. The black line shows the mean natural gas price for Pennsylvania monthly averages from 2012 to 2014 (EIA 2015b, CMEGroup 2015).

Given the Coskata process cost dominance, I estimated the Coskata costs stochastically using optimal plant locations and capacities. I then compared them to historical (2012-2014) gasoline and ethanol prices, and the lowest ATR and Celanese NGLF ethanol costs. Finally, I ran a Monte Carlo simulation with the cost parameters (uniform distributions over the ranges defined in Table A.2) and for the NG price (log logistic distribution fit to the data). Distribution assumptions are described further in Table A.5 of the Appendix Section A.6. The comparison is shown in Figure 2.7. Given the modeled uncertainty, Coskata NGLF ethanol is likely lower cost than corn-based ethanol and the lowest observed gasoline point cost. The NG price is found to be the largest contributor to costs, followed by the three plant cost parameters and trucking variable costs (Figure A.5 in the Appendix). However, when compared to gasoline costs using monthly historical gasoline and natural gas feedstock prices, shown in Figure 2.7(b), Coskata NGLF ethanol is almost always cheaper than gasoline.

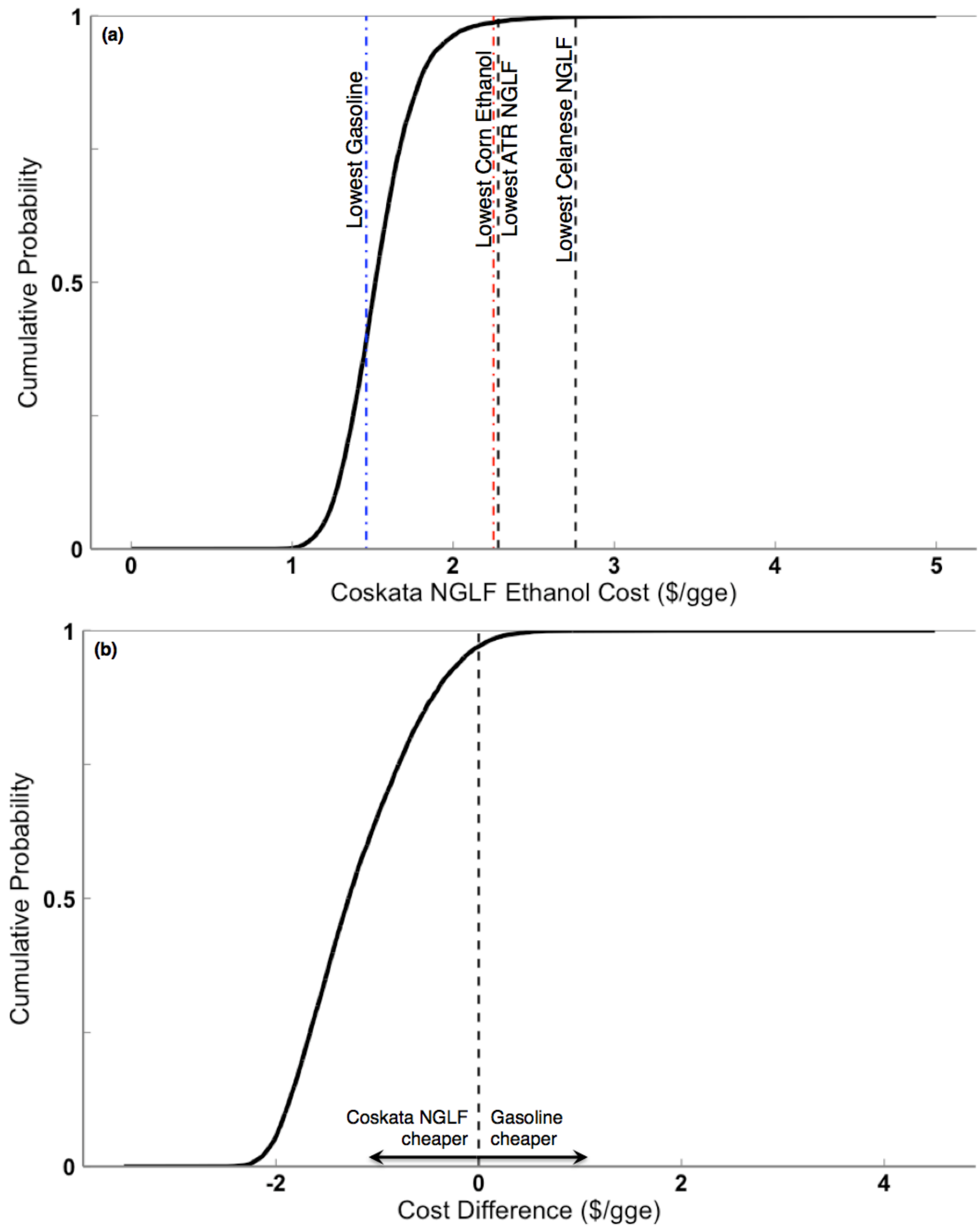


Figure 2.7. Coskata NGLF ethanol costs estimated stochastically assuming the base case plant locations and capacities. (a) Coskata NGLF ethanol cost compared to the lowest cost for gasoline, corn ethanol, NGLF ATR and NGLF Celanese. (b) Coskata NGLF ethanol cost compared to gasoline (using gasoline and natural prices for 2012 to 2014). The zero vertical line is where they are equal. Left of the zero line Coskata is cheaper, and right of the zero line gasoline is cheaper. Coskata is almost always less expensive.

Using the pioneer plant literature from Merrow et al., (1981), the capital costs for the Coskata process were adjusted by factors of 1.2 (low) and 3.7 (high) in the stochastic cost model. The results are compared to the original assumptions in Figure 2.8. For a factor of 1.2, costs are only slightly higher than the base case. A factor of 3.7 makes the process costs significantly more expensive, and there is an approximately 16% chance that the Coskata NGLF is less expensive than gasoline under this condition. A factor of approximately 2.7 gives Coskata a 50-50 chance of being less expensive than gasoline. Boxplots of the costs for the pioneer plant factors are shown in Figure A.6. Additional sensitivity analyses on a small plant scenario; percent ethanol in E85 and NG prices are in Appendix Section A.6.

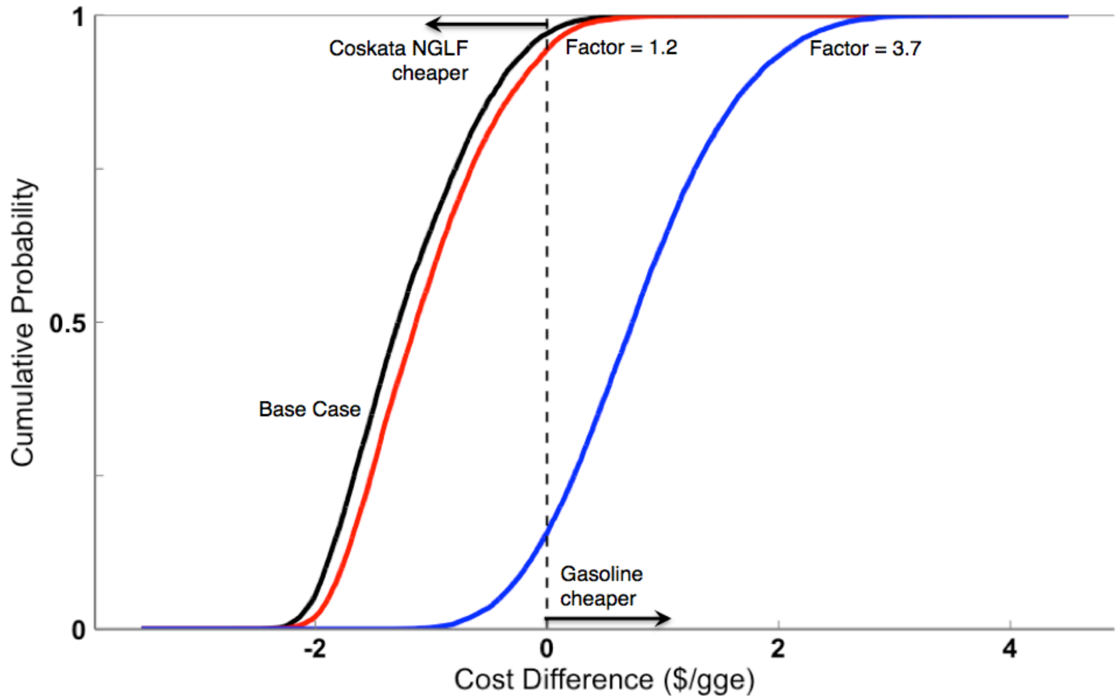


Figure 2.8. Coskata NGLF ethanol costs with pioneer plant factors compared to gasoline. Base case cost differences are a black line. Pioneer plant capital cost factors are shown for 1.2 (red) and 3.7 (blue), which is the assumed factor range for the NGLF processes. Historical prices for gasoline and natural gas from 2012 to 2014 were used as inputs. When a factor of 3.7 is applied to the capital costs, the likelihood of NGLF Coskata being less expensive changes from almost 100% to ~16%.

2.4.3 Ethanol Demand Considerations

A few assumptions from this analysis warrant further discussion, because of simplified or bounded assumptions, including the regional variation in NG prices, competition with corn ethanol, and pipeline capacities. While I examine a range of NG prices, I do not account for systematic regional variation. In reality, there may be some variation in the price of NG across the state of PA, which could impact the optimal location of the plants. Monthly average NG price differences could vary between $0-3/Mcf across PA counties.[124] Given the sensitivity of costs to natural gas prices, this could change the ethanol price by approximately $0.20-0.60/gge for Celanese and Coskata and $0.36-1.08/gge for ATR. Finally, a rise in the demand for NG for transportation fuel purposes could subsequently increase the NG price, which is not modeled here.

This analysis provides optimistic upper bounds for ethanol demand serviced by NGLF plants, including full capture of ethanol from E85, E10 or both. It is unlikely that an NGLF will capture the entire ethanol market given that corn ethanol is an established fuel mandated by the RFS2. A simple estimate of the potential change in costs from partial demand capture is shown in Figure 2.9. Vertical lines outline the ethanol demand quantities assuming 10%, 25%, 50% and 100% NGLF ethanol capture of the PA market. For the base case of 100% capture, both E85 and E10 demand exceed the capacity of a single plant. If NGLFs only meet 10%, 25% or 50% of the demand then one smaller plant is needed, and the $/gge costs increase as plant size decreases. A small demand of only 100 million gallons could nearly double the costs.

The estimated demand in this analysis is based on the assumed number of vehicles, average annual VMT, average miles per gallon and ethanol content in E85. While the interaction between these assumptions was not explored in detail, the results remain robust despite potential demand variation; for a 25% change in demand, the model results can change by approximately 5% or less.

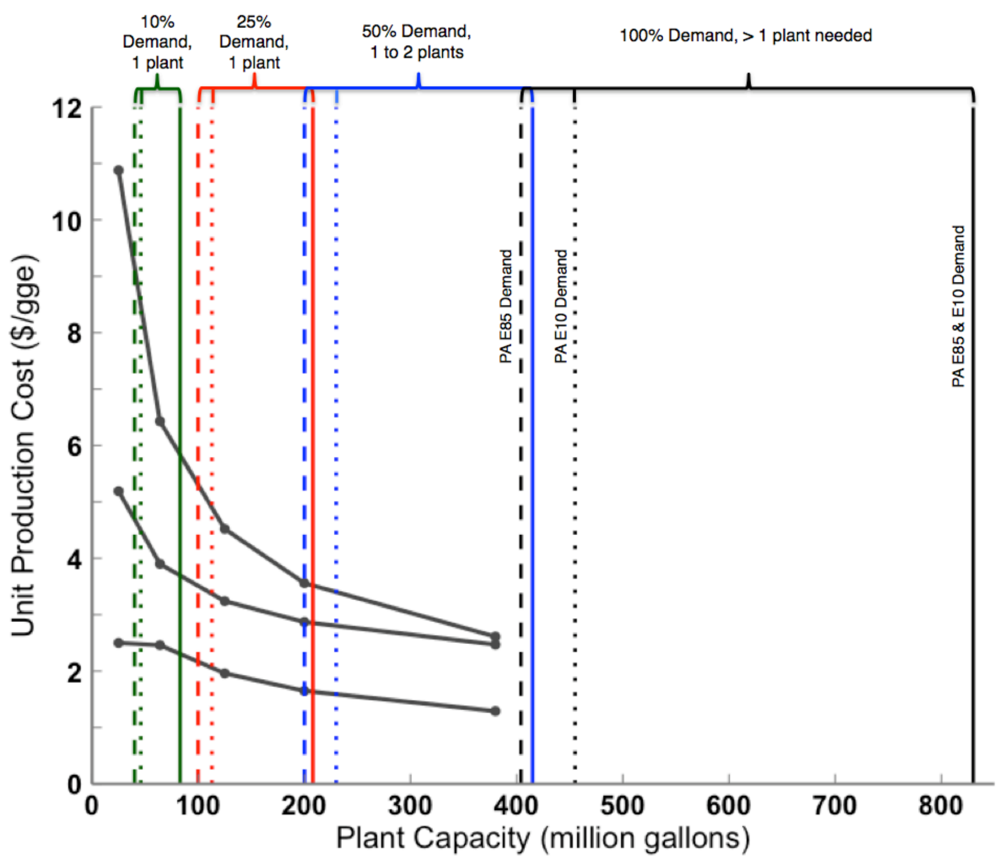


Figure 2.9. Estimated annual unit production costs in 2012 dollars per gasoline gallon equivalent (gge) per annual plant capacity for the three NGLF processes assuming the plants operate at full capacity. NG price is $3 per Mcf. Vertical lines show total ethanol demand assuming 10%, 25%, 50% and 100% capture. Smaller capture percentages would likely mean higher ethanol production costs.

Although this analysis was conducted for PA, the NGLF produced in state could service the surrounding region or another region of the country. Additional demand could reduce the total costs by supporting larger plants with better economies of scale, but out-of-state competition could also make NGLF plants less cost-competitive. Similarly, introducing an alternate ethanol source could impact the prices of corn or other biomass-based ethanol, which is not accounted for in this analysis. Finally, NG from shale deposits is not a guaranteed feedstock source. The United States Geological Survey (USGS) estimates an mean value of 84,000 billion cubic feet (Bcf) of undiscovered gas (as of 2011).[134] The average production from a NG shale well is estimated to be 2 Bcf, and NG production from this source might not be available at the volume required for the 30-year life of a NGLF plant especially when consider the alternate uses for NG (electricity and heating).[135] If the availability of natural gas decreases over time, the feedstock price of the gas would likely increase and could impact plant viability.

2.5 Conclusions

This analysis suggests that given current capital cost estimates for Coskata and ATR catalytic processes and recent of natural gas feedstock, gasoline, and corn ethanol prices, it is likely that NGLF ethanol can be produced at lower cost than corn ethanol or gasoline on an energy basis. This would make the NGLF processes potentially economically viable. However, it's common that early capital cost estimates derived in the research and development phase are underestimates when compared to nth plant costs. Higher capital costs, changes in future fuel prices, and/or limited demand – particularly in early years – could change this picture.

The cost estimates here, based on limited available information, are likely optimistic given the absence of existing large-scale facilities. While the estimates suggest that the Coskata process is the least expensive and most competitive process, it is difficult to conclude with certainty. Sensitivity analyses show that capital, O&M, and NG prices can impact the NGLF ethanol costs. Given the uncertainty, pilot projects may be valuable for better understanding the real costs of plant construction and operation associated with these processes.

While ethanol produced by renewable sources is incentivized by existing policies such as RFS2, there are currently no specific policy provisions to incentivize ethanol produced from NG. The benefits associated with NGLF ethanol for transportation – such as the use of endogenous resources, benefits from security of a national fuel source, and job creation – could justify a policy for ethanol production from NG, though further work is needed to understand how NG use in the transportation sector could impact NG prices for other uses like heating and electricity.

Chapter 3. Life Cycle Environmental Impacts of Ethanol Produced from Natural Gas for Light-duty Vehicles.

3.1 Abstract

Natural gas has become a growing energy source in the US for various end-uses, and its potential future as a transportation fuel has been the focus of recent policy discussions. I provide first-order life cycle greenhouse gas (GHG) emissions estimates for producing ethanol from natural gas to power light-duty Flexible Fuel Vehicles. Three processes are considered for producing ethanol from natural gas: (1) autothermal reforming (ATR) with catalytic conversion, (2) TCX, a process that produces intermediate products of methanol and acetic acid, developed by Celanese Corp., and (3) a fermentation process developed by Coskata Inc. I find that the average life cycle GHG emissions for a 100-yr global warming potential (GWP) are 137 g CO_2-eqiuv/MJ (ATR Catalytic), 119 g CO_2-eqiuv/MJ (Celanese TCX) and 156 g CO_2-eqiuv/MJ (Coskata fermentation). All processes have life cycle emissions well above gasoline, and the 20% reduction from gasoline required by the Renewable Fuel Standard (RFS2). Estimates for a 20-yr GWP are slightly higher. Upstream natural gas GHG emissions are estimated stochastically. I find that even in the unlikely scenario of zero emissions from the upstream, NGLF ethanol process emissions are still larger than gasoline, although with more overlap in the error bars. More detailed life cycle assessments with process modeling could further refine the emissions estimates. However, from this analyses, I conclude it would be difficult for GHG emissions from natural gas-derived ethanol to be less than or equal to existing fuels, let alone meet the RFS2 reduction requirements.

This chapter is based on the working paper: *Seki, S. M., Griffin, W. M., Michalek, J. J., Azevedo, I. L. and Hendrickson, C. (2016) Assessing the Economic and Environmental Viability of Ethanol produced from Natural Gas to Power Light-Duty Vehicles in Pennsylvania.*

3.2 Introduction

Natural gas (NG) is a widely used energy source for heating and electricity production; however, it currently plays only a minor role in the transportation sector. For transportation, NG is used as compressed NG (CNG) or liquefied NG (LNG) in dedicated heavy-duty and light-duty vehicles. Alternatively, it can be converted to liquid fuels, like ethanol for use by the existing light-duty fleet. I refer to these latter fuels as natural gas-derived liquid fuels (NGLFs). NGLFs have historically been economically uncompetitive with petroleum-based fuels, but recent changes in technology, NG prices, and legislative support for alternative transportation fuels could increase the viability of NGLFs. In Chapter 2 I compared the costs of producing ethanol NGLF with petroleum-based fuels and corn-ethanol.

I concluded that the cost of producing ethanol with some NGLF processes would more likely than not be cheaper than gasoline and corn-based ethanol. However, capital costs from these emerging processes and future natural gas and gasoline prices are highly uncertain. In addition to a cost evaluation, the emissions from an NGLF ethanol process should be assessed and compared to other pathways.

Currently the U.S. renewable fuel standard (RFS2) mandates bioethanol blending for vehicle fuels. The mandate encourages domestic ethanol production from corn and cellulosic sources. The purpose of the RFS2 is to promote energy independence, national security and reduce greenhouse gas (GHG) emissions through increased biofuel use over time.[3,4] The standard requires a 20% reduction from gasoline in GHG emissions for a renewable biofuel like corn ethanol.[3] The reduction percentages are higher for the other mandated fuels. Although NG is not considered a renewable fuel, these goals could also potentially be achieved by NG use as a transportation fuel, but not without meeting the minimum GHG emissions reduction.

A recent study found that CNG could have emissions reductions of 0-6% (mean values) for medium-duty vehicles when compared to baseline petroleum fuels.[14] However, for Class 8 heavy-duty transit buses and trucks, CNG GHG emissions increase when compared to conventional diesel.[14] For light-duty vehicles, in a separate paper, Tong (2015a) found that CNG had comparable life cycle emissions to conventional gasoline in long-term global warming scenarios, but found no improvement in emissions for methanol and ethanol liquid fuel pathways. Luk et. al. found that some air emission benefits are possible when comparing a gasoline vehicle to a light-duty CNG vehicle without increasing ownership costs.[98] Research into the costs and environmental impacts of CNG and some NGLF pathways have been explored, but the NGLF pathways used ethane as a feedstock as opposed to methane.

GHG emissions from the NG sector, especially upstream methane leakage received significant attention over the last few years. The 2010 synthesis paper by Weber and Calvin et al. assembled estimates from 6 other studies for shale gas upstream emissions including pre-production, production, processing and transmission.[91] The paper also compared estimates of emissions between conventional and shale gas production and found little difference between the two types of gas production.[91] Ongoing research continues to examine the methane emissions from NG production and transmission including some direct measurement approaches, and a reconciliation study to match top-down and bottom-up approaches in the Barnett Shale formation.[93-97] Understanding the life cycle emissions for any fuel, process or electricity made from natural gas is dependent on the accuracy of the upstream emissions. I model the upstream emissions as a distribution to capture the uncertainty in the estimates.

I consider three processes for converting NG to ethanol, selected to represent a range of technologies under development. The processes include: (1) methane autothermal reforming (ATR) with catalytic conversion to synthesis gas (syngas) and then to ethanol, (2) the conversion of acetic acid, produced from syngas, to ethanol developed by Celanese Corp. (TCX), and (3) ethanol fermentation using syngas as the feedstock, developed by Coskata Inc.[31,75-77] Figure 3.1 provides an overview of the three processes. All processes begin with processed NG, assumed to be 100% methane. Although some intermediate steps are similar, the three processes each generate ethanol through a unique production pathway. Life cycle assessments (LCAs) may have been conducted for some of these processes, but they are not publicly available. Therefore, I use available data and literature to put together a first-order GHG life cycle emissions estimate for the three processes, which is not currently in the literature.

In contrast with CNG and LNG for heavy-duty vehicles, a NGLF could be blended with gasoline and seamlessly integrated into the current fueling infrastructure. It would be readily available for use in the current light-duty conventionally fueled fleet including higher ethanol blends like E85. The end use emissions of NGLF ethanol fuel as E85 for Flexible Fuel Vehicles (FFVs) is compared to ethanol derived from ethane and conventional gasoline as estimated in Tong et al. (2015). I also discuss the potential impact from criteria air pollutants (CAP) for these processes, but maintain the focus on GHG emissions that are included in the RFS2 regulation.

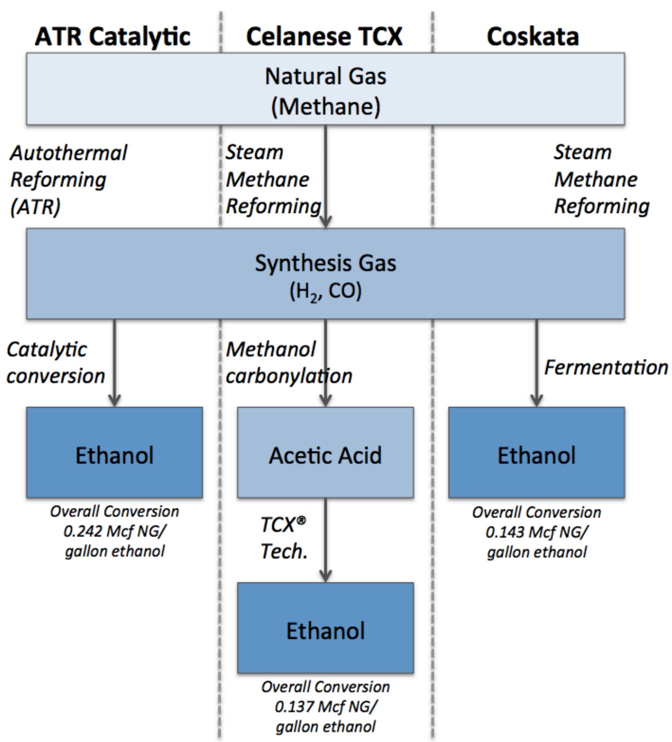


Figure 3.1. NGLF ethanol processes included in the analysis.

3.3 Data & Methods

I estimated the life cycle GHG emissions for three NGLF ethanol processes as outlined in Figure 3.1. Life cycle emissions estimates were not available in the form of LCAs for the processes; Therefore, the emissions were estimated from available emissions data for similar processes in the literature. The estimates are first-order (accuracy to one order of magnitude), and uncertainty in the numbers are included where possible. I use an attributional approach to the estimation, but also use system expansion where applicable for co-product credits. Alternative methods for allocation, including economic and energy could also be used for co-products, but I did not use them here. The system boundary includes four main phases: natural gas upstream production, NGLF ethanol production, fuel transport and fuel use in vehicles. The GHGs included are carbon dioxide (CO_2), methane (CH_4) and Nitrous Oxide (N_2O). The functional units are per megajoule (MJ) of ethanol produced and per kilometer (km) driven as shown in Figure 3.2.

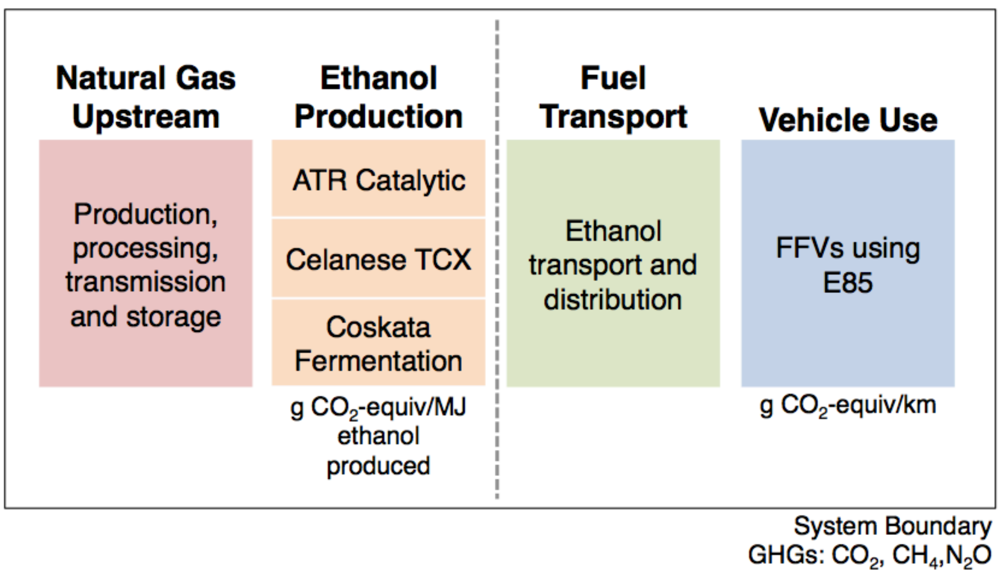


Figure 3.2. Life cycle GHG emission system boundary for the NGLF ethanol processes.

General assumptions for electricity emissions factors and Global Warming Potential (GWP) values were consistent with those from Tong et. al (2015) in order to make comparisons to their previous estimates for other NG pathways. The GWP values were taken from the Fifth Assessment Report from the IPCC (AR5) , and were included for 100-year and 20-year time frames, but adjusted into normal distributions using the given confidence intervals as shown in Table 3.1.[16,136] Both long and short-term implications of methane emissions have become an important concern when assessing the impacts from GHGs.[16] Where possible, emissions factors were estimated using the GWPs from IPCC AR5. However, some emissions factors were already estimated in CO_2-equivelant units, and could not be separated into the three GHG emission types. The significance of inconsistent GWP values is discussed in Section 3.5.

Table 3.1. Global Warming Potential (GWP) for the greenhouse gases based on the IPCC fifth assessment (AR5).[16,136]

Greenhouse Gases	100-yr	20-yr
CO_2	1	1
CH_4 (fossil)	Norm (36,8.5)	Norm (87,15.9)
N_2O	Norm (298,52.5)	Norm (268,34.2)

The electricity emissions factors considered were taken from Tong et. al (2015), based on the GREET model.[137] The GWP of 100-yr and 20-yr estimates are essentially equivalent, given the small contribution of methane and nitrous oxide. The electricity is assumed to be the average U.S. grid mix (2010) at the plant gate at 612 g CO_2-equivalent/kwh. As a sensitivity I assumed a "wall outlet" emissions factor, accounting for a 6.5% loss rate on transmission, is 649 g CO_2-equivalent/kwh.[137] As an additional sensitivity I assumed a NGLF ethanol processing plant could get its electricity from a Natural Gas Combined Cycle plant (at the plant gate), which could reduce the emissions factor to 456 g CO_2-equivalent/kwh.[16]

3.3.1 Upstream Natural Gas Emissions

NG upstream emissions included were assumed to be from Shale Gas production, which made up over 40% of gross NG withdrawals in the U.S., 29% from Pennsylvania in 2014.[90] The stages included were pre-production, production, processing, transmission and distribution. I used the baseline 100-yr and 20-yr GWP estimates from Tong et al. (2015), which aggregated various data sources in a bottom-up approach by estimating emissions for each individual activity.[14,16] Here I used the total mean values for the base analysis, and incorporate the fitted distributions for sensitivity analysis. The upstream NG emissions estimates are included in Table 3.2. The average implicit methane leakage rate is 1.3% for a 100-yr GWP and 2% for a 20-yr GWP.[16] Tong et al. also evaluated a pessimistic methane leakage scenario, which is included in the discussion. Research on methane leakage will continue and the estimates available for life cycle studies will be refined, but as this is a first-order estimate the current upstream emissions in Table 3.2 are likely the correct order of magnitude.

Table 3.2. Total upstream NG GHG emissions for 100-yr and 20-yr GWP. Mean values are shown with 95% confidence intervals in parentheses and fitted distributions. All values are from Tong et al. (2015).

Process	GHG emissions g CO_2-equiv/MJ
Upstream, 100-yr	17.2 (10.2-29.3), Log logistic (‘log location’ = 2.80, ‘log scale’ = 0.15)
Upstream, 20-yr	30.3 (19.3-49.7) Log logistic (‘log location’ = 3.05, ‘log scale’ = 0.14)

3.3.2 NGLF Ethanol Process Emissions

The three processes included in this analysis do not have life cycle emissions estimates publicly available. Therefore, I estimated the process emissions for each individually using data for similar processes. In all cases I estimated the emissions using available data from the literature, and relying on the stoichiometry of the process. Although Celanese and Coskata were developing the proprietary processes included, these can also be described as acetic acid to ethanol and fermentation processes, respectively. The details of the emissions estimate are described separately for each process.

Autothermal Reforming and Catalytic Conversion

The ATR process includes production of syngas through ATR, and then the catalytic conversion of the syngas (H_2 and O) into ethanol. Excess Hydrogen (H_2) is produced when making syngas, and is credited as a co-product for the process through system expansion. Table 3.3 includes assumptions for the emissions estimate and sources for the data. The stoichiometric equations for the process are included below and were used to estimate the emissions as described in this section.

$$3CH_4 + O_2 + H_2O \rightarrow 7H_2 + 3CO$$

$$2CO + 4H_2 \rightarrow CH_3CH_2OH + H_2O$$

$$3CH_4 + O_2 \rightarrow CH_3CH_2OH + 3H_2 + CO$$

The production of syngas through ATR assumes only CO_2 is produced, the GREET U.S. grid mix emissions factor (2010) was used to calculate the electricity emissions.[82,137] The hydrogen co-product credit was estimated using emissions from a steam methane reforming (SMR) process very common in hydrogen production.[78] In the Spath and Mann report, electricity is NERC mid-continental mix (mostly coal), which results in greater emissions than the U.S. grid mix, but has a small contribution to the estimate. The catalytic conversion of syngas to produce ethanol was primarily based on biomass feedstock report from the National Renewable Energy Laboratory, and supplemented with specific inputs from a life cycle assessment paper for lignocellulosic ethanol.[31,40] The calculations for the ATR catalytic conversion emissions are included below.

Table 3.3. Assumptions for emission estimates for ATR catalytic conversion.

Process	GHG emissions/ Electricity use/ production	Units	Source
ATR – GHG Elec use	8.74 14.44	kg CO_2e/kg H_2 MJ/kg H_2	Hajjaji et al. (2013).
SMR - GHG WGS GHG adj.[1]	10.1 9.81	kg CO_2e/kg H_2	Tong et al. (2015) Spath & Mann (2001) 100-yr ~ 20-yr GWP.
Catalytic Conversion	15,501 (7,046) 594,849	lbs H_2 (kg H_2) MJ EtOH	Dutta et al (2011) From process diagrams listed as per hour, but the hours cancel out.
Alcohol Synthesis Catalyst GHG	0.000010	kg CO_2e/MJ EtOH	Calculated from Mu et al. (2010). Molybdenite, at plant, kg, Global, Ecoinvent system process. 100-yr ~ 20-yr
Co-product GHG (Mixed Alcohol)	0.0192	kg CO_2e/MJ EtOH	Calculated from Mu et al. (2010). Treated as heating oil, at petro refinery, kg, EU, ETH-ESU database. Could not find data source. Assume 100, 20-yr are equiv

Abbreviations: ATR = Autothermal Reforming, GHG = Greenhouse Gas, Elec = Electricity, SMR = Steam Methane Reforming, WGS = Water Gas Shift, EtOH = Ethanol.

[1] SMR is used in this analysis to estimate co-product credits for hydrogen production. The WGS is not needed, and emissions for WGS are excluded.

$$
\begin{aligned}
GHG\ emissions_{ATR} &= \left(Elec_{ATR}\left[\frac{MJ}{kg\ H_2}\right] \times \frac{1}{3.6}\left[\frac{kwh}{MJ}\right] \times ElecGHGs_{Elec}\left[\frac{kg\ CO_2e}{kwh}\right]\right) \\
&\quad + ProcessGHGs_{ATR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right] \\
&= \left(14.44 \times \frac{1}{3.6} \times 0.612\right) + 8.74 = 11.2\,\frac{kg\ CO_2e}{kg\ H_2}
\end{aligned}
$$

The extra hydrogen produced was credited to the process via system expansion displacing hydrogen production from SMR. From the chemical equations, 4/3 of the hydrogen in the syngas is a co-product. The calculation for the credit is as follows:

$$Coproduct\ GHG\ emissions\ credit = ProcessGHGs_{SMR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right] \times \left(\frac{4}{3}\right) = 9.81 \times \left(\frac{4}{3}\right) = 13.1\,\frac{kg\ CO_2e}{kg\ H_2}$$

Given, that 4/3 of the hydrogen was a co-product, the remainder of hydrogen is in the syngas to be used to make ethanol. Therefore, the emissions calculation is as follows:

$$\begin{aligned} GHG\ Emissions\ with\ credits_{ATR} &= \left(\left(Total\ GHG\ emissions_{ATR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right] \times \left(\frac{7}{3}\right)\right) - Coproduct\ GHG\ emissions\ credit\left[\frac{kg\ CO_2e}{kg\ H_2}\right]\right) / \left(\frac{7}{3}\right) \\ &= \left(\left(11.2 \times \left(\frac{7}{3}\right)\right) - 13.1\right) / \left(\frac{7}{3}\right) = 5.6\,\frac{kg\ CO_2e}{kg\ H_2} \end{aligned}$$

The total emissions for the production of NGLF ethanol through ATR catalytic conversion was based on the amount of hydrogen needed to make the ethanol per hour.[31]

$$\begin{aligned} Total\ GHG\ Emissions\ with\ credits_{ATR\ Catalytic} &= \frac{Total\ GHG\ Emissions\ with\ credits_{ATR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right] \times Hydrogen\ use[kg\ H_2]}{Ethanol\ Production[MJ\ EtOH]} \\ &+ GHGEmissions_{AlcoholSynCatalyst}\left[\frac{kg\ CO_2e}{MJ\ EtOH}\right] \\ &- GHGEmissions_{MixedAlcoholCredit}\left[\frac{kg\ CO_2e}{MJ\ EtOH}\right] = \frac{5.6 \times 7{,}046}{594{,}849} + 0.000010 - 0.0192 \\ &= 0.0471\,\frac{kg\ CO_2e}{MJ\ EtOH} \times \frac{1{,}000\ g}{1\ kg} = 47\,\frac{g\ CO_2e}{MJ\ EtOH} \end{aligned}$$

Celanese TCX – Acetic Acid to Ethanol conversion

Actual process emissions for the Celanese process are not publicly available. Therefore, I estimated the emissions based on a similar process that converts methane to syngas using SMR, the syngas is converted to methanol (MeOH) using methanol synthesis, the methanol is converted to acetic acid (AcOH) using methanol carbonylation and finally the acetic acid is hydrogenated into ethanol.[83] Table 3.4 includes assumptions for the emissions estimate and sources for the data. The stoichiometric equations for the process are included below and were used to estimate the emissions as described in this section.[83]

$$2CH_4 + 2H_2O \rightarrow 6H_2 + 2CO$$

$$CO + 2H_2 \rightarrow CH_3OH$$

$$CH_3OH + CO \rightarrow CH_3COOH$$

$$CH_3COOH + 2H_2 \rightarrow CH_3CH_2OH + H_2O$$

$$2CH_4 + H_2O \rightarrow CH_3CH_2OH + 2H_2$$

Table 3.4. Assumptions for emission estimates for Celanese TCX, acetic acid to ethanol type conversion.

Process	GHG emissions/ Electricity use/ Production	Units	Source
SMR & MeOH GHG 100-yr	51.7 1.03	g CO_2e/MJ MeOH kg CO_2e/kg MeOH	Tong et al. (2015) Spath & Mann (2001)
SMR & MeOH GHG 20-yr	74.7 1.49	g CO_2e/MJ MeOH kg CO_2e/kg MeOH	Tong et al. (2015) Spath & Mann (2001)
MeOH to Acetic Acid	0.539	kg MeOH/kg Acetic Acid	US LCI Database. Acetic acid, at plant [138].
MeOH to Acetic Acid	0.00397	kg CO_2e/kg Acetic Acid	US LCI Database. Acetic acid, at plant [138].
Electricity use	0.00205 (NG turbine) 0.0218	kwh/kg Acetic Acid	
Acetic Acid to EtOH	0.000044	g CO_2e/MJ EtOH	Zhu and Jones (2009) process diagrams

Abbreviations: SMR = Steam Methane Reforming, MeOH = Methanol, GHG = Greenhouse gas, EtOH = Ethanol, US LCI = US Life Cycle Inventory Database[138]

The process emissions were calculated as follows using the parameters in Table 3.4. The emissions for producing methanol through SMR are 0.56 kg CO_2/kg MeOH, as listed in the table. From the US LCI database, 0.539 kg MeOH makes 1 kg AcOH. The total emissions for the SMR to MeOH process is estimated as follows:

$$GHG\ Emissions_{SMR\_MeOH\_100} = 1.03\frac{kg\ CO_2e}{kg\ MeOH}\times 0.539\frac{kg\ MeOH}{kg\ AcOH} = 0.555\frac{kg\ CO_2e}{kg\ AcOH}\times\frac{1000\ g}{1\ kg} = 555\frac{g\ CO_2e}{kg\ AcOH}$$

$$GHG\ Emissions_{SMR\_MeOH\_20} = 1.49\frac{kg\ CO_2e}{kg\ MeOH}\times 0.539\frac{kg\ MeOH}{kg\ AcOH} = 0.803\frac{kg\ CO_2e}{kg\ AcOH}\times\frac{1000\ g}{1\ kg} = 803\frac{g\ CO_2e}{kg\ AcOH}$$

Emissions from converting methanol into acetic acid were taken from the US LCI database, and include electricity requirements.

$$GHG\ Emissions_{AcOH} = \left(Elec_{AcOH}\left[\frac{kwh}{kg\ AcOH}\right]\times ElecGHGs_{Elec}\left[\frac{kg\ CO_2e}{kwh}\right]\right) + GHGEmissions_{AcOH}\left[\frac{kg\ CO_2e}{kg\ AcOH}\right] = (0.02385\times 0.612) + 0.00397 = 0.0186\frac{kg\ CO_2e}{kg\ AcOH}\times\frac{1000g}{1\ kg} = 18.6\frac{g\ CO_2e}{kg\ AcOH}$$

The emissions from converting acetic acid into ethanol were taken from a Pacific Northwest National Laboratory (PNNL) report prepared for the Department of Energy (DOE).[84] I used the ethanol production, acetic acid requirements and CO_2 emissions from the process diagrams.

$$Acetic\ Acid\ Ratio = \frac{Acetic\ acid\ input\left[\frac{lb}{hr}\right]}{Ethanol\ production\left[\frac{lb}{hr}\right]} = \frac{160{,}241}{117{,}806} = 1.36\frac{lbs\ AcOH}{lbs\ EtOH} = 1.36\frac{g\ AcOH}{g\ EtOH}\times\frac{0.79\ g}{ml}\times\frac{1\ ml}{0.001\ L}\times\frac{1\ L}{21.1\ MJ} = 50.9\ \frac{g\ AcOH}{MJ\ EtOH} = 0.059\ \frac{kg\ AcOH}{MJ\ EtOH} \rightarrow 19.6\frac{MJ\ EtOH}{kg\ AcOH}$$

$$GHG\ Emissions_{AcOH\_EtOH} = \frac{CO_2Emissions\left[\frac{lb}{hr}\right]}{Ethanol\ production\left[\frac{lb}{hr}\right]} = \frac{0.1383}{117{,}806} = 0.00000117\frac{lb\ CO_2e}{lb\ EtOH} = 0.00000117\frac{g\ CO_2}{g\ EtOH}\times\frac{0.79\ g}{ml}\times\frac{1\ ml}{0.001\ L}\times\frac{1\ L}{21.1\ MJ} = 0.000044\frac{g\ CO_2e}{MJ\ EtOH}$$

$$GHG\ Emissions_{AcOH\_EtOH} Per\ AcOH = 0.000044 \frac{g\ CO_2e}{MJ\ EtOH} \times 19.6 \frac{MJ\ EtOH}{kg\ AcOH} = 0.000864$$

$$Total\ GHG\ Emissions_{Celanese\_TCX\_100} = \frac{\left(GHG\ Emissions_{SMR\_MeOH} + GHG\ Emissions_{AcOH} + GHG\ Emissions_{AcOH\_EtOH} Per\ AcOH\right)\left[\frac{g\ CO_2e}{kg\ AcOH}\right]}{Acetic\ Acid\ Ratio\left[\frac{MJ\ EtOH}{kg\ AcOH}\right]}$$
$$= \frac{555 + 18.6 + 0.000864}{19.6} = 29.2 \frac{g\ CO_2e}{MJ\ EtOH}$$

$$Total\ GHG\ Emissions_{Celanese\_TCX\_20} = \frac{\left(GHG\ Emissions_{SMR\_MeOH} + GHG\ Emissions_{AcOH} + GHG\ Emissions_{AcOH\_EtOH} Per\ AcOH\right)\left[\frac{g\ CO_2e}{kg\ AcOH}\right]}{Acetic\ Acid\ Ratio\left[\frac{MJ\ EtOH}{kg\ AcOH}\right]}$$
$$= \frac{803 + 18.6 + 0.000864}{19.6} = 41.8 \frac{g\ CO_2e}{MJ\ EtOH}$$

Coskata – Fermentation Process

Actual process emissions for the Coskata process are not publicly available. Therefore, I estimated the emissions based on a similar process. The stoichiometric equations for the process are included below and were used to estimate the emissions as described in this section.

$$2CH_4 + 2H_2O \rightarrow 6H_2 + 2CO$$

$$2CO + 4H_2 \rightarrow CH_3CH_2OH + H_2O$$

$$2CH_4 + H_2O \rightarrow CH_3CH_2OH + 2H_2$$

Table 3.5. Assumptions for emission estimates for Coskata type fermentation conversion.

Process	GHG emissions/ Electricity use	Units	Source
SMR - GHG WGS GHG adj.[1]	10.1 9.81	kg CO_2e/kg H_2	Tong et al. (2015) Spath & Mann (2001) 100-yr ~ 20-yr GWP.
Fermentation Elec use	3.28	MJ/kg EtOH	Roy et al. (2015) & van Kasteren et al. (2005)
Separation (distillation & purification) Elec use	3.89	MJ/kg EtOH	Roy et al. (2015)

Abbreviations: SMR = Steam Methane Reforming, GHG = Greenhouse gas, WGS = Water Gas Shift, Elec = Electricity, EtOH = Ethanol.

I estimated the process emissions using the parameters in Table 3.5. The first step in the process is to produce syngas from methane using SMR. The same SMR estimates were used for ATR Catalytic hydrogen co-product credits. For the fermentation process, there is also a hydrogen co-product credit. Based on the stoichiometry 0.00647 kg H_2 from the SMR process makes 1 MJ of ethanol. Calculations for the emissions for producing 1 kg of hydrogen through SMR are as follows:

$$Coproduct\ GHG\ emissions\ credit = ProcessGHGs_{SMR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right]\times(2\ kg\ H_2) = 9.81\times(2) = 19.62\ kg\ CO_2e$$

$$GHG\ Emissions_{SMR\_ferm} = \frac{\left(ProcessGHGs_{SMR}\left[\frac{kg\ CO_2e}{kg\ H_2}\right]\times 3\ [kg\ H_2]\right) - \ Coproduct\ GHG\ emissions\ credit[kg\ CO_2]}{3\ [kg\ H_2]} \times\frac{0.00647\ kg\ H_2}{MJ\ EtOH} = \frac{(9.81\times 3)-19.62}{3}\times 0.00647 = 0.0211\frac{kg\ CO_2e}{MJ\ EtOH} = 21.2\frac{g\ CO_2e}{MJ\ EtOH}$$

Fermentation and separation emissions are based on the energy requirements to convert syngas to ethanol. The average U.S. grid electricity emissions were used.

$$GHG\ Emissions_{Ferm} = \left(Elec_{Ferm}\left[\frac{MJ}{kg\ EtOH}\right] + Elec_{Sep}\left[\frac{MJ}{kg\ EtOH}\right]\right)\times\frac{kg}{1.274\ L}\times\frac{L}{21.1\ MJ} \times ElecGHGs_{Elec}\left[\frac{g\ CO_2e}{kwh}\right]\times\frac{kwh}{3.6\ MJ} = (3.28+3.89)\times\frac{kg}{1.274\ L}\times\frac{L}{21.1\ MJ}\times 612\times\frac{kwh}{3.6\ MJ} = 45.3\frac{g\ CO_2e}{MJ\ EtOH}$$

$$Total\ GHG\ Emissions_{Ferm} = 21.2 + 45.3 = 66.5\frac{g\ CO_2e}{MJ\ EtOH}$$

3.3.3 Fuel Transport and Distribution

I used the estimates from GREET for fuel transportation of methanol, which are 1.82 (100-yr) g CO_2-equiv/MJ and 1.97 (20-yr) g CO_2-equiv/MJ.[137] If the ethanol transportation and distribution estimates were used instead, the emissions would be smaller by 0.68 to 0.78 g CO_2-equiv/MJ, respectively for each GWP.[137] Fuel transport and distribution accounts for less than 1% of the total emissions. As these emissions are a small component of the total emissions, changing to the ethanol emissions are unlikely to impact the overall estimates.

3.3.4 Combustion and Vehicle Use

The final part of the NGLF ethanol life cycle is the combustion of the fuel. If the life cycle is well-to-plant gate, the combustion of ethanol based in its carbon content is 70.6 g CO_2-equiv/MJ. When I consider the end use of the fuel the efficiency of the vehicle using the fuel becomes important, and the unit of emissions is g CO_2-equiv/km. NGLF ethanol would be blended with gasoline to produce E10 or E85 for use in FFVs. Following Tong et al. (2015), a representative gasoline and E85 FFV passenger and sports utility vehicle (SUV) were assumed to calculate the emissions per km. The fuel economy assumptions are included in Table 3.6. Vehicle manufacturing emissions are not included as they are the same for FFVs and gasoline vehicles.

Table 3.6. Fuel economy assumptions in miles per gasoline gallon equivalent.

Fuel	Passenger Vehicle	SUV	Source
Gasoline	33	25	Tong et al. (2015), which used fueleconomy.gov.
E85 Flexible Fuel Vehicle (FFV)	31.6	24.7	Tong et al. (2015), which used fueleconomy.gov.
Dedicated E85 vehicle	33.8	26.4	Improvement to fuel economy of E85 FFV by approximately 7%[137].

3.3.5 Comparison fuels

The recent paper from Tong et al. (2015) estimated the life cycle emissions for 8 natural gas based light-duty vehicle pathways, including ethanol made from ethane [16]. The pathways were also compared to conventional gasoline. In this analysis I compare the NGLF ethanol estimates to conventional gasoline (from Tong et al.), which are assumed to be equivalent for the 100/20-yr GWP and ethanol derived from ethane (from Tong et al.). The values used for comparison are listed in Table 3.7.

Table 3.7. Comparative fuels life cycle emissions. The life cycle emissions per MJ show the mean and 95% confidence intervals in parentheses.

Pathway	Life cycle GHG emissions (g CO_2-equiv/MJ)	Life cycle GHG emissions (g CO_2-equiv/km)	Source
Gasoline, 100/20yr	92 (85-101)	206	Tong et al. (2015)
20% reduction	74	-	
E85 from ethane			
100-yr	106 (95-120)	247	Tong et al. (2015)
20-yr	118 (104-140)	275	

3.4 Results

The GHG emissions for the four phases of the life cycle are shown in Figure 3.3. A 20% reduction in gasoline GHG emissions would be approximately 74 g CO_2-equiv/MJ, which is shown as the dashed line on Figure 3.3. Gasoline and ethanol from ethane have their upstream and process emission grouped together, and NGLF ethanol non-combustion emissions are broken down as shown. The NGLF estimates are higher than gasoline and ethanol derived from ethane, which is not surprising because of the optimization that both fuels have experienced in their long processing history. New potential processes are unlikely to be as efficient as modeled now. Additionally, higher emissions are expected as there are more processing steps for the NGLFs that tend to coincide with higher emissions.

Generally, all the NGLF processes have similar emissions, with Celanese TCX as the smallest, and Coskata as the largest. The Celanese TCX like process had the most available emissions estimates, and many of the sub-processes are already used to make other products. Therefore, I would expect this process to be more efficient, which may have lead to lower emissions estimates. As described in Zhu and Jones (2009), acetic acid has higher selling price than ethanol, therefore making ethanol results in a loss in profit[84], which may make the Celanese TCX process unlikely to be further developed.

When considering the motivation for producing ethanol from NG, meeting the EISA 2007 requirements are critical to receiving acceptance of an NGLF ethanol. A 20% reduction at a minimum in GHG emissions compared to gasoline would be required, and as shown in Figure 3.3 is unlikely to be met based on the estimates here. All three NGLF ethanol processes in the 100-yr and 20-yr GWP scenarios, are well above the 20% reduction line. Although not shown, corn ethanol GHG emissions are estimated to be approximately 61 g CO_2-equiv/MJ (with a range of 43 to 91 g CO_2-equiv/MJ, assuming a 100-yr GWP of 25 for CH_4).[62] NGLF ethanol estimates are also well above the high estimate for corn ethanol. Biomass based fuel emissions estimates benefit from the offset of their combustion emissions with the carbon sequestered in the biomass during photosynthesis (biogenic CO_2).[62] As NGLF ethanol is derived from a fossil carbon, it does not receive the same credit.

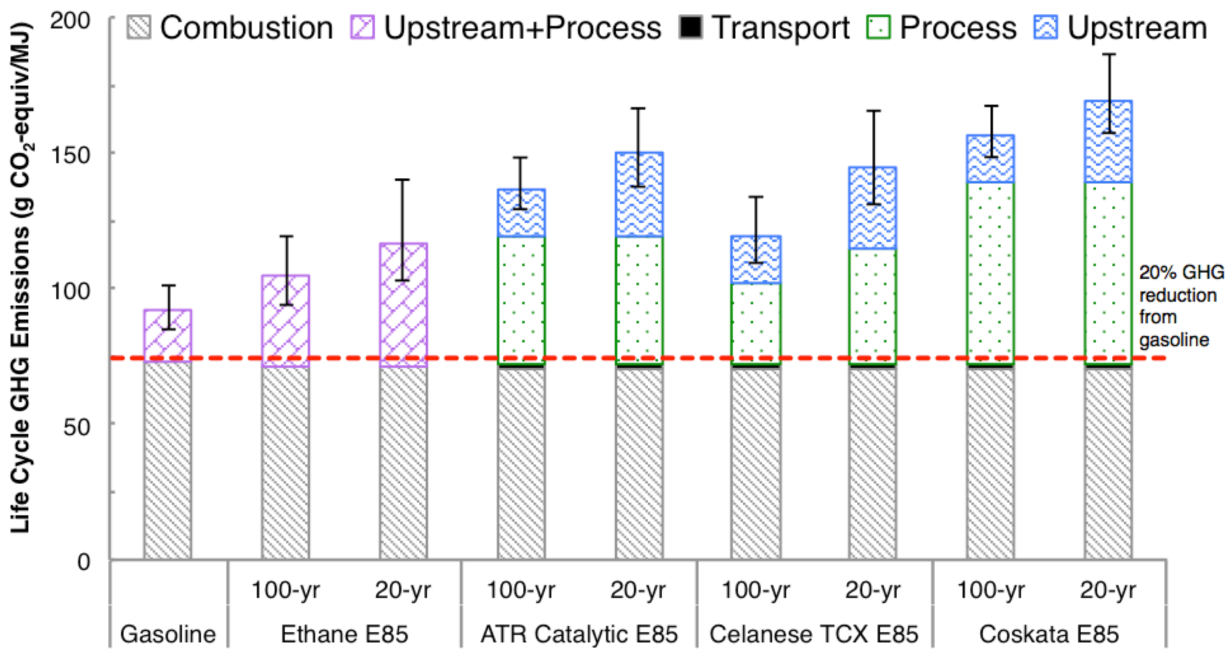


Figure 3.3. Total life cycle GHG emissions for the three NGLF ethanol processes compared to ethanol derived from ethane and gasoline in g CO_2-equiv/MJ. The dashed line is a 20% reduction in gasoline GHG emissions per the RFS2. The bars show the 95% confidence intervals that reflect uncertainty in the upstream emissions and GWP.

When considering the end use of the ethanol as a transportation fuel, the emissions are estimated on a g CO_2-equiv/km basis. The assumptions for vehicle fuel economy are listed in Table 3.6 for a passenger vehicle and an SUV. The results are shown in Figure 3.4, and upstream emissions are a sum of upstream, process and transport emissions. Emissions result patterns are very similar to the MJ basis, because the fuel economy for conventional gasoline vehicle is similar to FFV even when adjusted for the energy difference of the fuels. The NGLF ethanol fuels are well above gasoline, and have some overlap with the ethanol made from ethane.

Improvement in the fuel economy of FFVs or use of dedicated E85 vehicles would bring the NGLF E85 emissions closer to a gasoline vehicle as shown in Figure 3.4. This would improve the GHG emissions estimate per km. A fuel economy of 43 to 56 mpgge, for passenger vehicles, would be required for gasoline emissions to equal NGLF ethanol, on average. For an SUV, a fuel economy of 32 to 43 mpgge would be required. The range of fuel economy estimates is for the three NGLF ethanol processes assuming a 100-yr GWP. Given the Corporate Average Fuel Economy (CAFE) standard requirements, vehicles could reach these fuel economy levels by 2025. The fuel economy estimates also assume that gasoline efficiency stays the same, which is highly unlikely. Given a smaller increase in fuel economy, like a dedicated E85 vehicle, an improvement in the upstream and processing phases would also be required for the fuel economy improvement to make a difference.

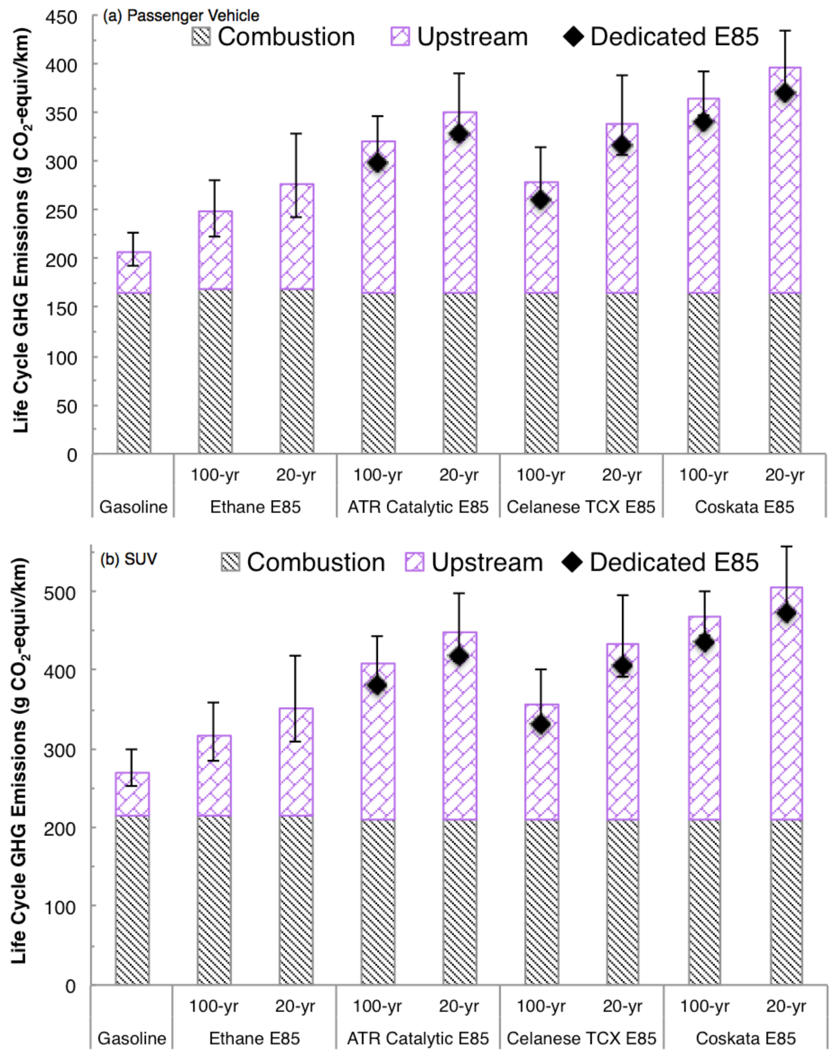


Figure 3.4. Life cycle GHG Emissions with vehicle use in g CO_2-equivalent/km. (a) For a passenger vehicle. (b) For a SUV. The bars show the 95% confidence interval estimates that reflect uncertainty in the upstream emissions and GWP. The black diamonds are the average emissions assuming the vehicle is a dedicated E85 vehicle with fuel economy improvements compared to an FFV.

3.5 Discussion

Estimating the emissions for NGLF ethanol required synthesizing various data sources. The NGLF estimates are first-order, and are generally much higher than comparative fuels. As I did not model the entire processes, there is room for efficiency improvement or missed co-product credits that could lower the estimated emissions. It is also likely that some emissions were not accounted for due to lack of available information. The uncertainty shown in the error bars in previous results figures does not account for the uncertainty in the process emissions, but rather is rooted in the upstream and GWP estimates (and the parameters that depend on them). To assess the impact of process emission inaccuracy, I removed all process emissions from the estimate for the NGLF ethanol pathways and compared them again to gasoline and ethanol derived from ethane. Figure 3.5(a) shows the results, and in the very unlikely scenario that there are no emissions from the process of making ethanol, the NGLF ethanol GHG emissions are still above the 20% reduction. However, there is now more overlap with the comparative fuels.

As discussed before, and modeled in the emissions estimate, there is uncertainty in the natural gas upstream emissions phase. Tong et al. (2015) considers a base case and pessimistic case (1.5 times the base case) for methane leakage in the upstream phase. Increasing the methane emissions in the upstream would only increase the total emissions difference between NGLF ethanol and the comparative fuels. Similarly, a decrease in methane emissions from the upstream would bring the estimates closer together. To see the impact that decreased upstream emissions could have on the total estimates I eliminated all upstream emissions from the estimate, and again compared NGLF ethanol to the comparative fuels. Figure 3.5(b) shows the life cycle GHG emissions with no upstream emissions. Even if both CO_2 and CH_4 emissions were eliminated from the upstream, the NGLF ethanol processes would still be well above the 20% reduction.

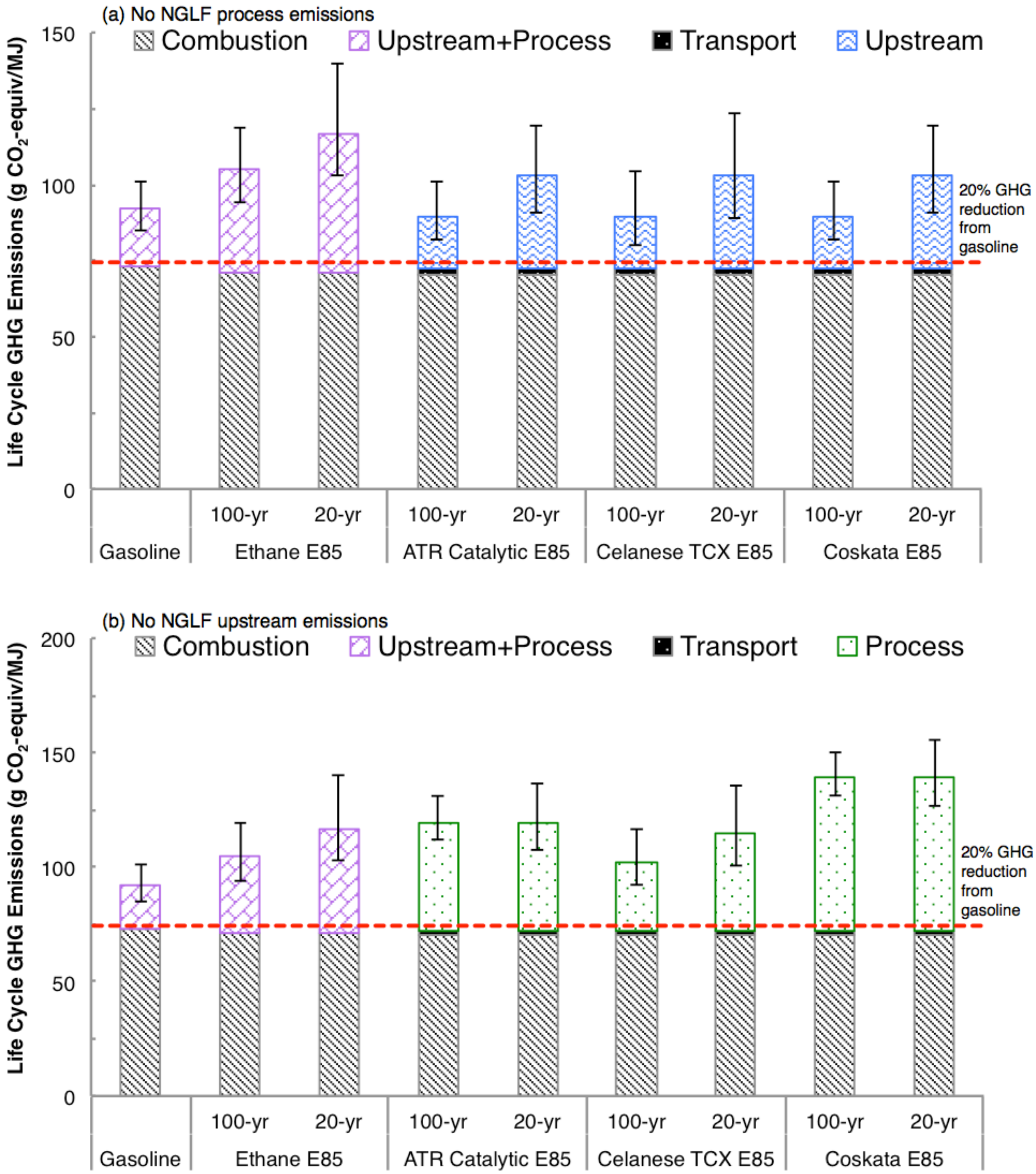


Figure 3.5. Life cycle GHG emissions scenarios for the three NGLF ethanol processes compared to ethanol derived from ethane and gasoline in g CO_2-equiv/MJ. (a) Here, the process emissions for the NGLF ethanol processes are not shown. (b) Upstream emissions for the NGLF ethanol processes are not shown. The dashed line is a 20% reduction in gasoline GHG emissions per the RFS2. The bars show the 95% confidence interval estimates that reflect uncertainty in the upstream emissions and GWP, where appropriate.

Given that the total emissions estimates for the process are much higher than gasoline, even the large range of assumptions made for sensitivity to the process and upstream NG emissions, it is unlikely that the assumptions related to GWP would change the results. Hence, even though some of the emissions factors were not adjusted to the IPCC AR5 estimates it is unlikely that this would change any of the overall comparisons.

Other parameters in model were also evaluated for impacts to the model results. The electricity emissions assumed in the base case was the U.S. average grid mix (2010). If I assume NGCC electricity (low end) or U.S. grid mix at the outlet (high end), the emissions would change. Additionally, although transportation and distribution emissions are low, if I cut them in half (low end) or doubled (high end) them I observed small changes to the overall emissions estimates. The results of the sensitivity of these parameters are shown in Figure 3.6 compared to the average base case (vertical black line). As expected, the transportation and distribution emissions have a very little impact of the life cycle emissions. The electricity emissions factor could have a larger impact if an average NGCC plant is assumed, but the emissions reduction in the electricity emissions alone are not enough to make NGLF ethanol GHG emissions comparable to gasoline.

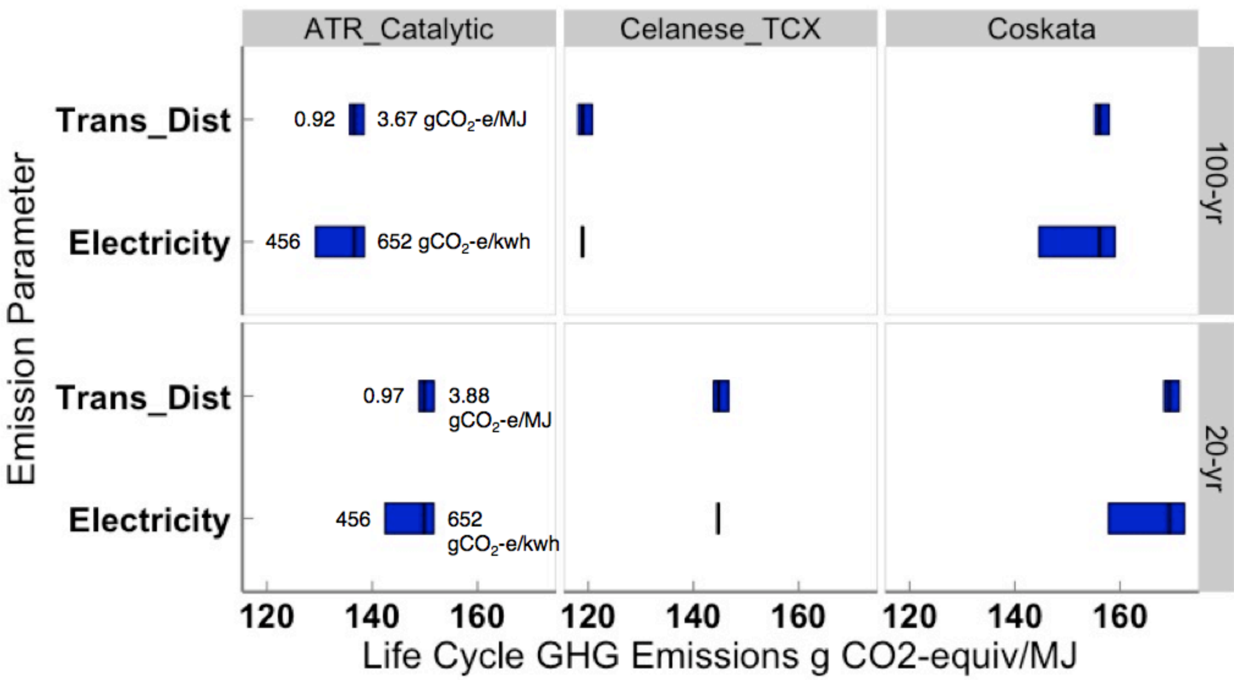


Figure 3.6. Life cycle GHG emissions sensitivity analysis results for electricity, transportation and distribution emission factors for all three processes, and both GWP scenarios. The parameter values are compared to the average base case life cycle emissions shown in Figure 3.3.

Using the average costs for making ethanol from NG in Chapter 2, and the emissions estimated in this Chapter, I calculated the trade-off between potentially reduced production costs and increased emissions. For Coskata, the only process to have costs lower than gasoline (using average costs, assuming meeting all demand), the costs are approximately \$1.23/gge less than gasoline. The average emissions for Coskata are 64 (100-yr GWP) and 77 (20-yr GWP) gCO_2-equiv/MJ more than gasoline (92 gCO_2-equiv/MJ on average). A dollar savings per metric ton of carbon dioxide equivalent emitted for Coskata is approximately \$0.13 to \$0.16/metric ton CO_2-equivalent. The social cost of carbon is estimated to be on average \$36/metric ton CO_2 (3% discount rate, for 2015)[139], which is 100 times larger than the potential cost of emissions for Coskata. This is not to say that the emissions from an NGLF process are acceptable, but puts into context the trade off between cost savings and emissions.

3.5.1 Criteria Air Pollutants

In addition to GHG emissions, CAP emissions should be considered in evaluating the benefits of an alternative fuel. In this analysis I focus on the GHG emissions as they are included in the EISA 2007 and RFS2, while the CAP emissions are not.[3,4] CAP emissions are identified by the Environmental Protection Agency as ground level ozone, particulate matter, carbon monoxide, sulfur oxides and nitrogen oxides. Unlike GHG emissions that are well-mixed in the atmosphere when released, the location CAP emissions matter and can contribute to health issues especially when released in high emission areas. Therefore, an improvement in CAP emissions from switching from corn ethanol to NGLF ethanol or switching from gasoline to E85, could help to make a case for the benefits of NGLF ethanol.

Litovitz et al. (2013) provided a first-order estimate of regional air-quality damages from shale gas extraction in Pennsylvania. The authors found that estimated damages ranged from \$7.2 to \$32 million dollars (2011), which are relatively small compared to other sectors. However, in some areas that already have high CAP emissions, the additional emissions from shale gas extraction can make a difference.[140] Other studies have looked at the CAP changes for switching from gasoline to E85, and have found there to be an increase in NOx that can impact both ozone and particulate matter, but also depends greatly on the source of the ethanol.[69-71] For the NGLF ethanol fuel, the CAP emissions data was even less prevalent than for GHG emissions. Therefore, I did not do a full life cycle estimate. For the processing of ethanol I could assume that an the NGLF plant would need to meet specific CAP limits for its area. That a plant located in a nonattainment area may have to meet more stringent limits on CAP emissions. Within Pennsylvania, there are nonattainment areas for ozone, PM and SO_2 in the counties around Philadelphia and Pittsburgh where it would be most cost-effective to locate a NGLF plant.[141] The additional production and consumption of ethanol in the transportation sector could also impact the production of gasoline at oil refineries, which are not included here. Previous estimates of this impact included emissions reductions of a few percent, but may differ for these processes.[69]

3.6 Conclusions

Producing ethanol from NG could be one way to use the abundant NG resources to produce a transportation fuel, which could then be used by the existing conventional and FFV fleet in the U.S. I estimated the cost of producing a NGLF ethanol in the previous chapter, and found that the cost of producing ethanol with some processes would more likely than not be cheaper than gasoline and corn-based ethanol. However, capital costs from these emerging processes and future NG and gasoline prices are highly uncertain. In addition to a cost evaluation, the emissions from an NGLF ethanol process need to be assessed and compared to other processes.

A first-order estimate of producing NGLF ethanol through three unique pathways would likely result in emissions that are much larger than gasoline, and the 20% reduction required by EISA 2007 and RFS2. Even accounting for the uncertainty in the upstream emissions and the processing, the GHG emissions are still larger. The combination of very low upstream and process emissions and significant improvement to the fuel economy of an FFV or dedicated E85 vehicle might result in GHG emissions closer to the target, but reduction in emissions of the required magnitude in those phases is unlikely to occur. A more refined design process could improve the emissions estimates, and would also allow for an ISO standard LCA that takes into account alternate allocation methods. A NGLF ethanol is unlikely to meet the 20% GHG emission reductions required of renewable fuels under EISA 2007 and RFS2.

Chapter 4. Refueling and Infrastructure Costs of Expanding Access to E85 in Pennsylvania.

4.1 Abstract

Even in competition with other alternative fuels, ethanol remains a significant part of the U.S. transportation system. Nationally, ethanol is blended with gasoline up to 10% for conventional vehicles, and up to 85% (E85) for use in Flexible Fuel Vehicles (FFVs). Federal mandates require increasing ethanol in the transportation sector. Meeting the mandates could mean increasing the blend in conventional gasoline, or the use of E85 in FFVs. This chapter estimates additional refueling costs for an FFV and infrastructure costs for expanding E85 access in Pennsylvania, which recently received government grants for biofuels infrastructure. I find that even with a subsidy to cover average infrastructure costs of \$0.03 to \$1.48 per gasoline gallon equilvalent (gge or \$0.01 to \$0.39/gasoline-liter-equivalent, gle) for the retailer, the consumer would still incur additional costs for refueling more often with E85. A refueling cost subsidy of \$3.60/gge (\$0.95/gle) is also higher than historical ethanol subsidies. Additionally, a subsidy to encourage E85 use could reduce emissions at a cost equivalent to \$1,320/metric ton CO_2, approximately two orders of magnitude above the average social cost of carbon, and is not a cost-effective mitigation strategy.

This chapter is based on the paper: *Seki, S. M., Griffin, W. M., Hendrickson, C. and Matthews, H.S. (2016) "Refueling and infrastructure costs of expanding access to E85 in Pennsylvania" (under review at ASCE Journal of Infrastructure Systems).*

4.2 Introduction

Even in competition with natural gas and electricity for electric vehicles, ethanol remains a significant part of the United States transportation fuel system. Ethanol is blended with gasoline up to 10% (E10) for conventional vehicles, and up to 85% (E85) for use in Flexible Fuel Vehicles (FFVs). The ethanol available is typically made from corn if produced in the United States, and federal mandates require increasing ethanol in the transportation sector. Meeting the federal mandates means increasing the blending and therefore use of ethanol, which could be done by increasing the blend in conventional gasoline beyond 10%, or increasing the current use of E85 in FFVs on the road. Higher ethanol blending is currently only approved up to 15% for conventional light-duty vehicles of model year 2001 and newer.[29] This paper quantifies the additional cost and availability issues with E85 fuel use for consumers, retailers and the government by estimating refueling convenience costs for an FFV and necessary infrastructure costs. Also, the paper explores how government support could increase use in

Pennsylvania. Unlike some previous refueling cost studies and other available refueling estimation tools, the costs are modeled stochastically to account for varying input parameter assumptions.[105,142,143]

The prevalence of ethanol use is due in part to the EISA of 2007 and the Renewable Fuel Standard (RFS2) which established a mandate for the use of domestically produced biofuels in the transportation sector.[3,4] EISA was enacted in order to (1) encourage energy independence and security, (2) increase renewable fuel production, (3) encourage the research and use of greenhouse gas (GHG) emissions capture and storage, and (4) improve Federal government energy performance.[3] The renewable fuel under the RFS is primarily corn ethanol and other advanced or renewable fuels like cellulosic ethanol, which have annually established quantities till year 2022.[4]

RFS2 volumes are managed through a Renewable Identification Number (RIN) system, with each RIN attached to a single gallon (1 gal = 3.79 L) of renewable fuel produced. Gasoline and diesel transportation fuel suppliers are required to produce a specific quantity of renewable fuels (per the RFS2), which are based on a percentage of their total annual fuel sales.[51] The company's obligatory renewable fuel quantity is referred to as the renewable volume obligation (RVO), and fuel suppliers can meet RVO's by earning (through production) or purchasing RINs.[51] The value of a RIN depends upon how much ethanol can be blended to meet mandates, and how much non-RVO companies are participating in the market.[51] The Environmental Protection Agency (EPA) can adjust the required volumes every year based on gasoline and diesel production and the growth of technology. Notably, the EPA has lowered the required volumes each year from 2011 to 2014 due to an inability to meet the proposed volumes from a supply and demand perspective.[4-7] The difficulty in meeting the mandates is attributed to conventional vehicles not approved to consume more than 10 to 15% ethanol blended with gasoline, thereby hitting the ethanol "blend wall", the lack of alternative biofuel development and a flat demand for fuel.[7,45] There are 17 million FFVs in the U.S., many of which typically purchase gasoline instead of E85.[9] Motivating more FFV owners to choose E85 is one way to increase ethanol consumption without the need for additional EPA higher blend approvals or additional alternative vehicles. It should be noted that automakers have an incentive to produce more FFVs under the Corporate Average Fuel Economy (CAFÉ) policy, but researchers have estimated that this credit actually contributes to increasing GHG emissions and gasoline consumption for the overall fleet each time an FFV is purchased instead of a conventional vehicle.[144]

Although there are FFVs available to use E85, there are many reasons why they may not be refueled with E85, including convenience and price.[23] As of October 2015, in the U.S. there were 2,679 public and 312 private stations that sell E85.[18] With approximately 105,000 total gasoline stations in the U.S.[24], only 2.5% of stations sell E85, which tend to be clustered in certain regions. Analyses have estimated that the availability of an alternative fuel is no longer a concern to alternative vehicle drivers when the percent of stations selling the alternative fuel is between 10-30%.[25,26]

Price is the other large barrier to E85 use. According to the Alternative Fuels Data Center (AFDC), the difference between gasoline and E85 has ranged from $0/liter to $0.09/liter ($0.36/gal) from years 2000 to 2014 for quarterly averages, with gasoline and E85 prices on average within 5% of each other and following similar trends over time as shown in Figure 4.1.[145] However, the price of E85 has consistently been higher than gasoline on a gasoline liter equivalent (gle) basis. Comparing E85 and gasoline on a liter-to-liter basis is not a perfect comparison; gle is a measure of energy equivalency that accounts for a difference in lower heating value LHV or energy content. A liter of E85 has an LHV of only 21,570 Btu compared to gasoline (E10) with 30,195 Btu.[145] The difference in energy content between E85 (assuming 85% ethanol in the fuel per liter) and gasoline means that it takes approximately 1.4 times more E85 fuel than E10 to travel the same distance. The AFDC assumes there is 70% ethanol in E85 per liter as an average ethanol content in E85, which makes the factor 1.3 (as shown in Figure 4.1). Additionally, FFVs that run on E85 may not have engines optimally tuned for the fuel, which could create additional inefficiencies that are not accounted for here. According to the AFDC, the difference in price on a gle basis between the two fuels has ranged from $0.03/gle to $0.31/gle ($0.10/gge to $1.19/gge) from years 2000 to 2014 for quarterly averages, with E85 consistently more expensive than gasoline.[145]

Numerous government subsidies have supported the blending and use of ethanol. Ethanol blenders received a $0.12/L ($0.45/gal) tax credit until it was terminated at the end of 2011 (this tax credit varied in value since it was created in 1978).[48,146] There is currently a $0.27/L ($1.01/gal) tax credit for cellulosic-based ethanol.[146] Additionally, there are two federally funded infrastructure grants available for installation of biofuel infrastructure, the Biofuels Infrastructure Program (BIP) and the Ethanol Infrastructure Grants and Loan Guarantees.[147,148] These programs partially subsidize the installation of equipment needed to sell biofuels.

Figure 4.1. National E85 and gasoline quarterly average fuel prices from 2000 to April 2015 from the Alternative Fuels Data Center.[145] The E85 price in gle assumes the energy equivalent conversion from gasoline to E85 is 1.3. This parameter could vary based on the actual ethanol content in E85 between 1.2 and 1.4, which is included as Figure B.1 in the Appendix. On a gle basis, E85 is always more expensive than gasoline.

Even with some tax credits and subsidies, E85 remains a small part of consumer fuel choice across the country. I use Pennsylvania as a case study as I have vehicle ownership location data for the state, and because Pennsylvania recently received federal funding for biofuel refueling infrastructure.[149] E85 made up 0.01% of total fuel (gasoline and E85 in gle) consumption in Pennsylvania in 2012.[150] The cost of increasing E85 use, as a way to meet future RFS2 mandates, will impact both FFV drivers and retailers. A previous study estimated convenience costs for FFVs, which were used in demand models to estimate the consumption of E85 with changing E85 prices.[105] Here I stochastically estimate refueling convenience costs and the costs of increasing E85 availability in Pennsylvania. I evaluate the costs to the consumer and retailer, the factors that drive costs, and where investment (possibly subsidies) should be directed to encourage increased E85 use.

4.3 Data and Methods

The total costs for E85 use in Pennsylvania were estimated in four steps as illustrated in Figure 4.2. The first step was to build a location-based refueling model, which outputs the number of required stations to service a fleet of FFVs, and a distribution of travel distances to E85 stations. The estimated number of stations was used to calculate private station costs, and the travel distances were used to estimate total refueling convenience costs. Finally, the costs were compared to get total private costs.

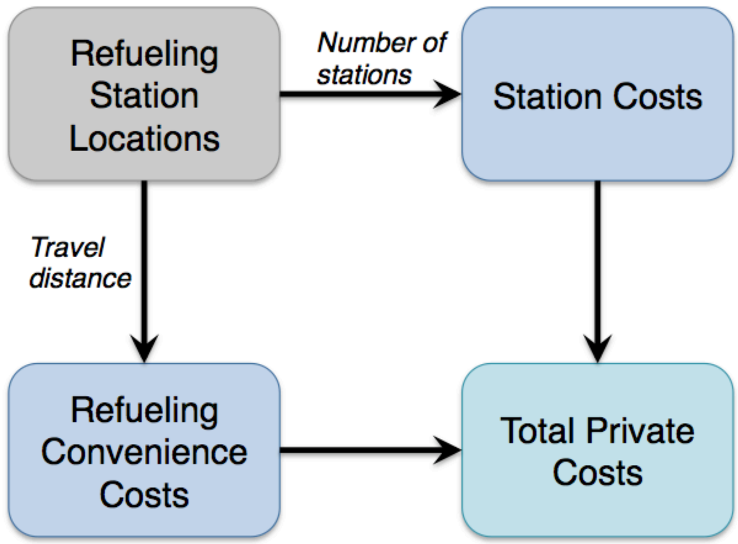


Figure 4.2. Modeling steps: Refueling station location model outputs number of stations and travel distance to E85 stations. These two outputs were used to estimate station and refueling convenience costs. The final costs are compared in the final modeling step.

4.3.1 E85 Refueling Station Location Model

According to the Pennsylvania Department of Transportation 2014 registration data and using a Vehicle Identification Number (VIN) decoder, I estimated there were approximately 600,000 FFVs registered in the state.[121,151] Figure 4.3 shows the wide distribution of FFVs in the state, where darker areas have a larger number of registered FFVs. The AFDC has record of 30 refueling stations in Pennsylvania that sell E85, which is less than the overall average for states in the U.S.[18] Four of these stations are only accessible when driving on the tolled Pennsylvania Turnpike, and were removed from the analysis. The 26 remaining stations are located in 24 unique ZIP Codes shown as dots in Figure 4.3, while the turnpike stations are shown as squares. Some FFVs in more rural locations outside of the Philadelphia and Pittsburgh areas have little access to E85.

To determine an average distance traveled to refuel from a registered vehicle ZIP Code I used a previous survey study on refueling patterns and National Household Travel Survey (NHTS) data[152,153], which indicate that the average refueling distance from home is 14.5 km (9 miles). Both data sets are limited surveys, and sensitivity on the refueling distance is included in the results section. Rather than assuming all FFVs in the state would or could drive to a station that sells E85, the data set of FFVs and distances were filtered using 14.5 km as a baseline travel distance from home to a refueling station. The analysis then locates new stations in ZIP Codes that have the largest number of FFVs in order for all FFVs to be at the equivalent baseline distance (14.5 km) to a station selling E85.

Great circle distances were used with ZIP Code centroids from registration location to station location, and a circuity factor of 1.23 was applied to the distances to account for the non-linearity in the actual road network.[114,154] Previous work for biomass production and transportation shows that using centroids with a circuity factor in place of an actual street network has no impacts on final results within the uncertainty of the overall analysis.[155]

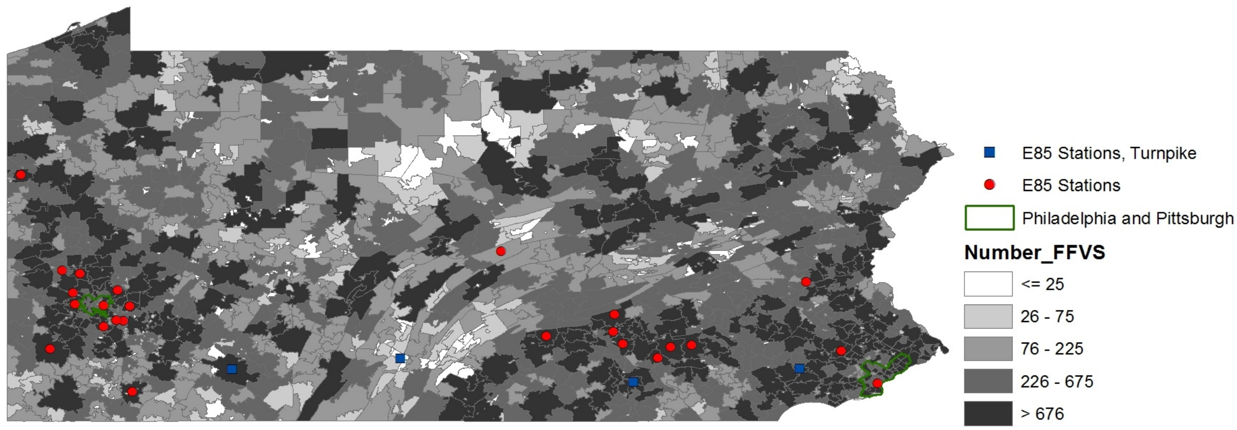


Figure 4.3. Number of registered FFVs per ZIP Code area in Pennsylvania. Darker areas have more FFVs. Dots are the ZIP Codes that currently have refueling stations that sell E85.[18] The outlined areas are the Pittsburgh (left) and Philadelphia (right) city areas.

In addition to distance, the station capacity was considered. Anecdotally, one retailer in Texas averages 3,790 L/day (1,000 gal/day) of E85 sales per station[156], and Propel Fuels in California averaged 532,800 L (140,585 gal) in 2014, approximately 1,500 L/day (385 gal/day)[157]. In Minnesota, where E85 sales are tracked, the 2014 monthly average sales per station were 17,800 L (4,704 gal), approximately 595 L/day (157 gal/day).[158] The assumed station capacities ranged from 570 to 5,700 L/day (150 to 1,500 gal/day) with a single pump at each location. Varying the percentage of FFVs in PA within 14.5 km sets the number of required stations to meet demand. The percentages vary from 25% (base case) to 100%.

4.3.2 Refueling Convenience Cost Model

The cost of refueling an FFV was previously modeled in a paper by Pouliot and Babcock (2014), but generated point estimates. Here costs were calculated with assumed distributions for the various parameters (Table 4.1). The remainder of the model was built using data from literature, and from the available PennDOT vehicle databases. The refueling convenience cost model parameters are listed in Table 4.1. Inputs were separated into driving behavior, car characteristics, time inputs and price. The refueling convenience cost for the average FFV changed based on percent of refueling with E85 (%E85), which was parameterized in the model. The time spent refueling was monetized using the Value of Time from the U.S. Department of Transportation evaluation of average values depending on business or personal time lost, but it does not consider specific consumer behavior and preferences.[159] Additionally, the distances traveled to stations are estimated from the registered or home location of the vehicles and do not account for the heterogeneity in refueling trips, which could also include travel to work, school or other activities.

Table 4.1. Refueling convenience cost model input parameter values.

Input	Units	Distribution	Minimum	Mean/Most Likely	Maximum	Standard Deviation	Source/Description of Input
Driving Behavior							
VMT	km *(miles)*	Normal	4,830 *(3,000)*	17,700 *(11,000)*	39,800 *(24,700)*	8,000 *(5,000)*	Annual Vehicle km (miles) Traveled - Inspection data (2011) & National Average (2009).
%E85	%	Parametric	0	-	1	-	Percentage of E85 refuels for FFV.
Car Characteristics							
EC	#	Uniform	1.2	-	1.4	-	Energy conversion factor based on the energy content of fuel, which ranges from E50 to E85[131], and E10 for gasoline. Based on Lower Heating Values.
KPLgas	km/L *(miles/gal)*	Normal	5 *(12)*	8 *(20)*	12 *(28)*	2 *(4)*	Kilometers per liter (KPL) for an FFV fueled by gasoline - VIN decoder database for all FFVs in the registration database.
KPLE85	km/gle	-		KPLgas/EC			KPL for an FFV fueled by E85. It is KPLgas/Energy Conversion - VIN decoder database for all FFVs in the registration database.
LPKgas	L/km *(gals/mile)*	Normal	0.19 *(0.08)*	0.12 *(0.05)*	0.07 *(0.03)*	0.02 *(0.01)*	Liters per km (LPK) consumed for an FFV fueled by gasoline. It is 1/KPLgas - VIN decoder database for all FFVs in the registration database.
LPKE85	gle/km	-		1/KPLE85			LPK consumed for an FFV fueled by E85. It is 1/KPLE85 - VIN decoder database for all FFVs in the registration database.
CAP	L *(gal)*	Normal	45 *(12)*	91 *(24)*	150 *(39)*	23 *(6)*	Capacity of the fuel tank for an FFV - VIN decoder database for all FFVs in the registration database.

Input	Units	Distribution	Minimum	Mean/Most Likely	Maximum	Standard Deviation	Source/Description of Input
Level	%	Triangular	0.09	0.18	0.27	-	The percentage of fuel remaining in the tank when the FFV driver decides to refuel. Based on literature.[160]
Time Inputs							
StaTimeGas	mins	Triangular	0	-	0	-	The time for an FFV to drive to a gasoline station.
StaTimeE85	mins	Discrete	See Figure 4.6 (≤14.5 km)				The time for an FFV to drive to a station selling E85. Based on distance calculations using registration data and AFDC location data.
WaitTime	mins	Triangular	0	2	10	-	Wait time at the station to get to a pump. Assumed a reasonable time, but it is relatively negligible.
PayTime	mins	Triangular	0	2	5	-	Pay time at the station. Assumed a reasonable time, but it is relatively negligible.
RefTime	L/min *(gal/min)*	Triangular	23 *(6)*	30 *(8)*	38 *(10)*	-	Rate at which fuel is pumped into the vehicle, based on literature.[23,161]
TimeVal	$/min	Triangular	0.16	0.23	0.28	-	The value of a FFV driver's time. Based on the U.S. Department of Transportation's guidance on the valuation of time for economic analyses.[159]
Price							
Pgas	$/L *($/gal)*	Triangular	0.87 *(3.29)*	0.94 *(3.55)*	1.03 *(3.89)*	-	Price per liter of gasoline. National average is used from 2012 to 2014.[145]
PE85	$/L *($/gal)*	Triangular	0.83 *(3.13)*	0.92 *(3.50)*	1.00 *(3.78)*	-	Price per liter of E85. National average is used from 2012 to 2014 (AFDC 2014).

Annual vehicle refueling convenience costs depend on the inputs described in Table 4.1, and are described in equations (1) through (5) below. The number of liters put into a tank at the time of refill was estimated as follows. The refill level, "Level", was taken from the literature, less the number of liters consumed while driving to a station, assuming a travel speed ranging from 40 to 80 km per hour (25 to 50 miles per hour).

$$RefuelAmountGas = \big(CAP - (CAP \times Level)\big) + \left(LPKGas \times \left(StaTimeGas \times \frac{Speed}{60}\right)\right) \quad Eq.(1a)$$

$$RefuelAmountE85 = \big(CAP - (CAP \times Level)\big) + \left(LPKE85 \times \left(StaTimeE85 \times \frac{Speed}{60}\right)\right) \quad Eq.(1b)$$

The number of refuels per year was calculated as follows:

$$AnnRefuelsGas = VMT \times (1 - \%E85) \times \frac{LPKGas}{RefuelAmount} \quad Eq.(2a)$$

$$AnnRefuelsE85 = VMT \times (\%E85) \times \frac{LPKE85}{RefuelAmount} \quad Eq.(2b)$$

The total time spent refueling consists of time spent traveling to the station, waiting, paying, and pumping. Other things such as buying food or drink, filling air, or vacuuming were not included.

$$TimeSpentGas = StaTimeGas + WaitTime + PayTime + \frac{RefuelAmount}{RefTime} \quad Eq.(3a)$$

$$TimeSpentE85 = StaTimeE85 + WaitTime + PayTime + \frac{RefuelAmount}{RefTime} \quad Eq.(3b)$$

The refueling costs per refuel trip for an FFV were calculated as follows accounting for gasoline versus E85 consumption.

$$RefuelCost = \begin{cases} Gas: \ [TimeSpentGas \times TimeVal] + \ [RefuelAmount \times PGas] \quad Eq.(4a) \\ E85: \ [TimeSpentE85 \times TimeVal] + \ [RefuelAmount \times PE85] \quad Eq.(4b) \end{cases}$$

$$AnnualCost = \ [AnnRefuelsGas \times RefuelCostGas] + \ [AnnRefuelsE85 \times RefuelCostE85] \quad Eq(5)$$

4.3.3 Station Costs and Capacity

In addition to the costs for FFV drivers for using more E85, there is a cost for increasing infrastructure in Pennsylvania. The refueling convenience cost model provides an estimate for the number of new E85 refueling infrastructure required to make E85 "reasonably" available for all FFVs in Pennsylvania. In this analysis a "new" station was an existing station that converts or installs the necessary infrastructure to also sell E85. The infrastructure costs for converting or installing new Underground Storage Tanks (USTs), piping, dispensers and other necessary construction vary between \$11,020 to \$21,630 for a UST conversion and new equipment and $65,920 to $77,250 for a new UST and equipment (all in 2014 dollars).[162] The costs depend on the number of stations that need to convert to selling E85, and the capacity of the stations as discussed in the location model section. The cost of additional stations was also modeled stochastically, assuming 100% E85 use by the FFVs within 14.5 km of an E85 station (with the percent of FFVs at the equivalent distance varied from 25% to 100%). The parameter distributions are listed in Table 4.2 when not already listed in Table 4.1.

Table 4.2. Parameter distributions for estimating the number of stations required for FFV E85 demand.

Input	Units	Distribution	Minimum	Mean/Most Likely	Maximum
Station Capacity	L/day *(gal/day)*	Uniform	570 *(150)*	-	5,700 *(1,500)*
Station Cost Conversion	$	Uniform	11,020	-	21,630
Station Cost New	$	Uniform	65,920	-	77,250
Percent Conversion	%	Point	-	30	-
Percent New	%	Point	-	70	-

4.4 Results

4.4.1 Refueling Station Location Model

As illustrated in Figure 4.3, the stations that currently sell E85 are in areas with more FFVs, but the fuel is not readily accessible to all FFV drivers. A count of registered FFVs and light-duty vehicles in the ZIP Codes of current stations is included as Table A.1 in the Appendix, which shows that the distribution of FFVs and light-duty vehicles is similar. The average distance for an FFV in PA to travel to the nearest existing station that sells E85 is 42 km (26 miles), which could explain why most FFV drivers only purchase gasoline. When the FFVs that are within 14.5 km of a station are removed, the average distance increases to 56 km (35 miles). The maximum distance an FFV must drive to refuel on E85 is over 193 km (120 miles). Cumulative distribution functions of the nearest distance stations are shown in Figure 4.4. Also shown in Figure 4.4 is nearest distance for an FFV to a gasoline station, which shows that almost 100% of FFVs are within 14.5 km, the equivalent distance, of a gasoline station.

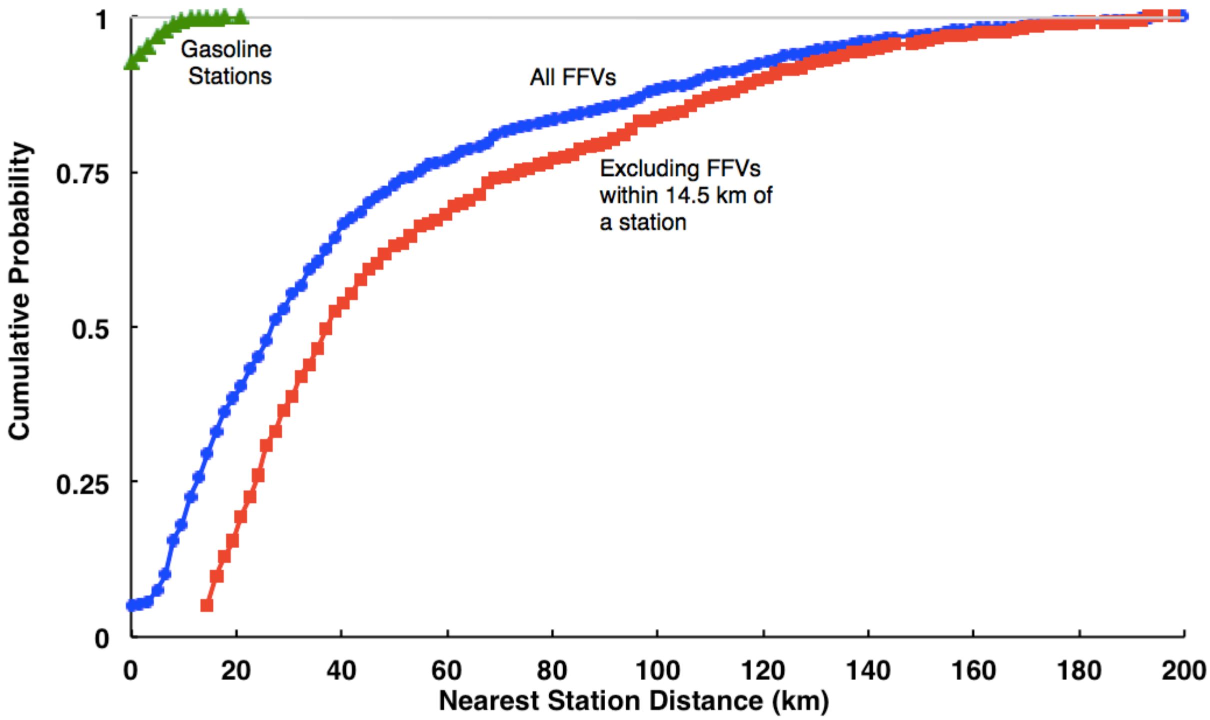


Figure 4.4. Cumulative distributions of the current nearest station for FFVs in Pennsylvania. The three lines are for all FFVs to E85 stations (circles), all FFVs excluding those that are currently within 14.5 km of an E85 station (squares) and all FFVs to gasoline stations (triangles).

Currently 153,000 FFVs, 25% of the PA FFV fleet, are within the 14.5 km equivalent distance from a station selling E85 as shown in Figure 4.3. To accommodate 100% of the FFV fleet, over 1,700 stations selling E85 would be required to meet the 14.5 km distance limit (Table 4.3).

Given that there are 3,000 to 4,000 refueling stations in Pennsylvania[163], to provide access to all FFVs and have sufficient station capacity, on average, approximately 43-57% of the current refueling stations would have to sell E85. At 30% availability of E85 stations, approximately 40-60% of the FFVs would be within 14.5 km of an E85 station. This range would provide fuel availability at the level (10-30%) suggested by Greene and Nicholas for which fuel availability is no longer part of the fuel purchasing decision to use E85. However, even if availability were not an issue, price would still impact the consumer choice for an alternative fuel.[25]

Table 4.3. Average number of additional E85 stations needed with average nearest station distances for the percent of FFVs that are within 14.5 km of a station.

Percent FFVs within 14.5 km	Average Number of Additional Stations	Average nearest station travel distance, km (miles)
25%	580	42 (26)
50%	1,000	31 (19)
75%	1,450	18 (11)
90%	1,750	13 (8)
100%	2,025	8 (5)

4.4.2 Station Retailer Costs

UST conversion and installation capital costs to support E85 are a significant investment for retailers. The costs of converting or installing new USTs, piping, dispensers and other necessary construction are included in Table 4.2. The estimate of station capacity is based on the assumptions in Table 4.2 and described in Section 4.3.3. Total costs are between $31 and $110 million on average, and are shown as cumulative probability distributions in Figure 4.5. The costs are directly linked to the number of stations, which is included in the Appendix as Figure B.2. The costs assume that stations that use existing USTs are replacing their midgrade tanks for E85 tanks, and that there is no loss in midgrade fuel sales as the midgrade can be blended (by mixing regular and premium) at the pump. If stations replace other USTs on site, there is an opportunity cost for potentially lost fuel sales revenue that is not accounted for here. Station number estimates and costs when assuming an equivalent distance of 8 or 24 km (5 or 15 miles) are included in the Appendix as Figure B.3 through Figure B.6.

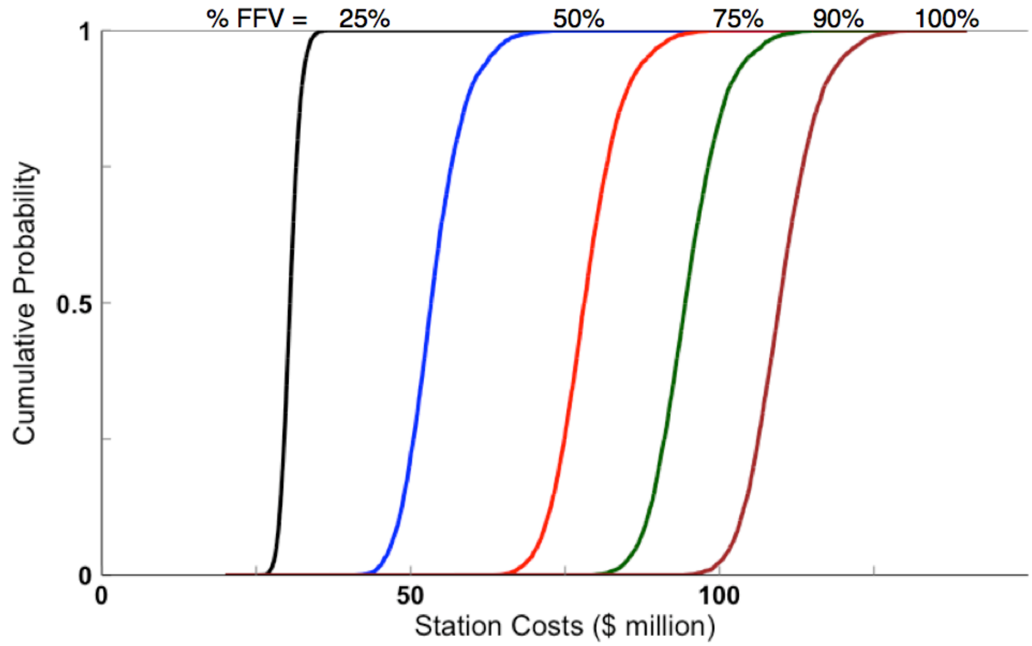


Figure 4.5. Station cost CDFs assuming varying FFV fleet fuel use.

Based on this model, over 1,700 additional stations selling E85 could provide equivalent access for all FFVs in Pennsylvania. The upgrade costs may prevent refueling station owners from making such a change. Subsidy programs may be needed at the state and federal level to encourage conversions. President Obama announced in May 2015 that the U.S. Department of Agriculture (USDA) would provide funding for biofuel infrastructure, including blend pumps totaling $100 million.[147] The funding can only be used to match state funded projects. Applications for the funding were accepted in June and July of 2015. Pennsylvania was identified as a finalist for 308 pumps.[149] The award amount for Pennsylvania was $7 million in federal funding to support 79 proposed stations and 308 proposed pumps (no tanks). Because state funding was required for this program, an additional $7 million can be assumed to be available for biofuels infrastructure. Based on the range of station upgrade costs used here and 30% conversions and 70% new USTs, $14 million could fund 230 to 280 stations with pumps and converted/new USTs. Alternately, $14 million spent on 308 pumps would be equivalent to $45,000 per pump, which is within the cost range used in this analysis. The potential stations able to be funded from the grant are well below the 1,700 estimated are needed to provide all FFVs with reasonable access to E85.

4.4.3 Refueling Convenience Cost Model

The distribution of distances from the FFV ZIP Code centroids to the E85 station ZIP Code centroids were used to estimate the travel time for a refueling trip in the refueling convenience cost model for FFVs that are within 14.5 km of a station. It is further assumed for this scenario model that FFVs located more than 14.5 km from an E85 station would not refuel with E85. A cumulative distribution of distances for FFVs to the existing E85 stations is shown in Figure 4.6.

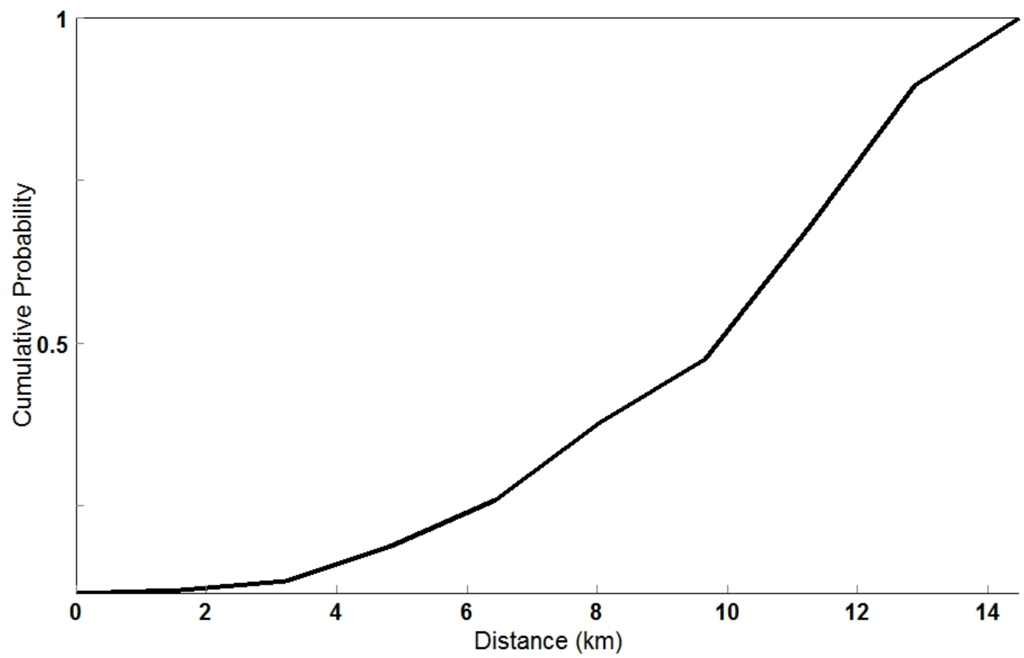
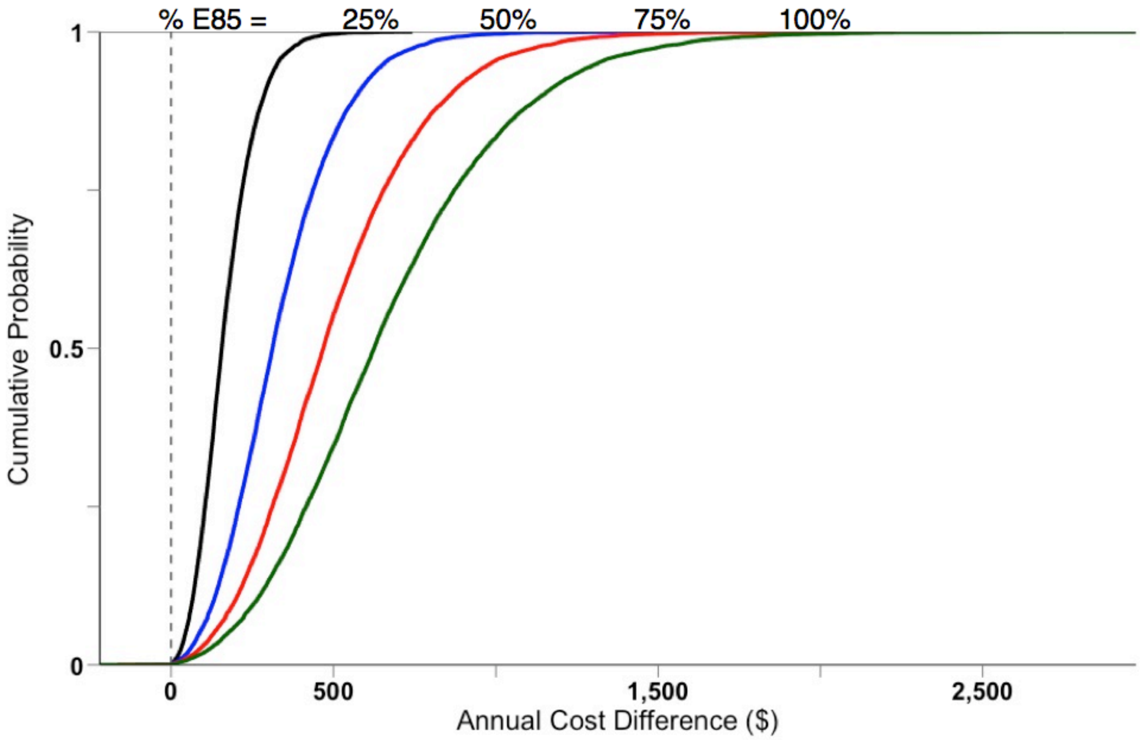


Figure 4.6. Probability distribution for distances from FFV ZIP Code areas to the nearest E85 stations. Distances are shown in discrete measures in kilometers, which accounts for the segments in the cumulative distribution.

The refueling convenience cost model estimates the annual private cost to the consumer for an FFV compared to a non-FFV, annual fuel consumption, and number of refuels. The results for refueling convenience cost and fuel consumption are shown in Figure 4.7(a) and (b) for E85 percent uses of 25%, 50%, 75% and 100%. As expected, both costs and consumption increase as E85 use increases. On average, the additional costs are \$150 to \$600 per year per FFV, depending on how often an FFV uses E85. The main contributors to cost differences are fuel prices, and the difference in energy content of the fuels. Energy content is modeled as a uniform distribution. Prices of the fuels are quarterly national averages from 2012 to 2014. The distance distributions for 8 and 24 km scenarios do not change refueling convenience costs, as they are a small contributor to the total costs.

(a)



(b)

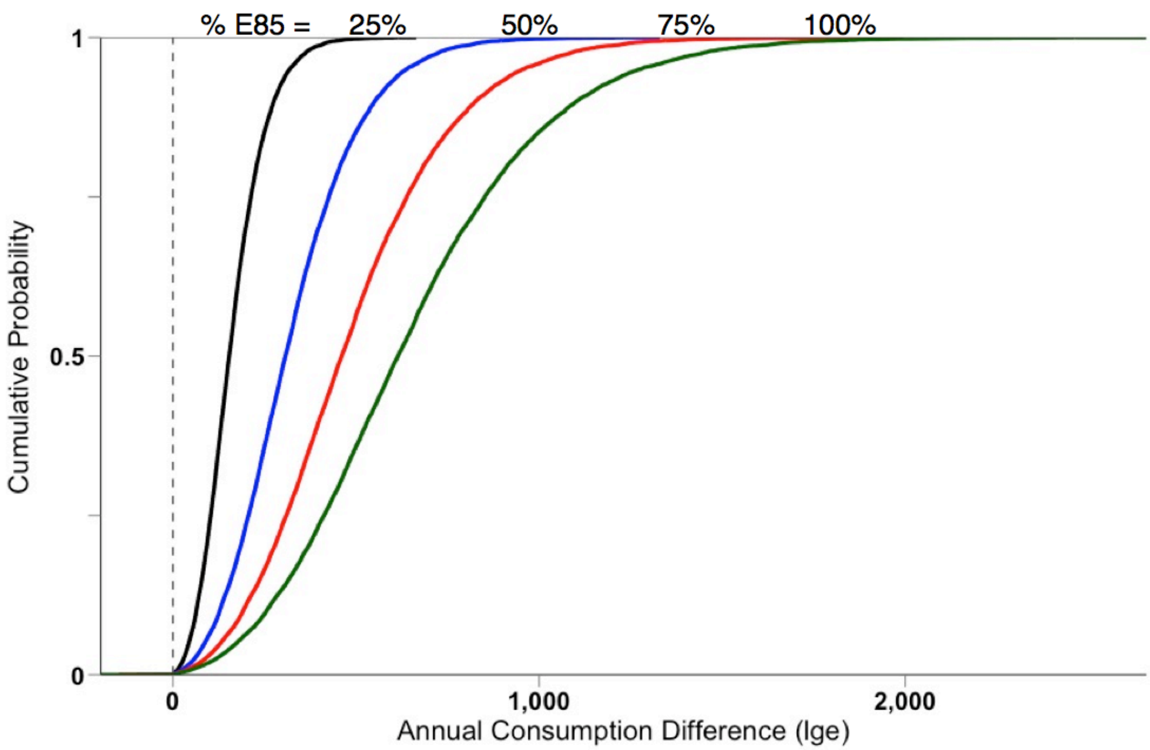


Figure 4.7. Cumulative Distribution Function (CDF) results from the refueling convenience cost model for %E85 of 25%, 50%, 75% and 100% for the average FFV. (a) Total annual cost in dollars compared to no E85 use. (b) Total annual consumption in gles for E85 compared to E10.

4.4.4 Breakeven E85 Price

Given the additional cost of using E85, I simulated a distribution of the breakeven E85 price compared to E10 use (current conventional gasoline). The breakeven price is an E85 price that would make the refueling convenience cost of using E85 equivalent to using E10 in an FFV. This price includes the differences in energy content, current E10 prices and refueling convenience. In the simulation, the E85 breakeven price was the unknown variable calculated assuming that refueling on E85 is equivalent to E10, which is explained further in the Appendix. Figure 4.8 shows the original E85 price used in the refueling convenience cost model and the breakeven E85 price. Overall, the mean breakeven E85 price would need to be approximately \$0.26/L (\$1/gal) less than the original mean E85 price. Compared to gasoline prices, the breakeven price is approximately \$0.40/L (\$1.50/gal) less.

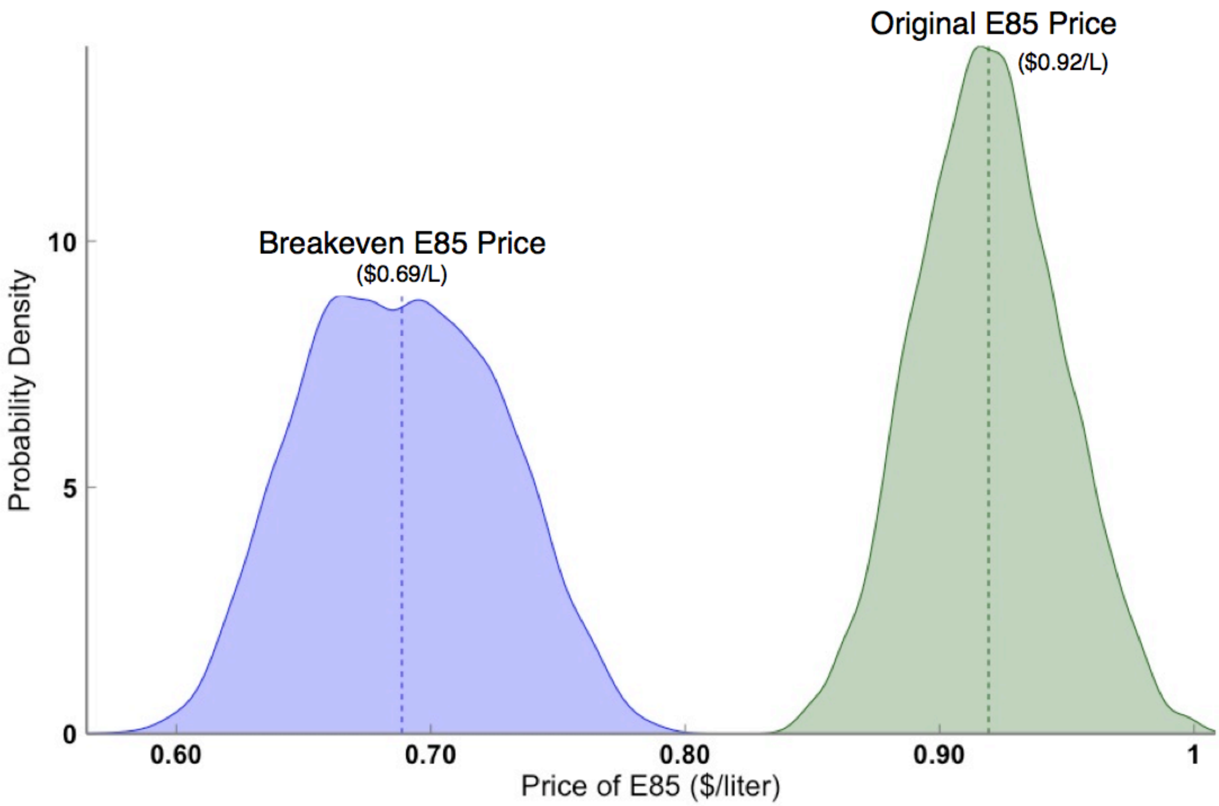


Figure 4.8. Breakeven price of E85 compared to the original E85 price. The breakeven price is the E85 price (holding all other parameters equal) for which there is no change in the overall cost for using more E85 fuel. Mean fuel prices are shown in parenthesis above the distributions.

A decrease in ethanol prices, and therefore E85 prices, is necessary to meet the breakeven E85 price. A technology change in ethanol processing and/or an increase in production may be necessary to achieve ethanol price decreases. Hettinga et al. (2009) estimated that with the projected increase in corn ethanol production for the year 2020, costs could decrease by 30-46%.[164] A reduction in ethanol costs of 30-46% could move E85 prices to the breakeven price, but the likelihood of a change of this magnitude is unknown. An increase in oil prices could also impact gasoline costs more than E85, and narrow the price difference between fuels.

4.4.5 Overall Costs

The additional average annual costs to consumers and retailers per FFV and per gle of E85 are summarized in Table 4.4. Station costs are estimated assuming 25 to 100% of FFVs are within 14.5 km of a station that sells E85, and E85 is chosen as fuel 25 to 100% of the time. The range of values for refueling costs is for 25 to 100% use of E85 in FFVs. The costs in the table are shown as CDFs in Figure 4.5 and Figure 4.7(a). Station costs are much less than consumer costs, as they are annualized and divided over a larger consumption. Although it is possible to reduce refueling costs significantly with the alternate price scenarios, such as reducing E85 to a breakeven cost as shown in Figure 4.8 it is unknown how likely the necessary reduction is. For a very low E85 use, say 5%, the refueling costs would be lower than the range shown, but would likely lead to smaller overall consumption of E85. However, station costs would be higher for 5% E85 use. The additional average costs of $0.95/L ($3.60/gal) could be prohibitive to consumer budgets, and the station costs could also be prohibitive depending on retail profit. Strategies for addressing these additional costs are discussed in the next section.

Table 4.4. Average annual cost differences for an FFV in Pennsylvania.

Price Scenarios	Total Add. Average Annual Costs per FFV for Pennsylvania	Total Add. Average Annual Costs per gle (gge) of E85 for Pennsylvania
Current E85 Refueling Costs	$150 to $600	$0.95 ($3.60)
Station Costs	$140 to $160	$0.01 to $0.08 ($0.03 to $0.30)

4.5 Discussion

The modeling estimates the costs using various assumptions on vehicle use by FFVs in Pennsylvania. This model does not predict how consumption would change with additional stations or changes in price. For further reference, Pouliot and Babcock (2014) and Greene (1998) discuss economic demand response models in their analyses. Figure 4.9 shows the sequence of potential station locations in Pennsylvania, based on locating stations near the most FFVs. The darker shaded areas have/are those that are closest to the largest number of FFVs.

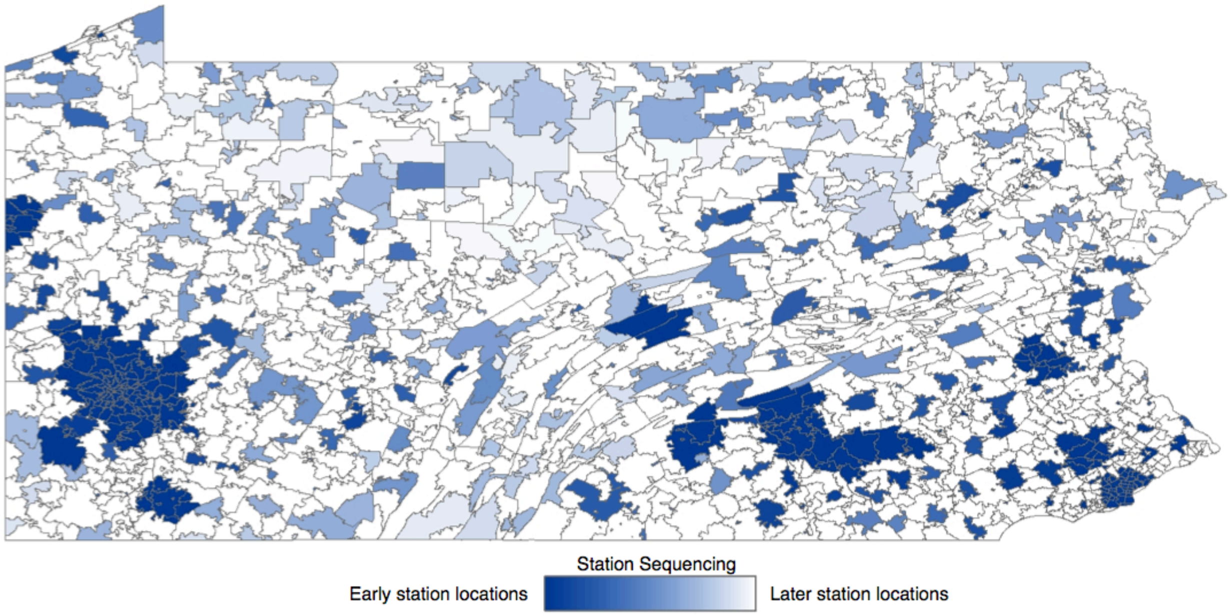


Figure 4.9. Sequence of station placement based on maximizing the number of FFVs within 14.5 km of a station. The darker the shade, the more FFVs are present in the area and the earlier a station would be placed. This map assumes 100% of FFVs are within 14.5 km of a station.

Using the demand model from Greene, one would expect that increasing availability alone from 2.5% to 20% for a cost of an additional \$0.03/L (\$0.10/gal) would increase the fraction of time E85 was chosen as fuel from almost 0 to ~0.17. Decreasing the price by \$0.03/L could lead to a fraction of use of ~0.47 (~50%). Additional consumption would strengthen the case for new infrastructure. Figure 4.10 shows the approximate cost per liter of the infrastructure for a 1-year period with full capital costs an interest rate of 5% over 10 years, assuming all FFVs choose E85 10% to 100% of the time. The figure shows the costs for the sequence of stations that brings all FFVs in Pennsylvania within 14.5 km of an E85 station. The initial bump in the figure is where stations are added to meet the potential demand for the 25% of FFVs that are already within 14.5 km of a station, where there are large costs for a smaller number of FFVs. For a gas station to breakeven, given an average infrastructure cost, the retailer would need to make a profit of approximately \$0.006 to \$0.075/L (\$0.23 to \$0.28/gal). Although there is some hope for the case of E85 chosen for 100% of refueling, a profit this large is not common in fuel retail given that the average profit on a liter of fuel is \$0.008 to \$0.01/L (\$0.03 to 0.05/gal) after all expenses.[165] Low E85 use makes it harder for retailers to breakeven.

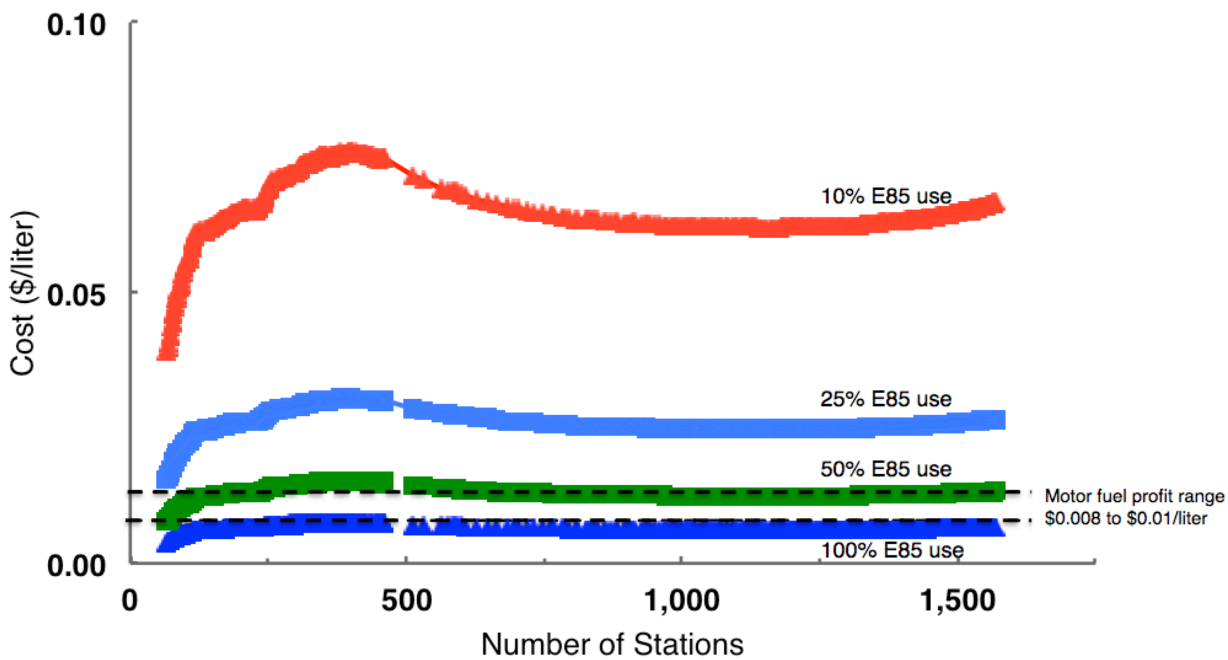


Figure 4.10. Cost per liter for the E85 infrastructure with an increasing number of stations, where the cost per liter is the profit that a retailer would need to make to breakeven on the infrastructure investment. The costs assume average infrastructure costs, 5% interest rate over 10 years, and from 10% to 100% E85 use by the FFVs in Pennsylvania. The costs increase to the point of meeting demand in the more metropolitan areas where there are already a few stations, but not enough to meet the demand of all of the FFVs at around 400 stations, and level off with some increase to meet the rest of the E85 demand. The dashed lines at the bottom are the typical range of profits for retailers.

Figure 4.11 shows the cost per liter for increasing number of stations assuming a range of finance years of 1 to 10 years, and a range in interest rates of 2 to 10% for the 100% E85 use by FFVs (most optimistic scenario). A change in the number of years, n, leads to a larger spread in the cost per liter than a change an interest rate. If the number of years financed is large and the interest rate is small (n=10, interest rate=2%, 100% E85 use) the cost per liter to the station owner over all the stations could be on average $0.01/L ($0.04/gal). This cost would increase as the E85 use decreased or with changing financing, to $0.05/L ($0.19/gal) for 1 year of financing or $0.01/L ($0.04/gal) for 5 years of financing. It is unlikely that a retailer would be able to make a profit unless the infrastructure was financed over 4 years or more and if all FFV drivers chose E85 for at least 50% of refueling. Financing or a subsidy that reduces infrastructure costs could decrease the amount of profit needed to breakeven for this investment, but it still assumes many FFVs are using E85. Increasing availability is only one part to increasing the consumption of E85. Without increased consumption, retailers would not breakeven on their investment.

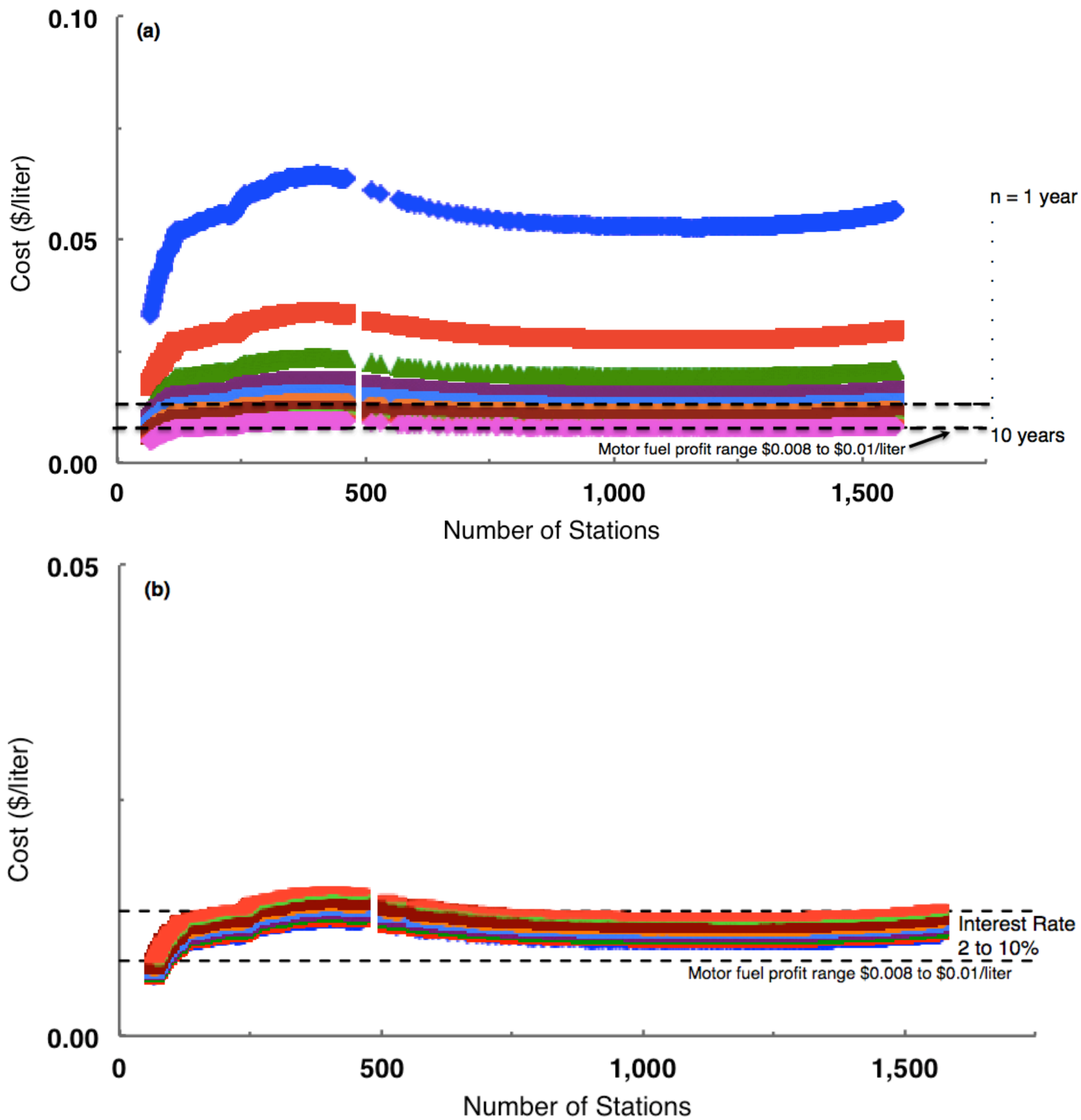


Figure 4.11. Cost per liter for infrastructure with increasing number of stations offering E85 assuming 100% E85 use by all FFVs in Pennsylvania. (a) Assume the station infrastructure is 100% financed over a 1 to 10 year period with a 5% interest rate (b) Assume the station infrastructure is 100% financed with an interest rate of 2 to 10% with a 10 year financing period, which shows little variation in the cost per liter. If fewer years were assumed, the curves in (b) would move up like shown in (a). These results indicate that financing period could have bigger impact than interest rate. The dashed lines at the bottom are the typical range of profits for retailers.

Given that increasing availability is not the only solution to encouraging more E85 refueling, price reduction methods should be considered. Retailers can reduce the price of E85 in comparison to E10 by blending their own fuel from gasoline and ethanol. The retailers receive RINs if they are blending their own fuels, which they do not need to satisfy the RFS2 because they are not producers. They can sell the RINs to companies that need the credits. The money obtained from the sale can go towards subsidizing the E85 fuel to make it less expensive than E10/gasoline at the pump. More research into the RIN system and market will be necessary to understand if this approach is possible and sustainable as it would be unlikely for a fuel producer to sell its own required RINs.

When the costs are adjusted, assuming the retailers obtain RINs and 100 percent of the profits are transferred to the consumer, the fuel price of E85 will change depending on the RIN market price. RIN prices in 2014 have been between $0.11 and $0.13/L ($0.40 and $0.50 per gal) of renewable fuel[51] A reduction in price by $0.11-0.13/L from RIN sales could reduce refueling convenience costs, but Figure 4.8 indicates the reduction in E85 prices would likely need to be more than the potential reduction from RIN sales. Selling RINs may not be possible for all E85 retailers as they may purchase their fuel after the RINs have been separated. Additionally, RINs are a commodity that could change drastically in price, which might make depending on their sale for reducing E85 prices unreliable.

4.5.1 Comparison of Costs, Subsidies and Other Price Reductions

The additional costs of increasing E85 availability and use, and potential subsidies or other cost reduction methods are summarized in Figure 4.12. The additional average cost to consumers is much higher than current or previous subsidies, and retailer costs are highly dependent on how often FFVs are refueled with E85. A low percentage, 5%, of E85 use could increase retailer costs to be on par with the current cellulosic ethanol subsidy. Consumer costs are also much higher than the value of a RIN, which could be potentially used to reduce E85 prices. Even if the state and federal government provided a subsidy to cover all infrastructure costs for the retailer, the consumer would still incur an additional cost for refueling more often with E85. Previous and current subsidies and RIN trading would still not be enough to subsidize that additional cost. Solving the availability issue does not fix the fuel price issue. Until E85 can be priced significantly less than gasoline, the additional costs of refueling with E85 will likely prevent an increase in ethanol consumption for FFVs.

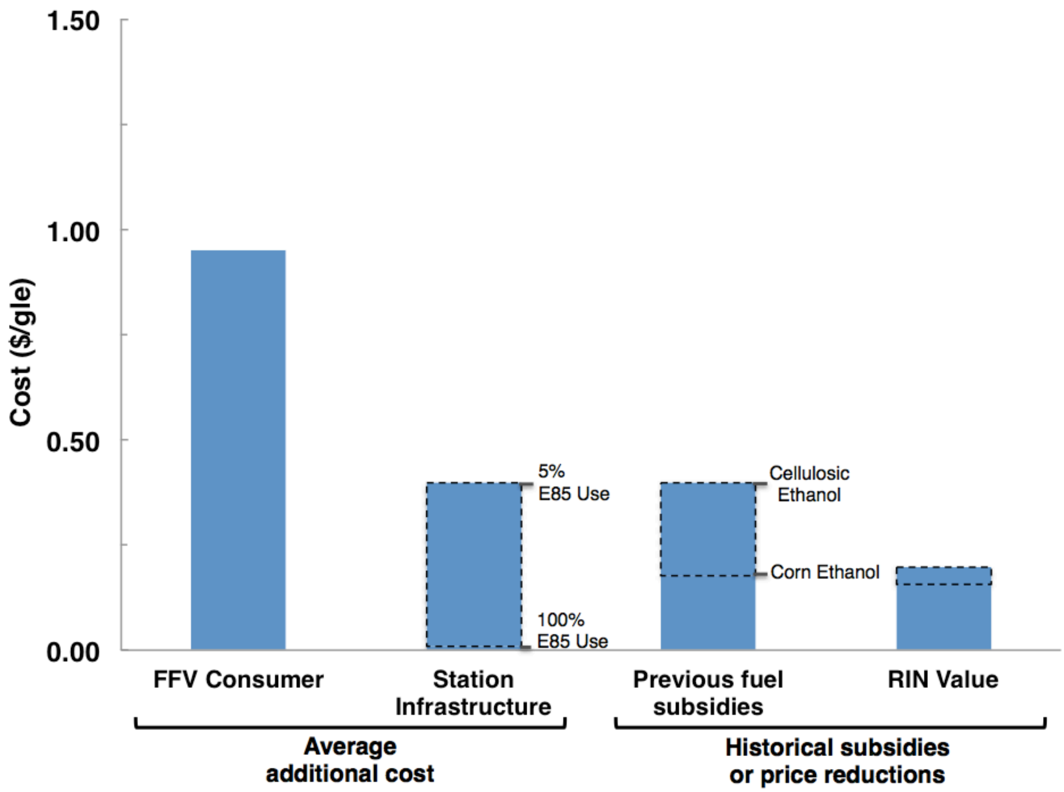


Figure 4.12. Cost for increasing E85 availability and use in FFVs in Pennsylvania compared to historical subsidies or other cost savings in dollars per gle. The costs are equal to or much higher than previous or existing ethanol subsidies. The costs are also much higher than the potential value of using RINs to subsidize fuel costs.

Although not a perfect comparison, other alternative fuels, including natural gas and electric vehicles, face their own infrastructure availability issues. The costs for providing infrastructure for compressed natural gas (CNG) can range from $657,000 to $1,000,000 per new station depending on the type of fueling system involved.[166] However, upfront cost for natural gas vehicle purchase or conversion[17,167] and required high mileage use to recover fuel cost savings[19] prevent widespread adoption in light-duty vehicles.[15] For electric vehicles, charging infrastructure can be installed at the home for $25 to $4,000 per installation, with the high end of the range for a faster charging rate.[168] Charging stations away from the home could be $1,050 for a low charging rate to $50,000 for a high charging rate.[168] Electric vehicle drivers also need to consider the range of their vehicles when considering the placement of charging infrastructure. The E85 new or replacement pump/UST infrastructure is two to three orders of magnitude less than new CNG fueling infrastructure (all new equipment), and is on par with the highest away electric vehicle charging per installation. However, FFVs do not face the same range issue as electric vehicles, and are much less expensive than electric and CNG vehicles.

This analysis considers Pennsylvania only, but could be applied to other states. A state level approach shows that location matters, and also allows for an assessment of current state subsidies. Individual state taxes or subsidies could impact the refueling convenience costs to make E85 cheaper than E10. This paper does not consider price elasticity in this analysis to estimate how demand will change with changing prices. A dynamic model would enable more estimation in consumption changes.

4.5.2 Emissions Considerations

As a first order estimate, on average switching from E10 to E85 is a reduction of 31.5 g CO_2-equivalent/MJ, assuming average emissions from gasoline and corn ethanol with land use change[58] For a subsidy of \$0.95/gle (\$3.60/gge) of E85 for an FFV driver, that is equivalent to \$0.042/MJ (assuming 3.79 L or one gallon of E85 is 86.5 MJ). The cost of mitigation is \$0.0013/ g CO_2-equivalent, which is equivalent to \$1,320/metric ton of CO_2 or \$360/metric ton of carbon. The cost of switching from E10 to E85 is approximately two orders of magnitude larger than the average social cost of carbon, which monetizes the social cost of releasing an additional metric ton of CO_2.[139] In this case, subsidizing E85 as a carbon mitigation strategy would not be cost-effective.

4.6 Conclusion

To meet the national renewable fuel mandates without rapid technological change, there needs to be more ethanol consumption in the transportation sector. Utilizing the existing FFV fleet to consume more E85 could be one way to increase ethanol consumption as a bridge to more permanent and higher impact solutions. This paper focuses on a state level approach to assessing the costs of increased E85 use and availability to consumers and retailers.

Historical national average prices of E85 and E10 show that on a gasoline liter equivalent basis, E85 has always been more expensive than E10.[145] Additionally, the lack of refueling stations offering E85 means that FFV drivers may need to drive further than a typical gasoline refueling station to use E85, which increases the annual cost of refueling for an FFV. The additional refueling convenience cost for an FFV is on average between \$150 to \$600 per year or \$0.95/gle. The range in costs depends on how often an FFV refuels with E85 (25% to 100%), which increases with more E85 use. This additional cost is higher than historical or current subsidies, and higher than the possible additional savings that could be provided by selling RINs. If a subsidy were provided so that E85 refueling was equal to E10 then the E85 price, on average, would need to be \$0.26/L (\$1/gal) less than the current E85 price.

E85 is available in less than 1% of the stations in Pennsylvania, and is at a reasonable distance for 25% of the state's FFVs fleet, but FFV drivers choose to not readily refuel with E85. Considering a limit on the capacity of the stations, and assuming FFVs always use E85, over 1,700 additional stations would need to offer E85 for all FFVs to be within 14.5 km of a station selling E85. The cost of additional stations could range on average between $31 and $110 million, depending on the level of access achieved (the number of FFVs with equivalent access to a station, 25% to 100%). This is equivalent to $0.01 to $0.08/gle, but would be larger if I assume 5% E85 use to $0.39/gle, which is similarly more expensive than current and historical ethanol subsidies and RIN prices. Pennsylvania recently received federal and state grants to fund additional biofuels infrastructure (pumps and USTs), adding to the relevancy of this study. Additionally, the more E85 sold, the more likely a retailer is to pay off the investment. Even if the state and federal government provided a subsidy to cover all infrastructure costs for the retailer, the consumer would still incur an additional cost for refueling more often with E85. The additional cost compared to refueling on E10 is much higher than previous ethanol subsidies and possible RIN credits, and the higher cost could prevent existing FFV drivers from purchasing E85 from the newly installed biofuels pumps throughout the state. Retailers cannot profit from E85 without customers, and customers need access to refueling stations to consume the fuel.

Finally, if a subsidy were offered to encourage more E85 use, the resulting reduction in CO_2 emissions the results costs would be two orders of magnitude above the social cost of carbon. Increasing E85 use, in this case, would not be a cost-effective mitigation strategy.

Chapter 5. Conclusions and Future Work

This chapter summarizes the results from the previous chapters, discusses the contributions of this work, and describes future work.

5.1 Research Questions Revisited

1. Cost of natural gas derived-liquid fuel ethanol:
   (a) *Is there a feasible process for making ethanol from natural gas?*
   There are numerous pathways that could be used to convert natural gas into ethanol. I explore the potential use of three different pathways. The processes include: (1) methane autothermal reforming with catalytic conversion to syngas and then to ethanol, (2) the conversion of acetic acid, produced from syngas, to ethanol developed by Celanese Corp. (TCX), and (3) ethanol fermentation using syngas as the feedstock, developed by Coskata Inc.
   (b) *How do process parameter values and assumptions impact the overall costs?*
   The cost parameter assumptions are uncertain in these estimates. I conducted sensitivity analyses on the assumptions and performed a pioneer plant capital cost overrun analysis to better understand the overall cost sensitivity. Natural gas feedstock price was the most sensitive parameter, and having a consistent feedstock price can make the investment in a new process more viable. When I considered a pioneer plant (first of its kind plant) capital cost factor of 3.7, the production of ethanol from natural gas became much less likely to be less expensive than gasoline.
   (c) *Where in Pennsylvania should NGLF plants be located? How do the processing costs compare to corn ethanol and gasoline?*
   The plant locations are generally located near the high demand areas around Pittsburgh and Philadelphia as shown in Figure 2.3. NGLF ethanol made with the Coskata process has a high probability of being less expensive than gasoline or corn ethanol. The ATR catalytic process is likely less expensive than corn ethanol and gasoline costs. The Celanese TCX process is least likely of the three to be less than gasoline or corn ethanol costs. There is still significant uncertainty in the capital costs for these processes and the future prices of gasoline and natural gas. Changes in the relative prices could impact the probability a NGLF ethanol is cost competitive with existing fuels.

2. Life cycle emissions from natural gas-derived liquid fuel ethanol:
   (a) *Are there data available for a life cycle GHG emissions estimate of an NGLF ethanol?*
   The data on emissions from producing NGLF ethanol do not exist in the current literature. In order to estimate the GHG emissions for the three NGLF ethanol processes, I used literature from similar processes for making syngas from natural gas, and then converting the syngas into ethanol through various processes.
   (b) *What are the life cycle GHG emissions for an NGLF ethanol?*
   The total life cycle GHG emissions for the three NGLF ethanol processes are on average between 119 and 156 g CO_2-equiv/MJ for 100-yr GWP, and between 145 and 169 g CO_2-equiv/MJ for 20-yr GWP. The lower end of the range estimates are for Celanese TCX, and the higher end of the range estimates are for Coskata fermentation.
   (c) *How do the GHG emissions compare to gasoline, corn ethanol and other natural gas based fuels? Can a NGLF ethanol meet the RFS2 GHG emissions reduction targets?*
   The three NGLF ethanol GHG emissions estimates are higher than gasoline, corn ethanol and ethanol derived from ethane even with the uncertainty surrounding the upstream natural gas emissions and GWP assumptions. The RFS2 requirement of a 20% reduction from gasoline for a renewable fuel is even further below the estimates.
   (d) *What are the implications of the emissions results? What are the limitations in the results?*
   Even if we could eliminate all upstream emissions from natural gas production, the NGLF ethanol does not meet the RFS2 requirements. Although for some processes there becomes more overlap with gasoline GHG emissions. Additionally, if all production emissions, the largest contributor besides combustion, were eliminated the results are similar to eliminating upstream natural gas emissions. The conclusion is that given estimates here it is unlikely that a NGLF ethanol would have emissions that meet the RFS2 reduction requirements. Even if I consider great improvements to methane leakage, more efficiencies in the processes themselves and improved fuel economy it would still be difficult to meet the reductions. However, the limitations in this work are around the data sources. The estimates could be better refined with actual, and full, process models for each pathway. The models may also better capture the co-products and other emissions savings that might be missed in this analysis.

3. Expanding E85 distribution and use in Pennsylvania:
   (a) *How available is E85 in Pennsylvania? How many FFVs have reasonable access?*
   Currently, the 600,000 FFVs registered in Pennsylvania are on average 26 miles from a station that sells E85. At a maximum, an FFV could be 120 miles from the nearest E85 station.

Compared to gasoline, almost 100% of FFVs are within 9 miles of a station. Approximately 153,000 FFVs, or 25% of the fleet in Pennsylvania, are within the 9 mile equivalent distance from a station selling E85.

(b) *What is the difference in cost for FFV drivers to refuel on E85 compared to E10?*
FFV drivers that choose to use E85 could experience additional average annual costs of $150 to $600 (for choosing E85 25% to 100% of refueling). Additional costs would decrease with less E85 use. When accounting for the stochastic modeling, these numbers could be larger depending on the assumptions. The main contributor to the additional costs are the fuel prices for E85 and E10. I found that in order for there to be no additional cost to a FFV driver using E85, the E85 fuel price would need to be on average $2.62/gallon or approximately $1/gallon less than current average E85 prices.

(c) *What are the infrastructure costs to increase the availability of E85?*
Infrastructure costs for additional E85 refueling locations to provide equivalent access FFVs could range from on average $31 million to $110 million depending on the percent of FFVs provided with access (25% to 100%). When accounting for the stochastic modeling, these numbers could be larger depending on the assumptions. Given the current federal and state funding available in Pennsylvania, this analysis is a relevant topic. The assumed $14 million in funding is marked for 79 proposed stations and 308 proposed tanks, which according to this analysis would not provide equivalent access for all FFVs in the state.

(d) *What needs to change to encourage more E85 use? What are the policy implications?*
The literature shows that E85 prices and fuel availability are two important factors to increasing E85 consumption. The current funding for infrastructure in Pennsylvania could provide some benefit at reduced cost to retailers, but consumers of E85 will still have additional costs for using more E85. Unless E85 prices can be reduced, it could be difficult to increase E85 consumption with just availability improvements.

5.2 Limitations

The analyses discussed in this dissertation each have their own limitations. In Chapter 2, the MILP model is restricted to Pennsylvania. In reality, fuel produced in Pennsylvania could be transported over the state line into neighboring areas. The inclusion of neighboring states would increase the potential ethanol demand, and could change the optimal plant locations and decrease the cost of production. The viability of a NGLF ethanol fuel is dependent on the price of the NG feedstock, and the relative price of gasoline and corn ethanol. If NG prices rise, and gasoline and corn ethanol prices are low the viability of any of the pathways is unlikely. Alternately, if NG prices are low, and gasoline and corn ethanol prices are high a

NGLF ethanol becomes more viable. Uncertainty in these prices over a 30-year plant life should be considered, especially if there is variability and volatility in the prices. New technology could emerge for using natural gas in the transportation sector or other sectors, which could impact the cost and availability of the resource in the long-term.

In Chapter 3, the GHG emissions estimate was first-order. More detailed process models for the NGLF ethanol processes could improve the estimates, and would allow for more consistent GWP assumptions. Emissions may be lower than estimated, but uncertainty in the upstream NG phase will likely still remain. With more accurate process emissions, more detailed sensitivity analyses with methane leakage and fuel economy could be possible.

In Chapter 4, refueling costs are modeled assuming FFV drivers make a trip from their home to the station and back. The costs don't account for trip sharing with trips to work, school or other errands. Trip sharing would likely reduce the costs, but the primary additional refueling cost is from the price difference between E10 and E85. For the station infrastructure costs, I assume a midgrade UST is replaced and there is no disruption to service at the station. Replacement of a premium or diesel tank could result in opportunity cost losses for the retailer, which is not accounted for in here. The loss in fuel sales may be more pronounced for a small retailer compared to a larger name brand retailer that could locate E85 at a few stations and still maintain premium or diesel sales at neighboring stations.

5.3 Discussion

Given the evolving transportation system, and the seemingly abundant source of natural gas, this dissertation evaluates the impacts from producing natural gas-derived ethanol and from expanding access to E85 (from an agnostic feedstock). Natural gas is not a renewable fuel, and does not fall under the RFS2 mandates. However, if a similar policy that encouraged the use of domestic fuels is considered the analyses summarized in this dissertation could contribute to that discussion. In Chapters 2 and 3 of this dissertation I am the first to estimate the life cycle cost and emissions from producing ethanol from natural gas (methane) through three unique pathways. I find that a NGLF ethanol could be cost competitive, but that there are still many uncertainties and unknowns in the estimates to confidently support a new, less expensive ethanol production method. Equally important, the GHG emissions from producing ethanol from natural gas would not meet the GHG reduction requirements of the RFS2, and are greater than gasoline and corn ethanol GHG emissions. Policy making around alternative transportation fuels will continue to consider both the economic and environmental impacts.

Although the last chapter is agnostic on the source of ethanol for E85, understanding the real costs of expanding access and use of E85 is important when considering the impacts of E85. The current ethanol policies and potential subsidies do no account for all of the private costs of increasing E85 access and use. Subsidies focused on the refueling infrastructure only address half of the costs. The RFS2 policy should be evaluated to determine if the underlying goals of the policy are enough and achievable to justify continued encouragement of ethanol (E85) consumption. If they are, under current conditions additional thought should be given to how best encourage consumers to use more E85 with additional annual refueling costs.

5.4 Future Work

As a result of the work covered in this dissertation, additional research questions have been revealed that could be addressed in future work.

1. The results of the Chapters 2 and 3 revealed that there is dearth of research on converting methane into ethanol. Although the research revealed that the costs and emissions are not currently competitive with existing fuels, there is an opening for more detailed process modeling and evaluations. More specific modeling, accounting for efficiencies and co-products could narrow the differences in both the cost and emissions estimates.

2. If it is revealed with more certainty that natural gas could be converted to a liquid fuel competitively or if natural gas is used more widely in the transportation sector (CNG/LNG), there is a need to understand how the pricing for natural gas would change. A large increase in natural gas use for transportation would impact natural gas for heating and electricity prices, and the assumed price for transportation use may also change. Investors and policy makers need to anticipate how changes in price could impact the natural gas system as a whole.

3. Many of the studies concerning ethanol and E85 have come to similar conclusions that price and availability are the most important considerations for consumers, but no specific choice modeling has been conducted to quantify a consumers willingness-to-pay for E85 and other fuels. Understanding what consumers are willing to pay for a fuel can inform future alternative fuel policies and business strategies.

4. The subsidies for ethanol are an area that could be further analyzed. Currently there are fuel subsidies (for cellulosic) and infrastructure subsidies. Both serve a purpose, but it would be interesting to evaluate which is more effective. How much should you invest in both in order to get the desired outcome, which is likely increased E85 consumption?

5. The benefits of ethanol as a high-octane fuel are also of interest. Some previous work on this has been completed, but it is likely that higher-octane fuels, with the benefit of better fuel economy, will continue to be discussed in policy decisions, with automakers and fuel producers. The full impact of higher-octane fuels could be further researched.

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Appendix A. NGLF Ethanol

A.1 Natural Gas Production and Transmission in Pennsylvania

Natural gas production totaled 3 Tcf in Pennsylvania in 2013.[169] These counties are the darkest shaded regions shown in Figure A.1. I assumed plant location is dependent on the location of natural gas transmission lines. Using data from the Penn State Marcellus Shale Center for Outreach and Research[170], 58 of the 67 PA counties have a natural gas transmission line within their borders. Here I assumed pipeline natural gas has been processed post-extraction to be nearly 100% methane, so I treat the two as equivalent.

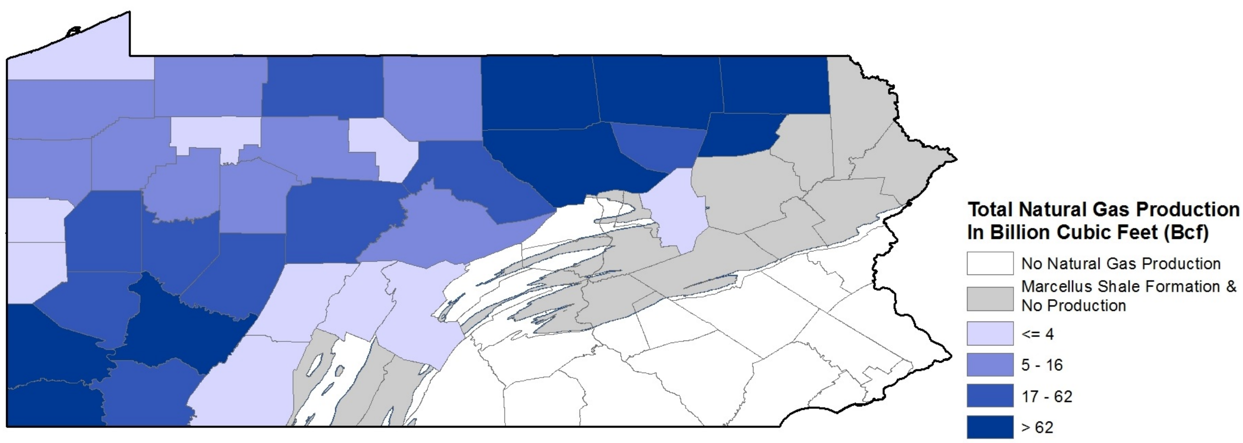


Figure A.1. Total natural gas production in 2013 by county in Pennsylvania measured in Mcf. Plot produced by using data from the PADEP.[169] Counties that produce natural gas are shown in shades of blue with the total 2013 production ranges listed in the figure legend. Darker shaded areas had larger production. Grey shading indicates an area that is within the Marcellus Shale region, but did not produce natural gas in 2013. White areas are those counties that are outside of the Marcellus Shale region, and do not produce natural gas.

Another crucial component for locating plants near transmission lines is the capacity of the line. Additional analyses can reveal if the current lines in PA could meet the capacities of the potential NGLF plants at given locations, which is estimated to be between 25 and 88 million Mcf per year. Depending on the plant, this could be a similar volume as a 25 to 50 MW NG plant.

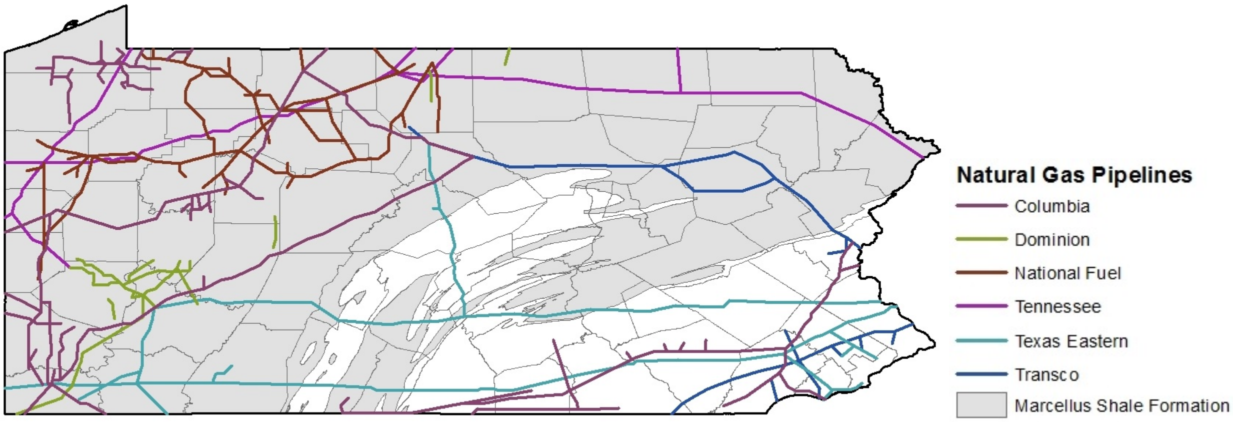


Figure A.2. Natural gas transmission lines in Pennsylvania by owner. Figure created by the authors using data from the Penn State Marcellus Shale Outreach Program.[170]

A.2 Details on Cost Estimate

Scaling Equation for Coskata Total Capital Cost

For Coskata, the costs were scaled using Equation S1 with the provided costs for a 25 M gallon, 125 M gallon and 200 M gallon plant. The logarithmic fit equation is:

$Capital\ Cost = 204.13 * \ln(Plant\ Capacity) - 623.23$ (Eq A.1)

Table A.1 lists the available capital cost data for each process in 2012 dollars. The costs were converted to 2012 dollars using Bureau of Labor Statistics inflation factors.[171] O&M costs were assumed to be a percent of the total costs (except for Celanese) and are included in Table A.2.[31] Sensitivity analyses were conducted on the major cost assumptions for the sensitivity values listed in Table A.2.

Bureau of Labor Statistics Inflation Rates

2007 to 2012 = 1.11
2010 to 2012 = 1.05
2011 to 2012 = 1.02
2013 to 2012 = 0.99
2014 to 2012 = 0.97

Table A.1. Base and estimated capital costs from available data sources in 2012 USD. Cost data points from other sources are shown in bold. Estimated (scaled) costs are shown in normal font.[31,76,77,80]

κ_j **Plant Capacity (million gallons per year)**	**ATR Catalytic Total Capital Cost ($ million)**	**Celanese Annual Capital & O&M Cost* ($ million)**	**Coskata Total Capital Cost ($ million)**
25	$330	$170	**$150**
64	**$580**	$250	$380
125	$870	$325	**$535**
200	$1,200	$390	**$650**
380	$1,700	**$510**	$800

*Celanese capital costs were provided as a $/gallon cost for a 380 million gallon/year capacity plant, and capital and O&M are not separated.

Table A.2. Universal cost assumptions for all NGLF processes considered.

Assumption	**Base Value**	**Sensitivity Values**	**Source / Justification**
Plant life, *n*	30 years	20 to 40 years	Dutta et al. (2011) & Pei et al. (2014)[31,75]
Discount rate, *r*	10%	5% to 15%	Dutta et al. (2011), Kocoloski et al. (2011) & Pei et al. (2014)[31,75,114]
Capital scaling factor, *p*	0.6	0.5 to 0.9	Dutta et al. (2011) & Kocoloski et al. (2011)[31,114]
Operation cost percent, f^{OM}	10%	5% to 15%	Dutta et al. (2011)[31]

A.3 Conversion factor for ATR catalytic

ATR was assumed to be 75% efficient.[75] Catalytic conversion of syngas to ethanol is approximately 79% efficient.[31] Overall the process is 60% efficient.

Based on stoichiometry, it takes 6.9 lbs of methane to make a gallon of ethanol, which is equivalent to 0.173 Mcf of methane per gallon of ethanol. Taking into account efficiency, the conversion factor is 0.242 Mcf methane per gallon of ethanol.

A.4 Ethanol Demand Quantities

Table A.3. Average Vehicle Miles Traveled (VMT) and Ethanol demand by county.

County	Average Annual VMT	E85 Demand (million gallons)	E10 Demand (million gallons)	E85 & E10 Demand (million gallons)
Adams	10,088	2.9	4.1	6.8
Allegheny	9,330	36	37	71
Armstrong	12,027	3.4	2.7	5.9
Beaver	10,227	7.0	6.5	13
Bedford	11,838	2.4	2.7	4.9
Berks	9,709	11	15	26
Blair	12,358	6.1	6.2	12
Bradford	10,576	3.5	2.8	6.1
Bucks	10,167	19	24	42
Butler	11,501	11	9.4	19
Cambria	8,427	5.0	4.8	9.4
Cameron	10,743	0.3	0.2	0.5
Carbon	9,794	2.1	2.8	4.7
Centre	9,855	4.1	4.6	8.5
Chester	10,439	15	19	34
Clarion	12,560	2.5	1.9	4.3
Clearfield	12,527	4.6	4.0	8.3
Clinton	10,627	1.6	1.5	3.0
Columbia	11,146	2.7	3.1	5.6
Crawford	12,062	4.8	4.1	8.6
Cumberland	9,041	7.2	9.2	16
Dauphin	9,793	8.4	11	19
Delaware	9,383	14	17	30
Elk	8,982	1.9	1.3	3.0
Erie	9,005	9.6	8.3	17
Fayette	10,095	5.6	5.4	11
Forest	13,885	0.4	0.3	0.7
Franklin	12,240	5.4	7.4	12
Fulton	12,119	0.7	0.9	1.5
Greene	11,456	2.7	1.8	4.3
Huntingdon	11,674	1.8	2.1	3.8
Indiana	11,006	4.6	4.1	8.4
Jefferson	15,451	3.7	3.0	6.5
Juniata	15,476	1.2	1.4	2.5
Lackawanna	9,291	5.9	6.9	12
Lancaster	9,695	14	19	32

Lawrence	8,559	3.5	3.2	6.5
Lebanon	10,393	4.1	5.7	9.5
Lehigh	9,390	8.3	12	20
Luzerne	9,107	8.9	11	19
Lycoming	10,220	5.2	5.0	9.8
McKean	11,669	2.8	1.9	4.5
Mercer	9,560	4.5	3.8	7.9
Mifflin	14,429	2.2	2.6	4.7
Monroe	13,202	5.8	8.6	14
Montgomery	9,399	21	27	47
Montour	10,615	0.9	0.8	1.7
Northampton	10,173	8.3	11.5	19
Northumberland	9,683	3.3	3.6	6.7
Perry	11,214	2.0	2.4	4.3
Philadelphia	8,677	18	27	44
Pike	13,889	2.8	3.6	6.2
Potter	10,302	1.1	0.8	1.8
Schuylkill	10,299	4.8	6.2	11
Snyder	10,876	1.5	1.7	3.0
Somerset	11,636	4.3	3.9	8.0
Sullivan	11,556	0.4	0.3	0.7
Susquehanna	10,664	2.4	1.9	4.1
Tioga	9,599	2.3	1.8	3.9
Union	10,093	1.3	1.5	2.7
Venango	11,219	2.6	2.3	4.7
Warren	10,588	2.3	1.7	3.8
Washington	10,564	12	8.9	20
Wayne	11,379	2.1	2.2	4.2
Westmoreland	10,046	17	16	32
Wyoming	11,391	1.9	1.6	3.4
York	10,349	14	18	31

VMT data is eSafety data from the Pennsylvania Department of Transportation for a sample of vehicles in each county.[121,129,130]

A.5 Assumptions

Table A.4. Assumptions used for NGLF production and distribution

	Assumption	Expected Impact on Study Conclusions
Capital and O&M costs	Based on available literature and industry reports	If the capital and O&M costs change based on changing interest rates, plant life, capital, operating percent, or other assumption, a 20% change in capital is approximately a \$0.15/gge to \$0.80/gge change in the overall NGLF ethanol cost, depending on the process. If more accurate estimates of capital costs are made available, this part of the model should be updated.
Natural gas prices	Pennsylvania natural gas hub prices from 2012 to 2014.	The range of US monthly average prices for natural gas between 2012 and 2014 was between approximately \$2 to \$8/Mcf. A sensitivity analysis also finds that a \$1/Mcf change in the natural gas price leads to an approximately \$0.21/gge to \$0.36/gge change in the ethanol cost. See Figure A.7. (CMEGroup 2015)
Corn ethanol production costs	Spot prices from the Agricultural Marketing Resource Center. Maximum and minimum monthly average prices from 2012 to 2014.	A distribution of corn ethanol production costs were used in the analysis, \$2.20 to \$4.60/ gge, to compare to the NGLF production costs from 2014-2014. If the range is smaller or shifts up/down, then the comparison with the NGLF production could be more or less favorable. (Agricultural Marketing Resource Center 2015)
Gasoline production costs	EIA gasoline costs. Maximum and minimum monthly average costs from 2012 to 2014.	A distribution of corn ethanol production costs were used in the analysis, \$1.60 to \$3.50/gallon, to compare to the NGLF production costs. If the range is smaller or shifts up/down, then the comparison with the NGLF production could be more or less favorable. (EIA 2015b)
Ethanol transport from plant to demand	Truck from the WGA report	Based on a preliminary analysis, the cost of transport is less expensive than rail transport at distances of less than 300 miles. In this case study in Pennsylvania, distances are less than 300 miles. Therefore, only truck transportation was considered, but is likely the less expensive option for transport at the estimated distances. (Parker *et al* 2008)
Transportation costs	Costs from the WGA report for transportation of NGLF ethanol by truck	Costs were assumed to have a fixed and variable component for truck transportation of \$0.02/gallon and \$0.02/gallon-mile, respectively. Transportation costs are for truck transportation, as the analysis is restricted to the state of Pennsylvania. Trucking is generally less expensive than rail for distances under 300 miles. All potential county-to-county distances in Pennsylvania are less than 300 miles. The analysis found that transportation costs were <5% of the total overall ethanol production costs. Therefore, changes to transportation costs have a small impact on the overall costs. (Parker *et al* 2008)
Ethanol demand location	Centroid of county	Previous work showed that this makes little difference in total transportation requirements.[155]
NGLF plant location	Centroid of county	Previous work showed that this makes little difference in total transportation requirements.[155]

Volume of E85 demand	Number of FFVs per county	Approximately 600,000 FFVs in Pennsylvania, organized by county. This is approximately 400 million gallons of ethanol demand per year. If the demand increases, there could be some cost savings due to better economies of scale, but it depends on the amount increased. The same can be said of a decrease in demand. The change in ethanol content discussed below demonstrates how demand can impact the overall NGLF ethanol costs.
Volume of gasoline E10 demand	Number of light duty vehicles per county	Approximately 10 million light duty vehicles in Pennsylvania, organized by county. This is approximately 455 million gallons of ethanol, and 5 billion gallons of gasoline demand per year. If the demand increases, there could be some cost savings due to better economies of scale, but it depends on the amount increased. The same can be said of a decrease in demand. The change in ethanol content discussed below demonstrates how demand can impact the overall NGLF ethanol costs.
E85 demand modeled as E85	Assume blend required has 85% ethanol and 15% gasoline by volume	The ethanol composition in E85 can be as low as 50% (ASTM 2014). A sensitivity analysis using a range of values for ethanol composition showed that there is some impact on the overall ethanol cost. (See SD Section 7)
Gasoline demand modeled as E10	Assume blend required has 10% ethanol and 90% gasoline by volume	A sensitivity analysis on the ethanol composition for E10 was not completed. However, the ethanol content is much lower than E85, which had minimal impact to the NGLF ethanol overall costs.

A.6 Sensitivity

The results of the sensitivity analysis are summarized in Figure A.3 arranged by process and by demand scenario. The blanks in the figure are where there was not enough cost information to do a sensitivity analysis. For ATR I include all parameters. For Celanese, I include scaling factor only. For Coskata, I include interest rates, O&M percent, plant life and capital costs. Again, the uncertainty in the results is due to natural gas prices for 2012 to 2014, and the parameter assumptions. The red boxplots assume the lowest parameter values considered, and the blue boxplots assume the highest parameter values. The original unit cost results are also included. The results indicate that there can be changes as high as \$0.80/gge depending on the assumptions. For the pessimistic case, changes could be even greater at \$2/gge for ATR. Plant life for ATR and Coskata appears to have the smallest impact on the outcome. Overall, Coskata is less sensitive to changes in assumptions, which is likely due to the flatness of the unit production costs. The scenario when all assumptions are high (pessimistic) or low (optimistic), there are much larger changes to the NGLF ethanol unit costs. ATR appears to have the largest changes, but it also has the most parameters adjusted in the sensitivity.

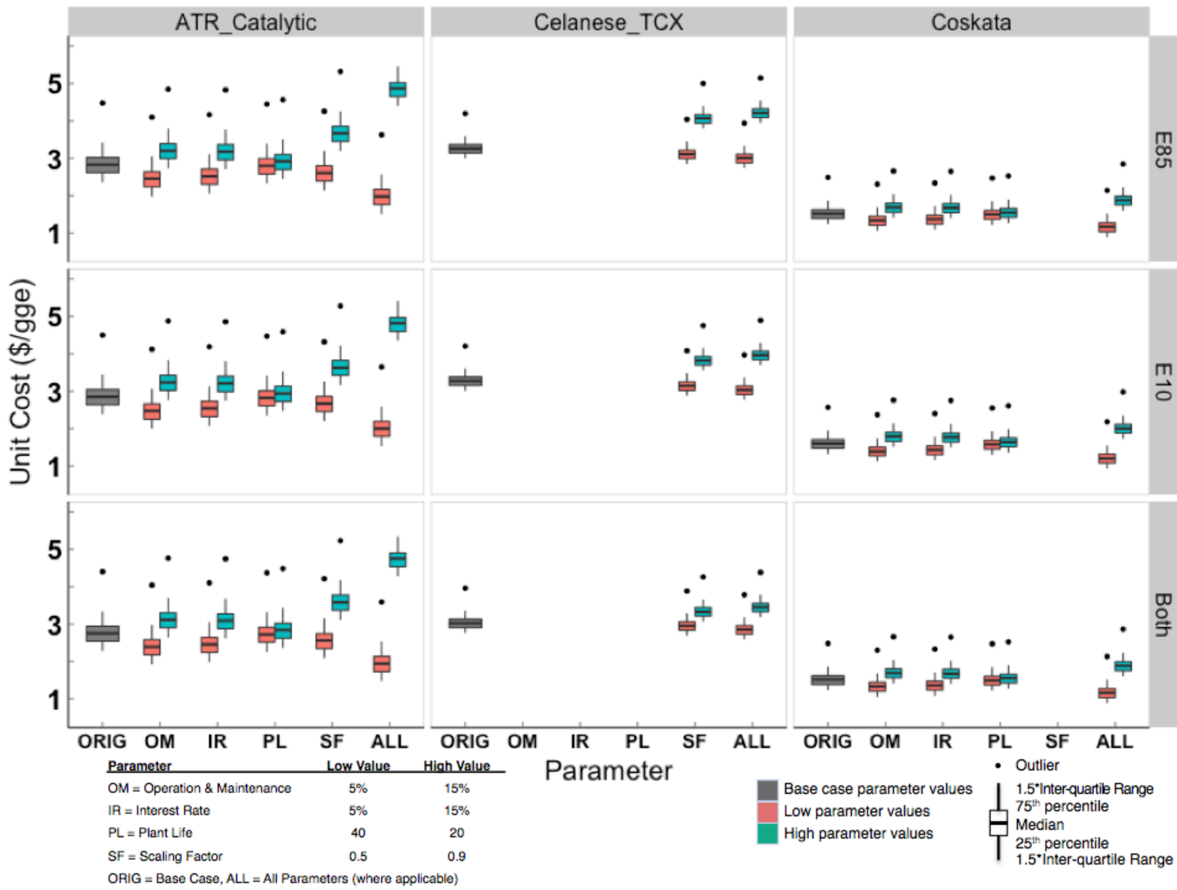
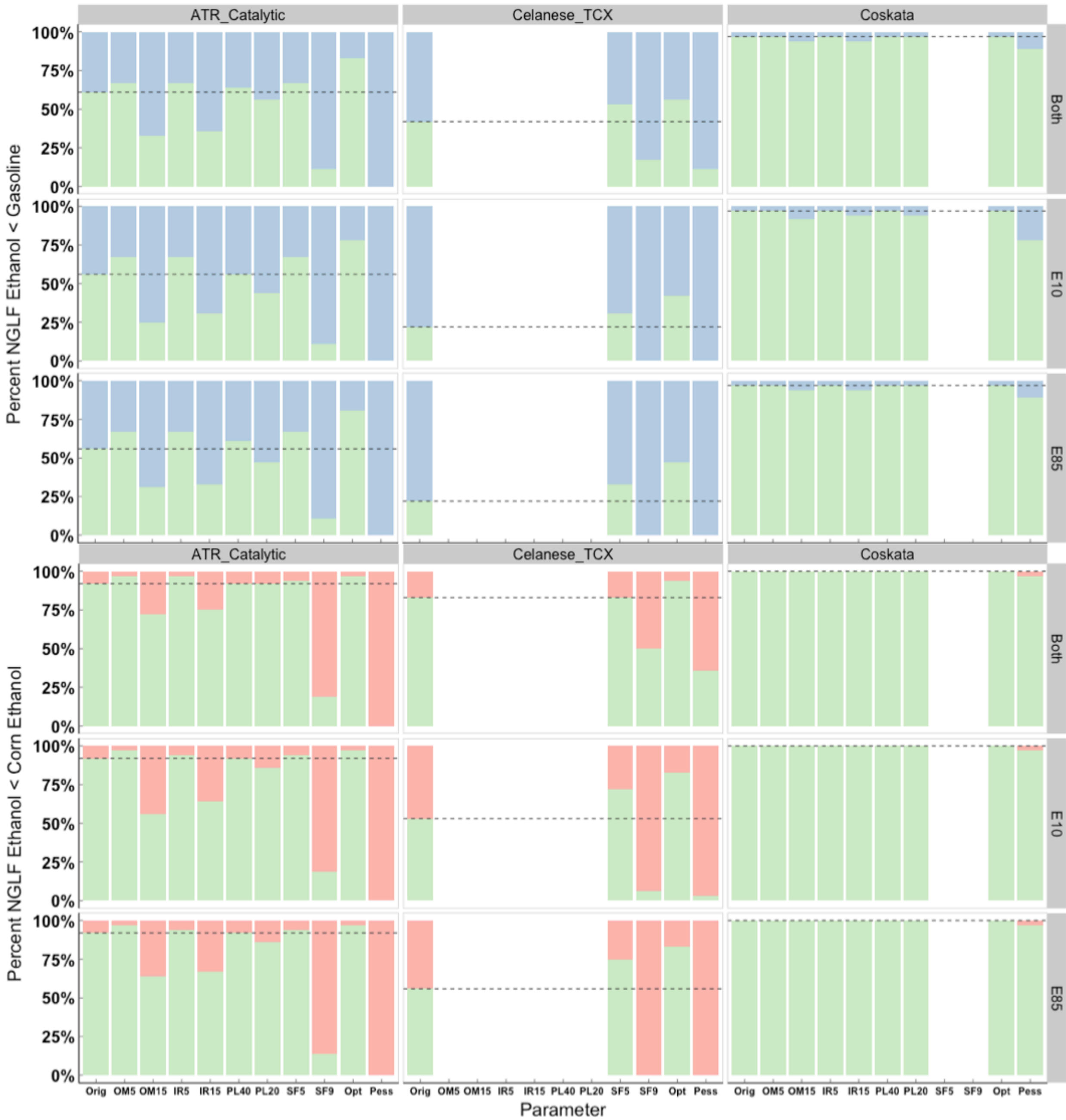


Figure A.3. Sensitivity analysis results for the process cost assumptions. Parameter values were varied based on the sensitivity values in Table A.2. Red boxplots assume the lowest parameter values as listed above the boxes in E85. Blue boxplots assume the highest parameter values as listed below the boxes in E85. Parameters that are blank did not have enough information for the sensitivity analysis.



Parameter	Low Value	High Value
OM = Operation & Maintenance	5%	15%
IR = Interest Rate	5%	15%
PL = Plant Life	40	20
SF = Scaling Factor	0.5	0.9

ORIG = Base Case, ALL = All Parameters (where applicable)

Figure A.4. Likelihood NGLF ethanol is less than gasoline and ethanol in \$/gge based on data from 2012 to 2014 for different plant cost parameter assumptions.[124,132,133]

Stochastic cost analysis for Coskata

The cost parameters used in the stochastic cost model for Coskata were based on the sensitivity values from Table A.2. Trucking costs were assumed to be +/-20% from the base costs in Table 2.1. Natural gas prices and gasoline costs were fitted from the 2012 to 2014 data.[124,132,133] Gasoline costs were best fit with a triangular distribution, but a uniform distribution was also tested and costs were slightly higher with that distribution.

Table A.5. Cost parameter distributions for Coskata (see also Table A.2).

Assumption	**Distribution**	**Values**
Plant life, *n*	Uniform	20 to 40 years
Discount rate, *r*	Uniform	5% to 15%
Operation cost percent, f^{OM}	Uniform	5% to 15%
Trucking Fixed Cost	Uniform	0.015 to 0.023
Trucking Variable Cost	Uniform	0.022 to 0.033
Natural Gas Price	Fitted Loglogistic	Location = 0.57 Scale = 0.94 Shape = 7.37
Gasoline Cost	Triangle	Minimum = 1.24 Most Likely/Max = 3.49

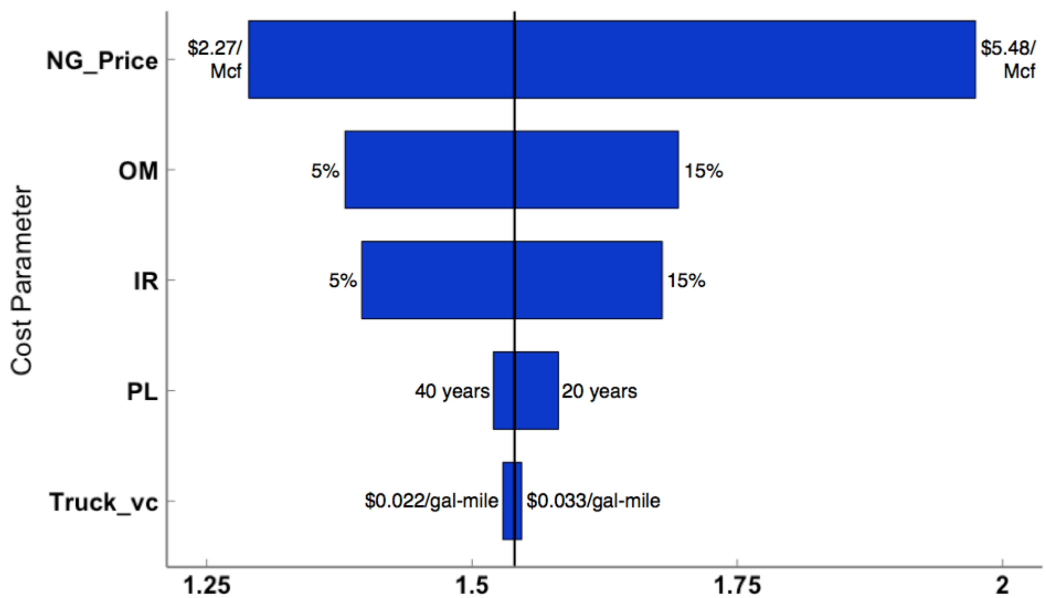


Figure A.5. Tornado diagram for cost components in the Coskata NGLF ethanol stochastic cost model.

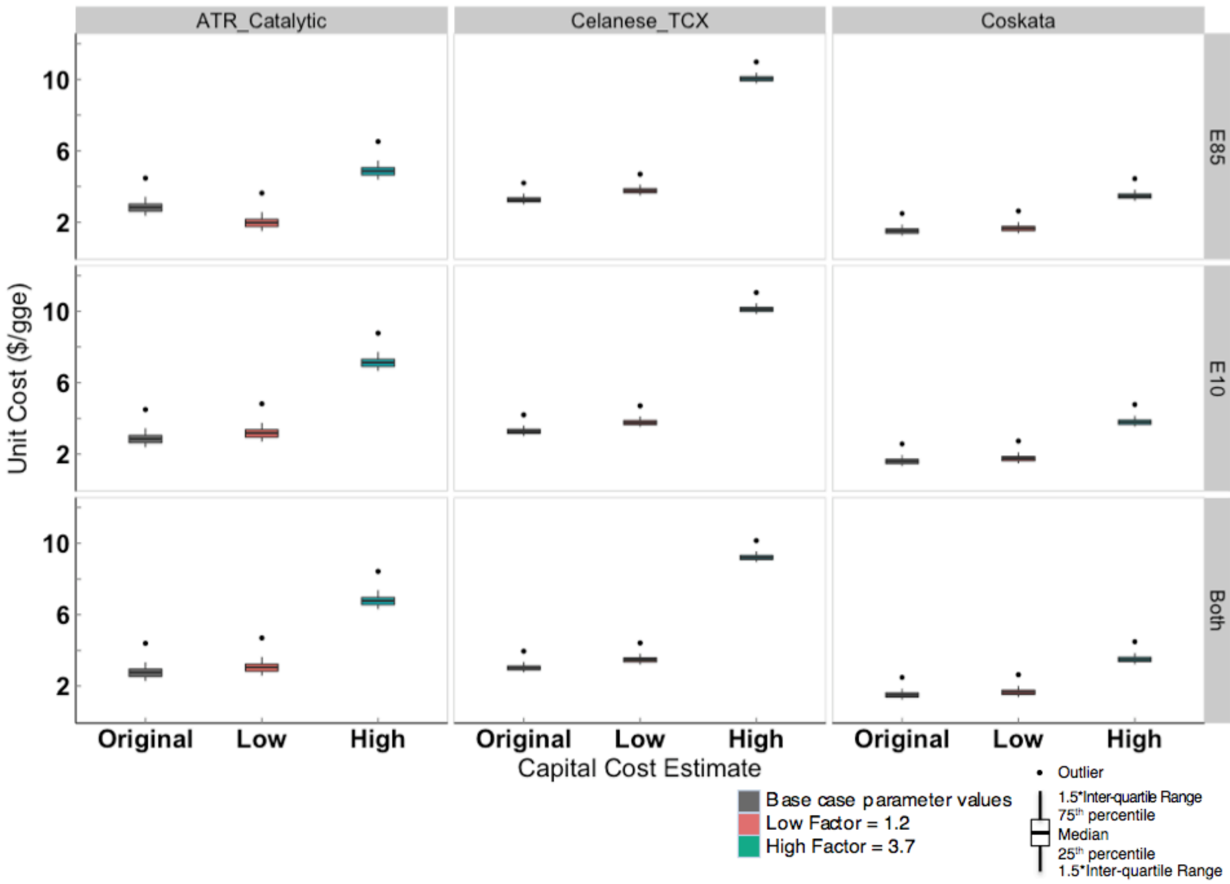


Figure A.6. NGLF ethanol unit costs for pioneer plant factors of 1.2 (low) and 3.7 (high).

Open plant location: Allowing the plants to be located in any of the 67 counties instead of restricting it to 58 does not change the model outcome, because high demand counties were already included in the base case. Even if the model changed county locations, the change in costs would be minimal because the transportation costs are so small. The location analysis is not as impactful a part of the model as the process costs.

NG Sensitivity: Figure A.7 shows the ethanol costs per process with increasing natural gas prices. Celanese and Coskata have similar sensitivity to natural gas prices, for every $1/Mcf change in natural gas price there is an approximately $0.21/gge change in the NGLF ethanol costs. For ATR Catalytic, the line is steeper and for every $1/Mcf change in the natural gas price, there is a $0.36/gge change in the ethanol cost. Although the ATR Catalytic process has lower capital expenses than Celanese, it has higher costs when natural gas prices are around $6/Mcf.

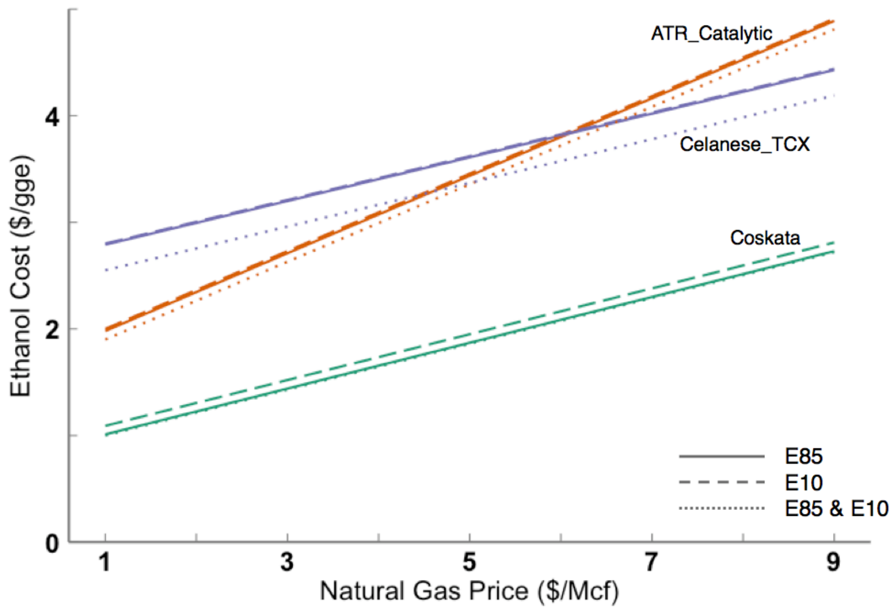


Figure A.7. Natural gas prices and ethanol costs ($/gge) from the optimization model by process. The ethanol costs are highest for Celanese, then ATR, and least expensive Coskata, except when the natural gas price is greater than $5/Mcf then ATR can be more expensive. As the natural gas prices increase, the ethanol costs also increase linearly at a slope of 0.21 for Coskata and Celanese, and 0.36 for ATR.

Small plants: One idea for processing is to locate small plants near wells that are still producing, but in smaller quantities and perhaps receive a lower price for natural gas by bypassing the transmission lines and fees. When the model is run for the Coskata process with plant capacity options of 25 million gallons or 64 million gallons to meet E85 demand, plants are built in 7 of the 58 allowed counties. There is no natural gas price that could make this scenario less costly than the base case, as the capital costs for smaller plants are large. Therefore, the small plant scenario is unlikely an economically feasible method for locating NGLF plants.

E85 Composition: Ethanol content in E85 could change the results of the analysis. E85 could have an ethanol content between 50% and 83% (ASTM 2014). I estimated the unit cost for NGLF ethanol of each process for the range of E85 compositions, including E50, E60, E70 and E75 The change in the percent impacts the ethanol demand for the E85 demand only scenario most significantly. Unit costs estimated were dependent on whether 1 or 2 plants were needed to meet demand. The percentages below 85% only required 1 plant, but capital costs are much higher at smaller demand sizes. In general, for assumptions of E50 and E60 ethanol content, costs increased due to higher capital costs. For E70 and E75, the costs decreased from the original because they were on the high end of a single large plant (compared to two plants required for the 85% scenario). On the high end, if E85 was always actually blended to be E50 (a 50% change in ethanol demand), unit costs could increase by 15% to 30%. Otherwise, the cost change was less than generally 10%. Although modeled this way, in reality, E85 is not consistently one blend level and costs would likely vary across the range estimated here.

A.7 Natural gas prices

In the results section, I discuss the difficulty of assessing whether an NGLF process is less expensive than gasoline or corn ethanol because of fluctuating commodity prices. Using average monthly natural gas hub data for Pennsylvania from 2012-2014 and the ethanol process costs from the model I compare the estimated NGLF ethanol cost to the average corn ethanol cost. In Figure A.8, the zero line is the cost equality line. Points above the line are dates when the NGLF process was more expensive than corn ethanol or gasoline, and points below the line are dates when the NGLF process was less expensive. For the highest cost scenario from the models, Celanese meeting E85 demand, the NGLF ethanol is less than corn ethanol 56% of the time. For the lowest cost scenario, Coskata meeting E85 and E10 demand, the NGLF ethanol is less than corn ethanol 100% of the time. Although the ethanol costs are lower bound estimates, this analysis indicates there is some potential for an NGLF ethanol to be cost competitive with corn ethanol. In comparison, for gasoline as shown in Figure A.8(b), for the highest cost scenario from the models, Celanese meeting E85 demand, the NGLF ethanol is less than gasoline 22% of the time. For the lowest cost scenario, Coskata meeting E85 and E10 demand, the NGLF ethanol is less than corn ethanol 97% of the time. Although the ethanol costs are lower bound estimates, this analysis indicates there is some potential for an NGLF ethanol to be cost competitive with gasoline for Coskata, but is much less competitive when produced through the Celanese process. The historical costs are also plotted as unit costs in Figure A.9, which show that with a decline in both corn ethanol and gasoline costs the competitiveness of a NGLF ethanol becomes less certain.

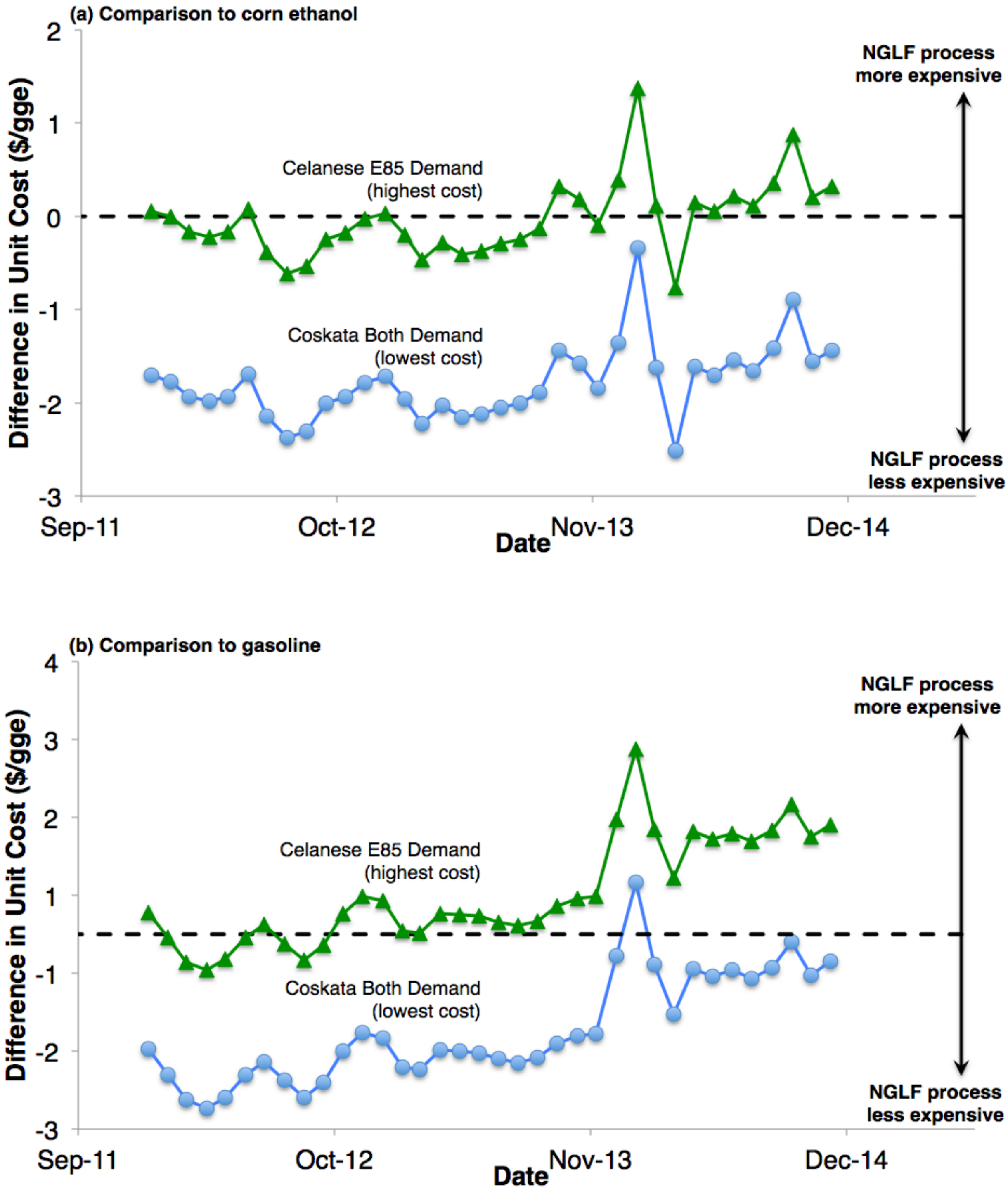


Figure A.8. Difference between NGLF ethanol, corn ethanol and gasoline costs. The costs for NGLF ethanol were estimated using historical natural gas prices paired with the process costs, and corn ethanol and gasoline costs are historical.[132,133] The dashed line is the cost equality line between NGLF ethanol and either corn ethanol (a) or gasoline (b). Points above the line are for dates when NGLF process is more expensive, and the points below are for dates when NGLF is less expensive. The triangles costs for the highest cost NGLF process, and the circles are for the lowest cost NGLF process.

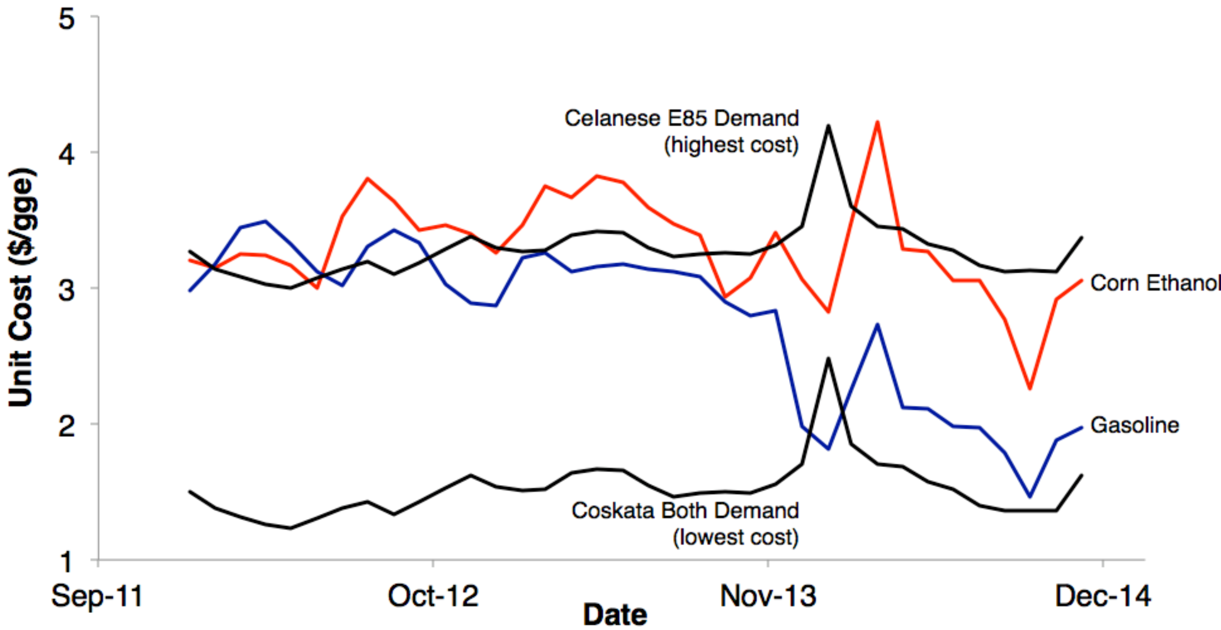


Figure A.9. Unit costs for NGLF ethanol, gasoline and corn ethanol from 2012 to 2014.[132,133] The NGLF costs in black are for the highest and lowest cost NGLF process.

Appendix B. E85 Refueling and Infrastructure

B.1 Historical E85 and Gasoline Prices

National E85 and gasoline quarterly prices are included as Figure B.1. E85 is shown in gles and liters. The gle energy conversion factor is shown as 1.2,1.3 and 1.4. The difference in the conversion factor depends on the assumed ethanol content in E85. The lowest conversion factor of 1.2 assumes an ethanol content of 50%, and the highest of 1.4 assumes an ethanol content of 85%, which are the acceptable range according the ASTM standards.[131]

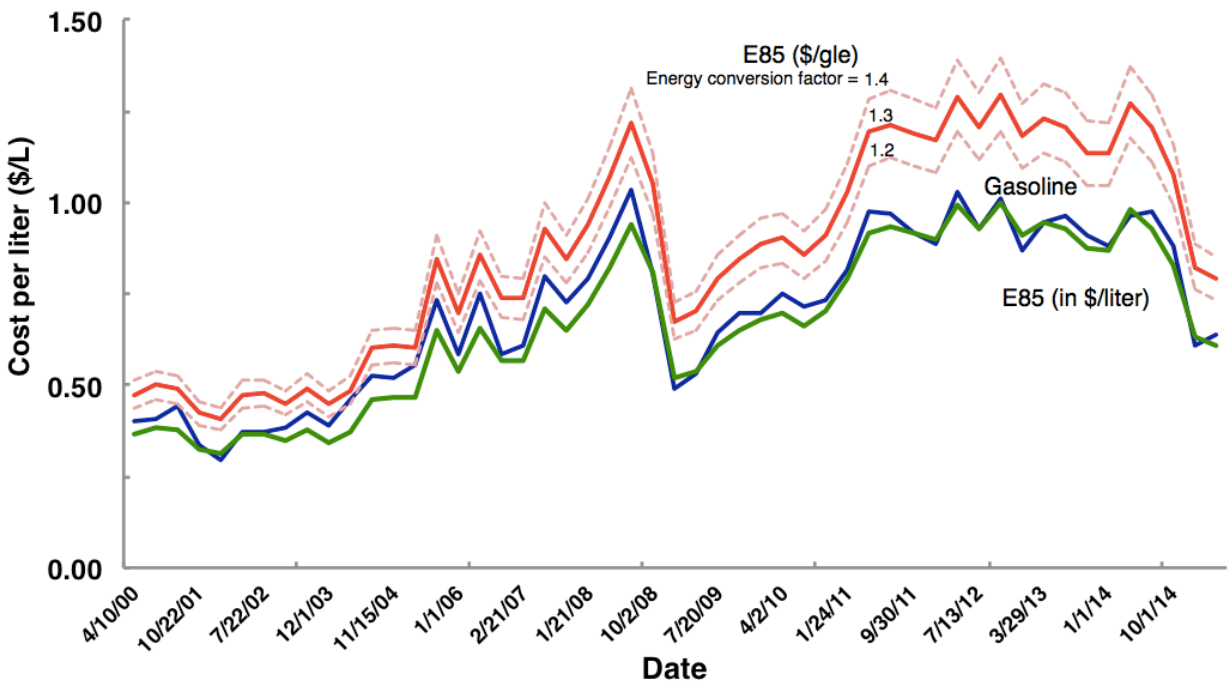


Figure B.1. National E85 and gasoline quarterly average fuel prices from 2000 to April 2015 from the Alternative Fuels Data Center.[145] The E85 price in gle assumes the energy equivalent conversion from gasoline to E85 is shown as 1.2, 1.3 or 1.4.

B.2 Vehicle Registration Counts

Table A.1 shows the percent of LDVs and FFVs in the ZIP Codes that currently have refueling stations that sell E85. In both case, LDV and FFV, the percent of the vehicles that are within those Zip Codes are just over 4% of their respective totals. This table does not cover all the vehicles that are at the 14.5 km equivalent distance, but the distribution of FFVs is similar to all registered LDVs in Pennsylvania.

Table B.1. Light-duty vehicle (LDV) and FFV registered vehicle counts for the 24 ZIP Codes in Pennsylvania that currently have a station that sells E85. The percents are for the total number of LDVs (10.9 million) and FFVs (600,000).

E85 Station ZIPCode	Number Reg LDVs	% TotalLDVs	Rank for TotalLDVs	Number FFVs	% ForFFVS	Rank for FFVs
15301	45,557	0.42%	6	3,754	0.62%	1
17543	41,105	0.38%	14	1,894	0.31%	24
19403	40,466	0.37%	15	2,231	0.37%	12
17112	36,834	0.34%	22	1,782	0.29%	30
17111	30,599	0.28%	43	1,658	0.27%	43
17013	27,927	0.26%	57	1,279	0.21%	89
15401	27,683	0.25%	60	1,831	0.30%	28
15146	24,195	0.22%	92	1,422	0.24%	63
17545	23,719	0.22%	95	1,162	0.19%	116
17057	22,224	0.20%	109	1,501	0.25%	55
15090	20,237	0.19%	138	1,199	0.20%	109
15205	19,231	0.18%	154	1,514	0.25%	53
17552	18,864	0.17%	158	858	0.14%	223
16148	16,329	0.15%	192	1,141	0.19%	122
15217	14,901	0.14%	234	445	0.07%	447
15025	13,132	0.12%	287	958	0.16%	178
15132	12,431	0.11%	302	851	0.14%	225
15005	9,578	0.09%	383	623	0.10%	321
15131	7,449	0.07%	472	453	0.07%	441
18106	7,321	0.07%	480	491	0.08%	413
15139	5,576	0.05%	589	357	0.06%	526
19107	3,932	0.04%	728	298	0.05%	601
17063	3,186	0.03%	803	152	0.03%	889
15225	1,349	0.01%	1115	93	0.02%	1072
Total	473,825	4.34%	NA	27,947	4.62%	NA

B.3 Equivalent Distance and Sensitivity

For an equivalent average refueling distance of 14.5 km, the number of stations required to meet the demand of FFVs in Pennsylvania are shown as a cumulative distribution function in Figure B.2.

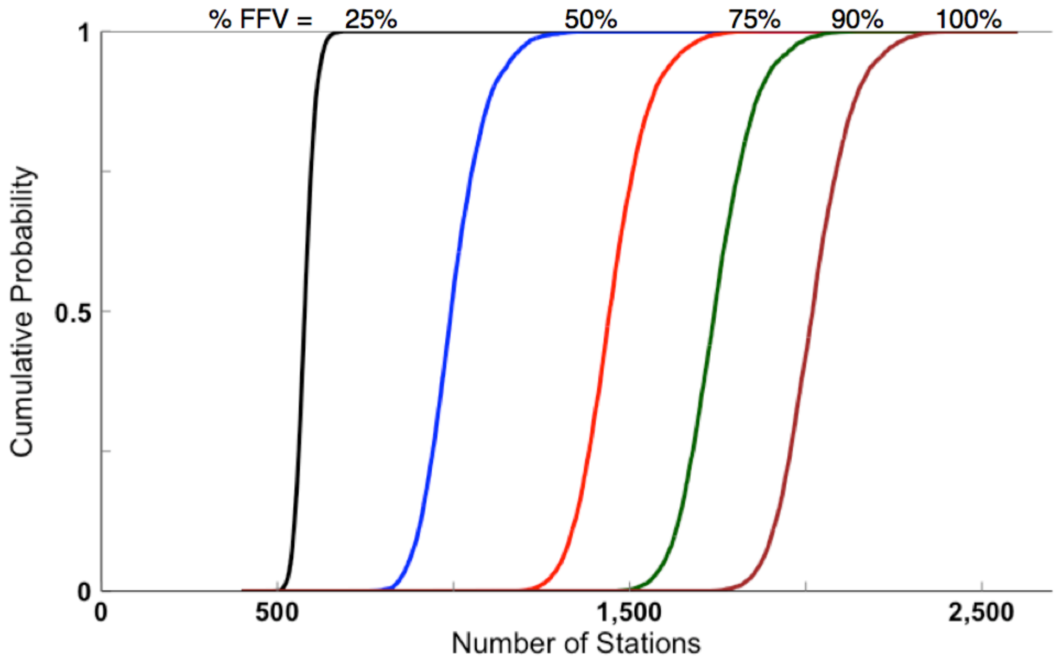


Figure B.2. Number of E85 stations required for FFVs to be within 14.5 km of a station per FFV capture percent.

If the equivalent distance for average travel to a refueling station is 8 km or 24 km, the number of required stations changes from the 14.5 km base case. The cumulative distribution functions for both alternative equivalent distances for the likely number of stations and the total costs for the stations are included as Figure B.3 through Figure B.6. In the case of the 8 km, the number of stations and costs increase, and both decrease for a 24 km distance when compared to the base case.

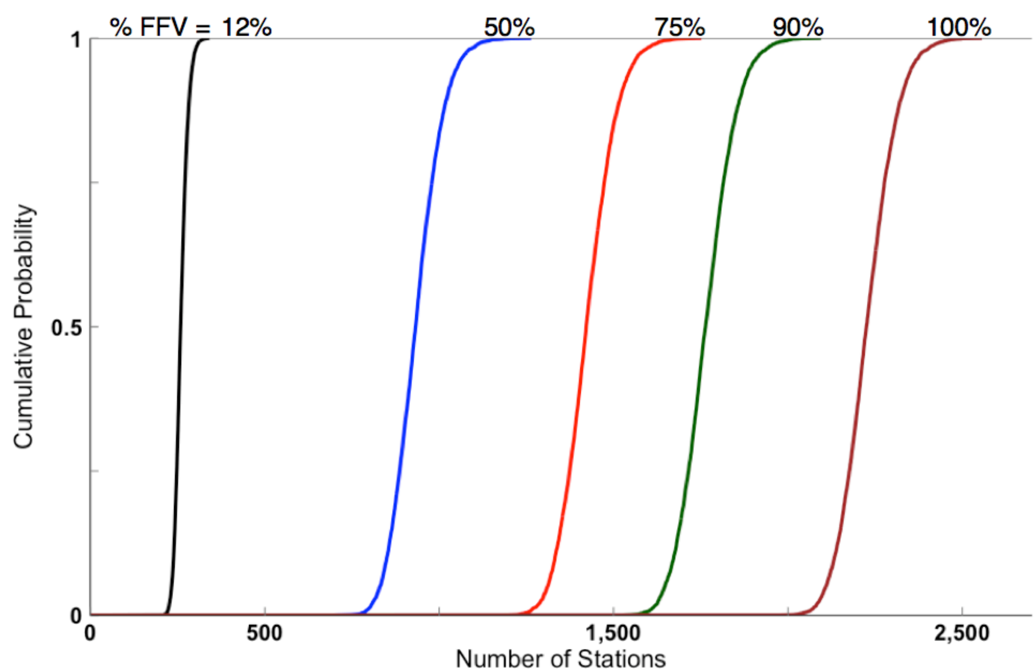


Figure B.3. Number of E85 stations required for FFVs to be within 8 km of a station per FFV capture percent.

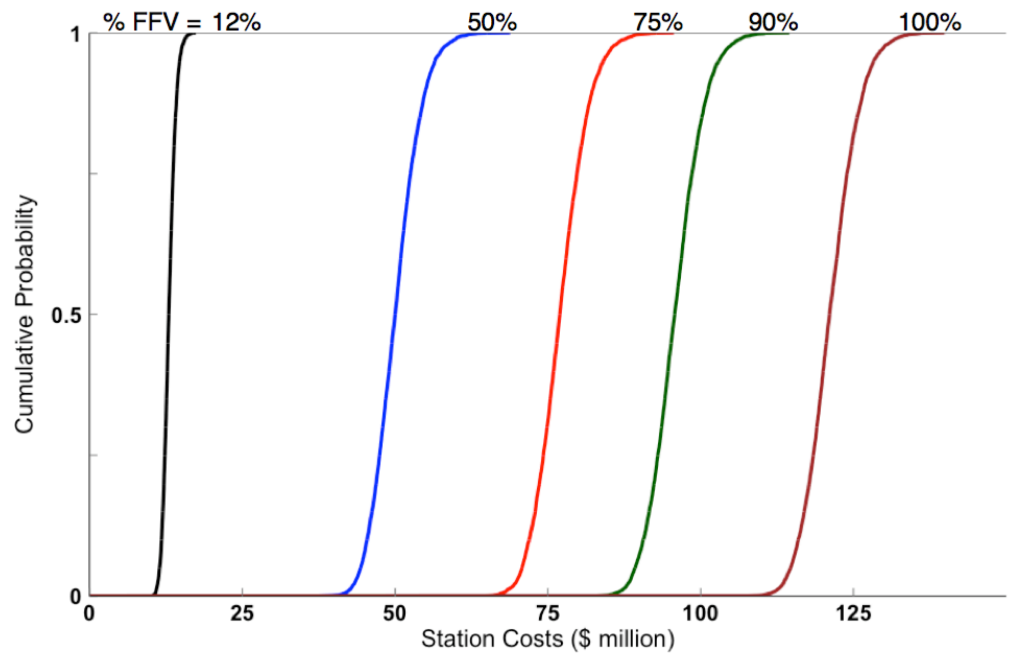


Figure B.4. Station cost CDFs assuming varying FFV capture percentages assuming a reasonable distance of 8 km.

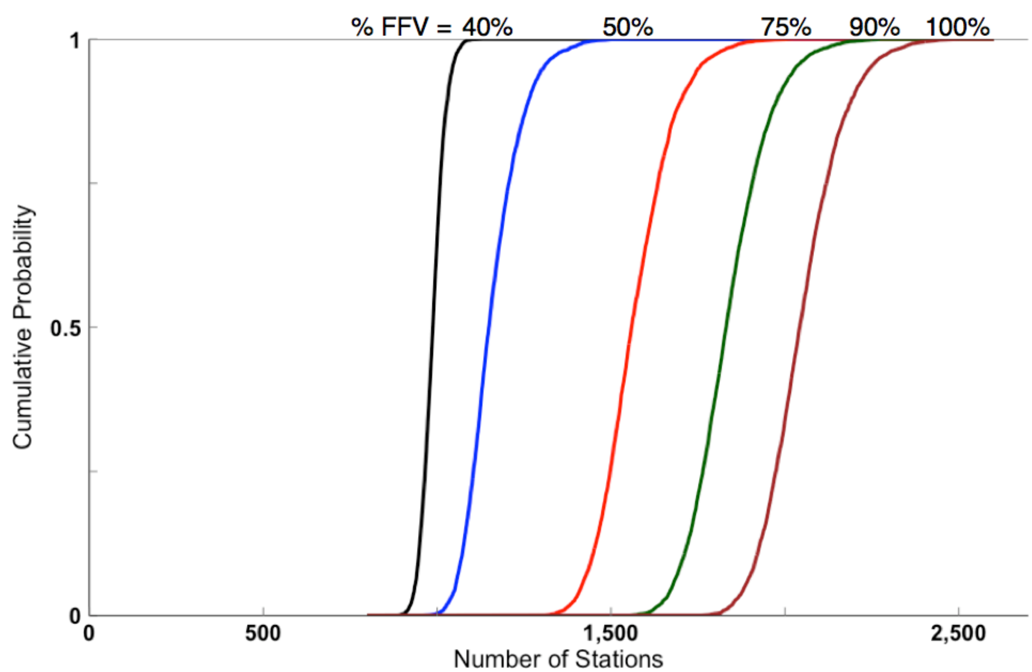


Figure B.5. Number of E85 stations required for FFVs to be within 24 km of a station per FFV capture percent.

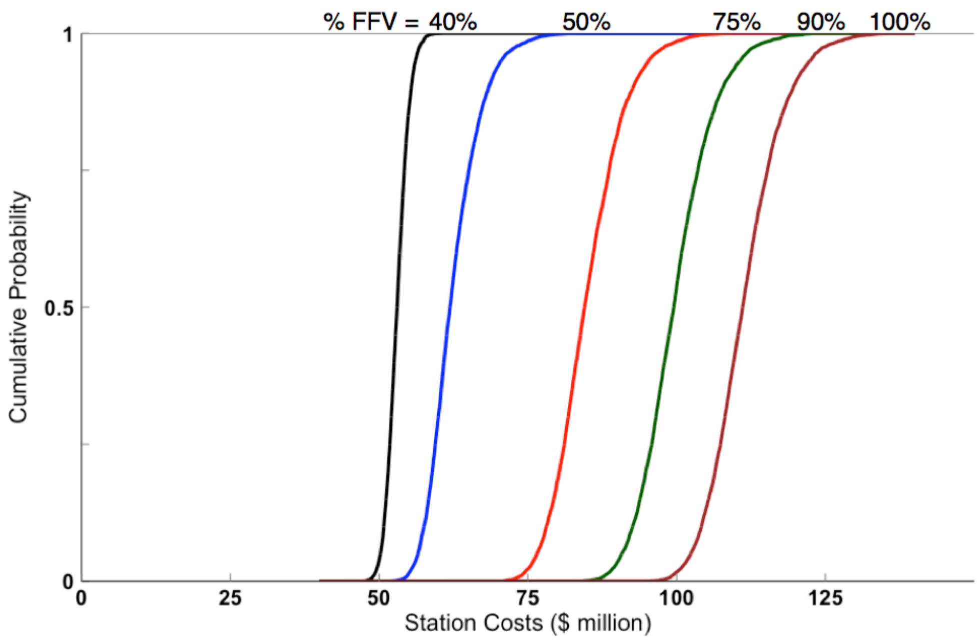


Figure B.6. Station cost CDFs assuming varying FFV capture percentages assuming a reasonable distance of 24 km.

B4. Breakeven E85 Price Equation

The breakeven E85 price was calculated by modifying the refueling convenience cost equation so that the price of E85 was calculated within the model. Where the RefuelCostGas is the total cost of refueling assuming only refueling with E10 (E85%=0). The other parameters in the equation are the same as those calculated in Equations 1 to 5.

$$Price\ E85 = \frac{\frac{RefuelCostGas - AnnualCostGas}{AnnRefuelsE85} - TimeCostE85}{RefuelAmountE85} \quad Eq.\ (B.1)$$