

VOLUME I

***Well-to-Wheel Energy Use and  
Greenhouse Gas Emissions of  
Advanced Fuel/Vehicle Systems  
– North American Analysis –***

***General Motors  
Corporation***

***Argonne National  
Laboratory***

***BP***

***ExxonMobil***

***and***

***Shell***

EXECUTIVE  
SUMMARY  
REPORT

June 2001

**General Motors  
Corporation**

**Argonne National  
Laboratory**

**BP**

**ExxonMobil**

**and**

**Shell**

V O L U M E I

**Well-to-Wheel Energy Use and  
Greenhouse Gas Emissions of  
Advanced Fuel/Vehicle Systems  
– North American Analysis –**

E X E C U T I V E  
S U M M A R Y  
R E P O R T

June 2001

## **DISCLAIMER**

Because many factors critical to the potential commercial viability of the technologies addressed in this study lie beyond the scope of the study's analysis, this report cannot provide the basis for dependable predictions regarding marketplace feasibility or timetables for implementation or commercialization of the technologies examined herein.

## **Preface**

### **Project Description and Acknowledgments**

#### **Need for the Study**

There are differing yet strongly held views among the various “stakeholders” in the advanced fuel/propulsion system debate. In order for the introduction of advanced technology vehicles and their associated fuels to be successful, it seems clear that four important stakeholders must view their introduction as a “win”:

- Society,
- Automobile manufacturers and their key suppliers,
- Fuel providers and their key suppliers, and
- Auto and energy company customers.

If all four of these stakeholders, from their own perspectives, are not positive regarding the need for and value of these advanced fuels/vehicles, the vehicle introductions will fail.

This study was conducted to help inform public and private decision makers regarding the impact of the introduction of such advanced fuel/propulsion system pathways from a societal point of view. The study estimates two key performance criteria of advanced fuel/propulsion systems on a total system basis, that is, “well” (production source of energy) to “wheel” (vehicle). These criteria are energy use and greenhouse gas emissions per unit of distance traveled.

The study focuses on the U.S. light-duty vehicle market in 2005 and beyond, when it is expected that advanced fuels and propulsion systems could begin to be incorporated in a significant percentage of new vehicles. Given the current consumer demand for light trucks, the benchmark vehicle considered in this study is the Chevrolet Silverado full-size pickup.

#### **How This Study Differs from Other Well-to-Wheel Analyses**

This study differs from prior well-to-wheel analyses in a number of important ways:

1. The study considers fuels and vehicles that might, albeit with technology breakthroughs, be commercialized in large volumes and at reasonable prices. In general, fuels and propulsion systems that appear to be commercially viable only in niche markets are not considered.
2. The study provides best estimates and associated confidence bounds of the criteria mentioned above to allow the reader to assess differences between fuel/vehicle propulsion systems on a more statistically sound basis. This approach provides not only the best estimate, but also a measure of the uncertainty around the best estimate.

3. The study incorporates the results of a proprietary vehicle model created and used by General Motors.
4. The well-to-wheel analysis involved participation by the three largest privately owned fuel providers: BP, ExxonMobil, and Shell.
5. The 15 vehicles considered in the study include conventional and hybrid electric vehicles with both spark-ignition and compression-ignition engines, as well as hybridized and non-hybridized fuel cell vehicles with and without onboard fuel processors. All 15 vehicles were configured to meet the same performance requirements.
6. The 13 fuels considered in detail (selected from 75 different fuel pathways) include low-sulfur gasoline, low-sulfur diesel, crude oil-based naphtha, Fischer-Tropsch naphtha, liquid/compressed gaseous hydrogen based on five different pathways, compressed natural gas, methanol, and neat and blended (E85) ethanol. These 13 fuels, taken together with the 15 vehicles mentioned above, yielded the 27 fuel pathways analyzed in this study.

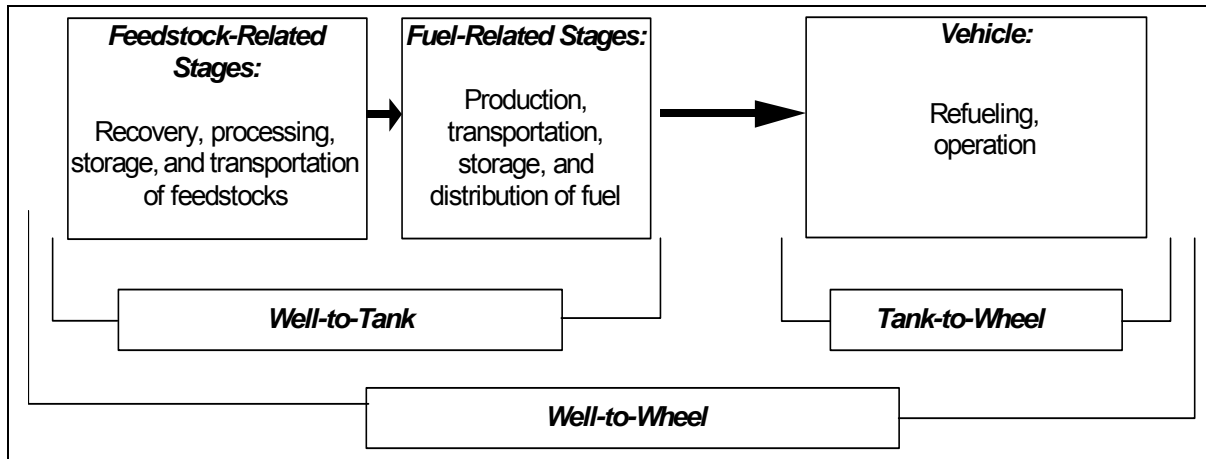
## **Format**

The study was conducted and is presented in three parts:

- Well-to-Tank (WTT): consideration of the fuel from resource recovery to delivery to the vehicle tank,
- Tank-to-Wheel (TTW): consideration of the vehicle from the tank to the wheel, and
- Well-to-Wheel (WTW): integration of the WTT and TTW components.

The following figure illustrates the stages involved in a full fuel-cycle analysis. Argonne's study covers the WTT (or feedstock and fuel-related) stages (Part 1). GM evaluated the fuel economy and emissions of various vehicle technologies using different fuels (TTW analysis) (Part 2). In a separate effort, Argonne's WTT results were combined with GM's TTW results to produce WTW results (Part 3).

Volume 1 of this report series contains the Executive Summary Report, Volume 2 the full three-part study report, and Volume 3 the complete WTT report submitted to GM by Argonne National Laboratory (including detailed assumptions and data).



Full Fuel-Cycle Analysis

## Study Organization

Mr. Greg Ruselowski of General Motors' Global Alternative Propulsion Center (GAPC) initiated the study. The study team was organized as follows:

### ***Program Management***

*Program Manager:* Dr. James P. Wallace III, Wallace & Associates  
*Assistant Program Manager:* Raj Choudhury, GM GAPC

### ***Part 1: Well-to-Tank Analysis***

*Project Leader and Principal Researcher:* Dr. Michael Wang, Argonne National Laboratory  
*Project Team:* Dr. Dongquan He, Argonne National Laboratory  
*GM Project Manager:* Dr. Anthony Finizza, AJF Consulting  
*Project Reviewers:*  
 BP: Andrew Armstrong and Dr. James Simnick  
 ExxonMobil: Gilbert Jersey and Dr. John Robbins  
 Shell: Jean Cadu  
 GM: Norman Brinkman  
 Argonne National Laboratory: Dr. Dan Santini

### ***Part 2: Tank-to-Wheel Analysis***

*Project Leader and Principal Researcher:* Trudy Weber, GM R&D and Planning Center  
*Project Team:* Dr. Moshe Miller, Advanced Development Corporation; Dr. David Masten, GAPC; and Gerald Skellenger, GM R&D and Planning Center  
*Project Reviewers:*  
 GM R&D and Planning Center: Dr. Hazem Ezzat, Dr. Roger Krieger, and Norman Brinkman

GM GAPC: Gary Stottler, Dr. Udo Winter, and Mattias Bork  
GM Powertrain: Dr. Fritz Indra, Tim Peterson, Arjun Tuteja,  
Dr. Ko-Jen Wu, and Tony Zarger  
GM Truck: Dr. Tanvir Ahmad  
GM ATV: Dr. Peter Savagian and John Hepke

***Part 3A: Well-to-Tank Pathways Down Select***

*Project Leader:* Dr. Anthony Finizza, AJF Consulting

*Project Reviewers:*

BP: Andrew Armstrong and Dr. James Simnick

ExxonMobil: Gilbert Jersey and Dr. John Robbins

Shell: Jean Cadu

Argonne: Dr. Michael Wang and Dr. Dan Santini

***Part 3B: Well-to-Wheel Integration***

*Project Co-Leaders:* Dr. Anthony Finizza, AJF Consulting, and  
Dr. James P. Wallace III, Wallace & Associates

*Project Reviewers:*

BP: Andrew Armstrong and Dr. James Simnick

ExxonMobil: Gilbert Jersey and Dr. John Robbins

Shell: Jean Cadu

GM: Norman Brinkman and Raj Choudhury

Argonne: Dr. Michael Wang and Dr. Dan Santini

## **Acknowledgments**

In addition to the participants cited above, the Program Team wishes to acknowledge the support of the following people: Tom Bond, Manager of Global Fuels Technology, BP; Tim Ford, Vice President Fuels, Shell International Petroleum Co. Ltd.; Dr. Eldon Priestley, Manager, Corporate Strategic Research, ExxonMobil Research and Engineering; Dr. James Katzer, Strategic Planning and Programs Manager, ExxonMobil Research and Engineering; Dr. Byron McCormick, Director of GM GAPC; Dr. James A. Spearot, Director, Chemical and Environmental Sciences Lab, GM R&D and Planning Center; Dr. Larry Johnson, Director of Argonne National Laboratory's Transportation Technology R&D Center; and Robert Larsen, Director of Argonne National Laboratory's Center for Transportation Research, all of whom provided invaluable support in the ongoing review process for this report.

The study participants would like to thank Tien Nguyen, Dr. Phillip Patterson, and David Rodgers of the U.S. Department of Energy's Office of Transportation Technologies; without their support of previous versions of the GREET model, this study would not have been possible. We would also like to acknowledge the editorial support of Mary Fitzpatrick of Argonne.

Additional acknowledgments are made in each part of the full report.

## **Responsibility**

Argonne assumes responsibility for the accuracy of Part 1 but acknowledges that this accuracy was enhanced through significant contributions and thorough review by the study team, especially participants from the energy companies cited.

GM is exclusively responsible for the quantification of comparative vehicle technologies considered in Part 2.

Part 3A sought to further down-select the 75 fuel pathways examined in Part 1 into fuels that appear to be potentially feasible at high volumes and reasonable prices. The three energy companies provided key input for the conclusions reached in this section.

The GM Well-to-Wheel Integration Model used for Part 3B was developed and simulated by AJF Consultants and Wallace & Associates and is the property of GM. GM, Argonne, and the energy companies have reviewed the model and its simulation results and find them consistent and rational, given the model input.

## **Next Steps**

A follow-up study to estimate criteria pollutants for the United States is in the planning stage. In addition, efforts are underway to provide a European counterpart to this study.



## Contents

Preface.....	iii
Notation.....	xi
Part 1: Well-to-Tank Energy Use and Greenhouse Gas Emissions of Transportation Fuels .....	1
ES-1.1 Introduction .....	1
ES-1.2 Methodology .....	1
ES-1.3 Results.....	4
ES-1.4 Conclusions .....	11
Part 2: Tank-to-Wheel Energy Use for a North American Vehicle .....	13
ES-2.1 Introduction .....	13
ES-2.2 Methodology .....	13
ES-2.3 Results .....	15
ES-2.4 Conclusions .....	17
Part 3: Well-to-Wheel Fuel/Vehicle Pathway Integration .....	19
ES-3.1 Introduction .....	19
ES-3.2 Methodology .....	19
ES-3.3 Results .....	24
ES-3.4 Conclusions .....	30

## Figures

ES-1.1 WTT Total Energy Use.....	6
ES-1.2 WTT Fossil Energy Use.....	7
ES-1.3 WTT Petroleum Use.....	9
ES-1.4 WTT GHG Emissions .....	10
ES-2.1 Performance Targets .....	15
ES-3.1 WTW Integration Process .....	23
ES-3.2 WTW Total System Energy Use: Conventional and Hybrid Fuel/Vehicle Pathways.....	26
ES-3.3 WTW GHG Emissions: Conventional and Hybrid Fuel/Vehicle Pathways.....	27
ES-3.4 WTW Total System Energy Use: Hybrid Fuel/FCV Pathways .....	28
ES-3.5 WTW GHG Emissions: Hybrid Fuel/FCV Pathways.....	29
ES-3.6 WTW Total System Energy Use: Non-Hybrid Fuel/FCV Pathways.....	29
ES-3.7 WTW GHG Emissions: Non-Hybrid Fuel/FCV Pathways.....	30
ES-3.8 WTW Total System Energy Use: “Selected” Fuel/Vehicle Pathways.....	31

## Figures (Cont.)

ES-3.9	Percent Energy Loss WTT vs. WTW: “Selected” Fuel/Vehicle Pathways .....	31
ES-3.10	WTW GHG Emissions: “Selected” Fuel/Vehicle Pathways.....	32

## Tables

ES-1.1	Representative Fuel Pathways Identified .....	4
ES-2.1	Fuel Economy and Performance Predictions .....	16
ES-2.2	Overview of Vehicle Configurations .....	17
ES-3.1	Summary of Pathways Selected for WTW Integration Analysis.....	22
ES-3.2	Fuel/Vehicle Pathways Analyzed.....	25

## Notation

### Acronyms and Abbreviations

ANL	Argonne National Laboratory
CARFG2	California Phase 2 reformulated gasoline
CARFG3	California Phase 3 reformulated gasoline
CC	combined-cycle
CG	conventional gasoline
CH <sub>4</sub>	methane
CIDI	compression ignition direct injection
CNG	compressed natural gas
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CONV	conventional vehicle
CS	charge sustaining
E100	neat (100%) ethanol
E85	a mixture of 85% ethanol and 15% gasoline (by volume)
EL	electrolysis
EPA	U.S. Environmental Protection Agency
EtOH	ethanol
FC	fuel cell
FCV	fuel cell vehicle
FG	flared gas
FP	fuel processor
FRFG2	Federal Phase 2 reformulated gasoline
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
G.H <sub>2</sub>	gaseous hydrogen
GAPC	Global Alternative Propulsion Center (General Motors Corporation)
GASO	gasoline
GHG	greenhouse gas
GM	General Motors Corporation
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
GWP	global warming potential
H <sub>2</sub>	hydrogen
HE100	herbaceous E100
HE85	herbaceous E85
HEV	hybrid electric vehicle
HPSP	Hybrid Powertrain Simulation Program
L.H <sub>2</sub>	liquid hydrogen
MeOH	methanol
MTBE	methyl tertiary butyl ether
N <sub>2</sub> O	nitrous oxide
NA	North American

NAP	naphtha
NG	natural gas
NiMH	nickel metal hydride
NNA	non-North-American
NO <sub>x</sub>	nitrogen oxide
PM <sub>10</sub>	particulate matter with diameter of 10 μm or less
PNGV	Partnership for a New Generation of Vehicles
SI	spark ignition
SO <sub>x</sub>	sulfur oxides
SULEV	Super Ultra-Low Emissions Vehicle
TTW	tank-to-wheel
USDA	U.S. Department of Agriculture
VOC	volatile organic compound
WTT	well-to-tank
WTW	well-to-wheel
ZEV	Zero Emissions Vehicle

## Units of Measure

Btu	British thermal unit(s)
g	gram(s)
gal	gallon(s)
kWh	kilowatt hour(s)
mi	mile(s)
mmBtu	million (10 <sup>6</sup> ) Btu
mph	mile(s) per hour
ppm	part(s) per million
μm	micrometer(s)

# PART 1

## Well-to-Tank Energy Use and Greenhouse Gas Emissions of Transportation Fuels

### ES-1.1 Introduction

The various fuels proposed for use in fuel cell vehicles (FCVs) and hybrid electric vehicles (HEVs) are subject to different production pathways and, consequently, result in different energy and greenhouse gas (GHG) emission impacts. The purpose of this study, conducted by Argonne National Laboratory's Center for Transportation Research and commissioned by the Global Alternative Propulsion Center (GAPC) of General Motors Corporation (GM), was to evaluate the energy and GHG emission impacts associated with producing different transportation fuels. For the study, Argonne examined energy use and GHG emissions from well to fuel available in the vehicle tank (well-to-tank [WTT] analysis). Three energy companies — BP, ExxonMobil, and Shell — participated in the study by providing input and reviewing Argonne's results. The timeframe for the WTT analysis is 2005 and beyond.

### ES-1.2 Methodology

To complete Part 1 of the study, a model developed by Argonne was used to estimate WTT energy and emission impacts of alternative transportation fuels and advanced vehicle technologies. The model, called GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation), calculates energy use in British thermal units per mile (Btu/mi) and emissions in grams per mile (g/mi) for transportation fuels and vehicle technologies.

For energy use modeling, GREET computes total energy use (all energy sources), fossil energy use (petroleum, natural gas, and coal), and petroleum use. For emissions modeling, GREET estimates three major GHGs specified in the Kyoto protocol (carbon dioxide [CO<sub>2</sub>]), methane [CH<sub>4</sub>], and nitrous oxide [N<sub>2</sub>O]) and five criteria pollutants (volatile organic compounds [VOCs], carbon monoxide [CO], nitrogen oxides [NO<sub>x</sub>] particulate matter with diameters of 10 μm or less [PM<sub>10</sub>], and sulfur oxides [SO<sub>x</sub>]). The three GHGs are combined with their global warming potentials (GWPs) to calculate CO<sub>2</sub>-equivalent GHG emissions. With the assistance of the project team, Argonne modified the GREET model to make it stochastic in nature, i.e., providing confidence bounds around best estimates to quantify uncertainty.

For this study, we estimated total energy, fossil energy, and petroleum use, as well as CO<sub>2</sub>-equivalent emissions of the three GHGs. Emissions of criteria pollutants were not included in this study.

### Fuels and Production Pathways

We analyzed 75 fuel pathways for application to HEVs and FCVs. The following sections briefly describe the fuels and production pathways chosen for our study. Volume 2 of this report series provides a complete list of the 75 production pathways analyzed and results for the 30 selected

pathways. Volume 3 of this report series provides analysis results for all 75 pathways and details regarding the assumptions used in our study. Appendices A and B in Volume 3 provide charts showing the probability distribution functions for key input parameters and results for all 75 pathways.

### ***Petroleum-Based Fuels***

The TTW study included three petroleum-based fuels: gasoline, diesel, and naphtha. For gasoline and diesel, we established cases to represent different fuel requirements. For gasoline, we considered federal conventional gasoline (CG), federal Complex Model Phase 2 reformulated gasoline (FRFG2), California Phase 2 reformulated gasoline (CARFG2), California Phase 3 reformulated gasoline (CARFG3), and the gasoline requirements in the U.S. Environmental Protection Agency's (EPA's) Tier 2 vehicle emission standards. These gasoline options contain sulfur at concentrations ranging from 5 parts per million (ppm) to over 300 ppm and may contain methyl tertiary butyl ether (MTBE), ethanol (EtOH), or no oxygenate.

For on-road diesel fuels, we included two options: a current diesel and a future diesel. The current diesel has a sulfur content of 120–350 ppm. The future diesel, which reflects the new diesel requirement adopted recently by EPA, has a sulfur content below 15 ppm.

Naphtha could serve as a fuel cell fuel. Virgin crude naphtha from petroleum refineries' distillation (without desulfurization) has a sulfur content of about 370 ppm. For fuel cell applications, we assumed that the sulfur content of crude naphtha would be reduced to about 1 ppm.

### ***Natural-Gas-Based Fuels***

We included these natural gas (NG)-based fuels: compressed natural gas (CNG), methanol (MeOH), Fischer-Tropsch diesel (FTD), Fischer-Tropsch naphtha, gaseous hydrogen (G.H<sub>2</sub>) produced in central plants, G.H<sub>2</sub> produced in refueling stations, liquid hydrogen (L.H<sub>2</sub>) produced in central plants, and L.H<sub>2</sub> produced in refueling stations. These fuels are produced from three NG feedstock sources: North American (NA) sources, non-North-American (NNA) sources, and NNA flared gas (FG) sources.

### ***Bio-Ethanol Options***

We included three ethanol production pathways: ethanol from corn, woody biomass (trees), and herbaceous biomass (grasses). Corn-based ethanol can be produced in wet milling or dry milling plants; we examined both. Corn-based ethanol plants also produce other products (primarily animal feeds). We allocated energy use and emissions between ethanol and its co-products by using the market value method.

In cellulosic (woody and herbaceous) ethanol plants, while cellulose in biomass is converted into ethanol through enzymatic processes, the lignin portion of biomass can be burned to provide needed steam. Co-generation systems can be employed to generate both steam and electricity. In this case, extra electricity can be generated for export to the electric grid. We took the generated electricity credit into account in calculating energy use and GHG emissions of cellulosic ethanol production.

## ***Electricity Generation***

Electricity plays a major role in battery-powered electric vehicles (EVs), grid-connected (or charge-depleting) HEVs, and hydrogen (H<sub>2</sub>) production via electrolysis. One of the key factors in determining the energy use and GHG emissions associated with electricity generation is electric generation mix (the mix of the power plants fired with different fuels). We included three generation mixes in our study — the U.S., California, and Northeast U.S. — to cover a broad range. NG-fired combined-cycle (CC) turbines with high energy-conversion efficiencies have been added to U.S. electric generation capacity in the last decade. We estimated energy use and GHG emissions associated with electricity generation in NG CC power plants, hydroelectric plants, and nuclear power plants separately.

Emissions estimates were calculated for four types of electric power plants: oil-fired, NG-fired, coal-fired, and nuclear. Other power plants, such as hydroelectric and windmill plants, generate virtually no operational emissions. Emissions from nuclear power plants are attributable to uranium recovery, enrichment, and transportation. Our estimate of emissions associated with electricity generation includes fuel production stages as well as electricity generation.

## ***Hydrogen Production via Electrolysis***

Production of H<sub>2</sub> from electricity (by electrolysis of water at refueling stations) may represent a means to provide H<sub>2</sub> for fuel cell vehicles. We evaluated H<sub>2</sub> production from electricity generated from hydroelectric and nuclear power, as well as from the three generation mixes (U.S., California, Northeast U.S.) and NG-fired CC turbines. The first two cases represent electricity generation with zero or near-zero GHG emissions.

## **Probability Distribution Functions for Key Parameters**

On the basis of our research of the efficiencies of WTT stages and input from the energy companies during this study, we determined probability distribution functions for key WTT stages (for details, see Appendix A in Volume 3 of this report series). The probabilistic simulations employed in this study, a departure from the range-based simulations used in many previous Argonne studies, are intended to address uncertainties statistically. For each activity associated with the production process of each fuel, we determined the following parametric values for probability: 20%, 50%, and 80% (P20, P50, and P80). For most parameters, we assumed normal probability distributions. For some of the parameters, where a normal distribution would not describe the parameter correctly, we assumed a triangular distribution.

## **Transportation of Feedstocks and Fuels**

We employed the following five-step approach to estimate energy use and GHG emissions for transportation of feedstocks and fuels.

- Determine transportation modes and their shares (i.e., ocean tankers, pipelines, barges, rail, and trucks) to be used to transport a given feedstock or fuel.
- Identify the types and shares of process fuels (e.g., residual oil, diesel fuels, natural gas, electricity) to be used to power each mode.

- Calculate the energy intensity and emissions associated with each transportation mode fueled with each process fuel.
- Estimate the distance of each transportation mode for each feedstock or fuel.
- Add together the energy use and emissions of all transportation modes for transporting the given feedstock or fuel.

### ES-1.3 Results

In our analysis, we found that many pathways to produce a given fuel were similar, so we were able to select a representative pathway. Other pathways were eliminated for reasons detailed in Volume 3 of this report series. In the end, we selected the 30 pathways listed in Table ES-1.1. In selecting the 30 pathways for presentation here, we did not include fuel plant designs with steam or electricity co-generation. These design options provide additional energy and emissions benefits for the fuels evaluated here (namely, G.H<sub>2</sub>, methanol, FT naphtha, and FTD), but whether these options are considered appropriate depends on the specific plant location relative to an energy infrastructure and potential customers. Moreover, in reality, these options could be considered for any fuel-producing facility. We also eliminated all pathways based on flared gas. FG-based pathways offer significant energy and emissions benefits; however, the amount of FG represents a small portion of the resource base. Results of all eliminated pathways are presented in Appendix B to Volume 3 of this report series. The following paragraphs discuss the results in terms of total energy use, fossil energy use, petroleum use, and GHG emissions.

Table ES-1.1 Representative Fuel Pathways Identified

Fuel Pathways
<i>Petroleum-Based</i>
(1) Conventional (current) gasoline
(2) 5–30 ppm sulfur (low-sulfur) RFG without oxygenate (future gasoline)
(3) Conventional (current) diesel
(4) Low-sulfur (LS) (future) diesel
(5) Crude naphtha
<i>NG-Based</i>
(6) CNG: NA NG
(7) CNG: NNA NG
(8) MeOH: NA NG <sup>a</sup>
(9) MeOH: NNA NG <sup>a</sup>
(10) FT naphtha: NA NG <sup>a</sup>
(11) FT naphtha: NNA NG <sup>a</sup>
(12) FTD: NA NG <sup>a</sup>
(13) FTD: NNA NG <sup>a</sup>
(14) G.H <sub>2</sub> – central plants: NA NG <sup>a</sup>
(15) G.H <sub>2</sub> – central plants: NNA NG <sup>a</sup>
(16) L.H <sub>2</sub> – central plants: NA NG <sup>a</sup>
(17) L.H <sub>2</sub> – central plants: NNA NG <sup>a</sup>
(18) G.H <sub>2</sub> – stations: NA NG <sup>a</sup>
(19) G.H <sub>2</sub> – stations: NNA NG <sup>a</sup>
(20) L.H <sub>2</sub> – stations: NA NG <sup>a</sup>
(21) L.H <sub>2</sub> – stations: NNA NG <sup>a</sup>
<i>Electricity-Based</i>
(22) Electricity: U.S. mix
(23) Electricity: CC turbines, NA NG-fired
<i>Electrolysis-Based</i> <sup>b</sup>
(24) G.H <sub>2</sub> electrolysis: U.S. mix
(25) G.H <sub>2</sub> electrolysis: CC turbine, NA NG
(26) L.H <sub>2</sub> electrolysis: U.S. mix
(27) L.H <sub>2</sub> electrolysis: CC turbine, NA NG
<i>Ethanol-Based</i>
(28) E100: corn (wet mill, market value) <sup>c</sup>
(29) E100: herbaceous cellulose <sup>c</sup>
(30) E100: woody cellulose <sup>c</sup>

<sup>a</sup> Without steam or electricity co-generation.

<sup>b</sup> In the case of electrolysis, water is converted to hydrogen and oxygen through the use of electricity, so both water and electricity are treated as feedstocks.

<sup>c</sup> Ethanol contains 5% gasoline as a denaturant.

## Total Energy Use

Total energy use from fuel production, i.e., WTT energy loss, is presented in Figure ES-1.1.<sup>1</sup> We found that petroleum-based fuels offer the lowest total energy use for each unit of energy delivered to vehicle tanks (see Figure ES-1.1, in which the tops and bottoms of the bars indicate the 80 and 20 percentiles, respectively). NG-based fuels (except CNG) generally use a large amount of total energy. The fuels with the highest energy use are L.H<sub>2</sub> (production in both central plants and refueling stations), G.H<sub>2</sub> and L.H<sub>2</sub> production via electrolysis, electricity generation, and cellulosic ethanol. L.H<sub>2</sub> suffers large efficiency losses during H<sub>2</sub> liquefaction. H<sub>2</sub> production via electrolysis suffers two large efficiency losses: electricity generation and H<sub>2</sub> production.

Total energy use by electricity generation is reduced when using NG-fired CC turbines rather than the U.S. electric generation mix because the average conversion efficiency of existing U.S. fossil fuel plants is 32–35%; the conversion efficiency of NG-fired CC turbines is over 50%.

Use of NNA NG for NG-based fuel production results in slightly higher total energy use than does use of NA NG, because transportation of liquid fuels to the United States consumes additional energy. In the cases of CNG, G.H<sub>2</sub>, and station-produced L.H<sub>2</sub>, the requirement for NG liquefaction for shipment of NNA gas sources to North America causes additional energy efficiency losses.

## Fossil Energy Use

Fossil fuels include petroleum, NG, and coal — the three major nonrenewable energy sources. Except for ethanol pathways, the patterns of fossil energy use are similar to those of total energy use (see Figure ES-1.2). For woody and herbaceous (cellulosic) ethanol pathways, the difference is attributable to the large amount of lignin burned in these ethanol plants. We accounted for the energy in lignin in calculating total energy use, but not in calculating fossil energy use. So fossil energy use is much lower than total energy use for the two cellulosic ethanol pathways.

For electricity generation and H<sub>2</sub> production via electrolysis, fossil energy use between the U.S. generation mix and NG-fired CC turbines is very similar because, while the U.S. generation mix has an overall conversion efficiency lower than that of CC turbines, some non-fossil fuel power plants under the U.S. average mix (such as nuclear and hydroelectric power plants) do not contribute to fossil energy use.

---

<sup>1</sup> Normally, results presented in the electrolysis and electricity pathways in GREET simulations include both energy losses from WTT and energy contained in the fuel delivered. Figures ES-1.1 and ES-1.2 present energy losses only.

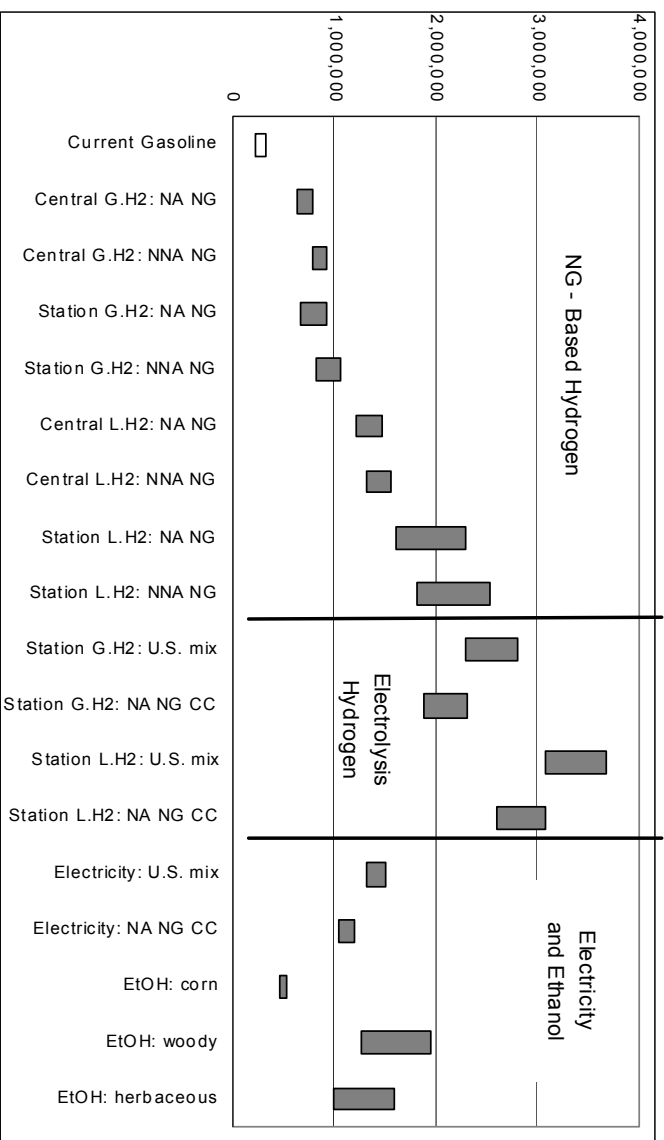
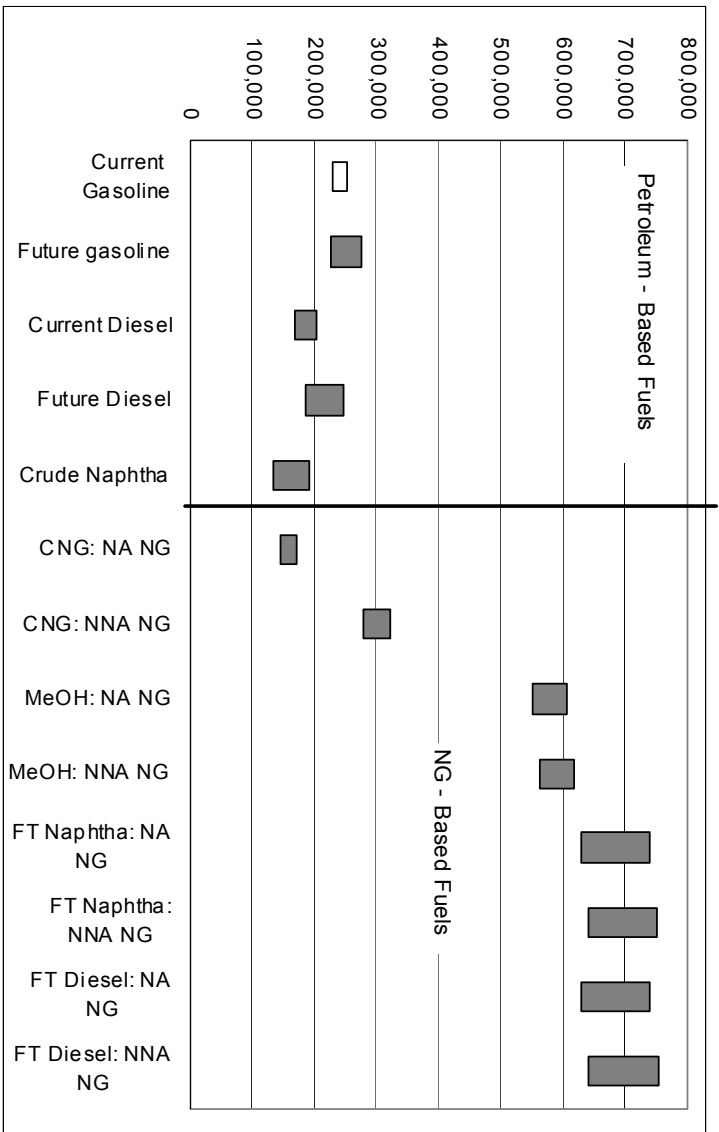


Figure ES-1.1 WTT Total Energy Use (Btu/mBtu) of fuel delivered to vehicle tanks)

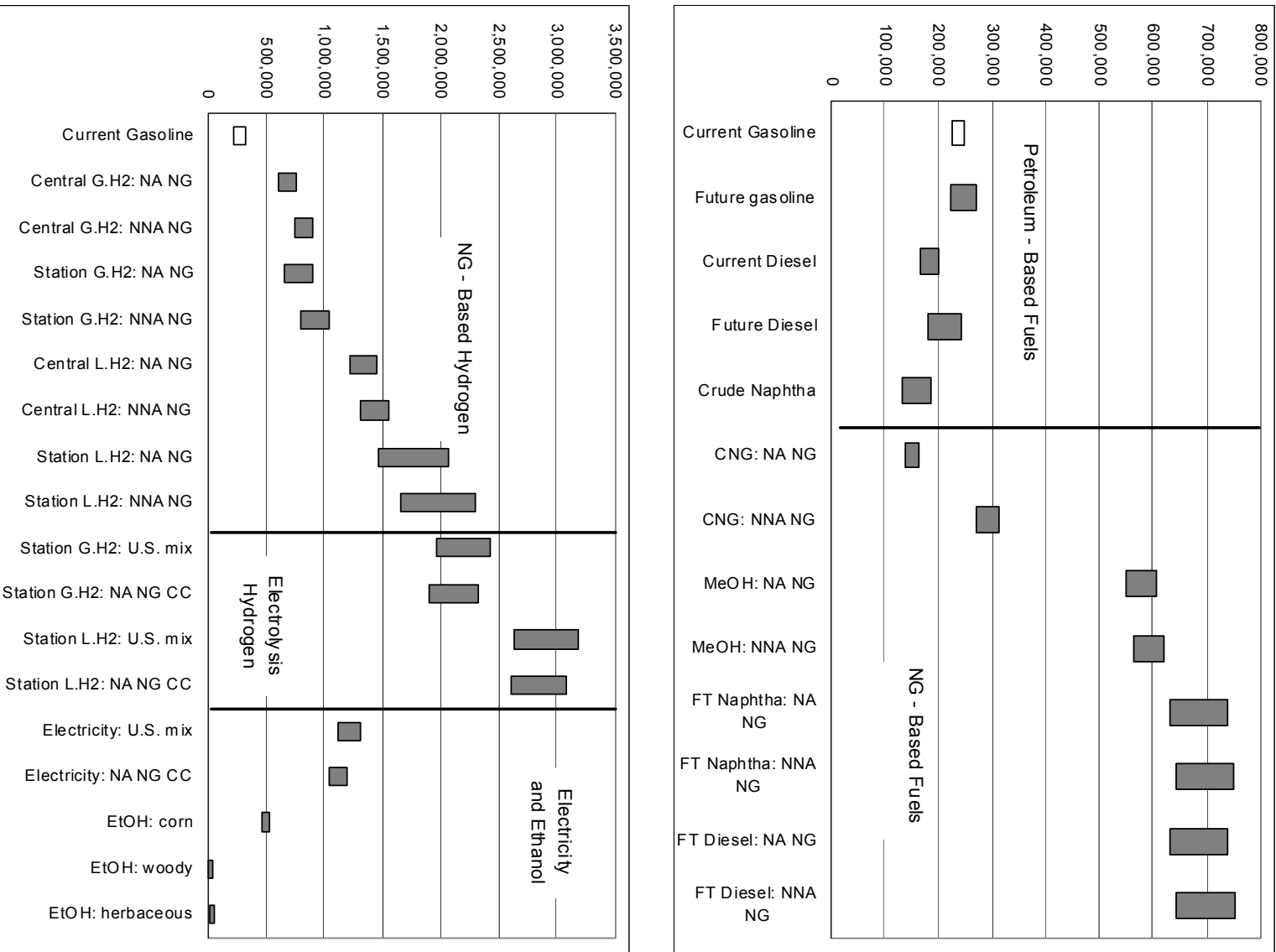


Figure ES-1.2 WTT Fossil Energy Use (Btu/mBtu) of fuel delivered to vehicle tanks)

## Petroleum Use

As expected, production of all petroleum-based fuels involves high petroleum use (see Figure ES-1.3). Methanol pathways have relatively high petroleum use because trucks and rails are used to transport a large quantity of methanol.

For electricity generation and H<sub>2</sub> production via electrolysis, we observed a large reduction in petroleum use from the U.S. average generation mix to NG-fired CC turbines because, under the U.S. generation mix, some (a small amount) electricity is generated by burning residual oil. In addition, mining and transportation of coal consume a significant amount of oil.

The high petroleum use for centrally produced G.H<sub>2</sub>, relative to station-produced G.H<sub>2</sub>, is attributable to the fact that the former is compressed in refueling stations with electric compressors only, while the latter is compressed by means of both electric and NG compressors. Electricity pathways also consume some petroleum.

The amount of petroleum used in the three ethanol pathways is similar to that used in the gasoline pathways because a large amount of diesel fuel is consumed during farming and during transportation of corn and cellulosic biomass.

## Greenhouse Gas Emissions

Figure ES-1.4 shows the sum of WTT CO<sub>2</sub>-equivalent emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O. Petroleum-based fuels and CNG produced from NA NG are associated with low WTT GHG emissions because of their high production efficiency. CNG from NNA NG has relatively high GHG emissions because of CH<sub>4</sub> emissions generated from liquid NG boiling-off and leakage during transportation (CH<sub>4</sub>, a GHG, is 21 times as potent as CO<sub>2</sub>). Methanol and FT fuels have high GHG emissions because of CO<sub>2</sub> emissions during fuel production that result from their low production efficiency relative to that of petroleum-based fuels.

All H<sub>2</sub> pathways have very high GHG emissions because all of the carbon in NG feedstock is removed during H<sub>2</sub> production, for which we did not assume carbon sequestration. For the electrolysis cases, CO<sub>2</sub> releases during electricity generation (attributable to fossil-fueled generation) are significant. L.H<sub>2</sub> production, electrolysis H<sub>2</sub> (both gaseous and liquid), and electricity generation have the highest GHG emissions. Relative to emissions from NG-fired CC turbine plants, there is a large increase in GHG emissions from the U.S. average electric generation mix, primarily because of the high GHG emissions from coal- and oil-fired electric power plants. Coal- and oil-fired plants contribute a large share of the U.S. average.

The three ethanol pathways have negative GHG emissions because of carbon uptake sequestration during growth of corn plants, trees, and grass. Corn ethanol has smaller negative GHG values because use of fossil fuels during corn farming and in ethanol plants offsets some of the CO<sub>2</sub> sequestered during growth of corn plants. All the carbon sequestered during biomass growth is released back to the air during combustion of ethanol in vehicles, which is accounted for in the integration of the well-to-tank and tank-to-wheel analyses in Part 3.

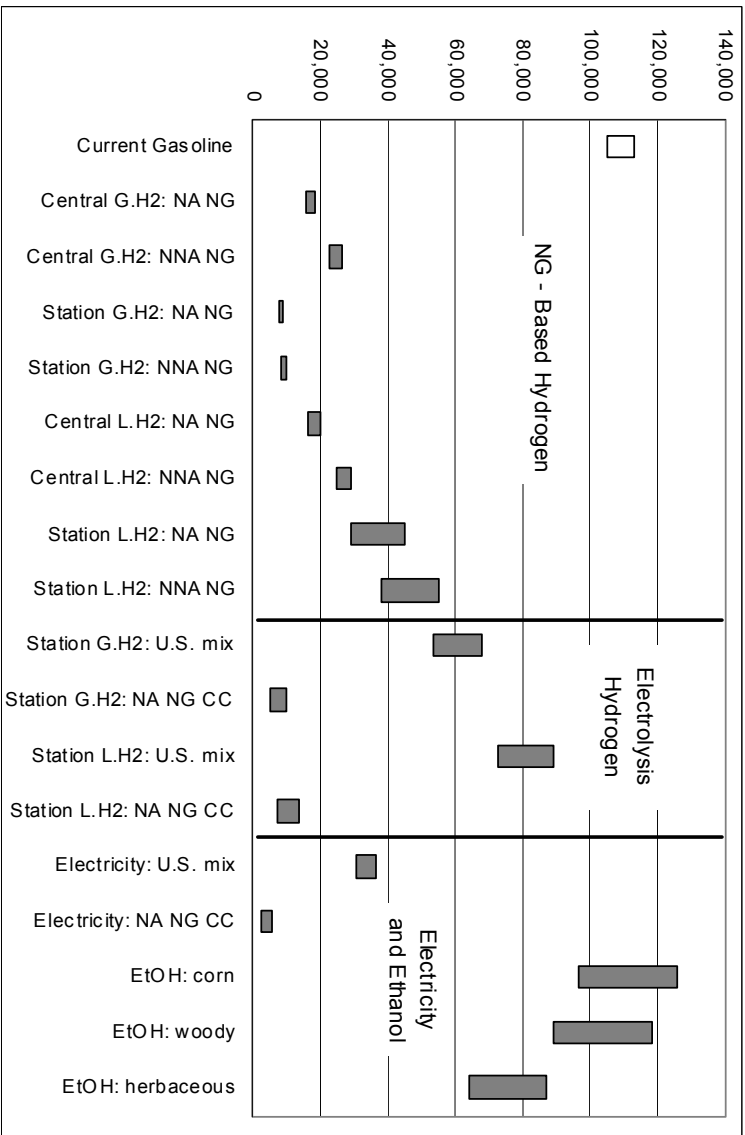
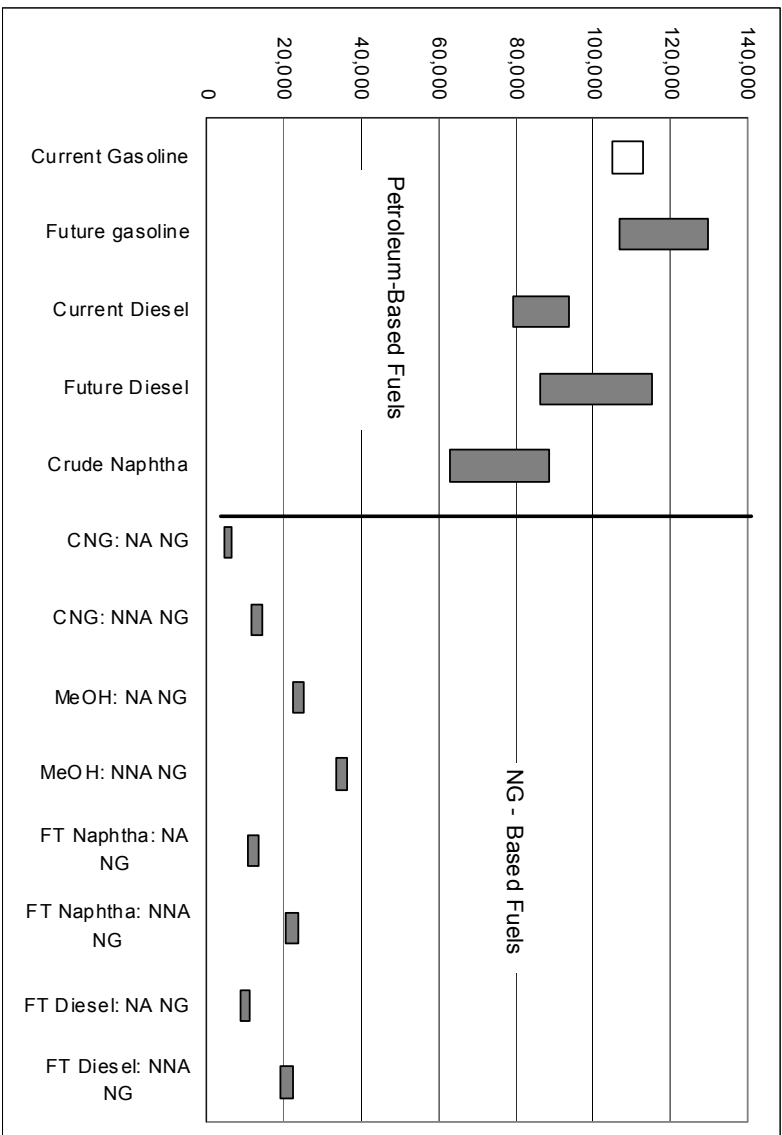


Figure ES-1.3 WTT Petroleum Use (Btu/mmBtu) of fuel delivered to vehicle tanks)

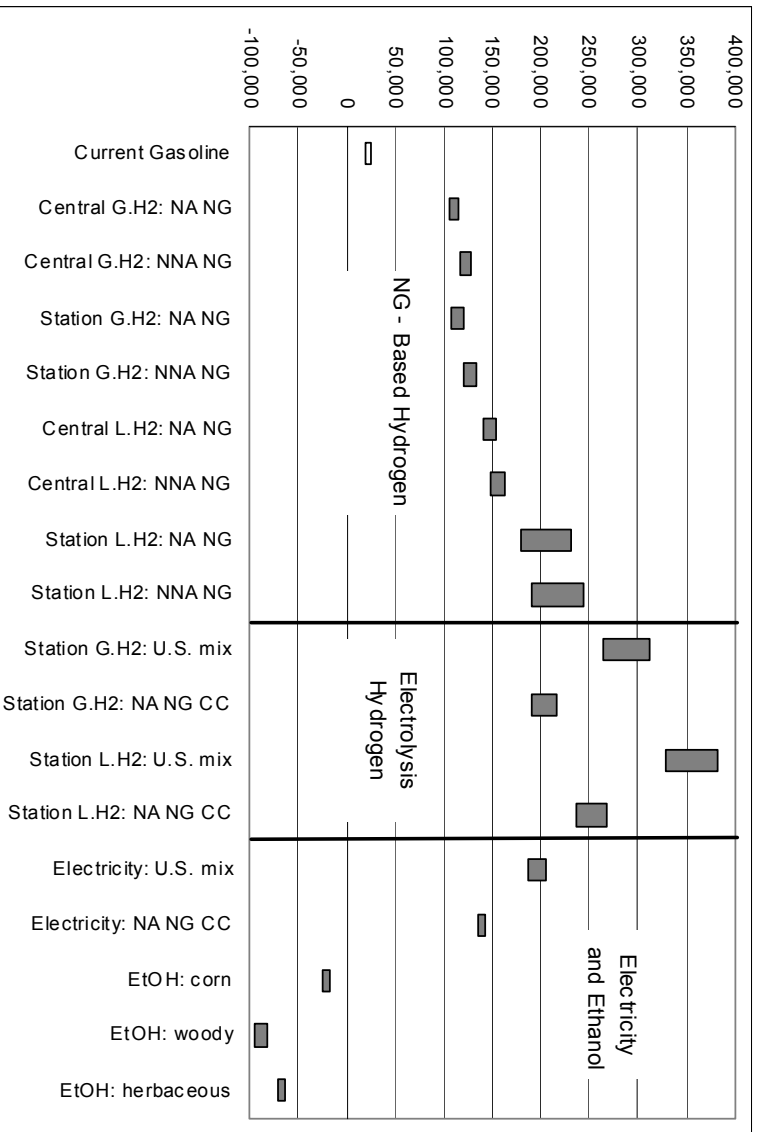
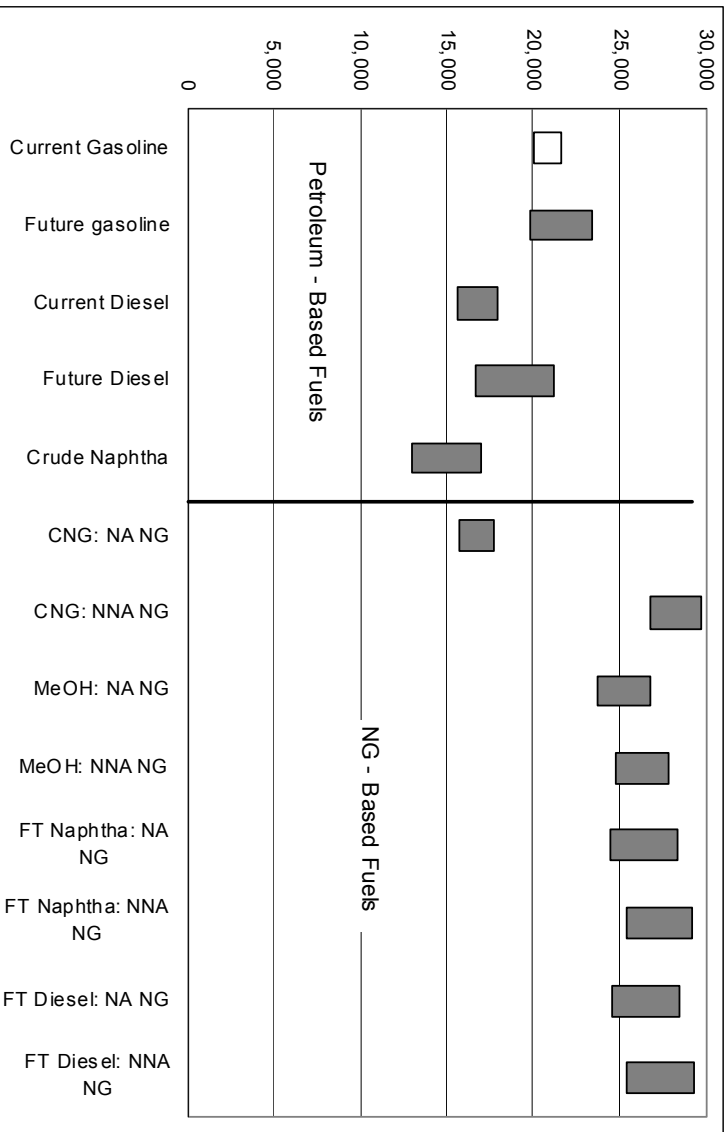


Figure ES-1.4 WTT GHG Emissions (g/mBtu) of fuel delivered to vehicle tanks)

## ES-1.4 Conclusions

Our WTT analysis resulted in the following conclusions. It is important to remember that WTT results are incomplete in evaluating fuel/propulsion systems. The systems must be evaluated on a WTW basis; this analysis is presented in Part 3 of this volume.

- *Total Energy Use.* For the same amount of energy delivered to the vehicle tank for each of the fuels evaluated in our study, petroleum-based fuels and CNG are subject to the lowest WTT energy losses. Methanol, FT naphtha, FTD, G.H<sub>2</sub> from NG, and corn-based ethanol are subject to moderate WTT energy losses. Liquid H<sub>2</sub> from NG, electrolysis H<sub>2</sub> (gaseous and liquid), electricity generation, and cellulosic ethanol are subject to large WTT energy losses.
- *Fossil Energy Use.* Fossil energy use — including petroleum, NG, and coal — follows patterns similar to those for total energy use, except for cellulosic ethanol. Although WTT total energy use of cellulosic ethanol production is high, its fossil energy use is low because cellulosic ethanol plants would burn lignin, a non-fossil energy, for needed heat.
- *Petroleum Use.* Production of all petroleum-based fuels requires a large amount of petroleum. Electrolysis H<sub>2</sub> (with the U.S. average electricity) and the three ethanol pathways consume an amount of petroleum about equal to that consumed by petroleum-based fuels. NG-based fuel pathways require small amounts of petroleum.
- *Greenhouse Gas Emissions.* Production of petroleum-based fuels and NG-based methanol, FT naphtha, and FTD results in a smaller amount of WTT GHG emissions than production of H<sub>2</sub> (gaseous and liquid) and electricity generation. WTT GHG emission values of the three ethanol pathways are negative because of carbon sequestration during growth of corn plants, trees, and grass.

Overall, our WTT analysis reveals that petroleum-based fuels have lower WTT total energy use than do non-petroleum-based fuels. L.H<sub>2</sub> production (in both central plants and refueling stations) and production of G.H<sub>2</sub> and L.H<sub>2</sub> via electrolysis can be energy-inefficient and can generate a large amount of WTT GHG emissions. Cellulosic ethanol, on the other hand, because it is produced from renewable sources, offers significant reductions in GHG emissions. The other fuel options examined here have moderate WTT energy and GHG emissions effects.



## **PART 2**

# **Tank-to-Wheel Energy Use for a North American Vehicle**

### **ES-2.1 Introduction**

The purpose of this portion of the study, conducted by GM, was to quantify the tank-to-wheel (TTW) energy use of advanced conventional and unconventional powertrain systems, focusing on technologies that are expected to be implemented in 2005–2010. We assessed these technologies on the basis of their potential for improving fuel economy while maintaining the vehicle performance demanded by North American consumers.

It is very important to recognize that certain major factors — specifically, packaging, transient response, cold-start performance, and cost — were not taken into consideration in this study. Therefore, the results should not be considered indicative of commercial viability; they should be viewed rather as an initial screening to identify configurations that are sufficiently promising to warrant more detailed studies and should be compared to one another on a relative, rather than an absolute, basis.

### **ES-2.2 Methodology**

We selected a full-size pickup truck as the baseline vehicle for this study. The GM proprietary Hybrid Powertrain Simulation Program (HPSP) vehicle simulation model was used to design and analyze each vehicle concept. With an extensive database of proprietary component maps, the HPSP can be used to model any conventional or advanced vehicle architecture or powertrain technology. We employed validated component characteristics to establish the fuel economy and energy required on the U.S. Environmental Protection Agency (EPA) urban and highway duty cycles.

### **Vehicle Architectures and Fuels**

The following vehicle architectures and fuels were included in our study:

1. Conventional (CONV) vehicle with spark ignition (SI) gasoline engine (baseline)
2. CONV vehicle with compression ignition direct injection (CIDI) diesel engine
3. CONV vehicle with SI E85 (a mixture of 85% ethanol and 15% gasoline by volume) engine
4. CONV vehicle with SI compressed natural gas (CNG) engine
5. Charge-sustaining (CS) parallel hybrid electric vehicle (HEV) with gasoline engine
6. CS parallel HEV with CIDI diesel engine
7. CS parallel HEV with SI E85 engine
8. Gasoline fuel processor (FP) fuel cell vehicle (FCV)
9. Gasoline FP fuel cell (FC) HEV
10. Methanol FP FCV

11. Methanol FP FC HEV
12. Ethanol FP FCV
13. Ethanol FP FC HEV
14. Gaseous hydrogen (G.H<sub>2</sub>)/liquid hydrogen (L.H<sub>2</sub>) FCV
15. G.H<sub>2</sub>/L.H<sub>2</sub> FC HEV

The baseline vehicle powertrain consisted of a gasoline engine and a 4-speed automatic transmission with a torque converter. The same transmission was used in the conventional architecture to run a diesel, an E85, and a CNG engine.

The parallel hybrid architecture selected for this study was an Input Power-Assist HEV with an electric drive at the transmission input, a 4-speed automatic transmission without a torque converter, and a full-size engine. We assumed that the electric drive could replace the torque converter and assist the engine for maximum vehicle acceleration performance. To maximize fuel economy, we implemented a charge-sustaining energy management strategy with fuel shutoff during standstill and deceleration and with battery launch at low acceleration demands. Gasoline, E85, and diesel engines were evaluated in this architecture.

We included fuel processor fuel cell systems in direct-drive and HEV powertrain architectures fueled by gasoline, methanol, and ethanol, as well as direct fuel cell and fuel cell HEV systems. The fuel processor and fuel cell HEV systems were also optimized with charge-sustaining energy management strategies.

### **Vehicle Simulation Model Input Data**

The baseline vehicle design parameters used in the study — such as mass and aerodynamic and rolling resistance coefficients — were based on a GM full-size pickup truck. The mass was adjusted for each vehicle's propulsion system independently; all other vehicle-level parameters were used consistently in all simulation models. We used the electric components based on validated maps for the electric drive system in the GM Precept (developed for the Partnership for a New Generation of Vehicles [PNGV]) and the nickel metal hydride (NiMH) battery technology.

Fuel cell stack and fuel processor component maps were based on small- to full-scale component data using GM proprietary modeling tools and validated on the GM HydroGen-1 FCV. The efficiency maps were based on a combination of current data and relatively near-term (one- to two-year timeline) projections. However, we recognize that significant development is required to scale up to the high power levels required for this application, specifically in the areas of thermal and water management, fuel processor dynamics, and startup.

### ***Performance Targets***

The performance targets shown in Figure ES-2.1 drove the powertrain sizing process. These metrics, evaluated through simulations, served as the design criteria for each vehicle concept. We determined vehicle mass on the basis of component sizes and optimized the powertrain operation on the driving cycles by implementing energy management and control strategies to achieve the

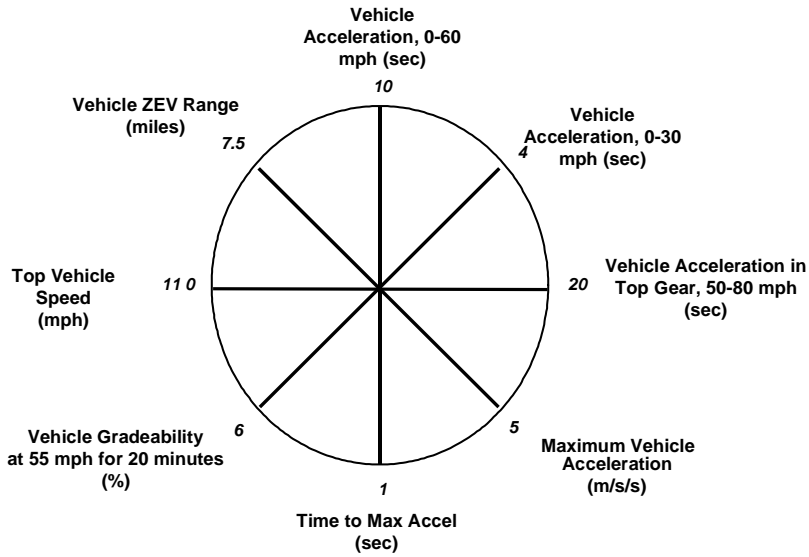


Figure ES-2.1 Performance Targets

maximum fuel economy for each vehicle concept. To provide more realistic and realizable fuel economy projections, we imposed constraints on component operation (e.g., engine, accessories, motors, batteries) to reflect vehicle driveability and comfort requirements. An additional requirement was that the vehicles suffer no performance degradation because of a lack of available energy from the battery (i.e., avoiding the so-called “turtle” effect). It should be noted that battery electric and charge-depleting battery electric HEVs were omitted from this detailed analysis because of their inability to meet overall vehicle range and other truck-related performance requirements.

### *Emissions Targets*

Emissions targets for all vehicles were based on Federal Tier 2 standards, which are divided into eight emission level categories (or bins) for the 2010 timeframe, when the Tier 2 standards will be completely phased in. We selected Bin 5 standards for all vehicles with internal combustion engines because they represent the fleet average. Bin 5 standards are also consistent with PNGV goals. Bin 2 standards (equivalent to Super Ultra-Low Emissions Vehicle [SULEV] II) were selected for the fuel processor/reformer FCVs, and Bin 1 (Zero-Emissions Vehicle [ZEV]) standards were selected for the hydrogen FCVs. Compliance with these standards has not been demonstrated; we assumed that considerable advances will be made in the technologies. The impact of emissions control on fuel consumption was included in this analysis.

### **ES-2.3 Results**

Table ES-2.1 presents the simulation results for each of the vehicle concepts included in this study. The only performance metric reported here is the 0–60 miles per hour (mph) performance time, which varies from vehicle to vehicle because the active constraints in each of these designs

Table ES-2.1 Fuel Economy and Performance Predictions

No.	Vehicle Configuration	Urban Fuel Economy (mpg GE) <sup>a</sup>	Highway Fuel Economy (mpg GE)	Complete Fuel Economy (mpg GE)	Gain in Fuel Economy over Baseline (%)	Tank to Wheels Efficiency (%)	Time (s to 60 mph)
1	Gasoline CONV SI	17.4	25.0	20.2	Baseline	16.7	7.9
2	Diesel CONV CIDI	20.2	30.4	23.8	18	19.4	9.2
3	E85 CONV SI	17.4	25.0	20.2	0	16.7	7.9
4	CNG CONV SI	17.0	24.7	19.8	-2	16.9	8.2
5	Gasoline SI HEV <sup>b, c</sup>	23.8	25.1	24.4	21	20.7	6.3
6	Diesel CIDI HEV <sup>c</sup>	29.1	29.8	29.4	46	24.6	7.2
7	E85 SI HEV <sup>c</sup>	23.8	25.1	24.4	21	20.7	6.3
8	Gasoline FP FCV	26.2	28.6	27.2	35	24.0	10.0
9	Gasoline FP FC HEV	31.9	28.5	30.2	50	27.3	9.9
10	Methanol FP FCV	28.8	32.4	30.3	50	26.6	9.4
11	Methanol FP FC HEV	35.8	33.0	34.5	71	31.1	9.8
12	Ethanol FP FCV	27.5	30.0	28.6	42	25.2	10.0
13	Ethanol FP FC HEV	33.5	29.9	31.8	57	28.7	9.9
14	G.H <sub>2</sub> FCV/ L.H <sub>2</sub> FCV	41.6	45.4	43.2	114	36.3	8.4
15	G.H <sub>2</sub> FC HEV/L.H <sub>2</sub> FC HEV	51.5	44.5	48.1	138	41.4	10.0

<sup>a</sup> GE = gasoline equivalent.

<sup>b</sup> All HEVs are charge sustaining.

<sup>c</sup> Parallel.

were maximum launch acceleration and top vehicle speed. Each of these concepts met those requirements, so the comparison of fuel economy and 0–60 mph acceleration time reported here can now be made on an “equal-performance” basis.

The **Tank-to-Wheel Efficiency** (column 6 in Table ES-2.1) is a measure of the overall efficiency of the vehicle system, defined as:

$$\text{Tank to Wheels Eff} = \frac{\text{Energy Output}}{\text{Energy Input}}$$

where the energy output of the drive system is the total amount of energy required to overcome the rolling resistance, aerodynamic, and inertial (acceleration) load over the driving cycle:

$$\text{Energy Output} = \sum [(\text{Roll Resist}) + (\text{Aero Resist}) + (Ma)] * V * \Delta t = \text{Energy @ Wheels}$$

and the total amount of energy input to the system is defined as:

$$\text{Energy Input} = \text{Energy Value of Fuel Consumed}$$

The vehicle fuel economy (on a gasoline-equivalent basis) and expected emission levels are summarized in Table ES-2.2. The fuel economy from Table ES-2.1 is shown here as the “50” entry — meaning that there is a 50% likelihood that the fuel economy may be higher (because of presently unexpected technological advances) or lower (because of unforeseen difficulties). The

Table ES-2.2 Overview of Vehicle Configurations

No.	Vehicle Configuration	Fuel Economy (mpg GE)			Emission Standard <sup>d</sup>
		20 percentile <sup>a</sup>	50 percentile <sup>b</sup>	80 percentile <sup>c</sup>	
1	Gasoline CONV SI (baseline)	19.2	20.2	26.3	Tier 2 Bin 5
2	Diesel CONV CIDI	22.0	23.8	30.9	"
3	E85 CONV SI	19.2	20.2	26.3	"
4	CNG CONV SI	18.8	19.8	25.7	"
5	Gasoline SI HEV <sup>e, f</sup>	22.2	24.4	30.5	"
6	Diesel CIDI HEV <sup>f</sup>	26.7	29.4	36.8	"
7	E85 SI HEV <sup>f</sup>	22.2	24.4	30.5	"
8	Gasoline FP FCV	23.7	27.2	32.6	Tier 2 Bin 2
9	Gasoline FP FC HEV	26.2	30.2	36.2	"
10	Methanol FP FCV	26.3	30.3	36.4	"
11	Methanol FP FC HEV	30.0	34.5	41.4	"
12	Ethanol FP FCV	24.9	28.6	34.3	"
13	Ethanol FP FC HEV	27.6	31.8	38.2	"
14	G.H <sub>2</sub> FCV/L.H <sub>2</sub> FCV	39.3	43.2	47.5	Tier 2 Bin 1
15	G.H <sub>2</sub> FC HEV/L.H <sub>2</sub> FC HEV	43.7	48.1	52.9	"

<sup>a</sup> 20% likelihood mpg lower.

<sup>b</sup> Equally likely above or below.

<sup>c</sup> 20% likelihood mpg higher.

<sup>d</sup> Federal standards: Tier 2 Bin 5, Tier 2 Bin 2 (SULEV II), Tier 2 Bin 1 (ZEV).

<sup>e</sup> All HEVs are charge sustaining.

<sup>f</sup> Parallel.

columns labeled 20 and 80 denote estimates for which the fuel economy has only a 20% likelihood of being below the lower bound and a 20% likelihood of being above the upper bound, respectively.

## ES-2.4 Conclusions

On the basis of the results listed in Table ES-2.1, GM made the following observations:

- FC systems use less energy than conventional powertrains because of the intrinsically higher efficiency of the FC stack.
- Hybrid systems show consistently higher fuel economy than conventional vehicles because of regenerative braking and engine-off during idle and coast periods (thus, the improvements occur mostly on the urban driving schedule).
- In the case of the FC and FP systems, the gains resulting from hybridization are lower because the “engine-off” mode is present in both systems.

- Hydrogen-based FC vehicles exhibit significantly higher fuel economy than those that employ a FP.

Again, important factors such as packaging, cold start, transient response, and cost were not considered within the scope of this work. This portion of the study addresses TTW efficiencies; when combined with the WTT analysis, it will provide the full-cycle WTW efficiencies.

## PART 3

### Well-to-Wheel Fuel/Vehicle Pathway Integration

#### ES-3.1 Introduction

Part 1 of this report presented energy use and greenhouse gas (GHG) emissions on a well-to-tank (WTT) basis for 75 fuel pathways analyzed by Argonne National Laboratory. In many cases, Argonne found that the results for various pathways were so similar that it was possible to reduce the number of the pathways by selecting a “representative” fuel within a fuel category. This was true for multiple gasoline and diesel pathways. Argonne pared its results down to 30 representative fuel pathways. For Part 2, researchers from GM quantified the energy use of 15 advanced powertrain systems (tank-to-wheel [TTW] analysis) (see Table ES-2.2).

This part of the report combines the results of Parts 1 and 2 into an analysis of well-to-wheel (WTW) efficiency and GHG emissions — providing a complete view of these alternative fuel/vehicle pathways. The first part of the Methodology section (Part A) describes the process and criteria used to reduce the 30 representative pathways selected in Part 1 to 13 pathways. The second part of the Methodology section (Part B) describes the process used to combine these 13 fuel pathways with the 15 vehicle pathways identified in Part 2 to obtain 27 fuel/vehicle combinations for further analysis of their WTW energy use and GHG emissions characteristics.

#### ES-3.2 Methodology

##### Part A: Selection of Well-to-Tank Pathways

In addition to the 30 fuel pathways identified in the WTT portion of the study, two E85 pathways were added to facilitate analysis of the two E85-fueled vehicles analyzed in Part 2 (see Table ES-2.2). Fuel use and GHG emissions information for the two E85 pathways (corn and herbaceous) is contained in Appendix B in Volume 3 of this report series. The 32 pathways were reduced to 13 on the basis of two criteria: resource availability and energy use. Two other criteria that can be used for screening fuel/technology pathways — economic/investment issues and technological hurdles — were not considered in this study, but may be addressed in follow-on work. The two electricity fuel pathways were not considered because neither battery-powered electric vehicles nor charge-depleting hybrid electric vehicles (HEVs) were considered (for reasons outlined in Part 2).

##### *Resource Availability*

During the integration analysis, we excluded 12 of the 30 fuel pathways selected in Part 1 on the basis of resource availability — the pathways involving North American natural gas (NG) (eight NG- and two electrolysis-based) and corn-based ethanol.

*North American NG-Based Pathways.* The current and potential North American NG resource base appears to be insufficient to supply wide-scale use of NG for transportation fuels in the U.S. market. Three recent studies cited in our report suggest that rapid incremental NG demand in the

United States, in particular for electricity generation, will put pressure on the North American gas supply, even without a significant transportation demand component. In order to supply a significant share of the transportation fuel market, NG would have to be obtained overseas eventually, primarily from Russia, Iran, and other Middle East nations.

Consistent with these studies, our assessment of NG resources is that high-volume, NG-based, light-duty fuel pathways would have to rely on non-North-American NG; as a result, we considered examination of non-North-American NG-based pathways to be far more feasible than North American NG-based pathways and dropped the latter from our analysis.

*Corn Ethanol-Based Pathways.* The current use of ethanol as a transportation fuel in the United States is about 1.5 billion gallons per year — equivalent to about 1 billion gallons of gasoline (on an energy basis). Today, the United States consumes in excess of 100 billion gallons of gasoline per year.

Recent U.S. Department of Agriculture (USDA) simulations show that production of corn-based ethanol could be doubled — to about 3 billion gallons per year — without drastic impacts on the animal feed and food markets.

Although the production of corn ethanol could be doubled in ten years, the amount produced still would be adequate to supply only the ethanol blend market. It does not appear that the supply of corn-based ethanol will be adequate for use in high-volume transportation applications; as a result, we eliminated corn-based ethanol from the analysis.

The economics of cellulosic ethanol are not currently competitive with those of gasoline. Further, it has yet to be determined whether cellulosic biomass faces resource availability constraints. Also, some experts have concluded that the technology for producing biofuels will have to be significantly improved to make this pathway viable. Because of the uncertainty here, we carried this pathway along to the WTW analysis.

### ***Energy Efficiency***

We eliminated two fuel pathways on the basis of energy inefficiency. NG-based liquid hydrogen (L.H<sub>2</sub>) produced at stations is significantly less efficient than L.H<sub>2</sub> produced at central plants. The low end of the distribution of efficiency estimates for L.H<sub>2</sub> produced at central plants is higher than the highest value of the distribution for L.H<sub>2</sub> produced at refueling stations — there is no overlap in the percentile range. Because the two candidate fuels are used in the same fuel cell vehicle (FCV), we eliminated the less efficient of the pair, L.H<sub>2</sub> produced at stations.

All four electrolysis pathways presented in Part 1 would normally be excluded because they do not offer acceptable energy efficiency and GHG emissions characteristics. The WTW efficiencies for several competing NG-based vehicles are already higher than the efficiencies in the electrolysis pathways based solely upon the WTT stage (Part 1 of the study). Many proponents of electrolysis, however, point to its potential use in the transition to high-volume H<sub>2</sub> FCV applications. For this reason, we exclude only the less efficient of the electrolysis pathways, L.H<sub>2</sub>.

Fischer-Tropsch (FT) naphtha, a candidate reformer fuel for FCVs, is surpassed by crude naphtha on a WTT efficiency basis because both candidate fuels can be used in the same vehicle. Likewise, Fischer-Tropsch diesel (FTD) offers lower energy efficiency than crude-based diesel. However, because the FT fuels are of interest to a broad range of analysts and may have other benefits (e.g., criteria pollutants) not captured in this analysis, they have not been eliminated from consideration.

Predicated on the screening logic described above, we pared the number of fuel pathways considered to the 13 listed in Table ES-3.1. These fuels, taken together with the 15 vehicles considered in Part 2, yield the 27 fuel/vehicle pathways analyzed on a WTW basis in this study.



## Part B: Well-to-Wheel Integration

The GM WTW integration modeling process takes stochastic outputs from Parts 1 and 2 for efficiency and GHG emissions and combines them into complete WTW results (see Figure ES-3.1).

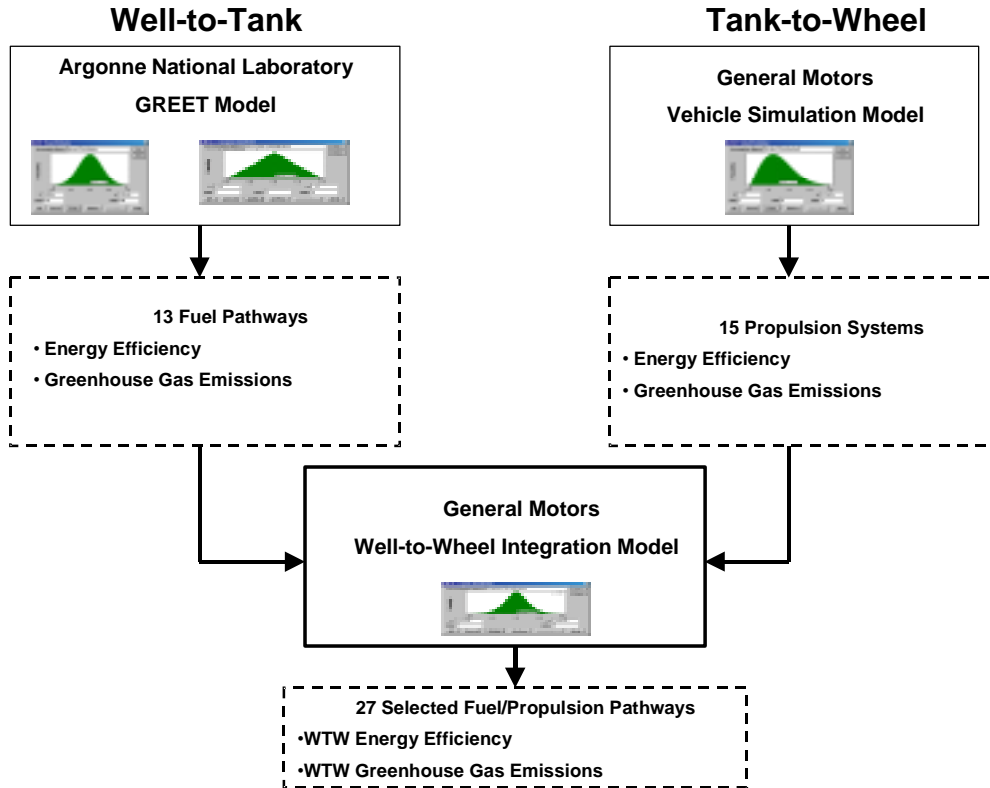


Figure ES-3.1 WTW Integration Process

### *Well-to-Tank (Part 1)*

The GREET model results for the WTT energy use are presented as a probability distribution for energy use and GHG emissions for each fuel pathway. For the integration analysis, these results were fitted to a set of continuous distributions using well-known goodness-of-fit tests. For each of the resulting 26 distributions (energy use and GHG emission for 13 fuels), the logistic distribution was the best-fitting distribution.

### *Tank-to-Wheel (Part 2)*

Part 2 of this study provides 20, 50, and 80 percentile fuel use estimates (in mpg gasoline equivalent) for 15 fuel/vehicle configurations (see Table ES-2.2). During the WTW integration process, each of these 20-50-80 percentiles was used to fit a Weibull distribution to each of the 15 fuel/vehicle configurations.

The CO<sub>2</sub> component of the GHGs contributed by the vehicle are related to the carbon content of the fuel because it is all combusted in the vehicle. Of course, there is no carbon in hydrogen fuels, so there is no CO<sub>2</sub> contribution from FCVs powered by H<sub>2</sub>. GHGs other than CO<sub>2</sub> were considered negligible at the vehicle level for the other fuel/vehicle pathways.

### ***Well-to-Wheel (Part 3)***

The WTT total energy use per mile for each fuel was computed on the basis of information provided in Part 1; vehicle fuel use per mile was computed from data provided in Part 2. Once the distributions from Parts 1 and 2 were developed, the joint probability distributions for WTW energy use and GHG emissions were simulated by using the Monte Carlo method. For example, 20, 50, and 80 percentiles for both energy use and GHG emissions are shown in the figures in Section ES-3.3. The end points of the bars in the figures are the 80 and 20 percentile points: the 50 percentile points of the various pathways are indicated by diamonds.

## **ES-3.3 Results**

The analysis that follows addresses the 27 fuel/vehicle pathways listed in Table ES-3.2 in terms of their total system energy use (in Btu/mi) and GHG emissions (in g/mi). Spark-ignition (SI) and compression-ignition direct-injection (CIDI) conventional and hybrid fuel/vehicle pathways are evaluated first, followed by HEV fuel cell vehicles, and non-hybridized FCVs. This section ends with a comparison of those pathways that appear to offer superior performance on the basis of energy use (Btu/mi) and GHG emissions (g/mi). It is very important to note that other factors (e.g., criteria pollutants, incremental fuel and vehicle costs) were not considered as part of our study.

### **Conventional and Hybrid Fuel/Vehicle Pathways**

Figure ES-3.2 shows the total system energy use (in Btu/mi) for conventional and hybrid fuel/vehicle pathways powered by SI or CIDI engines.

The figure shows that:

- The diesel CIDI HEV uses the least amount of total energy.
- The diesel CIDI conventional vehicle and the gasoline SI HEV yield roughly the same total system energy use.
- The CNG SI conventional vehicles offer no energy use benefit over gasoline conventional vehicles.
- FTD, even in a comparable technology vehicle (CONV or HEV), is more energy-intensive than crude-based diesel.
- There is considerable opportunity for energy use improvement over the 50 percentile estimates for all pathways, including the baseline gasoline SI conventional vehicle.
- Hybridizing these vehicles reduces energy use by over 15% (see Volume 2, Part 3B).

Table ES-3.2 Fuel/Vehicle Pathways Analyzed

No.	Fuel Pathway	Vehicle Configuration	Fuel Abbreviation	Vehicle Abbreviation
1	Low-sulfur gasoline	Gasoline CONV SI	GASO	SI CONV
2	Low-sulfur diesel	Diesel CONV CIDI	DIESEL	CIDI CONV
3	FTD: NNA NG	Diesel CONV CIDI	FTD	CIDI CONV
4	E85: herbaceous cellulose	E85 CONV SI	HE85	SI CONV
5	CNG: NNA NG	CNG CONV SI	CNG	SI CONV
6	Low-sulfur gasoline	Gasoline SI HEV <sup>a,b</sup>	GASO	SI HEV
7	Low-sulfur diesel	Diesel CIDI HEV <sup>b</sup>	DIESEL	CIDI HEV
8	FTD: NNA NG	Diesel CIDI HEV <sup>b</sup>	FTD	CIDI HEV
9	E85: herbaceous cellulose	E85 SI HEV <sup>b</sup>	HE85	SI HEV
10	Low-sulfur gasoline	Gasoline FP FCV	GASO	FP FCV
11	Crude naphtha	Gasoline FP FCV	NAP	FP FCV
12	FT naphtha: NNA NG	Gasoline FP FCV	FT NAP	FP FCV
13	Low-sulfur gasoline	Gasoline FP FC HEV	GASO	FP FC HEV
14	Crude naphtha	Gasoline FP FC HEV	NAP	FP FC HEV
15	FT naphtha: NNA NG	Gasoline FP FC HEV	FT NAP	FP FC HEV
16	MeOH: NNA NG	Methanol FP FCV	MEOH	FP FCV
17	MeOH: NNA NG	Methanol FP FC HEV	MEOH	FP FC HEV
18	E100: herbaceous cellulose	Ethanol FP FCV	HE100	FP FCV
19	E100: herbaceous cellulose	Ethanol FP FC HEV	HE100	FP FC HEV
20	G.H <sub>2</sub> – stations: NNA NG	G.H <sub>2</sub> FCV	G.H <sub>2</sub> RS	FCV
21	G.H <sub>2</sub> – stations: NNA NG	G.H <sub>2</sub> FC HEV	G.H <sub>2</sub> RS	FC HEV
22	G.H <sub>2</sub> – central plants: NNA NG	G.H <sub>2</sub> FCV	G.H <sub>2</sub> CP	FCV
23	G.H <sub>2</sub> – central plants: NNA NG	G.H <sub>2</sub> FC HEV	G.H <sub>2</sub> CP	FC HEV
24	L.H <sub>2</sub> – central plants: NNA NG	L.H <sub>2</sub> FCV	L.H <sub>2</sub>	FCV
25	L.H <sub>2</sub> – central plants: NNA NG	L.H <sub>2</sub> FC HEV	L.H <sub>2</sub>	FC HEV
26	G.H <sub>2</sub> electrolysis: U.S. mix	G.H <sub>2</sub> FCV	G.H <sub>2</sub> EL	FCV
27	G.H <sub>2</sub> electrolysis: U.S. mix	G.H <sub>2</sub> FC HEV	G.H <sub>2</sub> EL	FC HEV

<sup>a</sup> All HEVs are charge sustaining.

<sup>b</sup> Parallel.

Well-to-Wheel Total System Energy Use  
Conventional & Hybrid Fuel/Vehicle Pathways  
(SI & CIDI)

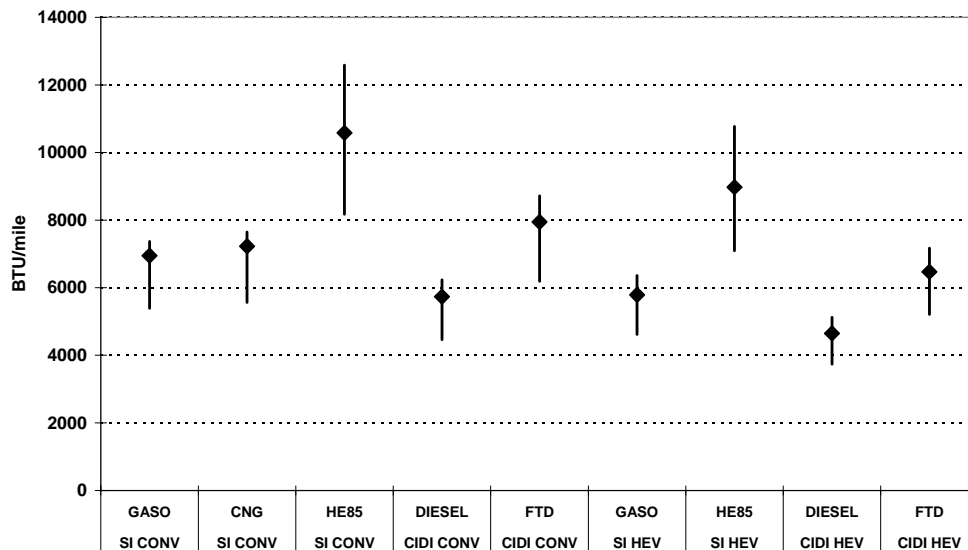


Figure ES-3.2 WTW Total System Energy Use: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI)

From the standpoint of GHG emissions, as shown in Figure ES-3.3:

- The herbaceous E85 (HE85)-fueled vehicles have by far the lowest GHG emissions.
- Among the other vehicles, the diesel CIDI HEV yields the largest potential GHG benefit.
- The CNG SI conventional vehicle generates somewhat higher GHG emissions than the diesel CIDI conventional vehicle.
- The FTD CIDI conventional vehicle and HEV have slightly higher GHG emissions than the crude oil-based diesel CIDI conventional vehicle and HEV.
- Once again, the asymmetric distributions indicate considerable opportunity for new-technology-based improvements in GHG emissions for all vehicles.

Well-to-Wheel GHG Emissions  
Conventional & Hybrid Fuel/Vehicle Pathways  
(SI & CIDI)

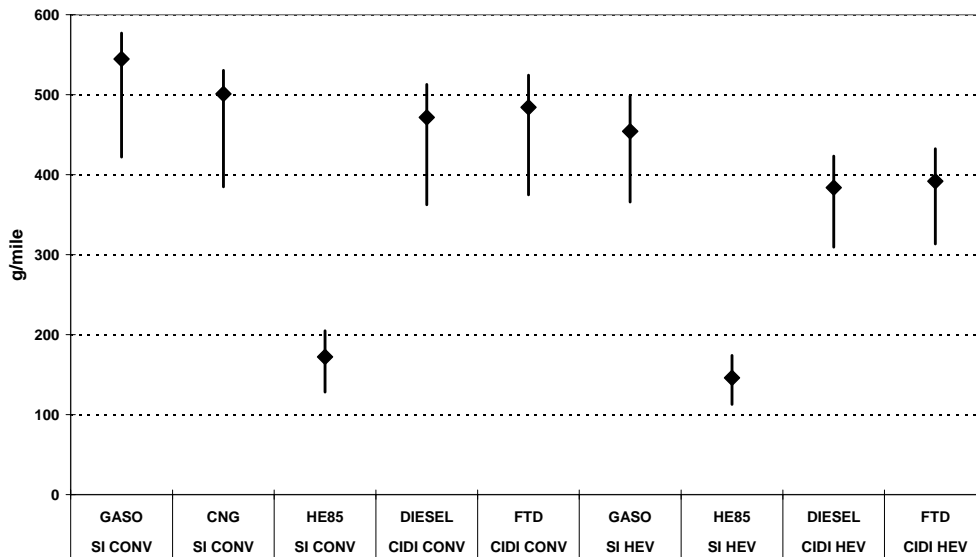


Figure ES-3.3 WTW GHG Emissions: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI)

### Fuel/Hybrid and Non-Hybrid FCV Pathways

Nine different fuel/FCV combinations were analyzed in terms of their total system energy use and GHG emissions performance. Because the hybrid versions of these FCVs show an approximately 10% advantage (see Volume 2, Part 3B) over their non-hybrid counterparts in terms of total systems energy use, their analysis results are discussed here.

As illustrated in Figure ES-3.4:

- Gasoline and naphtha fuel processor-based FC HEVs, as well as H<sub>2</sub>-fueled FC HEVs for which the H<sub>2</sub> is produced centrally or at the retail site from non-North-American NG, all offer the best total system energy use.
- Hybridized FCVs fueled by L.H<sub>2</sub> and FT naphtha involve higher energy consumption; MeOH use results in higher energy consumption, but is not statistically<sup>2</sup> different from gasoline, crude naphtha, or G.H<sub>2</sub>.
- The electrolysis-based H<sub>2</sub> FC HEV uses significantly more energy than the other pathways.

<sup>2</sup> Considering two pathways, if the 50-percentile (P<sub>50</sub>) point of one pathway lies outside the 20–80 percentile (P<sub>20</sub>–P<sub>80</sub>) range of a second pathway, the P<sub>50</sub> points of the two pathways are deemed to be statistically different.

- The HE100-based pathway fares poorly on total system energy use, although a significant portion of the energy used is renewable.

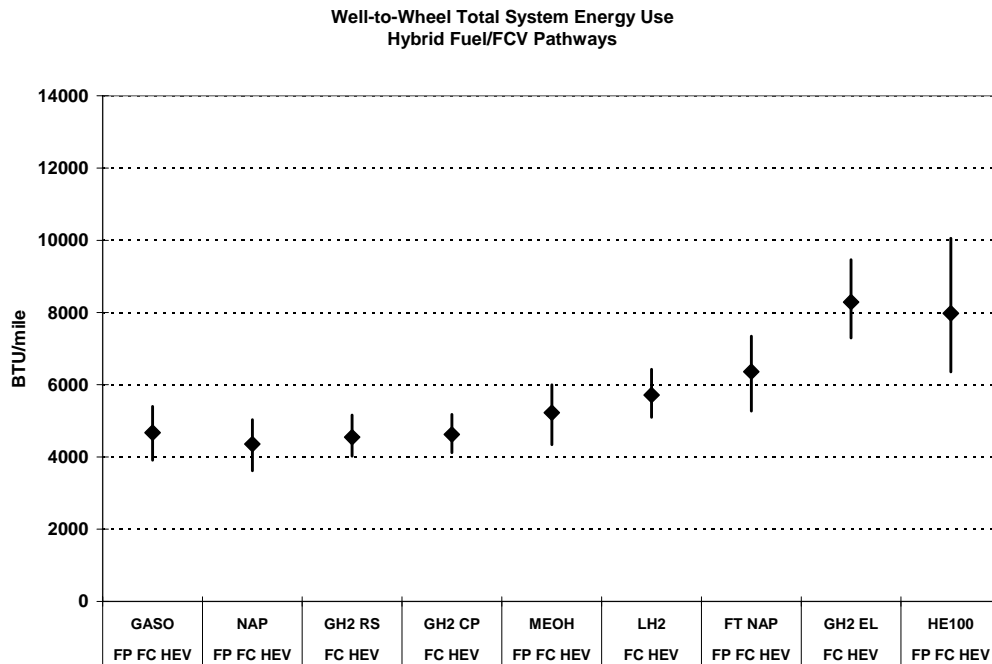


Figure ES-3.4 WTW Total System Energy Use: Hybrid Fuel/FCV Pathways

As shown in Figure ES-3.5, from a GHG standpoint, the analysis suggests:

- As expected, the HE100 FP FC HEV emits by far the lowest amount of GHGs.
- GHG emissions from the next lowest emitters, the two H<sub>2</sub> FC HEVs, are statistically the same.
- The naphtha and methanol FP FC HEVs are basically tied for third place.
- Gasoline FP FC HEVs and L.H<sub>2</sub> FC HEVs are statistically tied for fourth place.
- The G.H<sub>2</sub> electrolysis FC HEV pathways have the highest GHG emissions.

Figures ES-3.6 and ES-3.7 show non-hybridized versions of the pathways shown in Figures ES-3.4 and ES-3.5. In all cases, the energy use and GHG emissions are higher than for the corresponding hybridized FCVs. A quick review reveals that all of the rank order findings discussed above for the hybrid FCVs also apply to non-HEV versions.

Well-to-Wheel GHG Emissions  
Hybrid Fuel/FCV Pathways

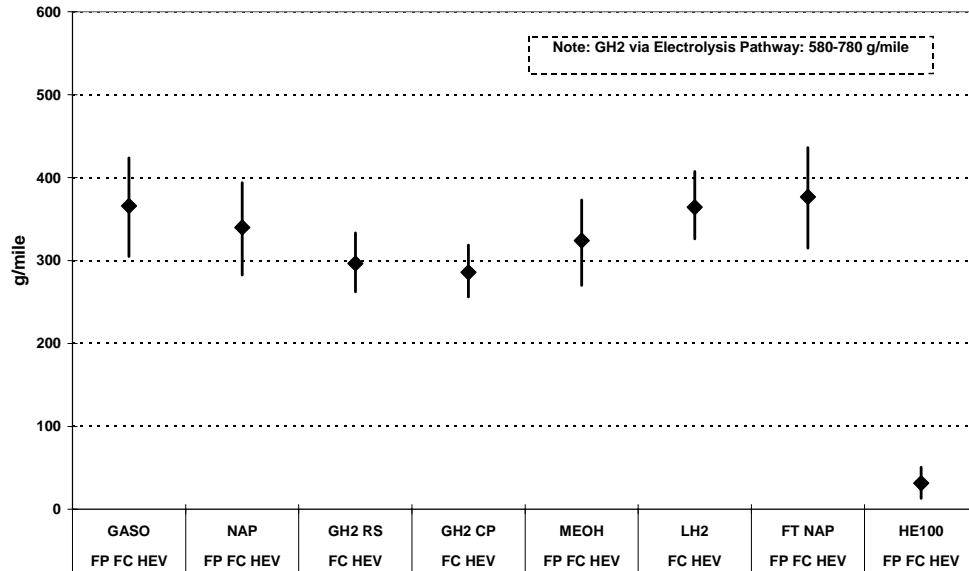


Figure ES-3.5 WTW GHG Emissions: Hybrid Fuel/FCV Pathways

Well-to-Wheels Total System Energy Use  
Non-Hybrid Fuel/FCV Pathways

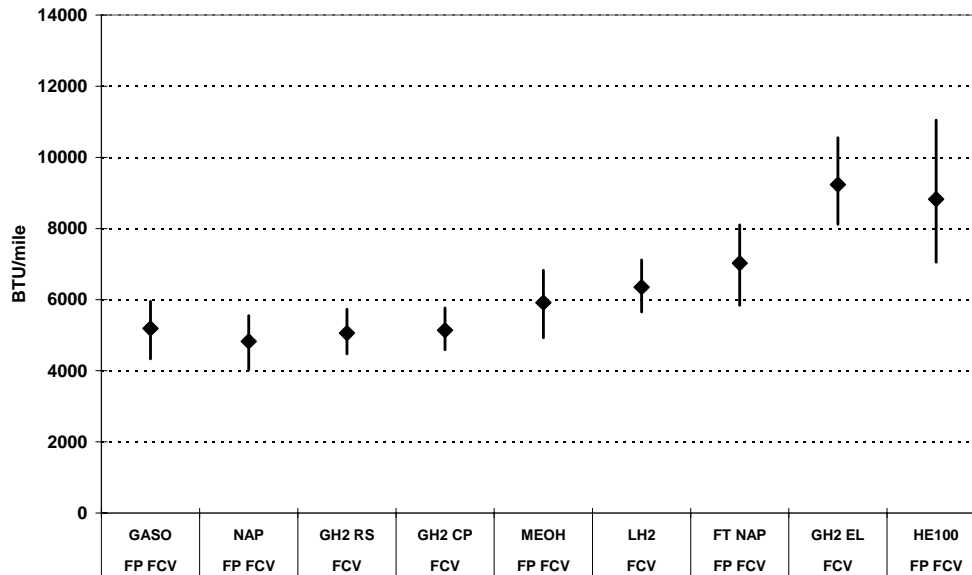


Figure ES-3.6 WTW Total System Energy Use: Non-Hybrid Fuel/FCV Pathways

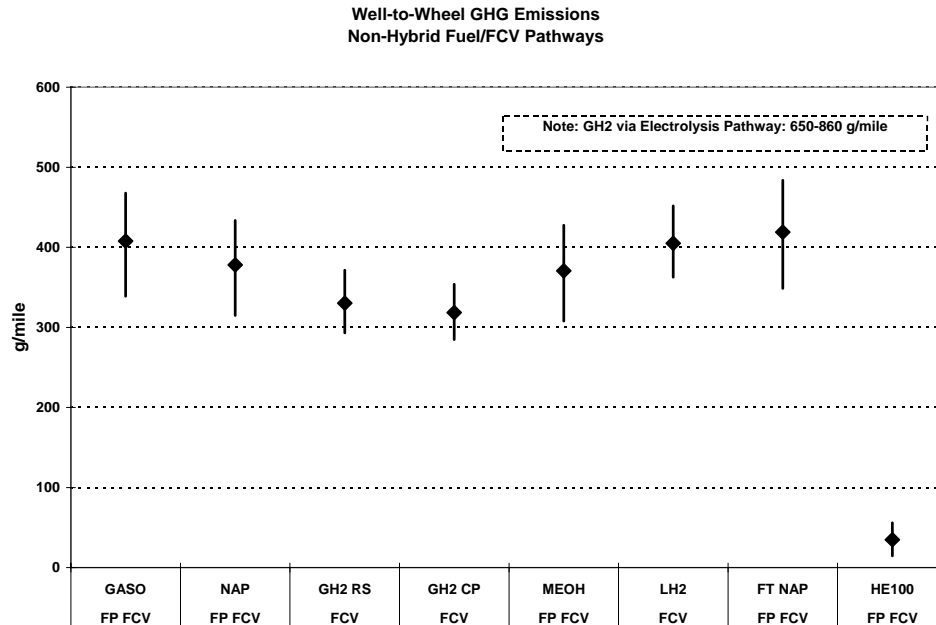


Figure ES-3.7 WTW GHG Emissions: Non-Hybrid Fuel/FCV Pathways

## ES-3.4 Conclusions

### Fuel Use

Key findings include the following:

- Figure ES-3.8 summarizes our results for total system energy use for selected pathways. From a statistical standpoint, the diesel CIDI HEV, gasoline and naphtha FP FC HEVs, as well as the two H<sub>2</sub> FC HEVs (represented by the G.H<sub>2</sub> [refueling station] FC HEV only in the figures) are all the lowest energy-consuming pathways.
- Figure ES-3.9 illustrates an interesting finding: all of the crude oil-based selected pathways have WTT energy loss shares of roughly 25% or less. The H<sub>2</sub> FC HEV share is over 60%; the MeOH FP FC HEV share is about 50%. A significant fraction of the WTT energy use of ethanol is renewable — over 90% for HE100.

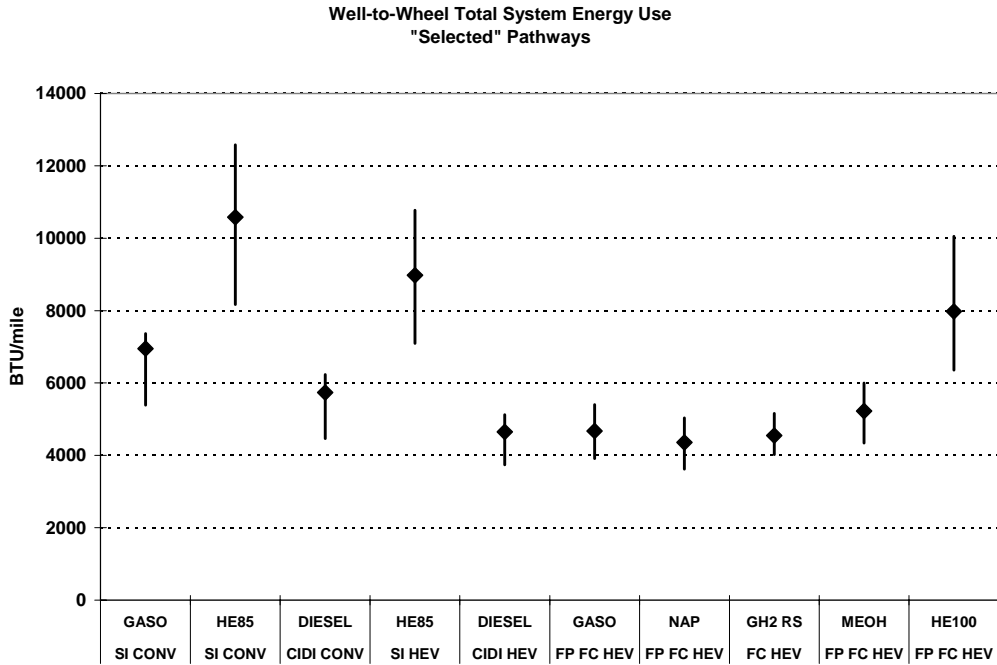


Figure ES-3.8 WTW Total System Energy Use: "Selected" Fuel/Vehicle Pathways

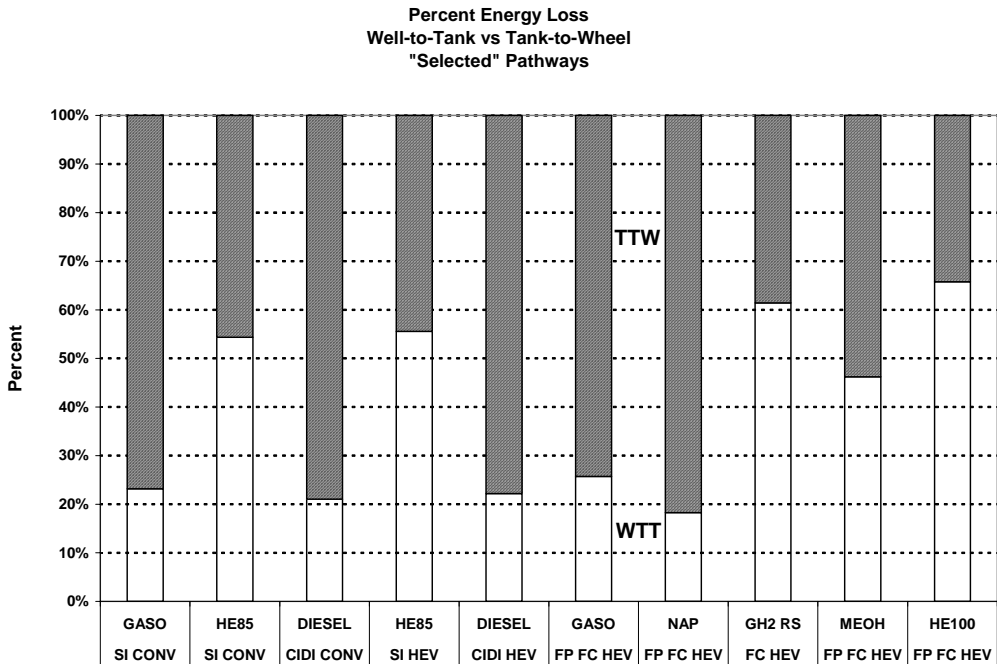


Figure ES-3.9 Percent Energy Loss WTT vs. TTW: "Selected" Fuel/Vehicle Pathways

## Greenhouse Gas Emissions

Key GHG findings are summarized in Figure ES-3.10 and include the following:

- The ethanol-fueled vehicles, as expected, yield the lowest GHG emissions per mile.
- The next lowest are the two H<sub>2</sub> FC HEVs (represented by the G.H<sub>2</sub> [refueling station] FC HEV in the figure).
- The H<sub>2</sub> FC HEVs are followed by the MeOH, naphtha, and gasoline FP HEVs and the diesel CIDI HEV, in that order.
- The diesel CIDI HEV offers a significant reduction in GHG emissions (27%) relative to the gasoline conventional SI vehicle.

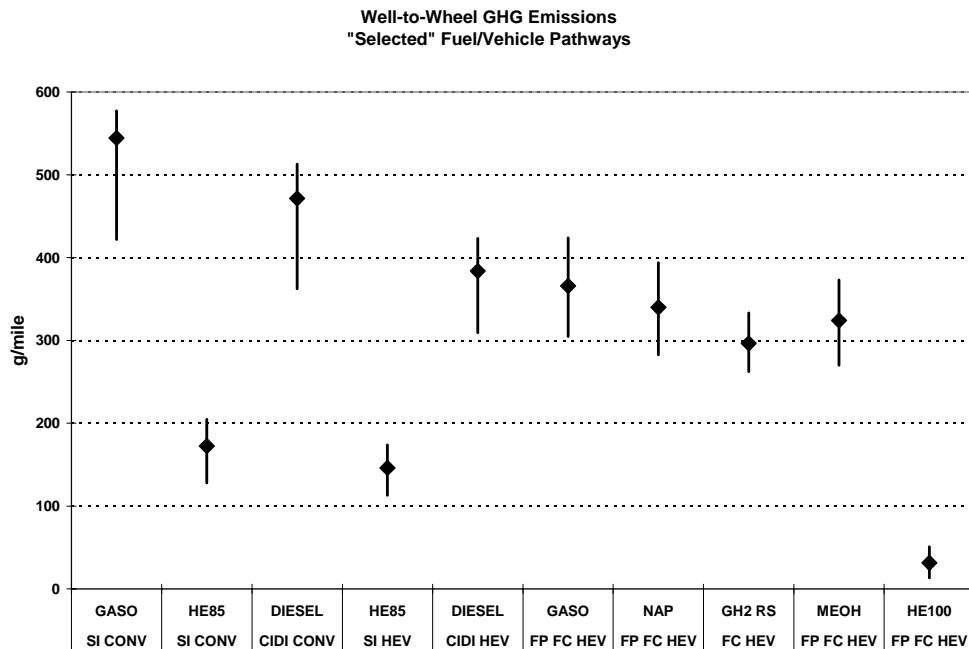


Figure ES-3.10 WTW GHG Emissions: "Selected" Fuel/Vehicle Pathways

## Integrated Fuel Use/GHG Emissions Results

Considering both total energy use and GHG emissions, the key findings are as follows:

- Among all of the crude oil- and NG-based pathways studied, the diesel CIDI HEV, gasoline and naphtha FP FC HEVs, and G.H<sub>2</sub> FC HEVs, were nearly identical and best in terms of total system energy use (Btu/mi). Among these pathways, however, expected GHG emissions were lowest for the H<sub>2</sub> FC HEV and highest for the diesel CIDI HEV.

- Compared to the gasoline SI (conventional), the gasoline SI and diesel CIDI HEVs, as well as the diesel CIDI (conventional) yield significant total system energy use and GHG emission benefits.
- The MeOH FP FC HEV offers no significant energy use or emissions reduction advantages over the crude oil-based or other NG-based FC HEV pathways.
- Ethanol-based fuel/vehicle pathways have by far the lowest GHG emissions of the pathways studied and also do very well on WTT energy loss when only fossil fuel consumption is considered.
- It must be noted that for the HE100 FP FC HEV pathway to reach commercialization, major technology breakthroughs are required for both the fuel and the vehicle.
- On a total system basis, the energy use (Btu/mi) and GHG emissions of CNG conventional and gasoline SI conventional pathways are nearly identical.
- The crude oil-based diesel vehicle pathways offer slightly lower total system GHG emissions and considerably better total system energy use than the NG-based FTD CIDI vehicle pathways. (Note that criteria pollutants are not considered here.)
- L.H<sub>2</sub>, FT naphtha, and electrolysis-based H<sub>2</sub> FC HEVs have significantly higher total system energy use and the same or higher levels of GHG emissions than the gasoline and crude naphtha FP FC HEVs and the G.H<sub>2</sub> FC HEVs.



VOLUME 2

***Well-to-Wheel Energy Use and  
Greenhouse Gas Emissions of  
Advanced Fuel/Vehicle Systems  
– North American Analysis –***

***General Motors  
Corporation***

***Argonne National  
Laboratory***

***BP***

***ExxonMobil***

***and***

***Shell***

**June 2001**

VOLUME 2

**General Motors  
Corporation**

**Argonne National  
Laboratory**

**BP**

**ExxonMobil**

**and**

**Shell**

***Well-to-Wheel Energy Use and  
Greenhouse Gas Emissions of  
Advanced Fuel/Vehicle Systems  
– North American Analysis –***

June 2001

## **DISCLAIMER**

Because many factors critical to the potential commercial viability of the technologies addressed in this study lie beyond the scope of the study's analysis, this report cannot provide the basis for dependable predictions regarding marketplace feasibility or timetables for implementation or commercialization of the technologies examined herein.

## **Preface**

### **Project Description and Acknowledgments**

#### **Need for the Study**

There are differing yet strongly held views among the various “stakeholders” in the advanced fuel/propulsion system debate. In order for the introduction of advanced technology vehicles and their associated fuels to be successful, it seems clear that four important stakeholders must view their introduction as a “win”:

- Society,
- Automobile manufacturers and their key suppliers,
- Fuel providers and their key suppliers, and
- Auto and energy company customers.

If all four of these stakeholders, from their own perspectives, are not positive regarding the need for and value of these advanced fuels/vehicles, the vehicle introductions will fail.

This study was conducted to help inform public and private decision makers regarding the impact of the introduction of such advanced fuel/propulsion system pathways from a societal point of view. The study estimates two key performance criteria of advanced fuel/propulsion systems on a total system basis, that is, “well” (production source of energy) to “wheel” (vehicle). These criteria are energy use and greenhouse gas emissions per unit of distance traveled.

The study focuses on the U.S. light-duty vehicle market in 2005 and beyond, when it is expected that advanced fuels and propulsion systems could begin to be incorporated in a significant percentage of new vehicles. Given the current consumer demand for light trucks, the benchmark vehicle considered in this study is the Chevrolet Silverado full-size pickup.

#### **How This Study Differs from Other Well-to-Wheel Analyses**

This study differs from prior well-to-wheel analyses in a number of important ways:

1. The study considers fuels and vehicles that might, albeit with technology breakthroughs, be commercialized in large volume and at reasonable prices. In general, fuels and propulsion systems that appear to be commercially viable only in niche markets are not considered.
2. The study provides best estimates and associated confidence bounds of the criteria mentioned above to allow the reader to assess differences between fuel/vehicle propulsion systems on a more statistically sound basis. This approach provides not only the best estimate, but also a measure of the uncertainty around the best estimate.

3. The study incorporates the results of a proprietary vehicle model created and used by General Motors.
4. The well-to-wheel analysis involved participation by the three largest privately owned fuel providers: BP, ExxonMobil, and Shell.
5. The 15 vehicles considered in the study include conventional and hybrid electric vehicles with both spark-ignition and compression-ignition engines, as well as hybridized and non-hybridized fuel cell vehicles with and without onboard fuel processors. All 15 vehicles were configured to meet the same performance requirements.
6. The 13 fuels considered in detail (selected from 75 different fuel pathways) include low-sulfur gasoline, low-sulfur diesel, crude oil-based naphtha, Fischer-Tropsch naphtha, liquid/compressed gaseous hydrogen based on five different pathways, compressed natural gas, methanol, and neat and blended (E85) ethanol. These 13 fuels, taken together with the 15 vehicles mentioned above, yielded the 27 fuel pathways analyzed in this study.

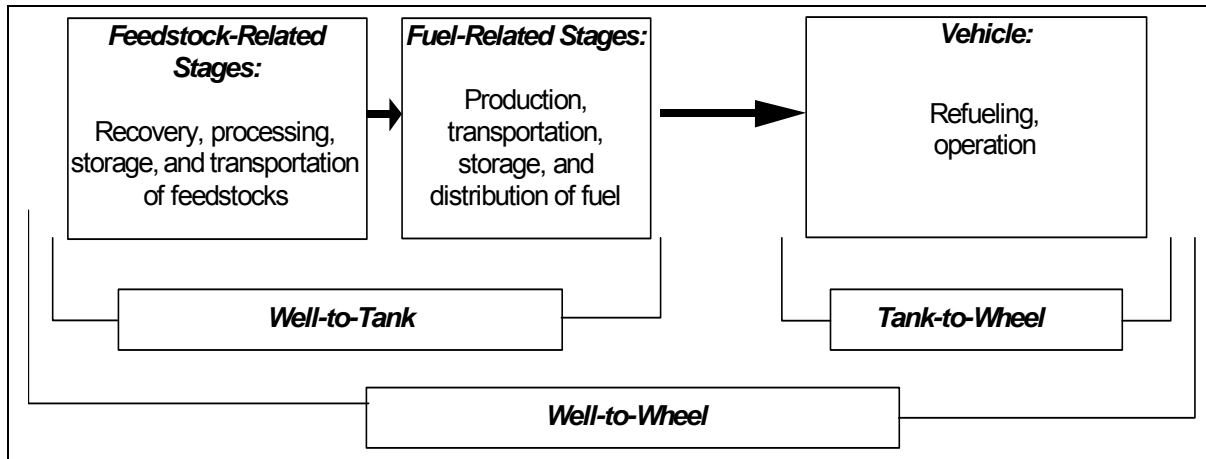
## **Format**

The study was conducted and is presented in three parts:

- Well-to-Tank (WTT): consideration of the fuel from resource recovery to delivery to the vehicle tank,
- Tank-to-Wheel (TTW): consideration of the vehicle from tank to the wheel, and
- Well-to-Wheel (WTW): integration of the WTT and TTW components.

The following figure illustrates the stages involved in a full fuel-cycle analysis. Argonne's study covers the WTT (or feedstock and fuel-related) stages (Part 1). GM evaluated the fuel economy and emissions of various vehicle technologies using different fuels (TTW analysis) (Part 2). In a separate effort, Argonne's WTT results were combined with GM's TTW results to produce WTW results (Part 3).

Volume 1 of this report series contains the Executive Summary Report, Volume 2 the full three-part study report, and Volume 3 the complete WTT report submitted to GM by Argonne (including detailed assumptions and data).



Full Fuel-Cycle Analysis

## Study Organization

Mr. Greg Ruselowski of General Motors' Global Alternative Propulsion Center (GAPC) initiated the study. The study team was organized as follows:

### ***Program Management***

*Program Manager:* Dr. James P. Wallace III, Wallace & Associates

*Assistant Program Manager:* Raj Choudhury, GM GAPC

### ***Part 1: Well-to-Tank Analysis***

*Project Leader and Principal Researcher:* Dr. Michael Wang, Argonne National Laboratory

*Project Team:* Dr. Dongquan He, Argonne National Laboratory

*GM Project Manager:* Dr. Anthony Finizza, AJF Consulting

*Project Reviewers:*

BP: Andrew Armstrong and Dr. James Simnick

ExxonMobil: Gilbert Jersey and Dr. John Robbins

Shell: Jean Cadu

GM: Norman Brinkman

Argonne National Laboratory: Dr. Dan Santini

### ***Part 2: Tank-to-Wheel Analysis***

*Project Leader and Principal Researcher:* Trudy Weber, GM R&D and Planning Center

*Team:* Dr. Moshe Miller, Advanced Development Corporation; Dr. David Masten, GAPC; and Gerald Skellenger, GM R&D and Planning Center

*Project Reviewers:*

GM R&D and Planning Center: Dr. Hazem Ezzat, Dr. Roger Krieger, and Norman Brinkman

GM GAPC: Gary Stottler, Dr. Udo Winter, and Mattias Bork

GM Powertrain: Dr. Fritz Indra, Tim Peterson, Arjun Tuteja, Dr. Ko-Jen Wu, and Tony Zarger  
GM Truck: Dr. Tanvir Ahmad  
GM ATV: Dr. Peter Savagian and John Hepke

***Part 3A: Well-to-Tank Pathways Down Select***

*Project Leader:* Dr. Anthony Finizza, AJF Consulting

*Project Reviewers:*

BP: Andrew Armstrong and Dr. James Simnick  
ExxonMobil: Gilbert Jersey and Dr. John Robbins  
Shell: Jean Cadu  
Argonne: Dr. Michael Wang and Dr. Dan Santini

***Part 3B: Well-to-Wheel Integration***

*Project Co-Leaders:* Dr. Anthony Finizza, AJF Consulting, and Dr. James P. Wallace III, Wallace & Associates

*Project Reviewers:*

BP: Andrew Armstrong and Dr. James Simnick  
ExxonMobil: Gilbert Jersey and Dr. John Robbins  
Shell: Jean Cadu  
GM: Norman Brinkman and Raj Choudhury  
Argonne: Dr. Michael Wang and Dr. Dan Santini

## **Acknowledgments**

In addition to the participants cited above, the Program Team wishes to acknowledge the support of the following people: Tom Bond, Manager of Global Fuels Technology, BP; Tim Ford, Vice President Fuels, Shell International Petroleum Co. Ltd.; Dr. Eldon Priestley, Manager, Corporate Strategic Research, ExxonMobil Research and Engineering; Dr. James Katzer, Strategic Planning and Programs Manager, ExxonMobil Research and Engineering; Dr. Byron McCormick, Director of GM GAPC; Dr. James A. Spearot, Director, Chemical and Environmental Sciences Lab, GM R&D and Planning Center; Dr. Larry Johnson, Director of Argonne National Laboratory's Transportation Technology R&D Center; and Robert Larsen, Director of Argonne National Laboratory's Center for Transportation Research, all of whom provided invaluable support in the ongoing review process for this report.

The study participants would like to thank Tien Nguyen, Dr. Phillip Patterson, and David Rodgers of the U.S. Department of Energy's Office of Transportation Technologies; without their support of previous versions of the GREET model, this study would not have been possible. We would also like to acknowledge the editorial support of Mary Fitzpatrick of Argonne.

Additional acknowledgments are made in each part of the full report.

## **Responsibility**

Argonne assumes responsibility for the accuracy of Part 1 but acknowledges that this accuracy was enhanced through significant contributions and thorough review by the study team, especially participants from the energy companies cited.

GM is exclusively responsible for the quantification of comparative vehicle technologies considered in Part 2.

Part 3A sought to further down-select the 75 fuel pathways examined in Part 1 into fuels that appear to be potentially feasible at high volumes and reasonable prices. The three energy companies provided key input for the conclusions reached in this section.

The GM Well-to-Wheel Integration Model used for Part 3B was developed and simulated by AJF Consultants and Wallace & Associates and is the property of GM. GM, Argonne, and the energy companies have reviewed the model and its simulation results and find them consistent and rational, given the model input.

## **Next Steps**

A follow-up study to estimate criteria pollutants for the United States is in the planning stage. In addition, efforts are underway to provide a European counterpart to this study.



## Contents

Preface.....	iii
Notation.....	xv

### **Part 1: Well-to-Tank Energy Use and Greenhouse Gas Emissions of Transportation Fuels**

1.1 Introduction.....	1-1
1.2 Methodology.....	1-1
1.2.1 Fuels and Production Pathways.....	1-2
1.2.1.1 Petroleum-Based Fuels.....	1-2
1.2.1.2 Natural-Gas-Based Fuels.....	1-3
1.2.1.3 Bio-Ethanol Options.....	1-8
1.2.1.4 Electricity Generation.....	1-8
1.2.1.5 Hydrogen Production via Electrolysis.....	1-9
1.2.2 Probability Distribution Functions for Key Parameters.....	1-9
1.2.3 Transportation of Feedstocks and Fuels.....	1-9
1.3 Results.....	1-13
1.3.1 Total Energy Use.....	1-16
1.3.2 Fossil Energy Use.....	1-16
1.3.3 Petroleum Use.....	1-17
1.3.4 Greenhouse Gas Emissions.....	1-17
1.4 Conclusions.....	1-22
1.5 Acknowledgments.....	1-22

### **Figures**

1.1 Well-to-Tank Stages Covered in Argonne’s Study.....	1-1
1.2 Pathways of Petroleum-Based Fuels.....	1-3
1.3 Pathways of Compressed Natural Gas Production.....	1-4
1.4 Pathways of Methanol Production.....	1-5
1.5 Pathways of Fischer-Tropsch Diesel and Naphtha Production.....	1-5
1.6 Pathways of Gaseous Hydrogen Production in Central Plants.....	1-6

## Figures (Cont.)

1.7	Pathways of Gaseous Hydrogen Production at Refueling Stations.....	1-6
1.8	Pathways of Liquid Hydrogen Production in Central Plants .....	1-7
1.9	Pathways of Liquid Hydrogen Production at Refueling Stations .....	1-7
1.10	Pathways of Ethanol Production .....	1-8
1.11	Pathways of Electricity Generation.....	1-10
1.12	Pathways of Hydrogen Production via Electrolysis of Water at Refueling Stations .....	1-10
1.13	Simulation of Transportation of Energy Feedstocks and Fuels .....	1-12
1.14	WTT Total Energy Use.....	1-18
1.15	WTT Fossil Energy Use.....	1-19
1.16	WTT Petroleum Use.....	1-20
1.17	WTT GHG Emissions .....	1-21

## Tables

1.1	Five Gasoline Options Included in This Study .....	1-3
1.2	Three Electricity Generation Mixes Analyzed.....	1-9
1.3	Parametric Probability Distribution Values for Key WTT Parameters.....	1-11
1.4	Energy Efficiencies for Feedstock and Fuel Transportation Calculated from GREET Outputs .....	1-13
1.5	Fuel Pathway Options Analyzed in Argonne’s WTT Study and Selected for Presentation in This Report .....	1-14

## **Part 2: Tank-to-Wheel Energy Utilization for a North American Vehicle**

2.1	Introduction .....	2-1
2.2	Methodology .....	2-1
2.2.1	Vehicle Architectures .....	2-4
2.2.2	Vehicle Criteria .....	2-8
2.2.2.1	Performance Targets .....	2-8
2.2.2.2	Emissions Targets .....	2-8
2.2.2.3	Vehicle Simulation Model Input Data .....	2-9
2.3	Results .....	2-10
2.4	Conclusions .....	2-11
2.5	Acknowledgments .....	2-12
2.6	References .....	2-12

### **Figures**

2.1	Energy Use in a Pickup Truck.....	2-2
2.2	HPSP Methodology.....	2-2
2.3	Sample Energy Use Diagram Provided by HPSP .....	2-3
2.4	Conventional Powertrain.....	2-5
2.5	Parallel Hybrid (Input Power Assist).....	2-5
2.6	Fuel Processor Fuel Cell Vehicle System .....	2-6
2.7	Fuel Processor Fuel Cell HEV System .....	2-6
2.8	Direct Fuel Cell Vehicle System.....	2-7
2.9	Direct Fuel Cell HEV System .....	2-7
2.10	Performance Targets .....	2-9

### **Tables**

2.1	Fuel Economy (Gasoline Equivalent) and Performance Predictions.....	2-10
2.2	Overview of Vehicle Configurations .....	2-11

## **Part 3: Well-to-Wheel Fuel/Vehicle Pathway Integration**

3.1	Introduction .....	3-1
3.2	Methodology .....	3-1
3.2.1	Part A: Selection of Well-to-Tank Pathways .....	3-1
3.2.1.1	Resource Availability .....	3-1
3.2.1.2	Energy Efficiency .....	3-6
3.2.2	Part B: Well-to-Wheel Integration .....	3-8
3.2.2.1	Well-to-Tank (Part 1) .....	3-8
3.2.2.2	Tank-to-Wheel (Part 2) .....	3-8
3.2.2.3	Well-to-Wheel (Part 3) .....	3-10
3.3	Results .....	3-10
3.3.1	Conventional and Hybrid Fuel/Vehicle Pathways .....	3-11
3.3.2	Fuel/Hybrid and Non-Hybrid FCV Pathways .....	3-13
3.4	Conclusions .....	3-18
3.4.1	Energy Use .....	3-18
3.4.2	Greenhouse Gas Emissions .....	3-18
3.4.3	Integrated Energy Use/GHG Emissions Results .....	3-20
3.5	References .....	3-21

### **Figures**

3.1	Potential Natural Gas Resources .....	3-5
3.2	Potential Oil Resources .....	3-5
3.3	Well-to-Wheel Integration Process .....	3-8
3.4	WTW Total System Energy Use: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI) .....	3-11
3.5	Percent Energy Loss, WTT vs. TTW: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI) .....	3-12
3.6	WTW GHG Emissions: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI) .....	3-13
3.7	WTW Total System Energy Use: Hybrid Fuel/FCV Pathways .....	3-15

## Figures (Cont.)

3.8	Percent Energy Loss, WTT vs. TTW: Hybrid Fuel/FCV Pathways .....	3-15
3.9	WTW GHG Emissions: Hybrid Fuel/FCV Pathways .....	3-16
3.10	WTW Total System Energy Use: Non-Hybrid Fuel/FCV Pathways .....	3-17
3.11	Percent Energy Loss, WTT vs. TTW: Non-Hybrid Fuel/FCV Pathways .....	3-17
3.12	WTW GHG Emissions: Non-Hybrid Fuel/FCV Pathways .....	3-18
3.13	WTW Total System Energy Use: “Selected” Fuel/Vehicle Pathways .....	3-19
3.14	Percent Energy Loss, WTT vs. TTW: “Selected” Fuel/Vehicle Pathways .....	3-19
3.15	WTW GHG Emissions: “Selected” Fuel/Vehicle Pathways .....	3-20

## Tables

3.1	Comparison of Studies of the U.S. Natural Gas Market .....	3-2
3.2	Incremental Increase in U.S. Natural Gas Demand in 2010 Relative to 1998 Base Year .....	3-2
3.3	EIA Baseline Forecast of the U.S. Transportation Market .....	3-3
3.4	Natural Gas Resource Base .....	3-4
3.5	Comparison of Selected Pathways .....	3-7
3.6	Summary of Pathways Selected for Well-to-Wheel Integration Analysis .....	3-7
3.7	Fuel/Vehicle Pathways Analyzed .....	3-10
3.8	Total WTW System Efficiency Improvements from Hybridization .....	3-12
3.9	Renewable Share of WTT Total Energy Use .....	3-12
3.10	Total System Efficiency Improvements from Hybridization of FCVs .....	3-14

## Appendixes to Part 3

Appendix 3A:	CO <sub>2</sub> Content of Fuels .....	3-23
Appendix 3B:	Energy Loss Split Calculation .....	3-25
Appendix 3C:	Data Used to Prepare Figures 3.4 through 3.15 .....	3-29



## Notation

### Acronyms and Abbreviations

ANL	Argonne National Laboratory
BSFC	brake-specific fuel consumption
CARFG2	California Phase 2 reformulated gasoline
CARFG3	California Phase 3 reformulated gasoline
CC	combined-cycle
CG	conventional gasoline
CH <sub>4</sub>	methane
CIDI	compression ignition direct injection
CNG	compressed natural gas
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CS	charge sustaining
CTR	Center for Transportation Research (Argonne National Laboratory)
CVT	continuously variable transmission
DOE	U.S. Department of Energy
E&P	exploration and production
E85	a mixture of 85% ethanol and 15% gasoline (by volume)
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EtOH	ethanol
FC	fuel cell
FCV	fuel cell vehicle
FG	flared gas
FP	fuel processor
FRFG2	Federal Phase 2 reformulated gasoline
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
GAPC	Global Alternative Propulsion Center (General Motors Corporation)
GASO	gasoline
G.H <sub>2</sub>	gaseous hydrogen
GHG	greenhouse gas
GM	General Motors Corporation
REET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
GRI	Gas Research Institute
GTI	Gas Technology Institute
GWP	global warming potential
H <sub>2</sub>	hydrogen
HE100	herbaceous E100
HE85	herbaceous E85
HEV	hybrid electric vehicle
HPSP	Hybrid Powertrain Simulation Program

ICE	internal combustion engine
L.H <sub>2</sub>	liquid hydrogen
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M85	a mixture of 85% methanol and 15% gasoline (by volume)
MeOH	methanol
MTBE	methyl tertiary butyl ether
N	nitrogen
N <sub>2</sub> O	nitrous oxide
NA	North American
NAP	naphtha
NG	natural gas
NGL	natural gas liquid
NiMH	nickel metal hydride
NNA	non-North-American
NO <sub>x</sub>	nitrogen oxides
NPC	National Petroleum Council
PM <sub>10</sub>	particulate matter with diameter of 10 μm or less
PNGV	Partnership for a New Generation of Vehicles
psi	pounds per square inch
R&D	research and development
RVP	Reid vapor pressure
SAE	Society of Automotive Engineers
SI	spark ignition
SO <sub>x</sub>	sulfur oxides
SULEV	Super Ultra-Low Emissions Vehicle
T&S	transportation and storage
TTW	tank-to-wheel
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
VOC	volatile organic compound
WTT	well-to-tank
WTW	well-to-wheel
ZEV	Zero Emissions Vehicle

## Units of Measure

Btu	British thermal unit(s)	mmBtu	million (10 <sup>6</sup> ) Btu
g	gram(s)	mph	mile(s) per hour
gal	gallon(s)	ppm	part(s) per million
kWh	kilowatt hour(s)	s	second(s)
m	meter(s)	μm	micrometer(s)
mi	mile(s)		

## **Part 1**

# **Well-to-Tank Energy Use and Greenhouse Gas Emissions of Transportation Fuels**

Michael Wang and Dongquan He  
Center for Transportation Research  
Argonne National Laboratory

June 2001



## 1.1 Introduction

Various fuels are proposed for use in fuel cell vehicles (FCVs) and hybrid electric vehicles (HEVs). Different fuels are made by different production pathways, and consequently they result in different energy and greenhouse gas (GHG) emission impacts. To fully analyze these impacts, full fuel-cycle analyses — from energy feedstock recovery (wells) to energy delivered at vehicle wheels — are needed.

The Global Alternative Propulsion Center (GAPC) of the General Motors Corporation (GM) commissioned the Center for Transportation Research (CTR) at Argonne National Laboratory (Argonne) to conduct a study to evaluate energy and emission impacts associated with producing different transportation fuels and delivering those fuels to vehicle tanks (well-to-tank [WTT] analysis). Argonne's study is part of an overall study by General Motors to analyze well-to-wheel energy use and GHG emissions impacts of advanced fuel/vehicle systems. Three energy companies — BP, ExxonMobil, and Shell — participated in the study by providing critical input and reviewing Argonne's results. The timeframe for the WTT analysis is 2005 and beyond.

This report was originally produced as an extensive summary of a sponsor report delivered by Argonne to GM. Detailed information regarding the methodology, assumptions, results, and references for Argonne's study are provided in the sponsor report, published as Volume 3 of this report series.

## 1.2 Methodology

Figure 1.1 illustrates the WTT stages covered in Argonne's study. GM conducted an in-house study to evaluate the fuel economy and emissions of various vehicle technologies using different fuels (tank-to-wheel [TTW] analysis). GM then combined Argonne's WTT results and GM's TTW results to obtain well-to-wheel (WTW) results. Argonne assumes responsibility for the accuracy of WTT results but acknowledges that this accuracy was enhanced through significant contributions and thorough review by the study team, especially participants from the energy companies.

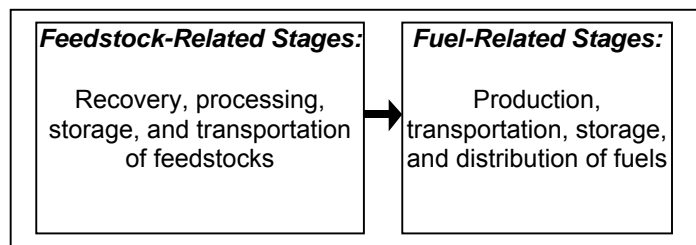


Figure 1.1 Well-to-Tank Stages Covered in Argonne's Study

To complete our WTT study, we used a model developed by Argonne to estimate WTT energy and emission impacts of alternative transportation fuels and advanced vehicle technologies. The model, called GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation), is capable of calculating WTW energy use (in British thermal units per mile [Btu/mi]) and emissions (in grams per mile [g/mi]) for transportation fuels and vehicle technologies; for our study, we used only the WTT portion of GREET.

For energy use modeling, GREET includes total energy use (all energy sources), fossil energy use (petroleum, natural gas, and coal), and petroleum use. For emissions modeling, GREET includes three major greenhouse gases (GHGs) specified in the Kyoto protocol (carbon dioxide [CO<sub>2</sub>]), methane [CH<sub>4</sub>], and nitrous oxide [N<sub>2</sub>O]) and five criteria pollutants (volatile organic compounds [VOCs], carbon monoxide [CO], nitrogen oxides [NO<sub>x</sub>] particulate matter with diameters of 10 μm or less [PM<sub>10</sub>], and sulfur oxides [SO<sub>x</sub>]). The three GHGs are combined with their global warming potentials (GWPs) to calculate CO<sub>2</sub>-equivalent GHG emissions. Emissions of the five criteria pollutants are further separated into total and urban emissions. Total emissions occur everywhere; urban emissions occur within urban areas. The separation is based on information regarding facility locations and is intended to provide an estimate of the exposure to air pollution caused by the criteria pollutants.

For this project, Argonne estimated total and fossil energy use, petroleum use, and CO<sub>2</sub>-equivalent emissions of the three GHGs. Emissions of criteria pollutants were not included in this study.

For our WTT study, we employed a new version of GREET that simulates transportation of energy feedstocks and fuels by using detailed input parameters regarding transportation modes and their corresponding distances for different energy feedstocks and fuels. The new version also incorporates a Monte Carlo simulation to formally address uncertainties involved in key input parameters. The new GREET version will soon be released to the public.

We analyzed 75 fuel pathways for application to (1) vehicles with stand-alone internal combustion engines (ICEs), (2) HEVs, and (3) FCVs. The following sections describe the fuels and production pathways chosen for our study. Volume 3 of this report series, which contains Argonne's sponsor report delivered to GM, provides results for the 75 pathways analyzed and details regarding the assumptions used in our study.

## **1.2.1 Fuels and Production Pathways**

### ***1.2.1.1 Petroleum-Based Fuels***

This study included three petroleum-based fuels: gasoline, diesel, and naphtha. For gasoline and diesel, we established cases to represent different fuel requirements. For gasoline, we included federal conventional gasoline (CG), federal Complex Model Phase 2 reformulated gasoline (FRFG2), California Phase 2 reformulated gasoline (CARFG2), California Phase 3 reformulated gasoline (CARFG3), and the gasoline requirements in the U.S. Environmental Protection Agency's (EPA's) Tier 2 vehicle emission standards. These gasoline types contain sulfur at concentrations ranging from 5 parts per million (ppm) to over 300 ppm and may contain methyl tertiary butyl ether (MTBE), ethanol (EtOH), or no oxygenates. Table 1.1 presents typical properties of the gasoline options analyzed in this study.

For on-road diesel fuels, we included two options: a current diesel and a future diesel. The current diesel has a sulfur content of 120–350 ppm. The future diesel reflects the new diesel requirement adopted recently by EPA, with a sulfur content below 15 ppm.

Table 1.1 Five Gasoline Options Included in This Study

Characteristic	Current Gasoline		Future Gasoline <sup>a</sup>		
	CG	FRFG2 with MTBE	RFG with MTBE	RFG with EtOH	RFG with no Oxygenate
RVP (psi, summer) <sup>b</sup>	8.9	6.7	6.7	6.7	6.7
Sulfur content (wt. ppm)	340	150	5-30	5-30	5-30
Benzene content (vol. %)	1.53	0.68	0.68	0.68	0.68
Aromatics content (vol. %)	32	25	25	25	25
Oxygen content (wt. %)	0.4	2.26	2.26	3.5	0

<sup>a</sup> Future gasoline reflects CARFG3 and EPA's Tier 2 gasoline requirements.

<sup>b</sup> RVP = Reid vapor pressure; psi = pounds per square inch.

Naphtha could be used as a fuel cell fuel. Virgin crude naphtha from petroleum refineries' distillation (without desulfurization) has a sulfur content of about 370 ppm. For fuel cell applications, we assumed that the sulfur content of crude naphtha would be reduced to about 1 ppm by means of hydrotreating or some other desulfurization measure.

Figure 1.2 shows WTT stages for the petroleum fuel pathways analyzed in this study. Crude recovery and crude refining (shaded) are the key stages for which we established probability distribution functions for their energy efficiencies in this study.

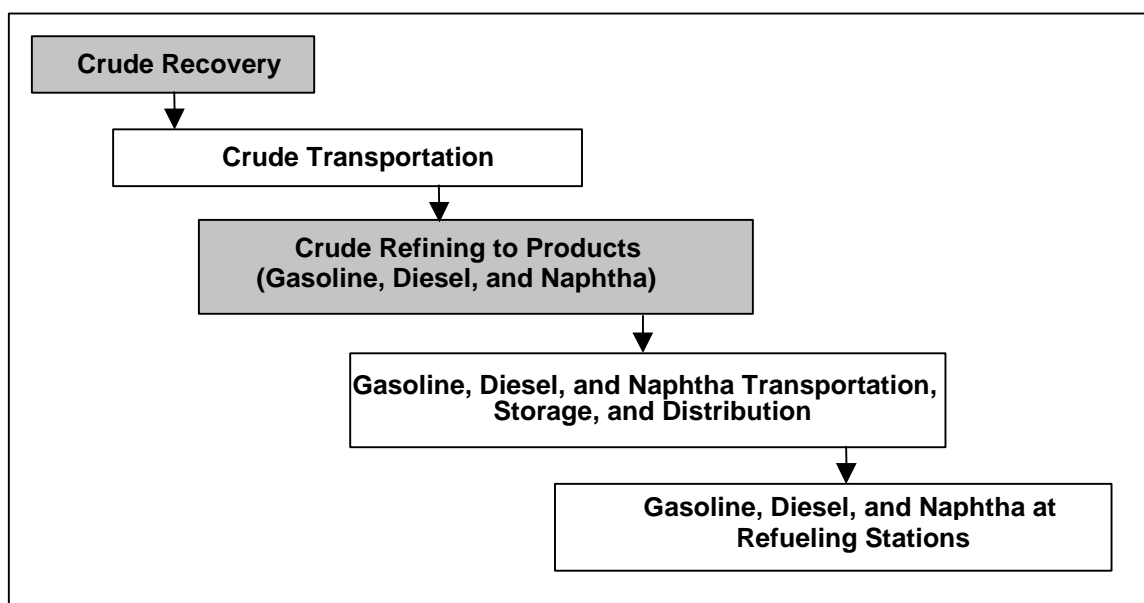


Figure 1.2 Pathways of Petroleum-Based Fuels

### 1.2.1.2 Natural-Gas-Based Fuels

Our study included the following fuels based on natural gas (NG): compressed natural gas (CNG), methanol (MeOH), Fischer-Tropsch diesel (FTD), Fischer-Tropsch (FT) naphtha, gaseous hydrogen (G.H<sub>2</sub>) produced in central plants, G.H<sub>2</sub> produced in refueling stations, liquid hydrogen (L.H<sub>2</sub>) produced in central plants, and L.H<sub>2</sub> produced in refueling stations. These fuels are produced from three NG feedstock sources: North American (NA) sources, non-North-American (NNA) sources, and NNA flared gas (FG) sources.

While liquid fuels (i.e., methanol, L.H<sub>2</sub>, FTD, and FT naphtha) can be produced in NNA locations and transported to the United States, CNG, G.H<sub>2</sub>, and station-produced L.H<sub>2</sub> must be produced in the United States. We assumed that liquefied natural gas (LNG) is produced in NNA locations and transported to the United States for use in production of these three fuels. Thus, we estimated and included energy use and emissions of LNG production and transportation for these fuel options. Figures 1.3 through 1.9 present the production pathways for each of the fuels. The stages that are shaded are the key stages for which we established probability distribution functions for their energy efficiencies.

We assumed that CNG would be stored onboard vehicles at a pressure of about 3,600 psi. We also assumed that the NG would need to be compressed from 15 psi to 4,000 psi by means of both electric and NG compressors.

Argonne assumed that G.H<sub>2</sub> would be stored onboard FCVs at pressures of about 5,000 psi and that G.H<sub>2</sub> would be compressed to 6,000 psi at refueling stations. For centrally produced G.H<sub>2</sub> that is to be transported via pipeline to refueling stations, we assumed that electric compressors would be used to compress G.H<sub>2</sub> from an initial pressure of 250 psi. For station-produced G.H<sub>2</sub>, we assumed that both electric and NG compressors would be used to compress G.H<sub>2</sub> from an initial pressure of 500 psi.

For production of L.H<sub>2</sub> from NNA NG and FG in central plants, we assumed that L.H<sub>2</sub> would be produced in NNA locations and transported to the United States via ocean tankers. For production of L.H<sub>2</sub> at refueling stations on the other hand, we assumed that LNG would be produced from NG and FG in NNA locations and transported to U.S. LNG terminals.

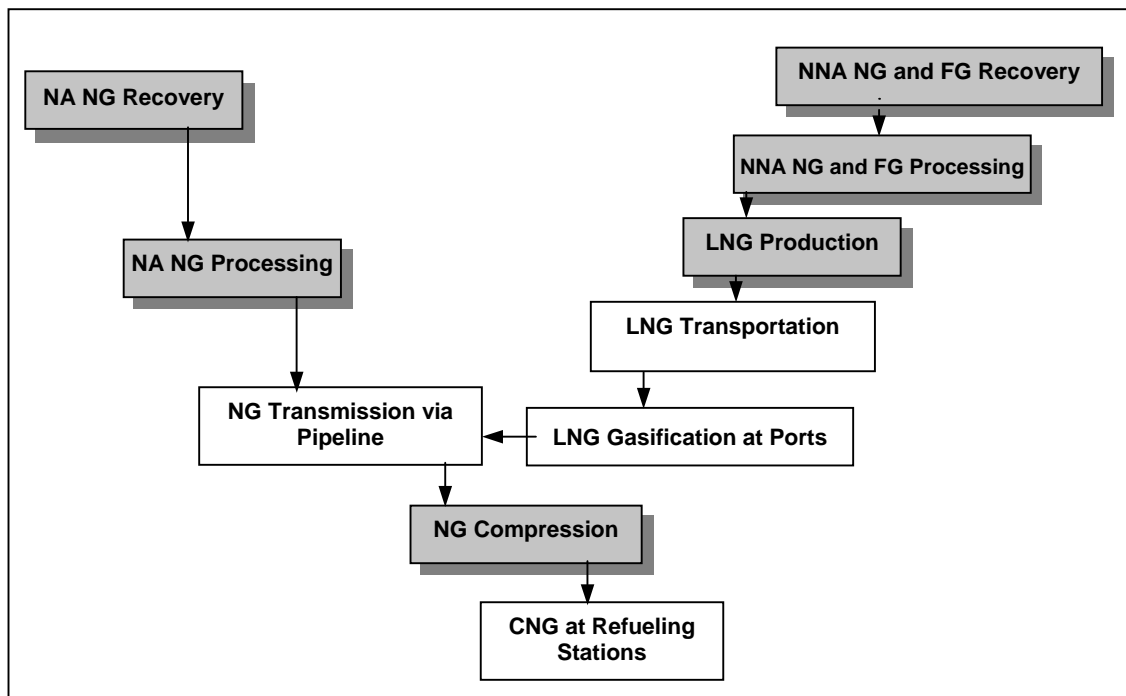


Figure 1.3 Pathways of Compressed Natural Gas Production

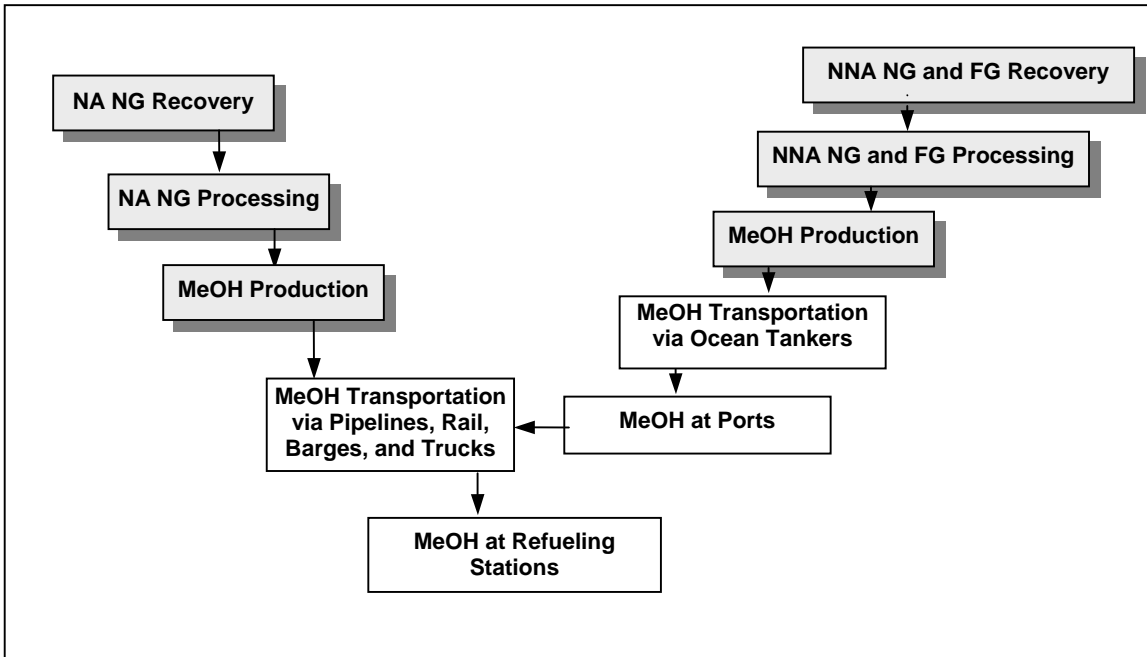


Figure 1.4 Pathways of Methanol Production

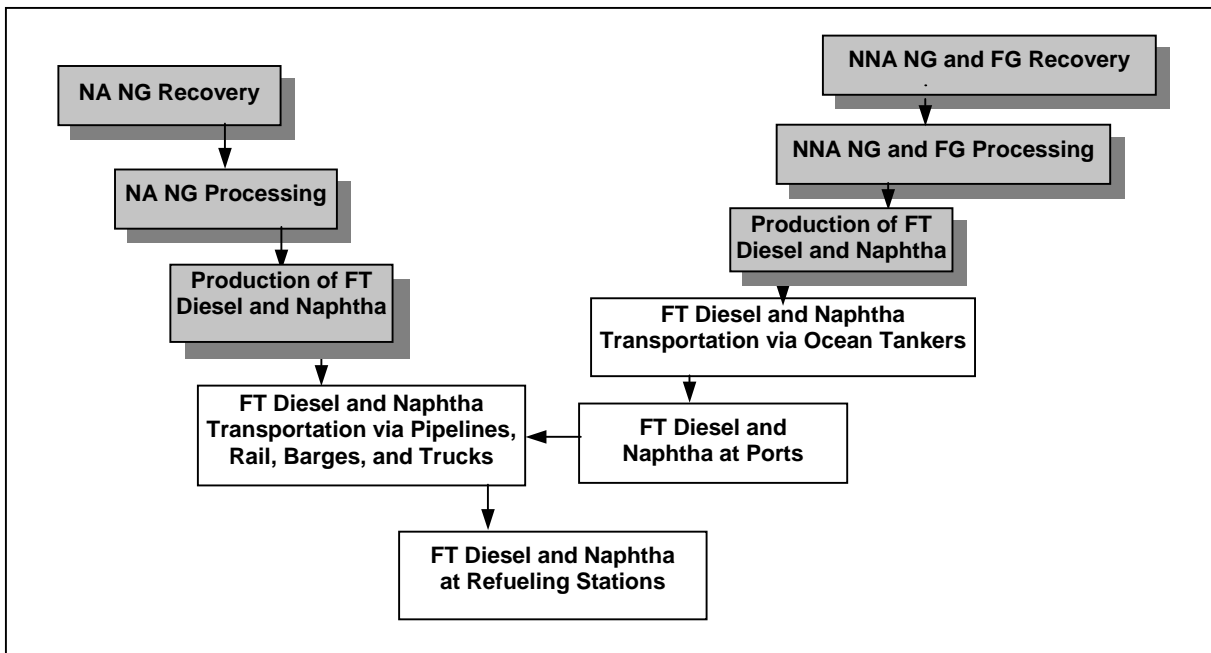


Figure 1.5 Pathways of Fischer-Tropsch Diesel and Naphtha Production

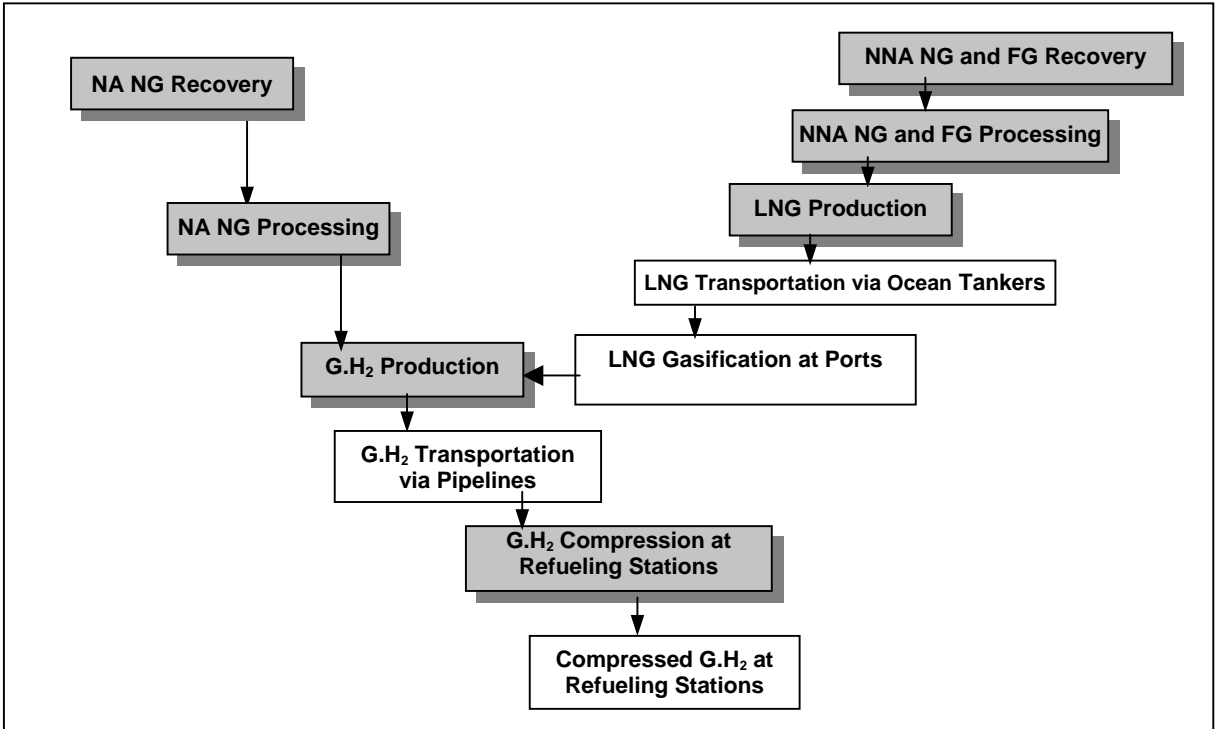


Figure 1.6 Pathways of Gaseous Hydrogen Production in Central Plants

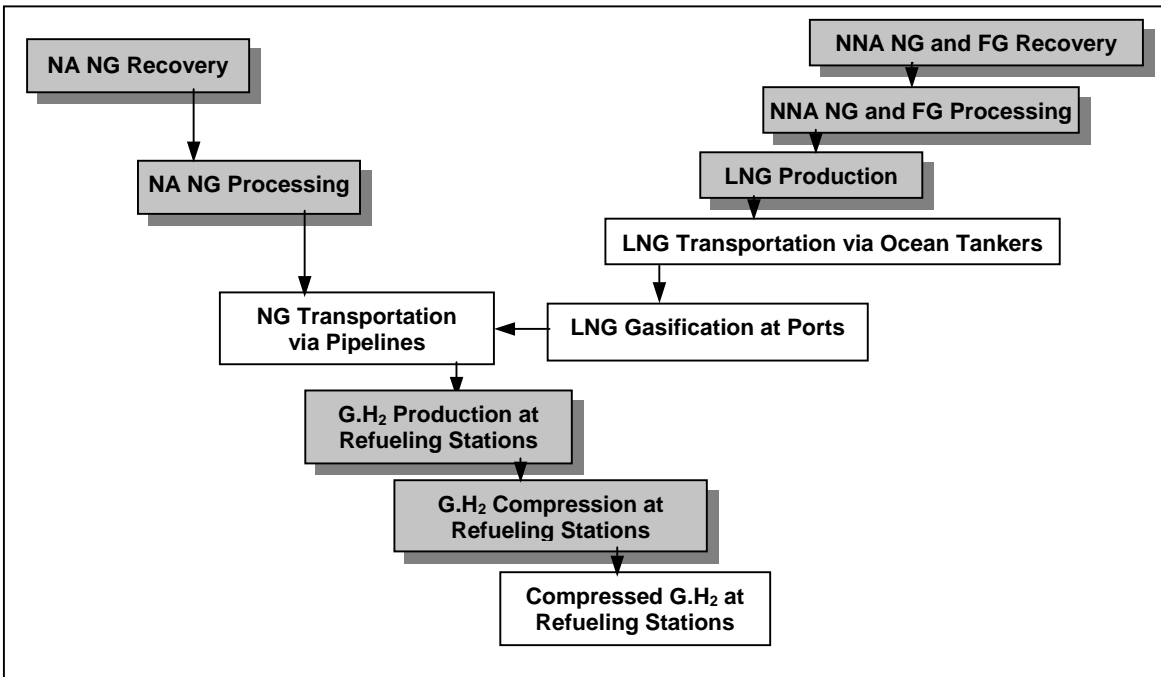


Figure 1.7 Pathways of Gaseous Hydrogen Production at Refueling Stations

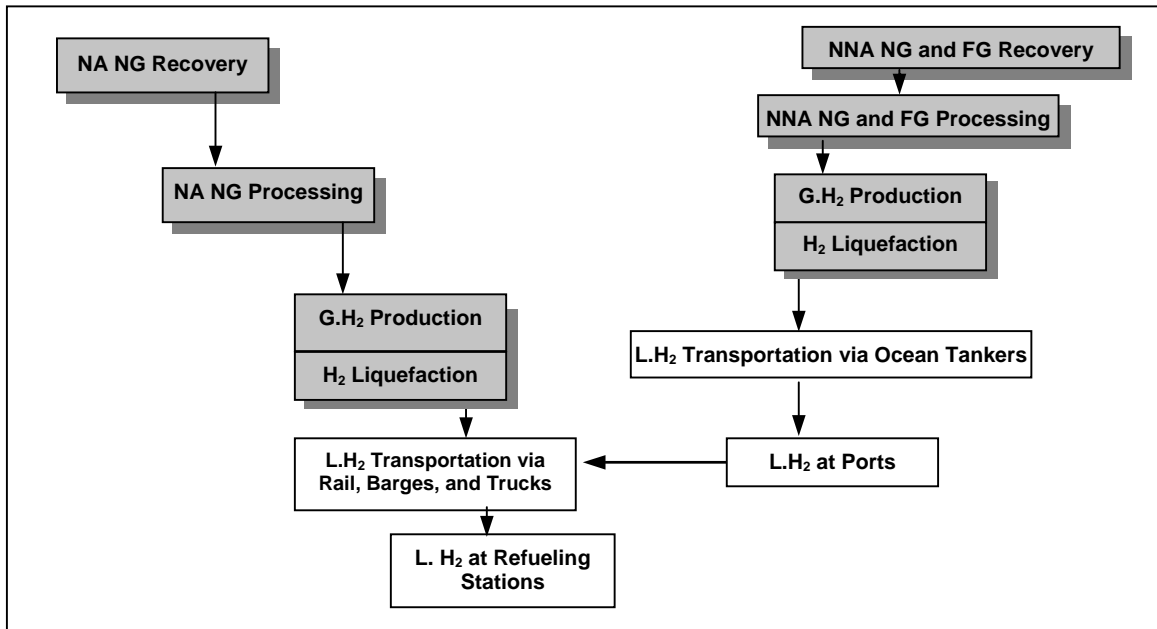


Figure 1.8 Pathways of Liquid Hydrogen Production in Central Plants

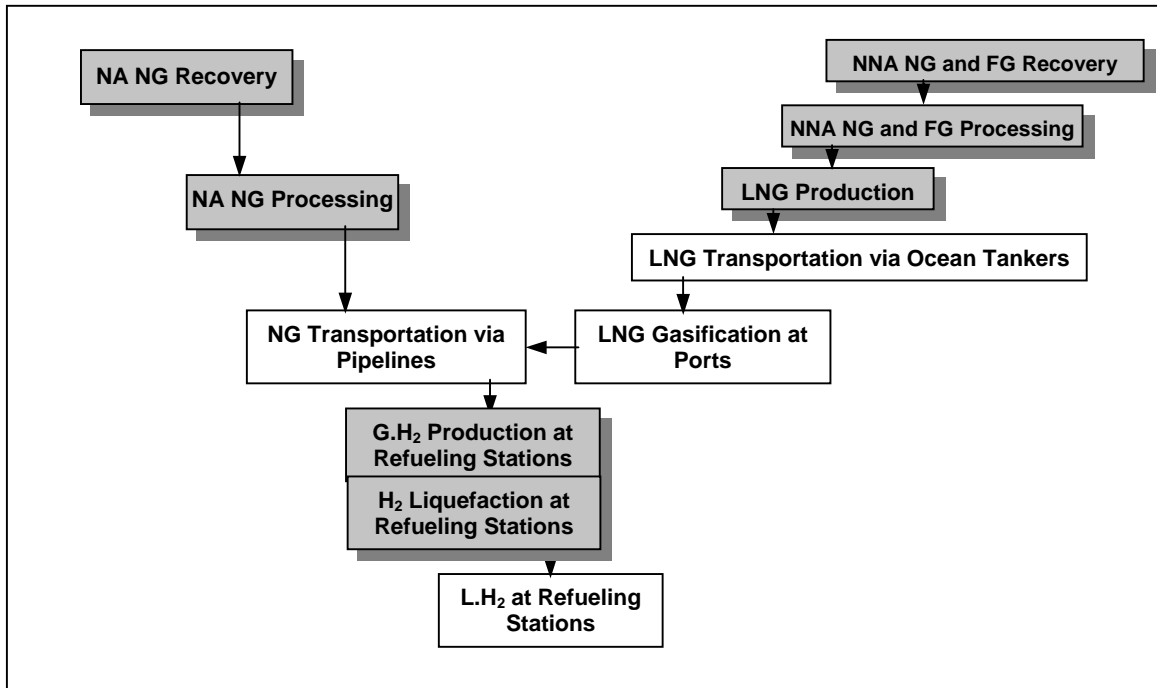


Figure 1.9 Pathways of Liquid Hydrogen Production at Refueling Stations

### 1.2.1.3 Bio-Ethanol Options

We included three ethanol production pathways: ethanol from corn, woody biomass (trees), and herbaceous biomass (grasses) (Figure 1.10). Corn-based ethanol can be produced in wet milling or dry milling plants; we examined both. Corn-based ethanol plants also produce other products (primarily animal feeds). We allocated energy use and emissions between ethanol and its co-products by using the market value method.

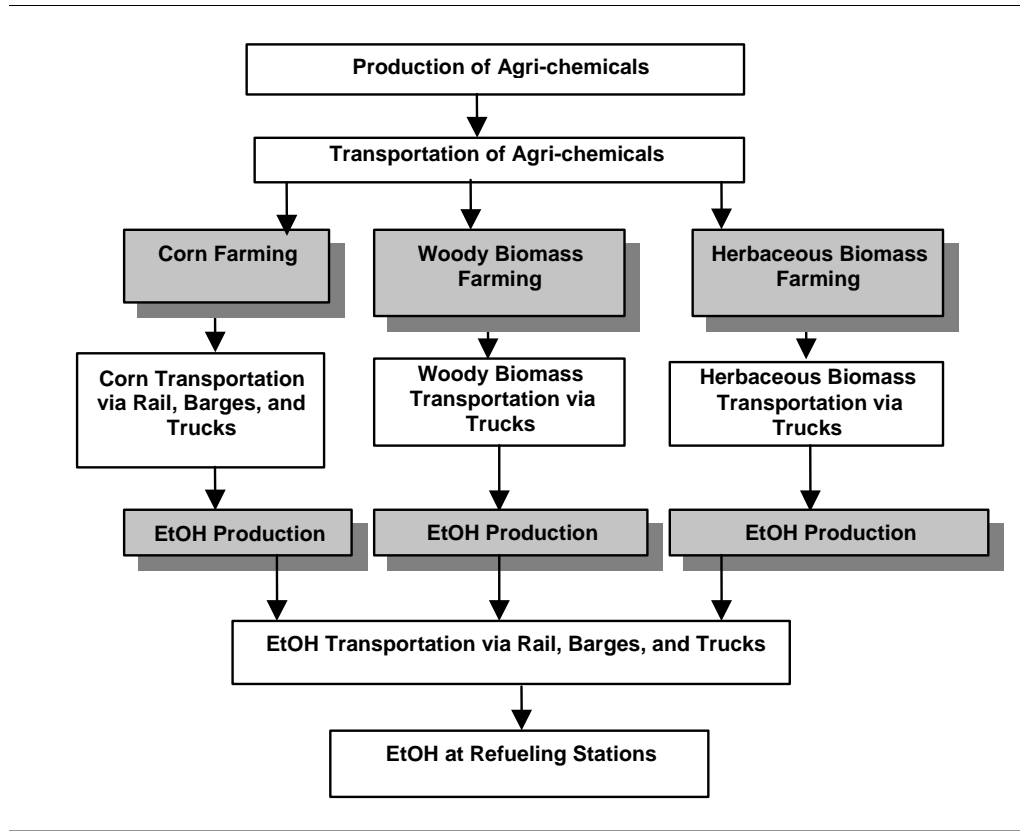


Figure 1.10 Pathways of Ethanol Production

In cellulosic (woody and herbaceous) ethanol plants, while cellulose in biomass is converted into ethanol through enzymatic processes, the lignin portion of biomass can be burned to provide needed steam. Co-generation systems can be employed to generate both steam and electricity. In this case, extra electricity can be generated for export to the electric grid. We took the generated electricity credit into account in calculating energy use and GHG emissions of cellulosic ethanol production.

### 1.2.1.4 Electricity Generation

Our study included three generation mixes — the U.S., the California, and the Northeast U.S. — to cover a broad range (Table 1.2). NG-fired combined-cycle (CC) turbines with high energy-conversion efficiencies have been added to U.S. electric generation capacity in the last decade. We included this technology in our analysis. We estimated energy use and GHG emissions associated with electricity generation in NG-fired CC power plants, hydroelectric plants, and nuclear plants separately.

Table 1.2 Three Electricity Generation Mixes Analyzed

Generation Mix	Power Source (%)				
	Coal	Oil	Natural Gas	Nuclear	Others <sup>a</sup>
U.S. Mix	54	1	15	18	12
California Mix	21	0	33	15	31
Northeast U.S. Mix	28	3	32	26	11

<sup>a</sup> Including hydro, geothermal, solar, wind, and other electric power plants.

Emissions estimates were calculated for four types of electric power plants: oil-fired, NG-fired, coal-fired, and nuclear. Other power plants, such as hydroelectric and windmill plants, have virtually zero operation emissions. Emissions from nuclear power plants are attributable to uranium recovery, enrichment, and transportation. As Figure 1.11 shows, our estimation of emissions associated with electricity generation includes fuel production and transportation, as well as electricity generation.

### 1.2.1.5 Hydrogen Production via Electrolysis

Production of H<sub>2</sub> from electricity (by electrolysis of water at refueling stations) may represent a means to provide H<sub>2</sub> for FCVs. (Figure 1.12). This production option helps avoid long-distance transportation and storage of H<sub>2</sub>. We evaluated H<sub>2</sub> production from electricity that is generated from hydroelectric and nuclear power as well as from the U.S. generation mix, the California generation mix, the Northeast U.S. generation mix, and NG-fired CC turbines. The first two cases represent electricity generation with zero or near-zero GHG emissions.

## 1.2.2 Probability Distribution Functions for Key Parameters

On the basis of our research of the efficiencies of WTT stages and input from the three energy companies (BP, ExxonMobil, and Shell) during this study, we determined probability distribution functions for key WTT stages (see Volume 3 for details). The probabilistic simulations employed in this study, a departure from the range-based simulations used in many previous Argonne studies, are intended to address uncertainties statistically. For each activity associated with the production process of each fuel, we determined the following parametric values for probability: 20%, 50%, and 80% (P20, P50, and P80). For most parameters, we assumed normal probability distributions. For some of the parameters, where a normal distribution would not describe the parameter correctly, we assumed a triangular distribution. Table 1.3 presents our estimated parametric values of distribution functions for key parameters.

## 1.2.3 Transportation of Feedstocks and Fuels

We employed the following five-step approach to estimate energy use and emissions for transportation of feedstocks and fuels. Figure 1.13 illustrates the method we used to simulate this portion of the fuel cycle.

- Determine transportation modes and their shares (i.e., ocean tankers, pipelines, barges, rail, and trucks) to be used to transport a given feedstock or fuel.
- Identify the types and shares of process fuels (e.g., residual oil, diesel fuels, natural gas, electricity) to be used to power each mode.

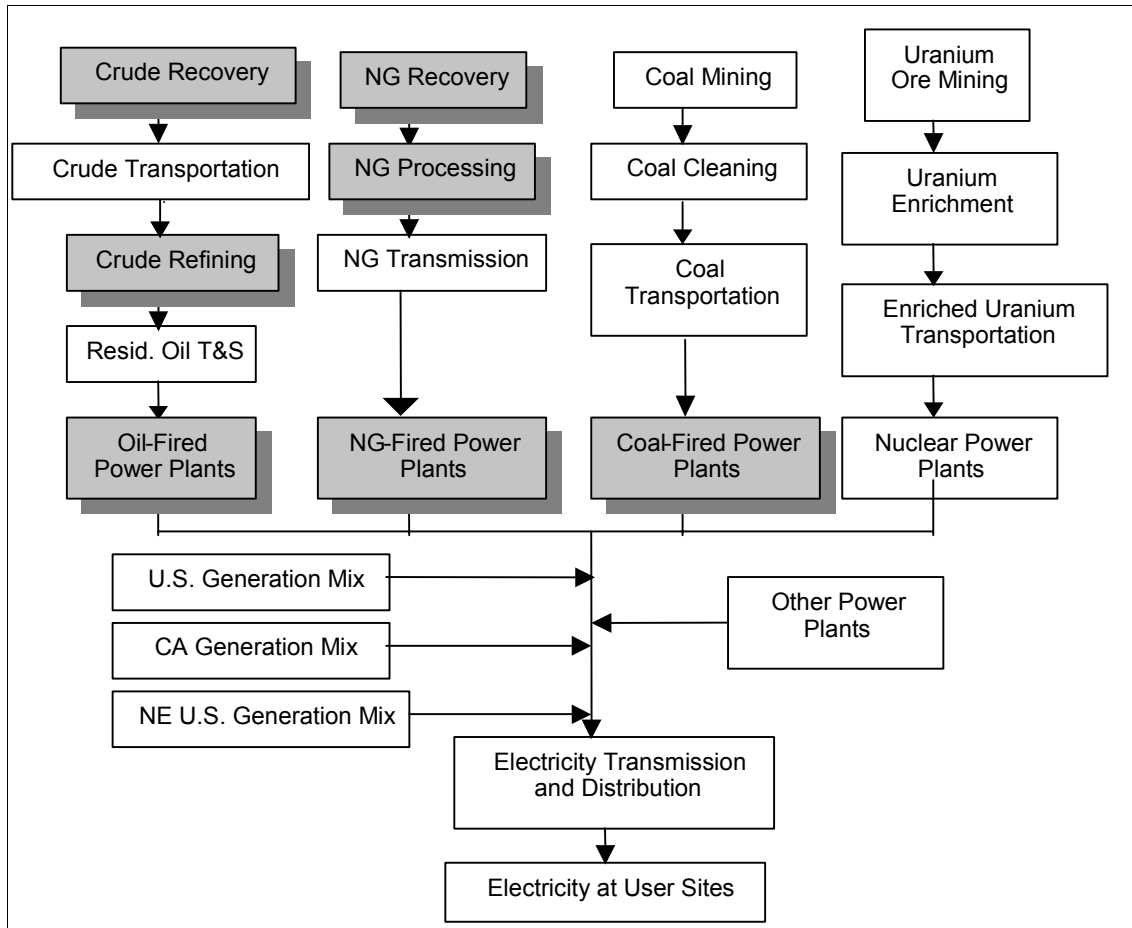


Figure 1.11 Pathways of Electricity Generation

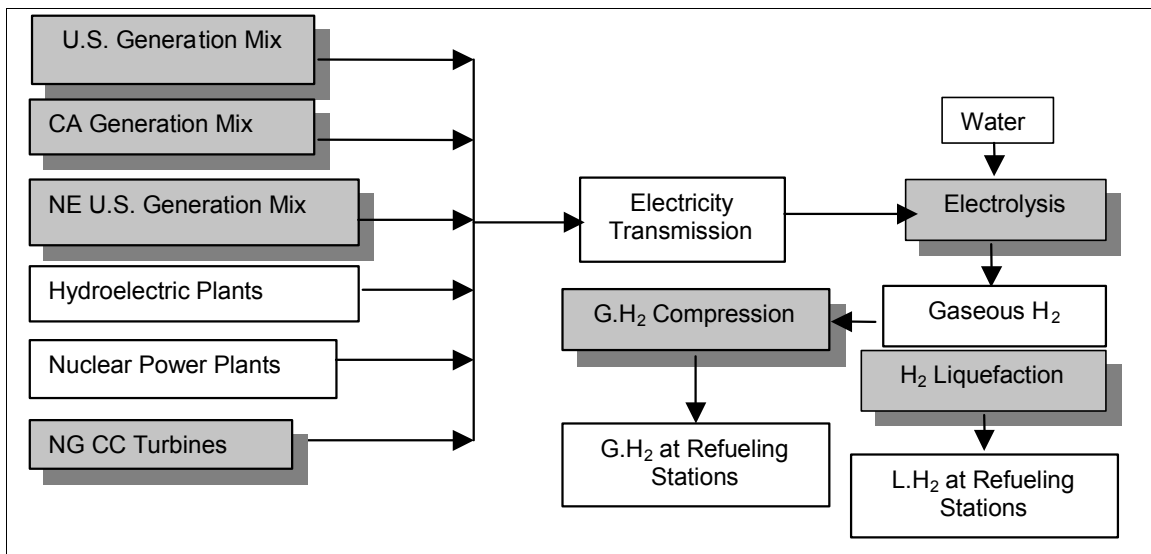


Figure 1.12 Pathways of Hydrogen Production via Electrolysis of Water at Refueling Stations

Table 1.3 Parametric Probability Distribution Values for Key WTT Parameters

Activity	Value at a Probability (%) <sup>a</sup>		
	P20	P50	P80
<i>Petroleum-Based Fuels</i>			
Petroleum recovery <sup>b</sup>	96.0	98.0	99.0
Petroleum refining: 340 ppm sulfur CG	85.0	85.5	86.0
Petroleum refining: 150 ppm sulfur RFG with MTBE: gasoline blendstock	85.0	86.0	87.0
Petroleum refining: 5–30 ppm sulfur RFG with MTBE: gasoline blendstock	84.0	85.5	87.0
Petroleum refining: 5–30 ppm sulfur RFG with EtOH: gasoline blendstock	84.0	85.5	87.0
Petroleum refining: 5–30 ppm sulfur RFG with no oxygenate	83.0	84.5	86.0
Petroleum refining: 120–350 ppm sulfur diesel	88.0	89.0	90.0
Petroleum refining: 5–30 ppm sulfur diesel	85.0	87.0	89.0
Petroleum refining: 5 ppm sulfur naphtha	89.0	91.0	93.0
<i>Natural-Gas-Based Fuels</i>			
NG recovery: NA NG, NNA NG, NNA FG	96.0	97.5	99.0
NG processing: NA NG, NNA NG, NNA FG	96.0	97.5	99.0
LNG production from NG and FG <sup>b</sup>	87.0	91.0	93.0
NG compression: NG compressor	92.0	93.0	94.0
NG compression: electric compressor <sup>b</sup>	96.0	97.0	98.0
MeOH production: with no steam production <sup>b</sup>	65.0	67.5	71.0
MeOH production: with steam production <sup>b</sup> – efficiency	62.0	64.0	66.0
MeOH production: with steam production, steam credit (Btu/mmBtu) <sup>b</sup>	64,520	78,130	90,910
FT diesel and naphtha production: with no steam production	61.0	63.0	65.0
FT diesel and naphtha production: with steam production	53.0	55.0	57.0
FT diesel and naphtha production: with steam production, steam credit (Btu/mmBtu)	189,000	200,000	210,500
G.H <sub>2</sub> production in central plants: with no steam production	68.0	71.5	75.0
G.H <sub>2</sub> production in central plants: with steam production	66.0	69.5	73.0
G.H <sub>2</sub> production in central plants: with steam production, steam credit (Btu/mmBtu)	120,000	145,000	170,000
H <sub>2</sub> liquefaction in central plants <sup>b</sup>	65.0	71.0	77.0
G.H <sub>2</sub> production in stations	62.0	67.0	72.0
G.H <sub>2</sub> compression for central G.H <sub>2</sub> : NG compressor <sup>b</sup>	82.5	85.0	87.5
G.H <sub>2</sub> compression for central G.H <sub>2</sub> : electric compressor <sup>b</sup>	90.0	92.5	95.0
G.H <sub>2</sub> compression for station G.H <sub>2</sub> : NG compressor <sup>b</sup>	83.5	86.0	88.5
G.H <sub>2</sub> compression for station G.H <sub>2</sub> : electric compressor <sup>b</sup>	91.5	94.0	96.5
H <sub>2</sub> liquefaction in stations	60.0	66.0	72.0
<i>Corn-to-Ethanol Pathways</i>			
Energy use for corn farming (Btu/bushel of corn) <sup>b</sup>	12,600	26,150	39,700
Nitrogen (N) fertilizer use in corn farms (g/bushel of corn)	370	475	580
N <sub>2</sub> O emissions in corn farms: N in N <sub>2</sub> O as % of N in N fertilizer <sup>b</sup>	1.0	1.5	2.0
Soil CO <sub>2</sub> emissions in corn farms (g/bushel of corn) <sup>b</sup>	0	195	390
Ethanol yield, dry mill plants (gal/bushel of corn) <sup>b</sup>	2.5	2.65	2.8
Ethanol yield, wet mill plants (gal/bushel of corn) <sup>b</sup>	2.4	2.55	2.7
Energy use in dry mill plants (Btu/gal of EtOH)	36,900	39,150	41,400
Energy use in wet mill plants (Btu/gal of EtOH)	34,000	37,150	40,300
<i>Cellulosic Biomass-to-Ethanol Pathways</i>			
Energy use for tree farming (Btu/dry ton of trees)	176,080	234,770	293,460
Energy use for grass farming (Btu/dry ton of grasses)	162,920	190,080	271,540
N fertilizer use for tree farming (g/dry ton of trees)	532	709	886

Table 1.3 Parametric Probability Distribution Values for Key WTT Parameters (Cont.)

Activity	Value at a Probability (%) <sup>a</sup>		
	P20	P50	P80
<i>Cellulosic Biomass-to-Ethanol Pathways (Cont.)</i>			
N fertilizer use for grass farming (g/dry ton of grasses)	7,980	10,630	13,290
N <sub>2</sub> O emissions in biomass farms: N in N <sub>2</sub> O as % of N in N fertilizer <sup>b</sup>	0.8	1.15	1.5
Soil CO <sub>2</sub> sequestration in tree farms (g/dry ton of trees) <sup>b</sup>	-225,000	-112,500	0
Soil CO <sub>2</sub> sequestration in grass farms (g/dry ton of grasses) <sup>b</sup>	-97,000	-48,500	0
Ethanol yield, woody biomass plants (gal/dry ton of trees)	76	87	98
Ethanol yield, herbaceous biomass plants (gal/dry ton of grasses)	80	92	103
Electricity credit of woody biomass plants (kWh/gal of EtOH) <sup>b</sup>	-1.73	-1.15	-0.56
Electricity credit of herbaceous biomass plants (kWh/gal of EtOH) <sup>b</sup>	-0.865	-0.57	-0.28
<i>Electric Power Plants</i>			
Oil-fired power plants: steam boiler	32.0	35.0	38.0
NG-fired power plants: steam boiler	32.0	35.0	38.0
NG-fired power plants: CC turbines <sup>b</sup>	50.0	55.0	60.0
Coal-fired power plants: steam boiler	33.0	35.5	38.0
Coal-fired power plants: advanced technologies	38.0	41.5	45.0
H <sub>2</sub> electrolysis efficiency	67.0	71.5	76.0

<sup>a</sup> Values are in percent unless otherwise indicated.

<sup>b</sup> A triangle distribution curve is assumed for these parameters. In this case, the P20 value is actually the P0 value and the P80 value is the P100 value.

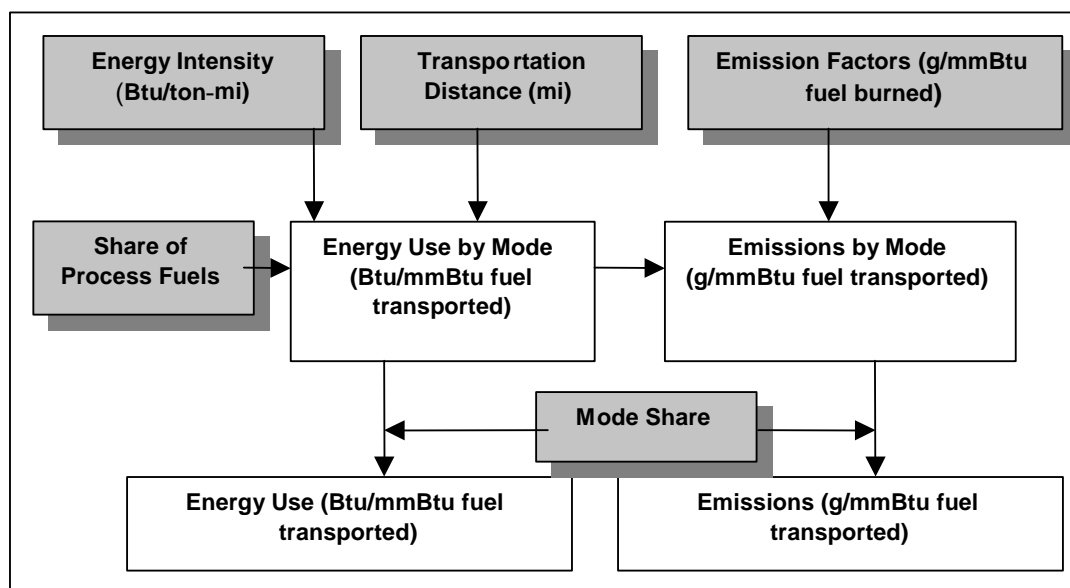


Figure 1.13 Simulation of Transportation of Energy Feedstocks and Fuels

- Estimate the distance of each transportation mode for each feedstock or fuel.
- Calculate the energy use and emissions associated with each transportation mode fueled with each process fuel.
- Add together the energy use and emissions of all transportation modes for transporting the given feedstock or fuel.

Table 1.4 presents energy efficiencies for transportation of various feedstocks and fuels. These efficiencies were output results with energy use results estimated by using the GREET model (with the detailed input parameters discussed above). For most of the feedstocks and fuels, transportation energy efficiencies are above 99%. As expected, transportation of NNA-produced fuels has lower energy efficiencies. Transportation of methanol also has low energy efficiencies because a large of portion of methanol was assumed to be transported to refueling stations via trucks within the United States.

Table 1.4 Energy Efficiencies for Feedstock and Fuel Transportation  
Calculated from GREET Outputs

Feedstock/Fuel	Energy Efficiency (%)
Crude oil from oil fields to U.S. refineries	99.0
Gasoline from U.S. refineries to refueling stations	99.4
Diesel from U.S. refineries to refueling stations	99.2
Petroleum naphtha from U.S. refineries to refueling stations	99.0
NG from NA NG processing plants to refueling stations	99.3
LNG from NNA plants to U.S. LNG terminals	98.5
MeOH from NA plants to refueling stations	98.0
MeOH from NNA plants to refueling stations	96.8
FT naphtha and diesel from NA plants to refueling stations	99.2
FT naphtha and diesel from NNA plants to refueling stations	98.2
Central G.H <sub>2</sub> from NA H <sub>2</sub> plants to refueling stations	96.3
L.H <sub>2</sub> from NA H <sub>2</sub> plants to refueling stations	98.9
L.H <sub>2</sub> from NNA H <sub>2</sub> plants to refueling stations	95.8
EtOH from NA EtOH plants to refueling stations	98.5

Efficiencies for pipeline transportation of G.H<sub>2</sub> are low because a large quantity of G.H<sub>2</sub> needs to be compressed and moved (because of the low volumetric energy content of G.H<sub>2</sub> at atmospheric pressure). Transportation of L.H<sub>2</sub> has low efficiencies because of the low energy content of L.H<sub>2</sub> and the boiling-off loss of L.H<sub>2</sub> during transportation. Ethanol's low transportation efficiency is attributable to the use of trucks to transport a large quantity of ethanol to refueling stations.

### 1.3 Results

We analyzed 75 fuel pathway options in this study (see Table 1.5). In this report, we present results for 30 representative pathways. The 30 representative pathways are indicated by an "X" in Table 1.5; results for each representative pathway are illustrated in the graphs in this section. Volume 3 of this report series provides results for all 75 of the pathways analyzed.

As the table shows, Argonne assumed that NA plants that produce methanol, FTD, FT naphtha, G.H<sub>2</sub>, and L.H<sub>2</sub> could be designed to co-produce steam or electricity for export. On the other hand, we assumed that NNA plants may be designed to co-generate only electricity for export. For NNA plants with FG as feed, we did not assume co-generation of steam or electricity.

For electricity generation, we included the U.S., the California, and the Northeast U.S. generation mixes to illustrate energy and emission effects of various electric generation mixes. We included NG-fired CC turbines, which are energy-efficient and which currently supply incremental electricity demand to many U.S. areas. For hydrogen (H<sub>2</sub>) production via

electrolysis, we included electricity generation from nuclear and hydroelectric power to show the effects of air-pollution-free electricity generation on H<sub>2</sub> production.

We analyzed four pathway options for corn-based ethanol, depending on milling technology and the manner of addressing ethanol co-products. Besides E100 (pure ethanol) for FCV applications, we included E85 (85% ethanol and 15% gasoline) for internal combustion engine (ICE) applications. (Note: Because ethanol contains about 5% gasoline as a denaturant for ICE applications, in our analysis, E85 actually contains about 80% ethanol and 20% gasoline.)

In selecting the 30 pathways for presentation here, we did not include fuel plant designs with steam or electricity co-generation. These design options provide additional energy and emissions benefits for the fuels evaluated here (namely, G.H<sub>2</sub>, methanol, FT naphtha, and FTD), but whether these options are considered appropriate depends on the specific plant location relative to an energy infrastructure and potential customers. We also eliminated all pathways based on flared gas. Flared-gas-based pathways offer significant energy and emissions benefits; however, the amount of flared gas represents a small portion of the resource base. Results of all eliminated pathways are presented in Volume 3 of this report series. The following paragraphs discuss the results in terms of total energy use, fossil energy use, petroleum use, and GHG emissions.

Table 1.5 Fuel Pathway Options Analyzed in Argonne’s WTT Study and Selected for Presentation in This Report

Fuel Pathways	Selected for Presentation (indicated by X )
<i>Petroleum-Based</i>	
(1) Conventional (current) gasoline (CG)	X
(2) RFG with MTBE (current federal RFG) (150 ppm sulfur)	
(3) RFG with MTBE (5–30 ppm sulfur)	
(4) RFG with EtOH (5–30 ppm sulfur)	
(5) Low-sulfur (LS) RFG without oxygenate (5–30 ppm sulfur)	X
(6) Conventional diesel (CD)	X
(7) Low-sulfur diesel (15 ppm sulfur)	X
(8) Crude oil naphtha	X
<i>NG-Based</i>	
(9) CNG: NA NG	X
(10) CNG: NNA NG	X
(11) CNG: NNA FG	
(12) MeOH: NA NG <sup>a</sup>	X
(13) MeOH: NA NG <sup>b</sup>	
(14) MeOH: NA NG <sup>c</sup>	
(15) MeOH: NNA NG <sup>a</sup>	X
(16) MeOH: NNA NG <sup>c</sup>	
(17) MeOH: NNA FG <sup>a</sup>	
(18) FTD: NA NG <sup>a</sup>	X
(19) FTD: NA NG <sup>b</sup>	
(20) FTD: NA NG <sup>c</sup>	
(21) FTD: NNA NG <sup>a</sup>	X
(22) FTD: NNA NG <sup>c</sup>	
(23) FTD: NNA FG <sup>a</sup>	
(24) FT naphtha: NA NG <sup>a</sup>	X
(25) FT naphtha: NA NG <sup>b</sup>	
(26) FT naphtha: NA NG <sup>c</sup>	
(27) FT naphtha: NNA NG <sup>a</sup>	X
(28) FT naphtha: NNA NG <sup>c</sup>	
(29) FT naphtha: NNA FG <sup>a</sup>	
(30) G.H <sub>2</sub> – central plants: NA NG <sup>a</sup>	X

Table 1.5 Fuel Pathway Options Analyzed in Argonne’s WTT Study and Selected for Presentation in this Report (Cont.)

Fuel Pathways	Selected for Presentation (indicated by X)
<i>NG-Based (Cont.)</i>	
(31) G.H <sub>2</sub> – central plants: NA NG <sup>b</sup>	
(32) G.H <sub>2</sub> – central plants: NA NG <sup>c</sup>	
(33) G.H <sub>2</sub> – central plants: NNA NG <sup>a</sup>	X
(34) G.H <sub>2</sub> – central plants: NNA NG <sup>c</sup>	
(35) G.H <sub>2</sub> – central plants: NNA FG <sup>a</sup>	
(36) L.H <sub>2</sub> – central plants: NA NG <sup>a</sup>	X
(37) L.H <sub>2</sub> – central plants: NA NG <sup>b</sup>	
(38) L.H <sub>2</sub> – central plants: NA NG <sup>c</sup>	
(39) L.H <sub>2</sub> – central plants: NNA NG <sup>a</sup>	X
(40) L.H <sub>2</sub> – central plants: NNA NG <sup>c</sup>	
(41) L.H <sub>2</sub> – central plants: from NNA FG <sup>a</sup>	
(42) G.H <sub>2</sub> – stations: NA NG <sup>a</sup>	X
(43) G.H <sub>2</sub> – stations: NNA NG <sup>a</sup>	X
(44) G.H <sub>2</sub> – stations: NNA FG <sup>a</sup>	
(45) L.H <sub>2</sub> – stations: NA NG <sup>a</sup>	X
(46) L.H <sub>2</sub> – stations: NNA NG <sup>a</sup>	X
(47) L.H <sub>2</sub> – stations: NNA FG <sup>a</sup>	
<i>Electricity Generation</i>	
(48) Electricity: U.S. generation mix	X
(49) Electricity: CA generation mix	
(50) Electricity: Northeast U.S. generation mix	
(51) Electricity: NA NG-fired CC turbines	X
<i>Electrolysis-Based Hydrogen<sup>d</sup></i>	
(52) G.H <sub>2</sub> – station: U.S. generation mix	X
(53) G.H <sub>2</sub> – station: CA generation mix	
(54) G.H <sub>2</sub> – station: Northeast U.S. generation mix	
(55) G.H <sub>2</sub> – station: NA NG-fired CC turbines	X
(56) G.H <sub>2</sub> – station: nuclear power	
(57) G.H <sub>2</sub> – station: hydroelectric power	
(58) L.H <sub>2</sub> – station: U.S. generation mix	X
(59) L.H <sub>2</sub> – station: CA generation mix	
(60) L.H <sub>2</sub> – station: Northeast U.S. generation mix	
(61) L.H <sub>2</sub> – station: NA NG-fired combined-cycle turbines	X
(62) L.H <sub>2</sub> – station: nuclear power	
(63) L.H <sub>2</sub> – station: hydroelectric power	
<i>Ethanol Options</i>	
<i>E-100 (pure ethanol)</i>	
(64) Dry mill, displacement	
(65) Dry mill, market value	
(66) Wet mill, displacement	
(67) Wet mill, market value	X
(68) Woody cellulose	X
(69) Herbaceous cellulose	X
<i>E-85<sup>e</sup></i>	
(70) Dry mill, displacement	
(71) Dry mill, market value	
(72) Wet mill, displacement	
(73) Wet mill, market value	
(74) Woody cellulose	
(75) Herbaceous cellulose	

<sup>a</sup> Without steam or electricity co-generation.

<sup>b</sup> With steam co-generation.

<sup>c</sup> With electricity co-generation.

<sup>d</sup> In the case of electrolysis, water is converted to hydrogen and oxygen through the use of electricity, so both water and electricity are treated as feedstocks.

<sup>e</sup> Ethanol contains 5% gasoline as a denaturant.

### 1.3.1 Total Energy Use

Total energy use from fuel production, i.e., WTT, includes use of all energy sources (non-renewable and renewable). Figure 1.14 presents two bars for each of the four electrolysis H<sub>2</sub> options and the two electricity options. The blank bars, which represent normal results for GREET simulations, include both energy losses from WTT and energy contained in the fuel delivered; the solid bars represent energy losses only. The latter are provided here to allow comparison of all fuels on a consistent basis and should be used for discussions concerning WTT results of this study. The information presented in the solid bars was used in the WTW integration process in this study. Similarly, Figure 1.15 presents two bars for each of the electrolysis H<sub>2</sub> and electricity options for fossil energy use. Again, the solid bars in Figure 1.15 should be used for discussions concerning WTT results.

We found that petroleum-based fuels and CNG offer the lowest total energy use for each unit of energy delivered to vehicle tanks (see Figure 1.14, in which the tops and bottoms of the bars indicate the 80 and 20 percentiles, respectively). NG-based fuels (except CNG) generally use the greatest amount of total energy. The fuels with the highest energy use are L.H<sub>2</sub> (production in both central plants and refueling stations), G.H<sub>2</sub> and L.H<sub>2</sub> production via electrolysis, and electricity generation. L.H<sub>2</sub> suffers large efficiency losses during H<sub>2</sub> liquefaction. H<sub>2</sub> production via electrolysis suffers two large efficiency losses: electricity generation and H<sub>2</sub> production.

Total energy use by electricity generation is reduced when using NG-fired CC turbines rather than the U.S. electric generation mix because the average conversion efficiency of existing U.S. fossil fuel plants is 32–35%; the conversion efficiency of NG-fired CC turbines is over 50%.

Use of non-North-American NG for NG-based fuel production results in slightly higher total energy use than does use of North American NG, because transportation of liquid fuels to the United States consumes additional energy. In the cases of CNG, G.H<sub>2</sub>, and station-produced L.H<sub>2</sub>, the requirement for NG liquefaction for shipment of NNA gas sources to North America causes additional energy efficiency losses.

### 1.3.2 Fossil Energy Use

Fossil fuels include petroleum, NG, and coal — the three major nonrenewable energy sources. Except for ethanol pathways, the patterns of fossil energy use are similar to those of total energy use (see Figure 1.15). For woody and herbaceous (cellulosic) ethanol pathways, the difference is attributable to the large amount of lignin burned in these ethanol plants. We accounted for the energy in lignin in calculating total energy use, but not in calculating fossil energy use. So fossil energy use is much lower than total energy use for the two cellulosic ethanol pathways.

For electricity generation and H<sub>2</sub> production via electrolysis, fossil energy use between the U.S. generation mix and NG-fired CC turbines is very similar because, while the U.S. generation mix has an overall conversion efficiency lower than that of CC turbines, some non-fossil fuel power plants under the U.S. average mix (such as nuclear and hydroelectric power plants) do not contribute to fossil energy use.

### 1.3.3 Petroleum Use

As expected, production of all petroleum-based fuels involves high petroleum use (see Figure 1.16). Methanol pathways have relatively high petroleum use because trucks and rails are used to transport a large quantity of methanol.

For electricity generation and H<sub>2</sub> production via electrolysis, we observed a large reduction in petroleum use from the U.S. average generation mix to NG-fired CC turbines because, under the U.S. generation mix, some (a small amount) electricity is generated by burning residual oil. In addition, mining and transportation of coal consume a significant amount of oil.

The high petroleum use for centrally produced G.H<sub>2</sub>, relative to station-produced G.H<sub>2</sub>, is attributable to the fact that the former is compressed in refueling stations with electric compressors only, while the latter is compressed by means of both electric and NG compressors. Electricity pathways also consume some petroleum.

The amount of petroleum use for the three ethanol pathways is similar to the amounts used for the petroleum gasoline pathways because of the large amount of diesel fuel that is consumed during farming and transportation of corn and cellulosic biomass. The amount of petroleum used for the herbaceous cellulosic ethanol pathway is less than that used for the corn ethanol and woody cellulosic ethanol pathways because corn ethanol consumes a relatively large amount of diesel fuel and because transportation of woody biomass, which has high moisture content, consumes more energy than does transportation of herbaceous biomass.

### 1.3.4 Greenhouse Gas Emissions

Figure 1.17 shows the sum of WTT CO<sub>2</sub>-equivalent emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O. Petroleum-based fuels and CNG produced from North American NG are associated with low WTT GHG emissions because of their high production efficiency. CNG from NNA NG has relatively high GHG emissions because of CH<sub>4</sub> emissions generated from liquid NG boiling-off and leakage during transportation (CH<sub>4</sub>, a GHG, is 21 times as potent as CO<sub>2</sub>). Methanol and FT fuels have high GHG emissions because of CO<sub>2</sub> emissions during fuel production that result from their low production efficiency relative to that of petroleum-based fuels.

All H<sub>2</sub> pathways have very high GHG emissions because all of the carbon in NG feedstock is removed during H<sub>2</sub> production, for which we did not assume carbon sequestration. For the electrolysis cases, CO<sub>2</sub> releases during electricity generation (attributable to fossil-fueled generation) are significant. L.H<sub>2</sub> production, electrolysis H<sub>2</sub> (both gaseous and liquid), and electricity generation have the highest GHG emissions. Relative to emissions from NG-fired CC turbine plants, there is a large increase in GHG emissions from the U.S. average electric generation mix, primarily because of the high GHG emissions from coal- and oil-fired electric power plants. Coal- and oil-fired plants contribute a large share of the U.S. average.

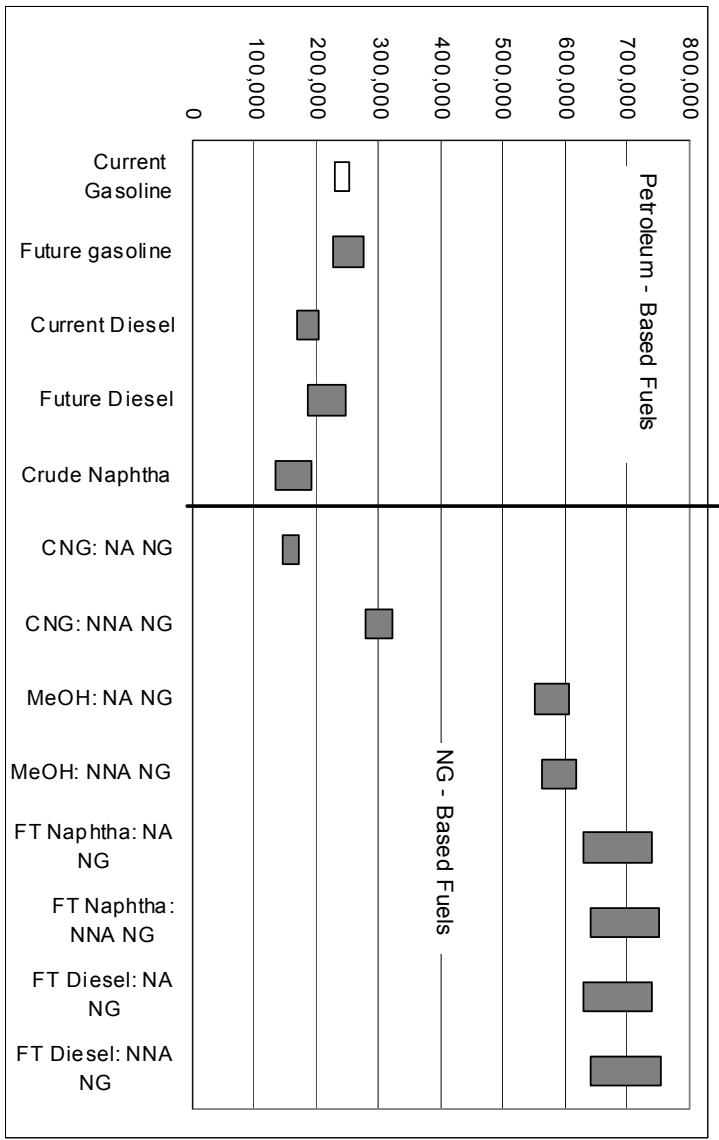
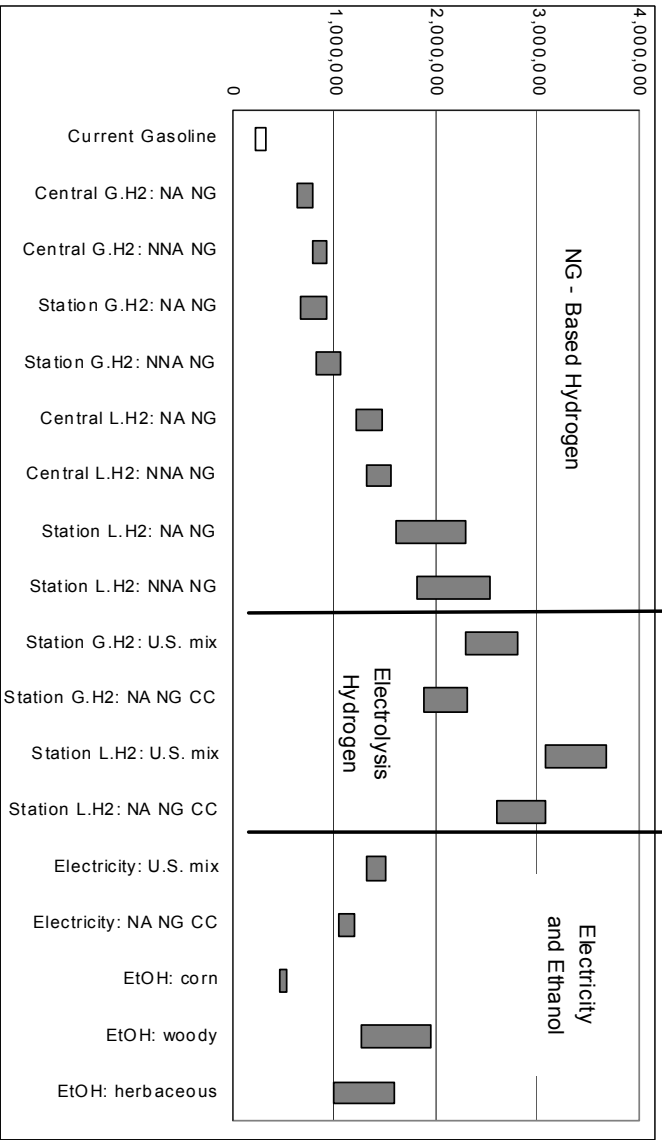
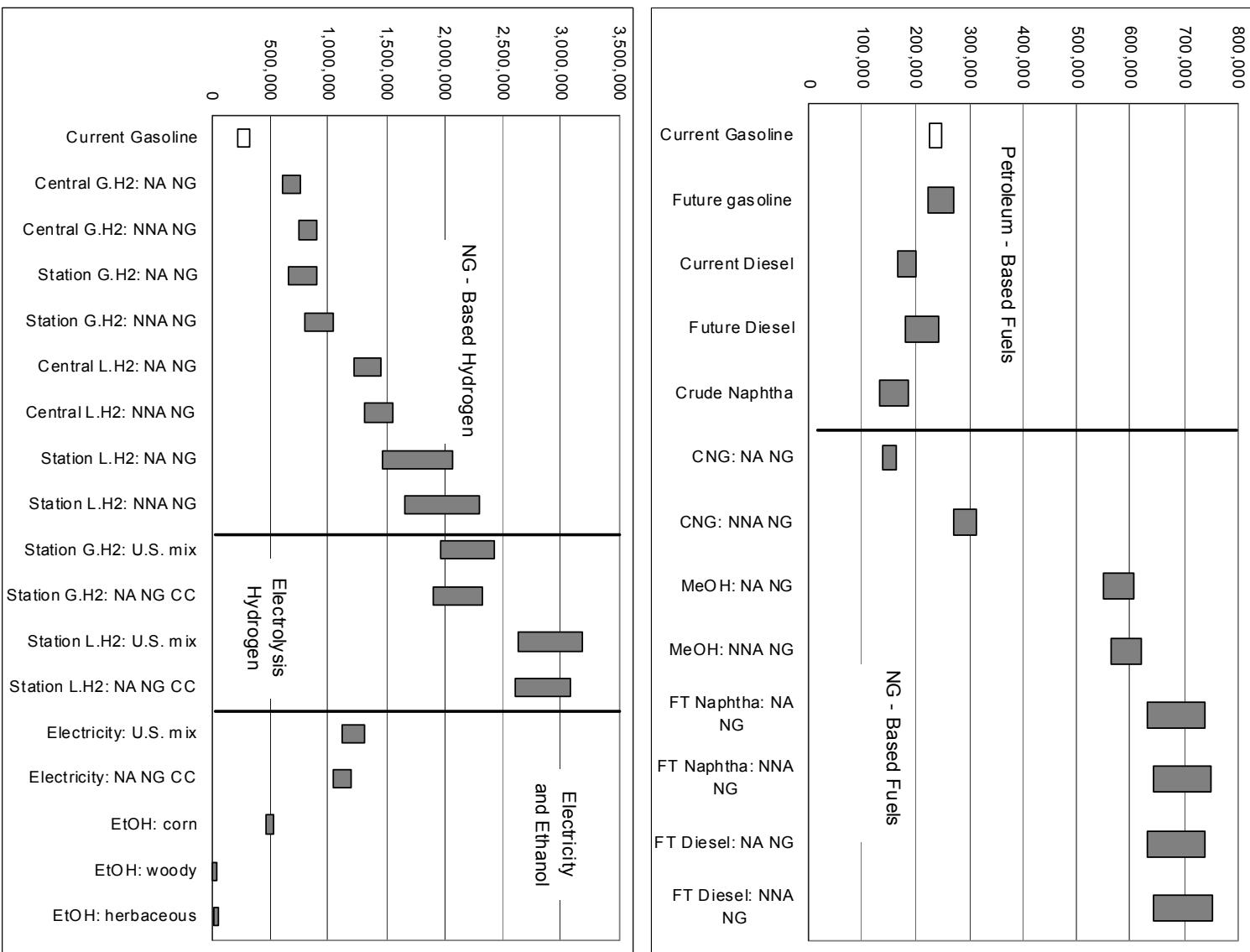


Figure 1.14 WTT Total Energy Use (Btu/mmbtu) of fuel delivered to vehicle tanks)

Figure 1.15 WTT Fossil Energy Use (Btu/mmBtu of fuel delivered to vehicle tanks)



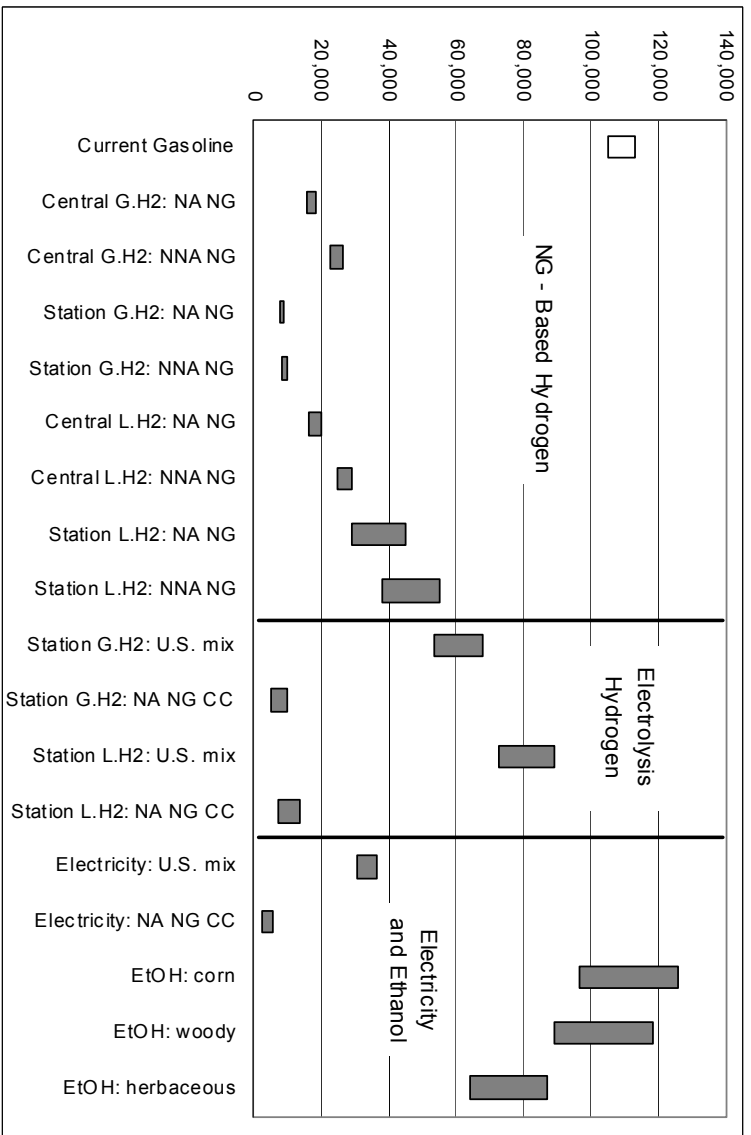
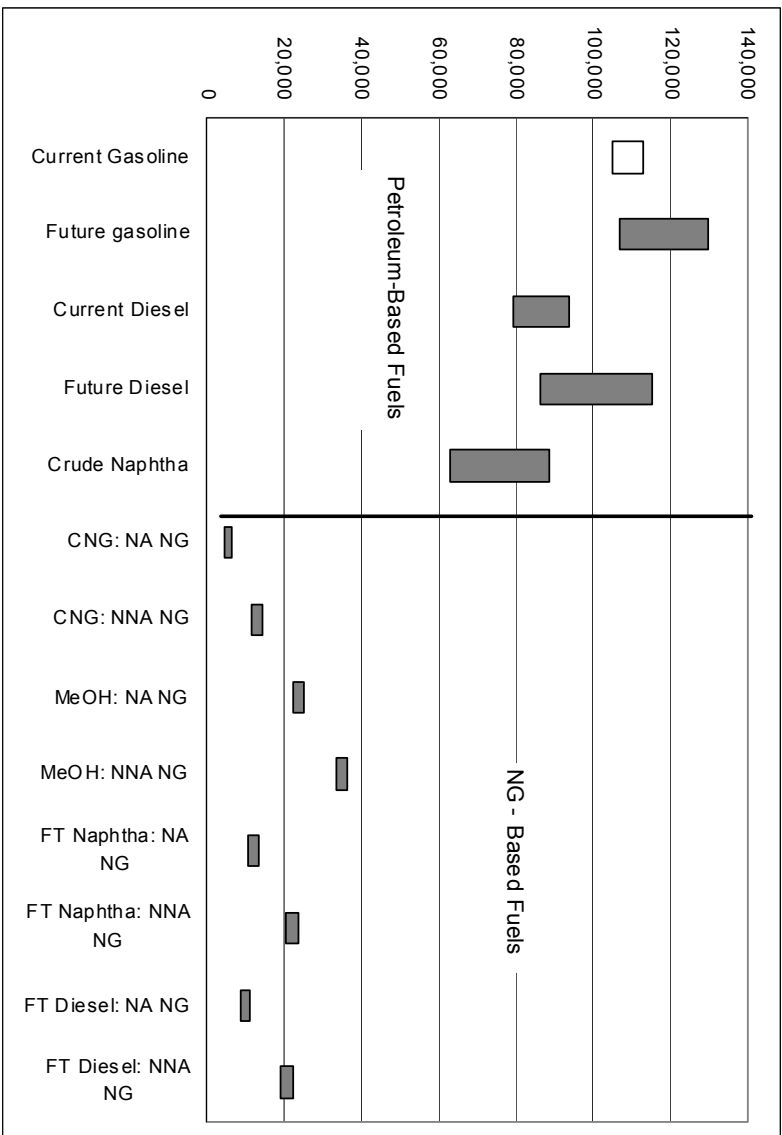


Figure 1.16 WTT Petroleum Use (Btu/mmBtu) of fuel delivered to vehicle tanks)

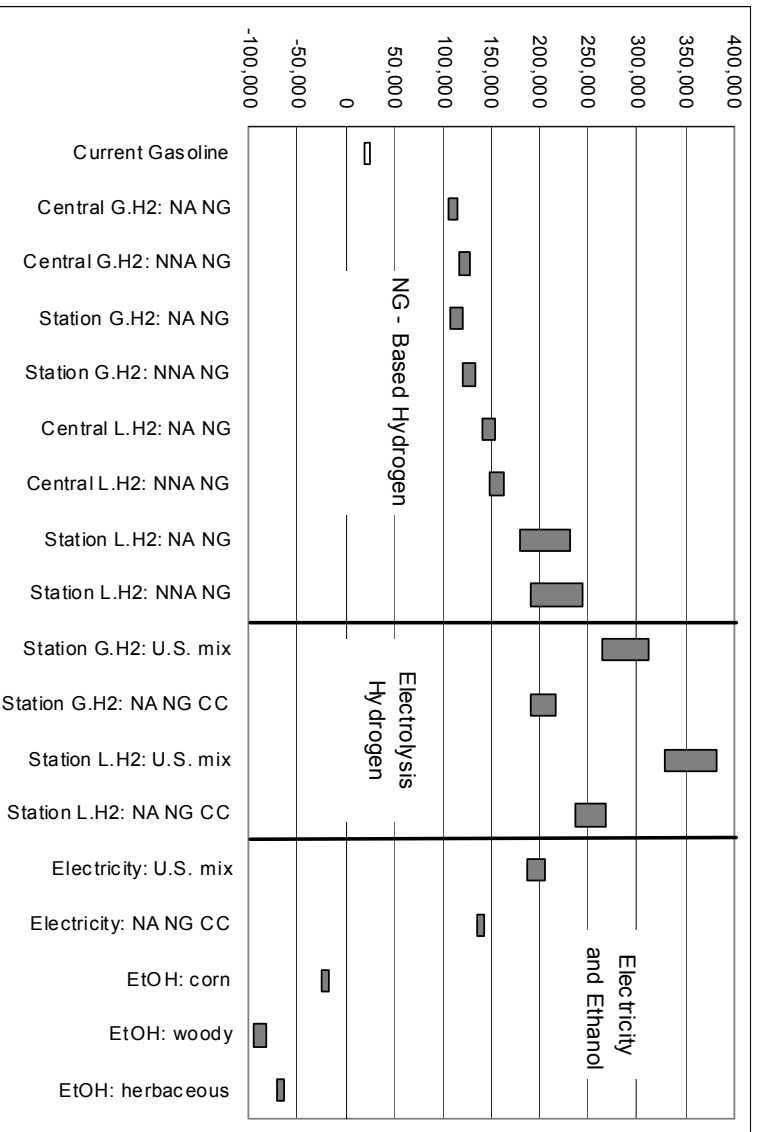
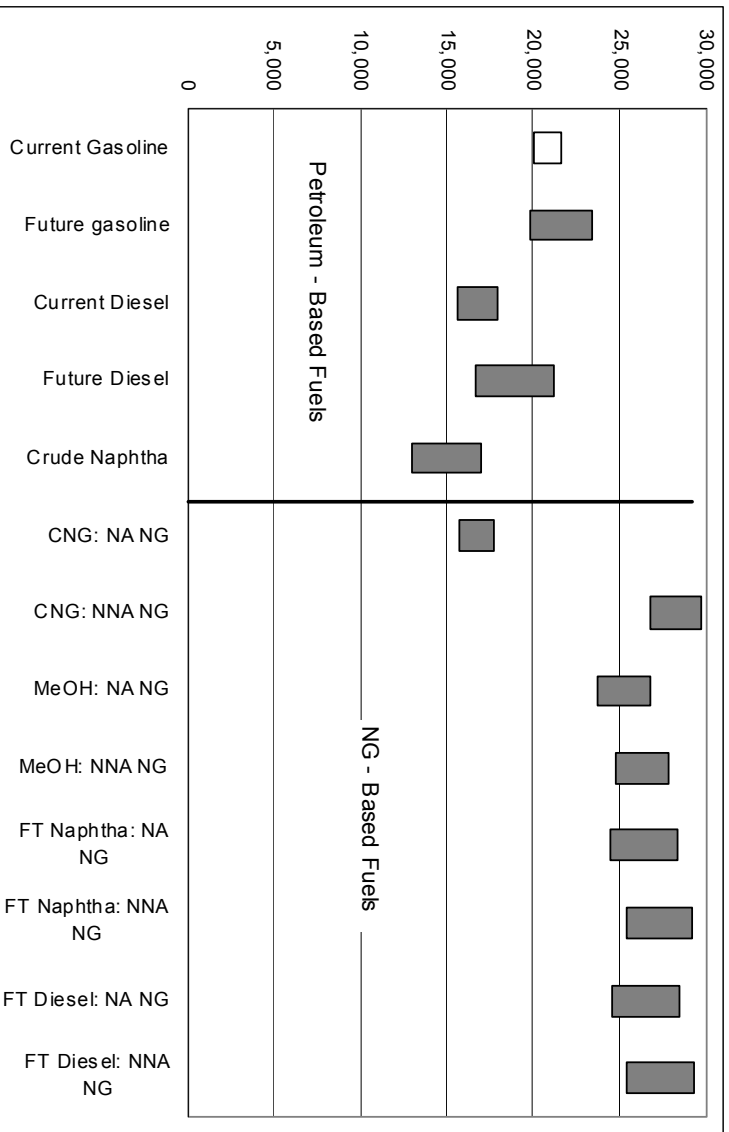


Figure 1.17 WTT GHG Emissions (g/mmBtu of fuel delivered to vehicle tanks)

The three ethanol pathways have negative GHG emissions because of carbon uptake sequestration during growth of corn plants, trees, and grass. Corn ethanol has smaller negative GHG values because use of fossil fuels during corn farming and in ethanol plants offsets some of the CO<sub>2</sub> sequestered during growth of corn plants. All the carbon sequestered during biomass growth is released back to the air during combustion of ethanol in vehicles, which is accounted for in the integration of well-to-tank and tank-to-wheel in Part 3.

## 1.4 Conclusions

Our WTT analysis resulted in the following conclusions. It is important to remember that WTT results are incomplete in evaluating fuel/propulsion systems. The systems must be evaluated on a WTW basis; this analysis is presented in Part 3 of this volume.

- *Total Energy Use.* For the same amount of energy delivered to the vehicle tank for each of the fuels evaluated in our study, petroleum-based fuels and CNG are subject to the lowest WTT energy losses. Methanol, FT naphtha, FTD, and G.H<sub>2</sub> from NG and corn-based ethanol are subject to moderate WTT energy losses. Liquid H<sub>2</sub> from NG, electrolysis H<sub>2</sub> (gaseous and liquid), electricity generation, and cellulosic ethanol are subject to the largest WTT energy losses.
- *Fossil Energy Use.* Fossil energy use — including petroleum, NG, and coal — follows patterns similar to those for total energy use, except for cellulosic ethanol. Although WTT total energy use of cellulosic ethanol production is high, its fossil energy use is small because cellulosic ethanol plants burn lignin, a non-fossil energy, for needed heat.
- *Petroleum Use.* Production of all petroleum-based fuels requires a large amount of petroleum. Electrolysis H<sub>2</sub> (with the U.S. average electricity) and the three ethanol pathways consume an amount of petroleum about equal to that consumed by petroleum-based fuels. NG-based fuel pathways require only small amounts of petroleum.
- *Greenhouse Gas Emissions.* Production of petroleum-based fuels and NG-based methanol, FT naphtha, and FTD results in a smaller amount of WTT GHG emissions than production of H<sub>2</sub> (gaseous and liquid) and electricity generation. WTT GHG emission values of the three ethanol pathways are negative because of carbon uptake during growth of corn plants, trees, and grass.

Overall, our WTT analysis reveals that petroleum-based fuels have lower WTT total energy use than do non-petroleum-based fuels. L.H<sub>2</sub> production (in both central plants and refueling stations) and production of G.H<sub>2</sub> and L.H<sub>2</sub> via electrolysis can be energy-inefficient and can generate a large amount of WTT GHG emissions. Cellulosic ethanol, on the other hand, because it is produced from renewable sources, offers significant reductions in GHG emissions. The other fuels options examined here have moderate WTT energy and GHG emissions effects.

## 1.5 Acknowledgments

Argonne's WTT work was funded by the Global Alternative Propulsion Center of GM. Argonne would like to acknowledge guidance and input from the GM project managers, Dr. Tony Finizza, Dr. Jim Wallace, and Greg Ruselowski. We are grateful to Dr. James Simnick and Andrew Armstrong of BP, Gilbert Jersey and Dr. John Robbins of ExxonMobil, Norman Brinkman of the

GM R&D Center, and Jean Cadu of Shell for their input to and review of this report. We would also like to thank our Argonne colleagues Marianne Mintz, Dan Santini, and Chris Saricks for their input.

Finally, Argonne would like to thank Tien Nguyen, Dr. Phillip Patterson, and David Rodgers of the U.S. Department of Energy's Office of Transportation Technologies; without their support of previous versions of the GREET model, this study would not have been possible. We would also like to acknowledge the excellent editorial support of Mary Fitzpatrick of Argonne.



## **Part 2**

# **Tank-to-Wheel Energy Utilization for a North American Vehicle**

Trudy R. Weber  
Thermal and Energy Systems Lab  
GM R&D and Planning Center

Gerald D. Skellenger  
Electrical and Controls Integration Lab  
GM R&D and Planning Center

David A. Masten  
Global Alternative Propulsion Center  
General Motors Corporation

June 2001



## 2.1 Introduction

The purpose of this study, conducted by General Motors R&D and Planning Center and General Motors Corporation, was to quantify the tank-to-wheel energy use of advanced conventional and unconventional powertrain systems, focusing on technologies that are expected to be implemented in 2005 and beyond. These technologies were assessed on the basis of their potential for improving fuel economy while maintaining vehicle performance. The propulsion systems included in this study were a conventional powertrain (with gasoline, diesel, E85, and CNG engines), a parallel electric hybrid powertrain (using gasoline, diesel, and E85 engines), and direct and battery-hybrid fuel cell systems (with reformers for gasoline, methanol, and ethanol, and without reformers). Each of the vehicle architectures was modeled and designed to meet a set of specified performance requirements, such as maximum launch acceleration, 0–60 mile per hour (mph) time, passing maneuvers, and gradeability. Dominant among these requirements in sizing the powertrain and selecting appropriate ratios were the peak acceleration and top speed of the vehicle.

The baseline vehicle selected for this study was a full-size pickup truck. We employed vehicle simulation models using validated GM proprietary component characteristics to establish the fuel economy and energy required on the EPA urban and highway duty cycles. The GM proprietary Hybrid Powertrain Simulation Program (HPSP) vehicle simulation model was used to design and analyze each vehicle concept.

This report briefly discusses each of these vehicle models and the assumptions made in our simulations and presents the fuel economy and performance predictions based on this input.

Figure 2.1 illustrates how the energy is used in a typical pickup truck while negotiating EPA's urban and highway driving cycles. Advanced powertrain technologies are targeted at reducing the engine and driveline losses, eliminating the braking losses through regeneration and hybrid technologies, and powering the accessories with advanced energy management strategies. Advanced vehicle-level technologies impact the mass and the aerodynamic and rolling resistance losses.

## 2.2 Methodology

The HPSP is a GM-proprietary tool that, with an extensive database of proprietary component maps, can model any conventional or advanced vehicle architecture or powertrain technology.

Figure 2.2 provides an overview of the HPSP modeling and simulation approach. The model simulates power and energy flows in the vehicle driveline while capturing all losses and inefficiencies in the components and subsystems.

The model implements a “backward-driven” approach, which uses the driving cycle velocity profile to determine the road-load and acceleration requirements of the vehicle (Weber 1988; Rohde and Weber 1984). The algorithm then works its way backward through all the powertrain components, taking losses into account along the way. In this way, the output requirement(s) at the energy source(s) (i.e., fuel tank, battery, or both) are used to determine the vehicle fuel consumption. If present in the component data, emissions may be integrated over the duty cycle;

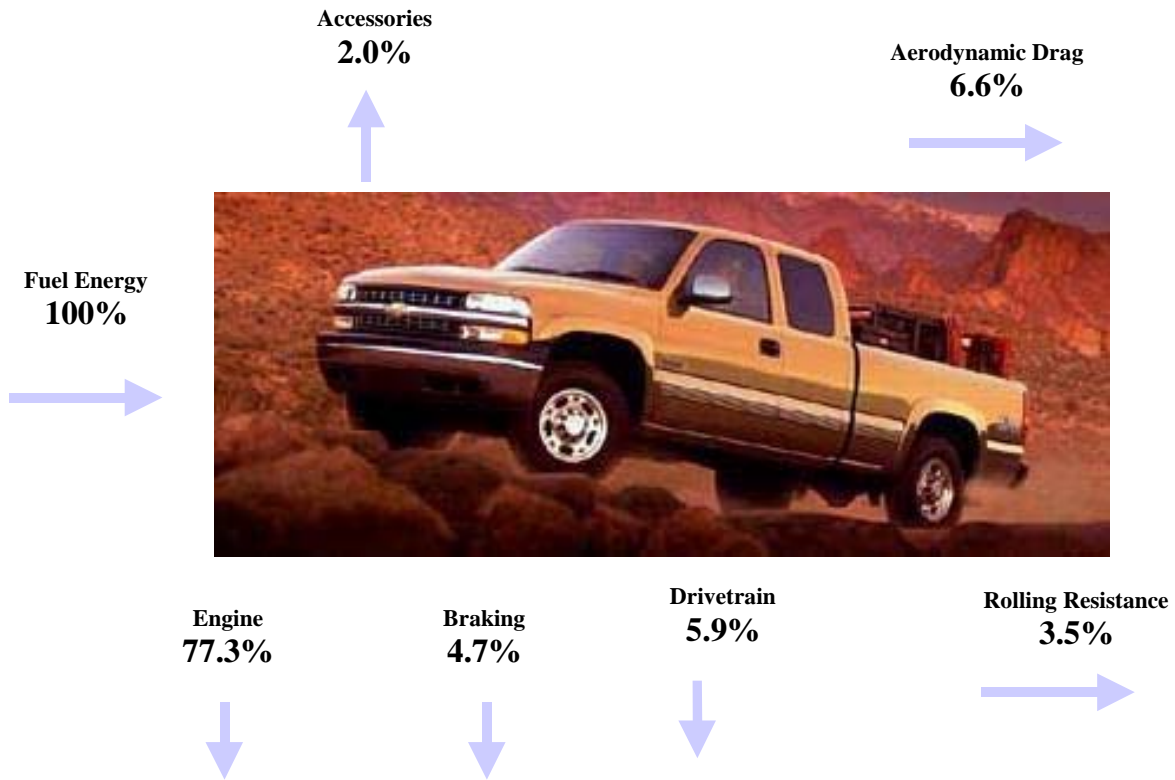


Figure 2.1 Energy Use in a Pickup Truck

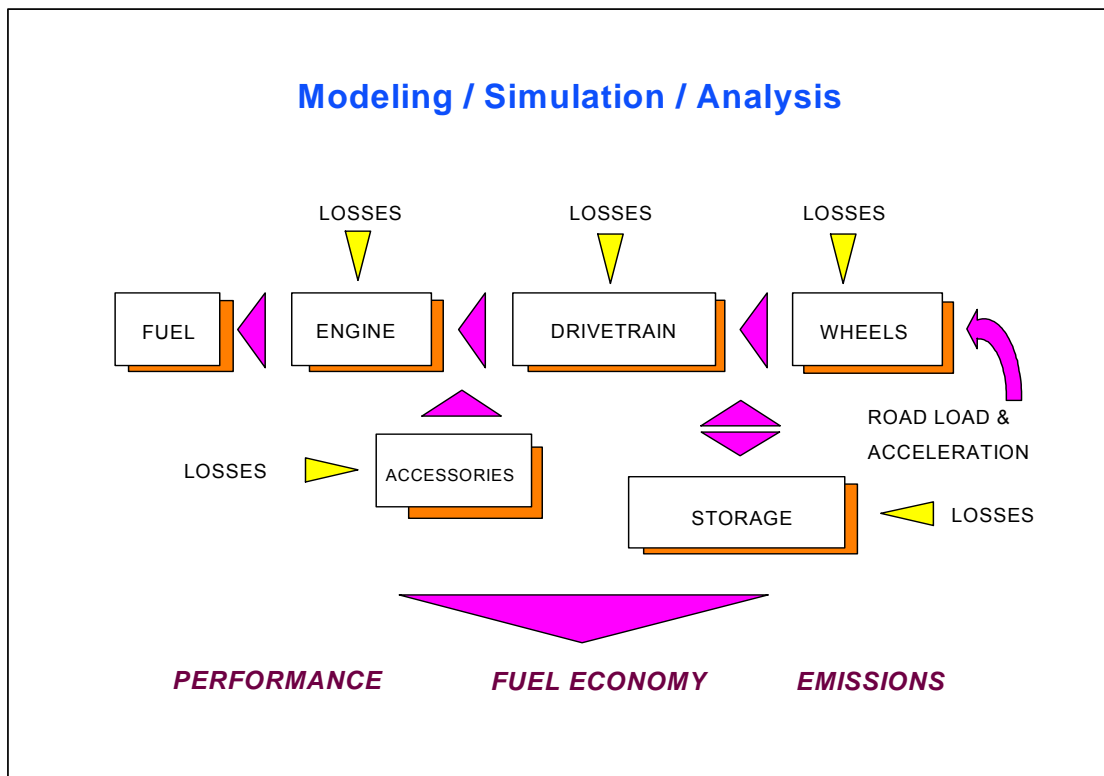


Figure 2.2 HPSP Methodology

however, emissions were not simulated in this work. Instead, the various vehicles were postulated to satisfy certain tailpipe emission classes, as shown in the results provided in Section 2.3.

By iterating on the acceleration response of the vehicle until the full power levels of the engine are reached, we can establish the maximum performance for a specified powertrain in the same manner.

The HPSP simulation models have been validated on numerous occasions for conventional and for hybrid drive systems. When component maps, vehicle parameters, and control strategies implemented in a vehicle were input into the vehicle model, the measured fuel economies in the vehicle were consistently within 1% of the model predictions. In addition to conventional vehicles, the following unconventional architectures were validated: the EV1 electric car, the Freedom Series hybrid vehicle (Skellenger et al. 1993), and the Partnership for a New Generation of Vehicles (PNGV) Precept concept car.

Conventional and hybrid powertrains were modeled in this environment by the appropriate inclusion of energy transfer and energy storage devices (i.e., batteries). Component efficiency characteristics and assumptions regarding the control and energy management strategies were kept consistent among all vehicle models. Figure 2.3 illustrates, through sample output for a hypothetical vehicle, the type of information that was generated and analyzed for the various vehicles during our study.

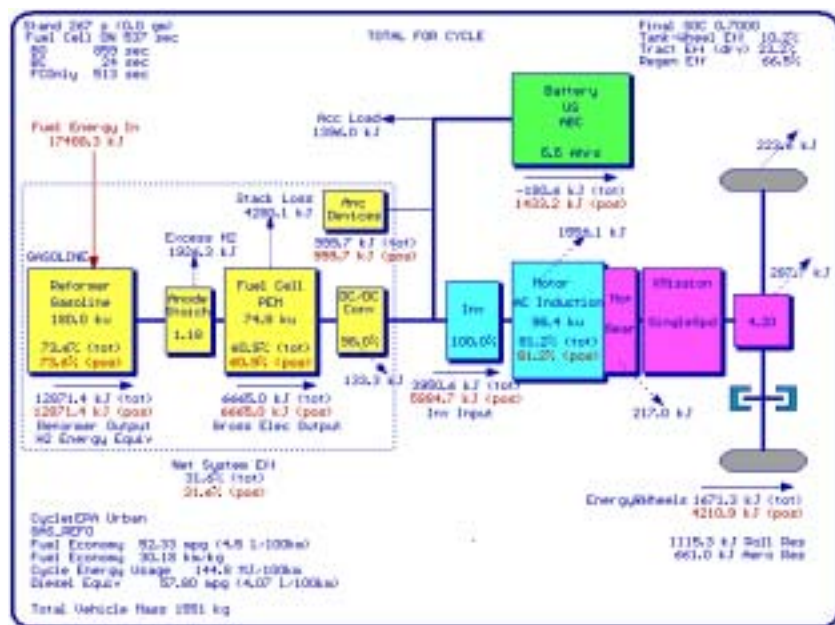


Figure 2.3 Sample Energy Use Diagram Provided by HPSP

### 2.2.1 Vehicle Architectures

The following vehicle architectures and fuels were included in GM's TTW study:

1. Conventional (CONV) vehicle with spark ignition (SI) gasoline engine (baseline)
2. CONV vehicle with compression ignition direct injection (CIDI) diesel engine
3. CONV vehicle with SI E85 (a mixture of 85% ethanol and 15% gasoline by volume) engine
4. CONV vehicle with SI compressed natural gas (CNG) engine
5. Charge-sustaining (CS) parallel hybrid electric vehicle (HEV) with gasoline engine
6. CS parallel HEV with CIDI diesel engine
7. CS parallel HEV with SI E85 engine
8. Gasoline fuel processor (FP) fuel cell vehicle (FCV)
9. Gasoline FP fuel cell (FC) HEV
10. Methanol FP FCV
11. Methanol FP FC HEV
12. Ethanol FP FCV
13. Ethanol FP FC HEV
14. Gaseous hydrogen (GH<sub>2</sub>)/liquid hydrogen (LH<sub>2</sub>) FCV
15. GH<sub>2</sub>/LH<sub>2</sub> FC HEV

Figure 2.4 illustrates the powertrain architecture for the conventional vehicle that is considered the baseline vehicle for this study. A multi-speed manual, automatic, or continuously variable transmission (CVT) may be incorporated, and a torque converter or starting clutch may be used for launching the vehicle. The engine model, which consists of a brake-specific fuel consumption (BSFC) map, can represent any desired technology level and/or can be adjusted to any displacement. HPSP provides engine scaling and sizing capabilities, and constraints on engine operating conditions can be imposed. In this study, the baseline vehicle powertrain consisted of a gasoline engine and a 4-speed automatic transmission with a torque converter. A diesel engine with the same transmission in this conventional architecture represents case 2 in the above list; cases 3 and 4 are the conventional engine running on E85 ethanol and on CNG.

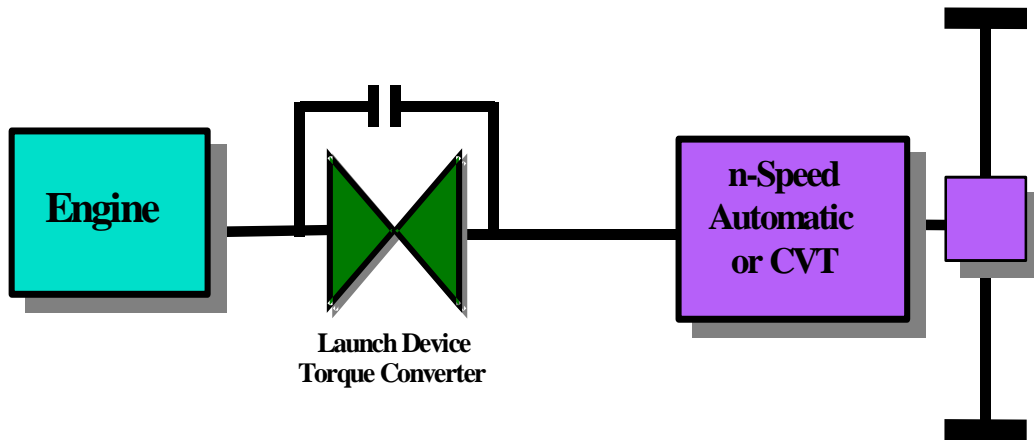


Figure 2.4 Conventional Powertrain

The parallel hybrid architecture for cases 5 through 7 is shown in Figure 2.5. It is an input power-assist HEV with an electric drive at the transmission input. This concept may or may not include a torque converter, and the transmission can be any type. For this study, we used a 4-speed automatic transmission with a starting clutch for launching the vehicle. We assumed that the electric drive could replace the torque converter and assist the engine for maximum vehicle acceleration performance. The energy management strategy implemented for maximizing the fuel economy was a charge-sustaining strategy with fuel shut-off during standstill and deceleration periods and with battery launch at low acceleration demands. Gasoline, E85, and diesel engines were evaluated in this architecture.

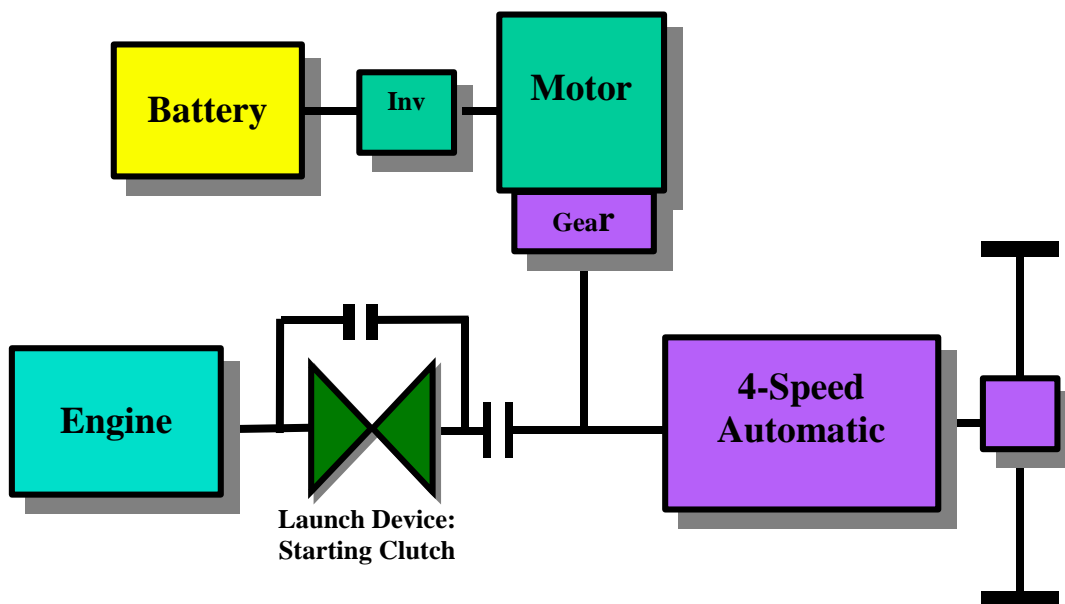


Figure 2.5 Parallel Hybrid (Input Power Assist)

Internal combustion engine series hybrids were not considered in this study. First, because the 7.5-mile all-electric range can be met with a relatively small battery pack and moderately sized electric drive, thereby eliminating one of the drivers toward the series architecture. Furthermore, it is GM's experience that, when trying to maximize fuel economy in a hybrid vehicle, parallel

hybrids most often emerge triumphant because the efficiency of the mechanical transmission path is greater than the efficiency of any electrical path. Finally, the FC hybrids (Cases 9, 11, 13, and 15) are series electric hybrids, and the energy conversion efficiency of a FC stack is noticeably greater than that of a combustion engine. Therefore, the FC series hybrids would consume less fuel than their ICE counterparts; therefore, there was no need to carry a series ICE HEV concept forward.

Cases 8 through 13 are FP systems in direct-drive and HEV powertrain architectures using gasoline, methanol, and ethanol as the fuel of choice. The subsystems included in the FP system models are shown in Figures 2.6 and 2.7 for the direct and the HEV vehicle architectures. Each component in the diagrams was characterized with efficiency data as a function of transmitted power.

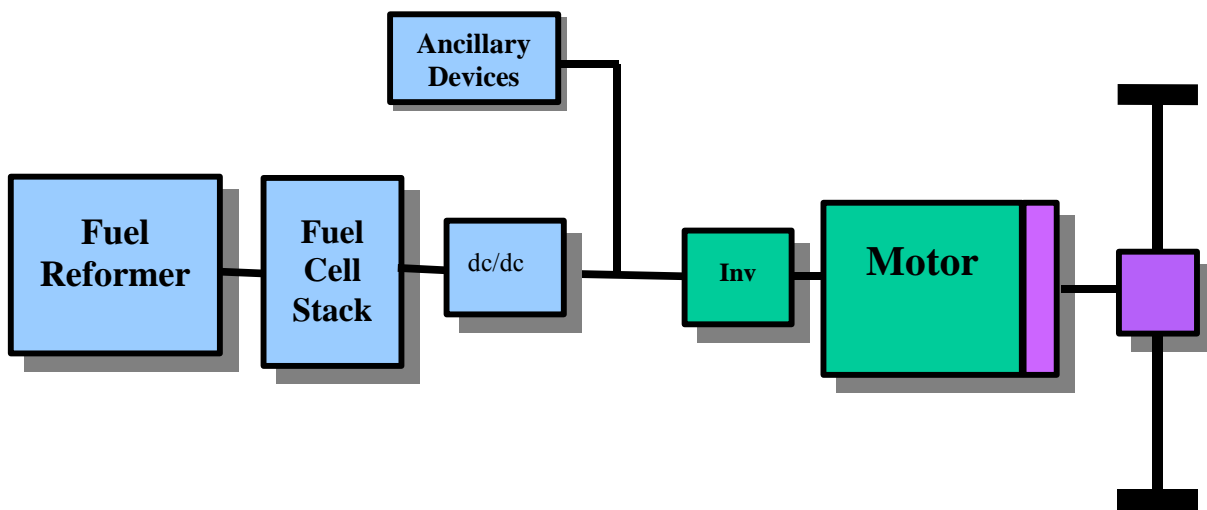


Figure 2.6 Fuel Processor Fuel Cell Vehicle System

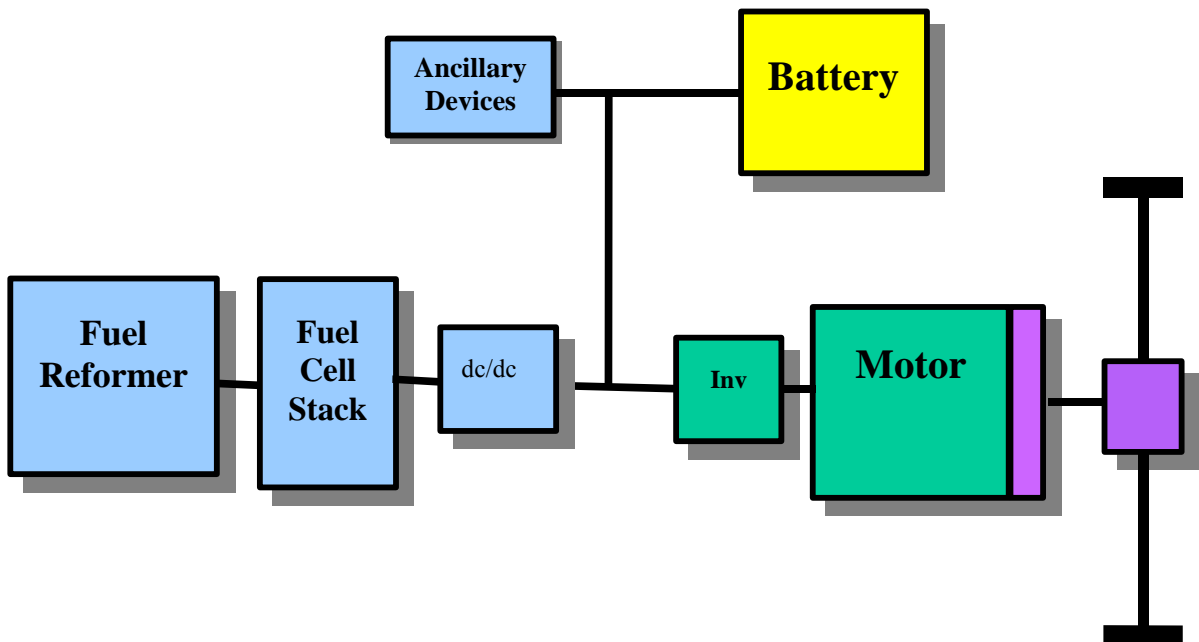


Figure 2.7 Fuel Processor Fuel Cell HEV System

Cases 14 and 15 are the direct FC and the FC HEV systems modeled and analyzed in this study. Figures 2.8 and 2.9 capture the components used in these concepts. The FP and FC HEV systems were also optimized with charge-sustaining energy management strategies.

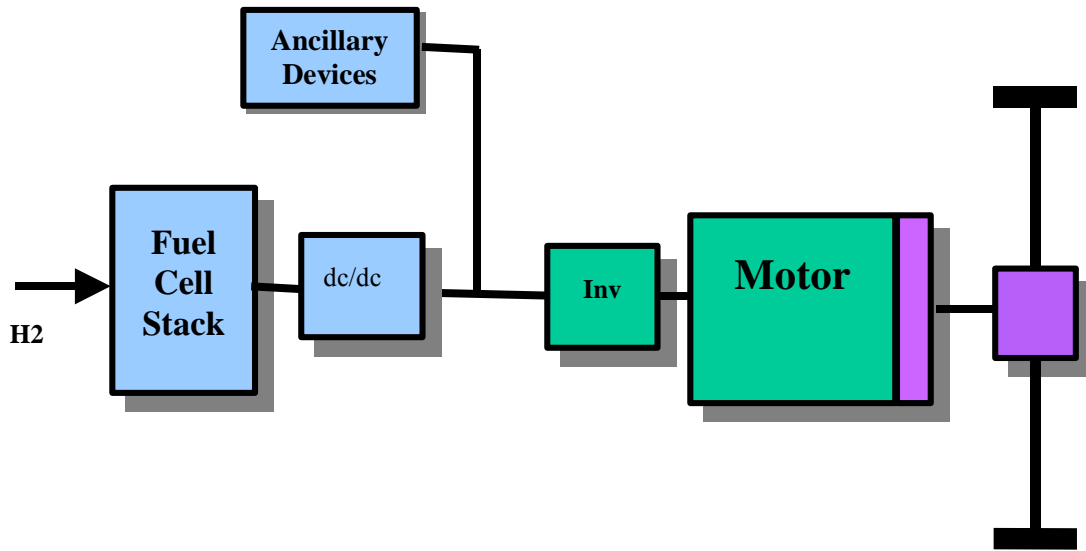


Figure 2.8 Direct Fuel Cell Vehicle System

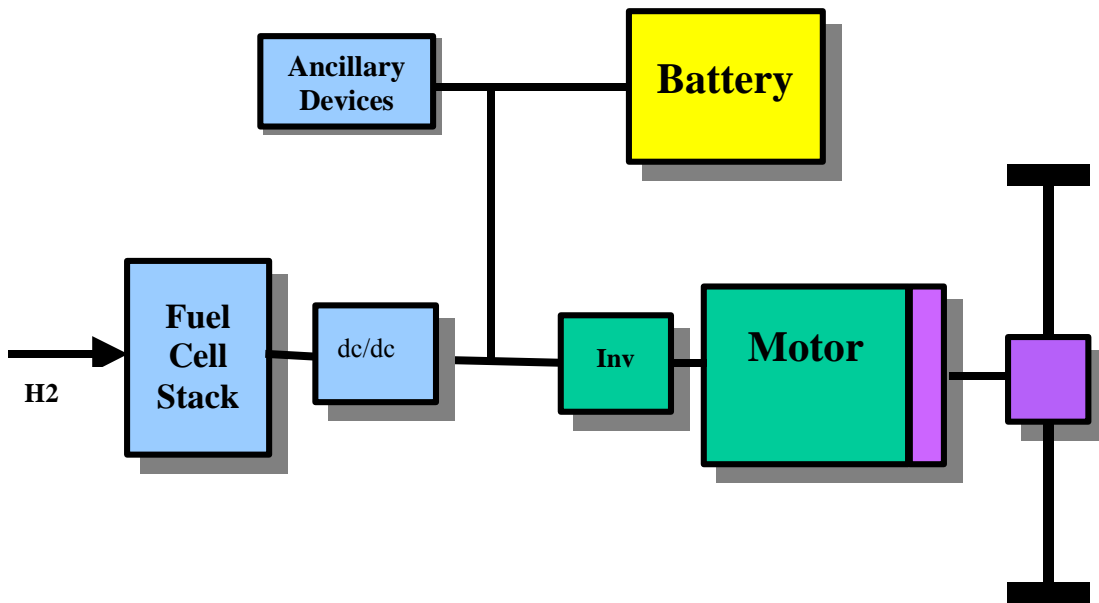


Figure 2.9 Direct Fuel Cell HEV System

## 2.2.2 Vehicle Criteria

### 2.2.2.1 Performance Targets

The performance targets shown in Figure 2.10 were the drivers in the powertrain sizing process. These metrics were evaluated through simulations and served as the design criteria for each vehicle concept.

We also required that the vehicles suffer no performance degradation because of a lack of available energy from the battery (i.e., avoiding the so-called “turtle” effect). In essence, the fuel converter (engine or FC) must remain at the same power level whether or not batteries are present. The ability of each technology to meet this criterion was tested by simulating the vehicle over 10 successive US06 driving cycles with no recharge of the battery permitted at the end of the run.

The preceding restriction also led toward a relatively small battery pack, which rendered charge-depleting hybrids and battery electric vehicles impractical with all available battery technology. For the hybrid vehicles, the battery was sized to drive one urban cycle on batteries providing only about 7.5 miles Zero Emissions Vehicle (ZEV) range.

The most dominant parameter affecting the performance of a vehicle is its mass. The vehicle mass was consistently estimated on the basis of battery and motor size, known engine and transmission masses, and projected FC system masses. The motors were sized to either achieve or assist in achieving the vehicle performance metrics shown in Figure 2.10; the maximum acceleration of 5 m/s/s was dominant among these design constraints. The final drive and motor ratios were selected to meet the top vehicle speed requirement.

Having determined the vehicle mass (based on component sizes) that met the specified performance requirements, we optimized the powertrain operation on the driving cycles by implementing energy management and control strategies to achieve maximum fuel economy for each vehicle concept. We imposed constraints on component operation (e.g., engine, accessories, motors, batteries) reflecting vehicle driveability and comfort requirements to provide more realistic and realizable fuel economy projections.

### 2.2.2.2 Emissions Targets

Emissions targets for all vehicles were based on Federal Tier 2 standards, which are divided into eight emission level categories (or bins) for the 2010 timeframe, when the Tier 2 standards are completely phased in. Bin 5 standards were selected for all vehicles with ICEs because they represent the fleet average. Bin 5 standards are also consistent with PNGV goals. Bin 2 standards (equivalent to Super Ultra Low Emissions Vehicle [SULEV] II) were selected for the FP (reformer) FC vehicles, and Bin 1 (ZEV) standards were selected for the hydrogen FC vehicles. Compliance with these standards has not been demonstrated; we assumed that considerable advances will be made in the technologies. The impact of emissions control on fuel consumption was included in this analysis.

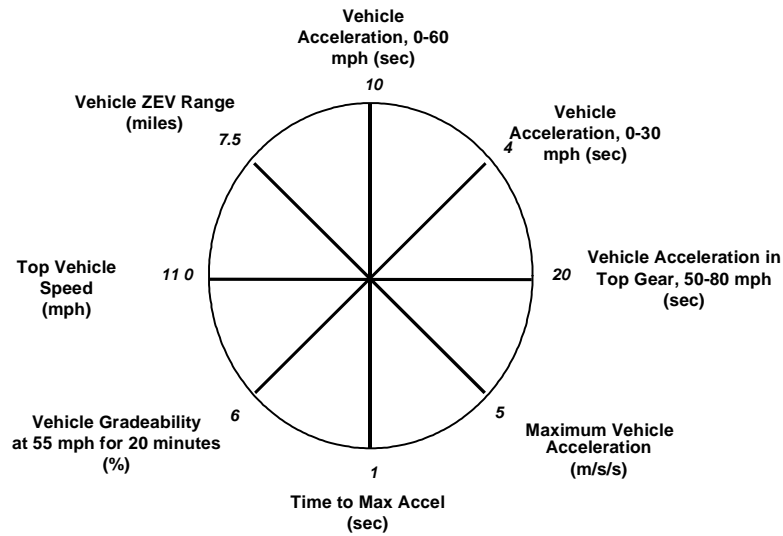


Figure 2.10 Performance Targets

### 2.2.2.3 Vehicle Simulation Model Input Data

The baseline vehicle design parameters used in the study — such as mass, aerodynamic, and rolling resistance coefficients — were based on a GM full-size pickup truck. Except for the mass, which was adjusted for each vehicle’s propulsion system independently, these vehicle-level parameters were used consistently in all the simulation models.

The electric components used in the models were based on validated maps for the electric drive system, and the nickel metal hydride (NiMH) battery data were based on the GM Precept PNGV vehicle.

FC stack and FP component maps were based on small- to full-scale component data using GM proprietary modeling tools; they were validated on the GM HydroGen-1 FC vehicle. Previous GM FC system and modeling development were reported in Allison Gas Turbine Division and General Motors Corporation 1994; General Motors Corporation 1999; Fronk et al. 2000; and Busshardt et al. 2000. The efficiency maps are based on a combination of present data and relatively near-term (one to two-year timeline) projections. However, we recognize that significant development is required to scale to the large power levels required for this chosen application, specifically thermal and water management, FP dynamics, and startup.

Certain major factors — specifically, packaging, transient response, cold-start performance, and cost — were not taken into consideration in this work. Therefore, the results should not be considered indicative of commercial viability; they should be viewed rather as an initial screening to identify configurations that are sufficiently promising to warrant more detailed studies.

## 2.3 Results

Table 2.1 summarizes the simulation results for each of vehicle concepts included in this study. The only performance metric reported here is the 0–60 mph performance time, which varies from vehicle to vehicle because the active constraints in each of these designs were maximum launch acceleration and top vehicle speed. Each of these concepts met those requirements; thus, the comparison of fuel economy and 0–60 mph acceleration time reported here can now be made on an “equal-performance” basis.

Table 2.1 Fuel Economy (Gasoline Equivalent) and Performance Predictions

No.	Vehicle Configuration	Urban Fuel Economy (mpg GE) <sup>a</sup>	Highway Fuel Economy (mpg GE)	Complete Fuel Economy (mpg GE)	Gain in Fuel Economy over Baseline (%)	Tank-to-Wheel Efficiency (%)	Time (s to 60 mph)
1	Gasoline CONV SI	17.4	25.0	20.2	Baseline	16.7	7.9
2	Diesel CONV CIDI	20.2	30.4	23.8	18	19.4	9.2
3	E85 CONV SI	17.4	25.0	20.2	0	16.7	7.9
4	CNG CONV SI	17.0	24.7	19.8	-2	16.9	8.2
5	Gasoline SI HEV <sup>b,c</sup>	23.8	25.1	24.4	21	20.7	6.3
6	Diesel CIDI HEV <sup>c</sup>	29.1	29.8	29.4	46	24.6	7.2
7	E85 SI HEV <sup>c</sup>	23.8	25.1	24.4	21	20.7	6.3
8	Gasoline FP FCV	26.2	28.6	27.2	35	24.0	10.0
9	Gasoline FP FC HEV	31.9	28.5	30.2	50	27.3	9.9
10	Methanol FP FCV	28.8	32.4	30.3	50	26.6	9.4
11	Methanol FP FC HEV	35.8	33.0	34.5	71	31.1	9.8
12	Ethanol FP FCV	27.5	30.0	28.6	42	25.2	10.0
13	Ethanol FP FC HEV	33.5	29.9	31.8	57	28.7	9.9
14	GH <sub>2</sub> FCV/ LH <sub>2</sub> FCV	41.6	45.4	43.2	114	36.3	8.4
15	GH <sub>2</sub> FC HEV/ LH <sub>2</sub> FC HEV	51.5	44.5	48.1	138	41.4	10.0

<sup>a</sup> GE = gasoline equivalent.

<sup>b</sup> All HEVs are charge sustaining.

<sup>c</sup> Parallel.

The **Tank-to-Wheel Efficiency** shown in Table 2.1 is a measure of the overall efficiency of the vehicle system, defined as:

$$\text{Tank to Wheel Eff} = \frac{\text{Energy Output}}{\text{Energy Input}}$$

where the energy output of the drive system is defined as the total amount of energy required to overcome the rolling resistance, aerodynamic, and inertial (acceleration) load over the driving cycle:

$$\text{Energy Output} = \sum [(Roll Resist) + (Aero Resist) + (Ma)] * V * \Delta t = \text{Energy@Wheels}$$

and the total amount of energy input to the system is defined as:

$$\text{Energy Input} = \text{Energy Value of Fuel Consumed}$$

Note that the vehicle auxiliary/accessory load is not included in this definition of energy output.

Finally, the vehicle fuel economy (on a gasoline-equivalent basis) and expected emission levels are summarized in Table 2.2. The fuel economy from Table 2.1 is shown here as the “50” entry, meaning that there is a 50% likelihood that the fuel economy may be higher (due to some presently unknown technological advance), or lower (due to unforeseen difficulties). The columns labeled 20 and 80 denote estimates wherein the fuel economy has only a 20% likelihood of being lower than the lower bound and a 20% likelihood of being higher than the higher bound, respectively.

Table 2.2 Overview of Vehicle Configurations

No.	Vehicle Configuration	Fuel Economy (mpg GE)			Emission Standard <sup>d</sup>
		20 percentile <sup>a</sup>	50 percentile <sup>b</sup>	80 percentile <sup>c</sup>	
1	Gasoline CONV SI (baseline)	19.2	20.2	26.3	Tier 2 Bin 5
2	Diesel CONV CIDI	22.0	23.8	30.9	“
3	E85 CONV SI	19.2	20.2	26.3	“
4	CNG CONV SI	18.8	19.8	25.7	“
5	Gasoline SI HEV <sup>e,f</sup>	22.2	24.4	30.5	“
6	Diesel CIDI HEV <sup>f</sup>	26.7	29.4	36.8	“
7	E85 SI HEV <sup>f</sup>	22.2	24.4	30.5	“
8	Gasoline FP FCV	23.7	27.2	32.6	Tier 2 Bin 2
9	Gasoline FP FC HEV	26.2	30.2	36.2	“
10	Methanol FP FCV	26.3	30.3	36.4	“
11	Methanol FP FC HEV	30.0	34.5	41.4	“
12	Ethanol FP FCV	24.9	28.6	34.3	“
13	Ethanol FP FC HEV	27.6	31.8	38.2	“
14	GH <sub>2</sub> FCV/LH <sub>2</sub> FCV	39.3	43.2	47.5	Tier 2 Bin 1
15	GH <sub>2</sub> FC HEV/LH <sub>2</sub> FC HEV	43.7	48.1	52.9	“

<sup>a</sup> 20% likelihood mpg lower.

<sup>b</sup> Equally likely above or below.

<sup>c</sup> 20% likelihood mpg higher.

<sup>d</sup> Federal standards: Tier 2 Bin 5, Tier 2 Bin 2 (SULEV II), Tier 2 Bin 1 (ZEV).

<sup>e</sup> All HEVs are charge sustaining.

<sup>f</sup> Parallel.

## 2.4 Conclusions

On the basis of the results listed in Table 2.1, GM made the following observations:

- FC systems use less energy than conventional powertrains because of the intrinsically higher efficiency of the FC stack.
- Hybrid systems show consistently higher fuel economy than conventional vehicles because of regenerative braking and engine-off during idle and coast periods (thus, the improvements occur mostly on the urban driving schedule).
- In the case of the FC and FP systems, the gains resulting from hybridization are lower because the “engine-off” mode is present in both systems.
- Hydrogen-based FC vehicles exhibit significantly higher fuel economy than those that employ a FP.

Again, important factors such as packaging, cold start, transient response, and cost were not considered within the scope of this work. This portion of the study addresses TTW efficiencies; when combined with the WTT analysis, it will provide the full-cycle WTW efficiencies.

## 2.5 Acknowledgments

The authors of this report would like to thank the following people for their contributions in providing critical data for the study, reviewing the results, and providing valuable feedback and comments on the content of the report: Fritz Indra, Tim Peterson, Tony Zarger, Ken Patton, Roger Clark, Randall Yost, David Schmidt, Tanvir Ahmad, Ko Jen Wu, Roger Krieger, Arjun Tuteja, John Hepke, Peter Savagian, Dave Hilden, Norm Brinkman, Gary Herwick, Byron McCormick, Gary Stottler, Martin Fasse, Peter Kilian, Volker Formanski, Udo Winter, Matthias Bork, and Raj Choudhury. Particular recognition goes to Dr. Moshe Miller of the Advanced Development Corporation (ADC) for supporting the modeling, simulation, and analysis efforts and providing valuable consultations.

## 2.6 References

Allison Gas Turbine Division and General Motors Corporation, 1994, *Research and Development of Proton-Exchange-Membrane (PEM) Fuel Cell System for Transportation Applications*, U.S. Department of Energy, Contract No. DE-AC02-90CH10435.

Busshardt, J., D. Masten, M. Sinha, P. Kilian, and S. Raiser, 2000, *Dynamic Modeling and Simulation of a Fuel Cell Propulsion System*, VDI Berichte nr. 1559, 2000, presented at the 10<sup>th</sup> International Congress, Numerical Analysis and Simulation in Vehicle Engineering, Wurzburg, Germany, Sept. 14.

Fronk, M., D. Wetter, D. Masten, and A. Bosco, 2000, *PEM Fuel Cell System Solutions for Transportation*, SAE paper 2000-01-0373, Society of Automotive Engineers World Congress, Detroit, Mich., March 6.

General Motors Corporation, 1999, *Research and Development of a Proton Exchange Membrane (PEM) Fuel Cell System for Transportation Applications*, U.S. Department of Energy, Contract No. DE-AC02-90CH10435.

Rohde, S.M., and T.R. Weber, 1984, *On the Control of Vehicles with Multiple Power Sources*, Proceedings of the American Control Conference.

Skellenger, G.D., M.G. Reynolds, and L.O. Hewko, 1993, *Freedom: An Electric-Hybrid Research Vehicle Concept*, Proceedings of the International Conference on Hybrid Power Plants for Automobiles, Zurich, Switzerland, Nov.

Weber, T.R., 1998, *Analysis of Unconventional Powertrain Systems*, FISITA, Sept. 25–30.

## **Part 3**

### **Well-to-Wheel Fuel/Vehicle Pathway Integration**

Dr. Anthony Finizza  
AJF Consulting

Dr. James P. Wallace III  
Wallace & Associates

June 2001



## **3.1 Introduction**

Part 1 of this report presented energy use and GHG emissions on a well-to-tank basis for 75 fuel pathways analyzed by Argonne National Laboratory. In many cases, Argonne found that the results for various pathways were so similar that it was possible to reduce the number of the pathways by selecting a “representative” fuel within a fuel category. This was true for multiple gasoline and diesel pathways. Argonne pared its results down to 30 representative fuel pathways. For Part 2, researchers from GM quantified the energy use of 15 advanced powertrain systems (tank-to-wheel [TTW] analysis) (see Table 2.1).

This part of the report combines the results of Parts 1 and 2 into an analysis of well-to-wheel (WTW) efficiency and GHG emissions — providing a complete view of these alternative fuel/vehicle pathways. The first part of Section 3.2 (Methodology) describes the process and criteria used to reduce the 30 representative pathways selected in Part 1 to 13 pathways. The second part (Part B) describes the process used to combine these 13 fuel pathways with the 15 vehicle pathways identified in Part 2 to obtain 27 fuel/vehicle combinations for further analysis of their WTW energy use and GHG emissions characteristics. Sections 3.3 (Results) and 3.4 (Conclusions) address the key findings of our analysis.

## **3.2 Methodology**

### **3.2.1 Part A: Selection of Well-to-Tank Pathways**

In addition to the 30 fuel pathways identified in the WTT portion of the study, two E85 pathways were added to facilitate analysis of the two E85-fueled vehicles analyzed in Part 2 (see Table ES-2.2). Fuel use and GHG emissions information for the two E85 pathways (corn and herbaceous) is contained in Appendix B in Volume 3 of this report series. The 32 pathways were reduced to 13 on the basis of two criteria: resource availability and energy use. Two other criteria that can be used for screening fuel/technology pathways — economic/investment issues and technological hurdles — were not considered in this study, but may be addressed in follow-on work. The two electricity fuel pathways were not considered because neither battery-powered electric vehicles nor charge-depleting hybrid electric vehicles (HEVs) were considered (for reasons outlined in Part 2).

#### ***3.2.1.1 Resource Availability***

During the integration analysis, we excluded 12 of the 30 fuel pathways selected in Part 1 on the basis of resource availability — the pathways involving NA NG (eight NG- and two electrolysis-based) and corn-based ethanol.

#### ***North American NG-Based Pathways***

The current and potential NA NG resource base appears to be insufficient to supply wide-scale use of NG for transportation fuels in the U.S. market.

Three recent studies suggest that rapid incremental NG demand in the United States, in particular for electricity generation, will put pressure on the NA gas supply, even without a significant transportation demand component. These studies — conducted by the Energy Information

Administration (EIA 2000) of the U.S. Department of Energy (DOE), the Gas Technology Institute (GTI) (formerly the Gas Research Institute [GRI 2000], and the National Petroleum Council (NPC 1999) — predict rapid NG demand growth in the United States, primarily to fuel incremental electricity generation and to meet growing population needs (see Table 3.1). In all three of these studies, the demand for NG grows by almost a third by the year 2010 from a base year of 1998. The primary use for this incremental demand (see Table 3.2) is gas-fired CC electricity generation. This sector alone will require 40–50% of the incremental NG demand. Industrial and residential use will also place heavy demands on the NG industry.

Table 3.1 Comparison of Studies of the U.S. Natural Gas Market<sup>a</sup>

Parameter	Base	EIA <sup>b</sup>		GRI <sup>c</sup>		NPC <sup>d</sup>	
	1998	2005	2010	2005	2010	2005	2010
<i>Consumption (Total)</i>	21.8	25.2	28.1	25.7	28.6	26.3	29.0
Residential	4.6	5.3	5.5	5.1	5.4	5.6	5.8
Commercial	3.0	3.6	3.8	3.5	3.8	3.7	3.8
Industrial	8.4	8.8	9.3	9.5	10.3	9.6	10.2
Electricity generation	3.7	5.4	6.9	5.2	6.4	5.1	6.6
Transportation (vehicles)	0.0	0.1	0.1	0.1	0.3	0.0	0.0
Other <sup>e</sup>	2.1	2.0	2.5	2.3	2.4	2.3	2.6
<i>Supply (Total)</i>	22.0	25.4	28.8	25.7	28.6	26.3	29.0
U.S. Production	18.8	20.9	23.2	21.8	24.5	22.6	25.1
Net Imports							
Canada	3.0	4.3	4.8	3.6 <sup>f</sup>	3.9 <sup>f</sup>	3.7	3.8
Mexico	0.0	-2	-3	NE <sup>g</sup>	NE	0.0 <sup>f</sup>	0.1 <sup>f</sup>
LNG	0.0	0.4	0.5	0.0	0.0	NE	NE

<sup>a</sup> Values are in trillion (10<sup>12</sup>) cubic feet.

<sup>b</sup> EIA (2000).

<sup>c</sup> GRI (2000).

<sup>d</sup> NPC (1999).

<sup>e</sup> Includes lease and plant fuel, pipeline fuel, etc.

<sup>f</sup> Not broken out in source documents.

<sup>g</sup> NE = not estimated.

Table 3.2 Incremental Increase in U.S. Natural Gas Demand in 2010 Relative to 1998 Base Year<sup>a</sup>

Parameter	EIA	GRI	NPC
<i>Consumption (Total)</i>	6.3	6.8	7.2
Residential	0.9	0.8	1.2
Commercial	0.8	0.8	0.8
Industrial	0.9	1.9	1.8
Electricity generation	3.2	2.7	2.9
Transportation (vehicles)	0.1	0.1	0.0
Other <sup>b</sup>	0.4	0.3	0.5
Electricity increment (as % of total increment)	51	40	40

<sup>a</sup> Values are in trillion (10<sup>12</sup>) cubic feet.

<sup>b</sup> Includes lease and plant fuel, pipeline fuel, etc.

It is important to note that the three studies assume that the rate of electricity demand growth will be roughly the same from 1999 to 2010 as it has been in the prior 10 years (1989 to 1999) — 2.1% per year — and that it will be only slightly higher than it was from 1979 to 1989. The researchers predicated their view on the basis of the assumption that electricity use will become more efficient. If electricity demand is higher than the studies predict, it will put an even greater strain on the NG supply.

The three studies cited project only token use of NG as a transportation fuel. Even in the most optimistic GRI forecast, only 1% of NG will be used for transportation in 2010. Given the tight gas supply in the base case, it is clear that significant gas imports would be required if NG is to play a major role as a NA transportation fuel. To expand the use of NG to fuel a sizable portion of the light-duty transportation market by 2010 and beyond would require an even greater transition than the three studies envision. Table 3.3 illustrates the magnitude of the U.S. transportation market.

Can this incremental amount of NG needed for wide-scale transportation use come from North America without substantial increase in prices or improvements in technology? All three studies imply that finding the resource base to produce this incremental supply would represent a major challenge for domestic producers. The import of large pipeline volumes from Canada, beyond those already envisioned, is also not likely. Some analysts expect exploitation of NG potential on the North Slope of Alaska. These reserves of 30+ trillion cubic feet are embodied in the reserve estimates. While this volume represents a sizeable NG resource, it is earmarked for residential and electric utility use in the Midwest.

Table 3.4 shows the resource potential for NG worldwide. The data comprise reserves that have been found and are producible given today’s technology and prices (known reserves), the U.S. Geological Survey’s (USGS’s) assessment of reserves yet to be found (undiscovered reserves), and the USGS’s estimate of NG added from reserves discovered over time (reserve growth). The phenomenon of reserve or field growth, in which the initial estimates of reserves are increased as exploration and production (E&P) technology improves, accounts for a

Table 3.3 EIA Baseline Forecast of the U.S. Transportation Market<sup>a,b</sup>

Fuel	1998	2005	2010	Increment 2010/1998
Motor gasoline	15.12	17.17	18.47	3.35
Diesel	4.82	6.09	6.78	1.96
LPG <sup>c</sup>	.02	.03	.04	.02
CNG	.01	.06	.09	.08
E85	.01	.02	.03	.02
M85 <sup>d</sup>	.00	.00	.00	.00
<i>Totals</i>	19.98	23.37	25.41	5.43

<sup>a</sup> Source: EIA (2000).

<sup>b</sup> Values were converted into trillion (10<sup>12</sup>) cubic feet equivalents from EIA forecasts, which are in quadrillion Btu (1 trillion cubic feet = 0.97 quadrillion Btu).

<sup>c</sup> LPG = liquefied petroleum gas.

<sup>d</sup> M85 = a mixture of 85% methanol and 15% gasoline (by volume).

Table 3.4 Natural Gas Resource Base<sup>a</sup>

Region	Natural Gas (billions of barrels of oil equivalent) <sup>b</sup>			Oil (billions of barrels)
	Known Reserves	Undiscovered Reserves	Total Known and Undiscovered Reserves	Total Known and Undiscovered Reserves
Former Soviet Union	352	287	640	173
Middle East and North Africa	374	244	618	956
Asia-Pacific	53	68	120	69
Europe	33	56	88	41
North America	46	121	168	201
Central & South America	43	87	130	200
Sub-Saharan Africa	27	42	69	105
South Asia	12	21	34	9
World	941	926	1,867	1,754
Estimated reserve growth (done on world basis only)			652	674
Total future resources available			2,519	2,428
Other liquids (natural gas liquids [NGLs])				270

<sup>a</sup> Sources: *Oil & Gas Journal* (2000) for known reserves; USGS (2000) for undiscovered reserves and reserve growth.

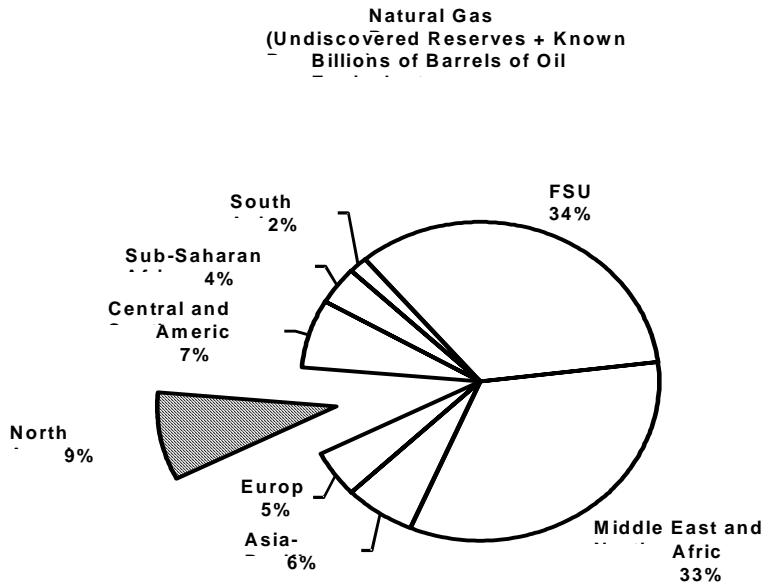
<sup>b</sup> 1 barrel = 5.61 thousand cubic feet.

significant amount of oil and gas not currently accounted for in the undiscovered reserve and known reserve estimates.

As Figure 3.1 shows, North America accounts for only about 9% of the resource potential of NG. (The figure does not include reserve growth, but the share should not differ much from the estimate shown because the reserve growth for the United States is approximately 10% of the world reserve growth.) It is clear that the United States would have to rely on NNA gas at some point in its quest to penetrate the transportation market with wide-scale use of NG-based fuels.

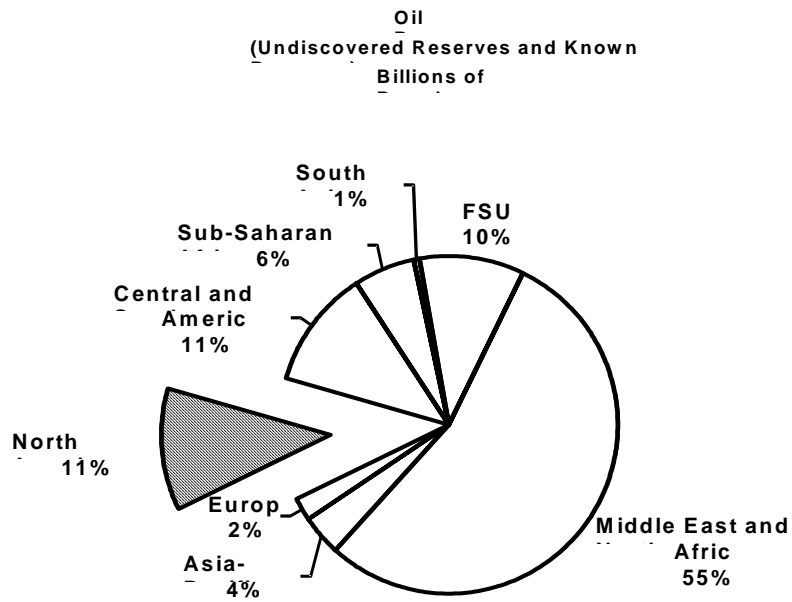
It is interesting to note that North America holds a similar percentage (11%) of oil resources (see Figure 3.2). This explains, in part, the need for imported crude oil to supply the U.S. transportation sector.

Consistent with these studies, our assessment of NG resources is that high-volume, NG-based, light-duty fuel pathways would have to rely on non-North-American NG; as a result, we considered examination of NNA NG-based pathways to be far more feasible than NA NG-based pathways and dropped the latter from our analysis.



Source: USGS 2000  
12/18/0

Figure 3.1 Potential Natural Gas Resources



Source: USGS 2000  
12/18/0

Figure 3.2 Potential Oil Resources

### ***Corn Ethanol-Based Pathways***

The current use of ethanol as a transportation fuel in the United States is about 1.5 billion gallons per year — equivalent to about 1 billion gallons of gasoline (on an energy basis). Today, the United States consumes in excess of 100 billion gallons of gasoline per year.

Recent U.S. Department of Agriculture (USDA) simulations show that production of corn-based ethanol could be doubled — to about 3 billion gallons per year — without drastic impacts on the animal feed and food markets (Price et al. 1998).

Although the production of corn ethanol could be doubled in ten years, the amount produced still would be adequate to supply only the ethanol blend market and potential use in RFG (if MTBE is going to be banned nationwide and if the RFG oxygenate requirements will be kept). It does not appear that the supply of corn-based ethanol will be adequate for use in high-volume transportation applications; as a result, we eliminated corn-based ethanol from the analysis.

The economics of cellulosic ethanol are not currently competitive with those of gasoline. Further, it has yet to be determined whether cellulosic biomass faces resource availability constraints. Also, some experts have concluded that the technology for producing biofuels will have to be significantly improved to make this pathway viable (Kheshgi et al. 2000). Because of the uncertainty here, we carried this pathway along to the WTW analysis.

#### ***3.2.1.2 Energy Efficiency***

We eliminated two fuel pathways on the basis of energy inefficiency. LH<sub>2</sub> from NG produced at stations had significantly lower WTT efficiency than LH<sub>2</sub> produced at central plants. The low end of the distribution of efficiency estimates for LH<sub>2</sub> produced at central plants is higher than the highest value of the distribution for LH<sub>2</sub> produced at refueling stations — there is no overlap in the percentile range (see Table 3.5). Because the two candidate fuels are used in the same vehicle (FCVs), we eliminated the less efficient of the pair, LH<sub>2</sub> produced at stations.

All four electrolysis pathways presented in Part 1 would normally be excluded because they do not offer acceptable energy efficiency and GHG emissions characteristics. The WTW efficiencies for several competing NG-based vehicles are already higher than the efficiencies in the electrolysis pathways based solely upon the WTT stage (Part 1 of the study). Many proponents of electrolysis, however, point to its potential use in the transition to high-volume H<sub>2</sub> FCV applications. For this reason, we exclude only the less efficient of the electrolysis pathways, LH<sub>2</sub>.

FT naphtha, a candidate reformer fuel for FCVs, is surpassed by crude naphtha on a WTT efficiency basis because both candidate fuels can be used in the same vehicle. Likewise, Fischer-Tropsch diesel (FTD) offers lower energy efficiency than crude-based diesel. However, because the FT fuels are of interest to a broad range of analysts and may have other benefits (e.g., criteria pollutants) not captured in this analysis, they have not been eliminated from consideration.

Table 3.5 Comparison of Selected Pathways

Pathway	Well-to-Tank Efficiency (%)		
	20 percentile	50 percentile	80 percentile
LH <sub>2</sub> – central plants	39	41	43
LH <sub>2</sub> – stations	28	32	35
GH <sub>2</sub> electrolysis: U.S. mix	26	28	30
LH <sub>2</sub> electrolysis: U.S. mix	21	23	25

Predicated on the screening logic described above, we pared the number of fuel pathways considered to the 13 listed in Table 3.6. These fuels, taken together with the 15 vehicles considered in Part 2, yield the 27 fuel/vehicle pathways analyzed on a WTW basis in this study.

Table 3.6 Summary of Pathways Selected for Well-to-Wheel Integration Analysis

Pathways Identified in Part 1	Excluded		Carried to Well-to-Wheel Analysis	No.
	Resource Availability	Energy Efficiency		
<i>Oil-Based</i>				
1 Current gasoline	Used as reference only.			
2 Low-sulfur gasoline			X	1
3 Current diesel	Used as reference only.			
4 Low-sulfur diesel			X	2
5 Crude naphtha			X	3
<i>Natural-Gas-Based</i>				
6 CNG: NA NG	X			
7 CNG: NNA NG			X	4
8 MeOH: NA NG	X			
9 MeOH: NNA NG			X	5
10 FT naphtha: NA NG	X			
11 FT naphtha: NNA NG			X	6
12 FTD: NA NG	X			
13 FTD: NNA NG			X	7
14 GH <sub>2</sub> – central plants: NA NG	X			
15 GH <sub>2</sub> – central plants: NNA NG			X	8
16 LH <sub>2</sub> – central plants: NA NG	X			
17 LH <sub>2</sub> – central plants: NNA NG			X	9
18 GH <sub>2</sub> – stations: NA NG	X			
19 GH <sub>2</sub> – stations: NNA NG			X	10
20 LH <sub>2</sub> – stations: NA NG	X			
21 LH <sub>2</sub> – stations: NNA NG		X		
<i>Electricity-Based</i>				
22 Electricity: U.S. mix	Discussed in Part 2			
23 Electricity: CC turbine, NA NG	Discussed in Part 2			
<i>Electrolysis-Based</i>				
24 GH <sub>2</sub> electrolysis: U.S. mix			X	11
25 GH <sub>2</sub> electrolysis: CC turbine, NA NG	X			
26 LH <sub>2</sub> electrolysis: U.S. mix		X		
27 LH <sub>2</sub> electrolysis: CC turbine, NA NG	X			
<i>Ethanol-Based</i>				
28 E100: corn	X			
29 E100: herbaceous cellulose			X	12
30 E100: woody cellulose <sup>a</sup>				
<i>Additional Pathways Considered</i>				
31 E85: corn	X			
32 E85: herbaceous cellulose			X	13

<sup>a</sup> Deleted: herbaceous cellulose considered representative of cellulosic pathways.

### 3.2.2 Part B: Well-to-Wheel Integration

The GM WTW integration modeling process takes stochastic outputs from Parts 1 and 2 for efficiency and GHG emissions and combines them into complete WTW results (see Figure 3.3).

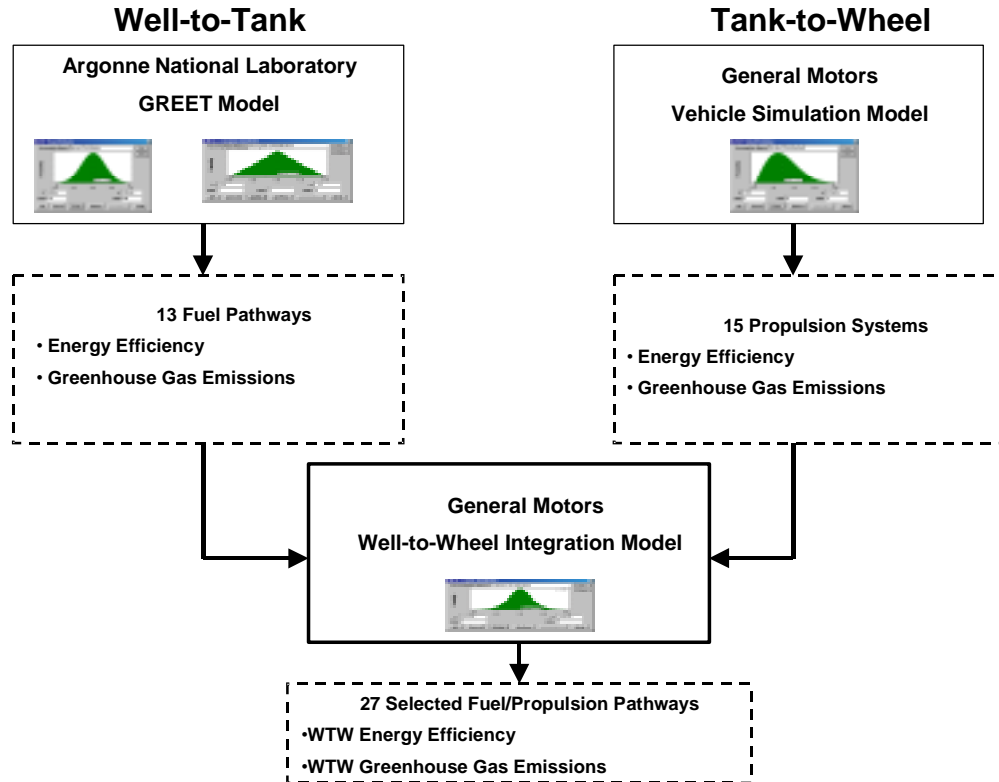


Figure 3.3 Well-to-Wheel Integration Process

#### 3.2.2.1 Well-to-Tank (Part 1)

The GREET model results for the WTT energy use are presented as a probability distribution for energy use and GHG emissions for each fuel pathway. For the integration analysis, these results were fitted to a set of continuous distributions using well-known goodness-of-fit tests. For each of the resulting 26 distributions (energy use and GHG emissions for 13 fuels), the logistic distribution was the best-fitting distribution. The logistic distribution is asymmetric with narrower tails than the normal. The fit was performed in Crystal Ball™ among all continuous distributions available.

#### 3.2.2.2 Tank-to-Wheel (Part 2)

Part 2 of the study provides 20, 50, and 80 percentile fuel use estimates (in mpg gasoline equivalent) for the 15 fuel/vehicle configurations selected in Part 2 (see Table 2.2). During the WTW integration process, each of these 20-50-80 percentiles was used to fit a Weibull distribution to each of the 15 fuel/vehicle configurations.

The CO<sub>2</sub> component of the GHGs contributed by the vehicle are related to the carbon content of the fuel because it is all combusted in the vehicle. Of course, there is no carbon in hydrogen fuels, so there is no CO<sub>2</sub> contribution from FCVs powered by H<sub>2</sub>. GHGs other than CO<sub>2</sub> were considered negligible at the vehicle level for the other fuel/vehicle pathways.

***WTW Total Energy Use Calculations***

The WTW total system energy use, in Btu/mi, was computed as follows:

$$\frac{\text{Btu}}{\text{mi}} = \frac{1}{\text{WTT Eff}} \times \frac{\text{GGE}}{\text{mi}} \times \frac{112,985 \text{ Btu}}{\text{GGE}},$$

where

$$\text{WTT Eff} = \text{well-to-tank efficiency} = \frac{1,000,000}{(1,000,000 + E)},$$

GGE = gallons of gasoline equivalent, and

E = energy lost per million Btu in the WTT process.

The WTT efficiencies were computed from information provided in Part 1; the vehicle fuel consumption per mile was provided in Part 2.

***WTW Greenhouse Gas Emissions Calculations***

The WTW GHG emissions, in g/mi, were computed as follows:

Well-to-wheel GHG emissions = well-to-tank GHG emissions + tank-to-wheel GHG emissions,

where

$$\text{Well-to-tank GHG emissions (g/mi)} = \frac{\text{WTT GHG emissions (g)}}{\text{WTT (million Btu)}} \times \frac{\text{GGE}}{\text{mi}} \times \frac{112,985 \text{ Btu}}{\text{GGE}}$$

(the first term is provided in Part 1 and the second in Part 2) and

$$\text{Tank-to-wheel GHG emissions (g/mi)} = \frac{\text{TTW GHG emissions (g)}}{\text{TTW (million Btu)}} \times \frac{\text{GGE}}{\text{mi}} \times \frac{112,985 \text{ Btu}}{\text{GGE}}$$

(the first term is provided in Appendix 3A and the second in Part 2).

### 3.2.2.3 Well-to-Wheel (Part 3)

The WTT total energy use per mile for each fuel was computed on the basis of information provided in Part 1; vehicle fuel use per mile was computed from data provided in Part 2. Once the distributions from Parts 1 and 2 were developed, the joint probability distributions for WTW energy use and GHG emissions were simulated by using the Monte Carlo method. Resulting 20, 50, and 80 percentiles for both energy use and GHG emissions are shown in the figures in Section 3.3. The end points of the bars in the figures are the 80 and 20 percentile points: the 50 percentile points of the various pathways are indicated by diamonds.

## 3.3 Results

The analysis that follows addresses the 27 fuel/vehicle pathways listed in Table 3.7 in terms of their total system energy use (in Btu/mi) and GHG emissions (in g/mi). We evaluated SI and CIDI conventional and hybrid fuel/vehicle pathways first, followed by HEV FC vehicles, and non-hybridized FCVs. Section 3.4 provides a comparison of those pathways that appear to offer superior performance on the basis of energy use (Btu/mi) and GHG emissions (g/mi). It is very important to note that other factors (e.g., criteria pollutants, incremental fuel and vehicle costs) were not considered as part of our study.

Table 3.7 Fuel/Vehicle Pathways Analyzed

No.	Fuel Pathway	Vehicle Configuration	Fuel Abbreviation	Vehicle Abbreviation
1	Low-sulfur gasoline	Gasoline CONV SI	GASO	SI CONV
2	Low-sulfur diesel	Diesel CONV CIDI	DIESEL	CIDI CONV
3	FTD: NNA NG	Diesel CONV CIDI	FTD	CIDI CONV
4	E85: herbaceous cellulose	E85 CONV SI	HE85	SI CONV
5	CNG: NNA NG	CNG CONV SI	CNG	SI CONV
6	Low-sulfur gasoline	Gasoline SI HEV <sup>a,b</sup>	GASO	SI HEV
7	Low-sulfur diesel	Diesel CIDI HEV <sup>b</sup>	DIESEL	CIDI HEV
8	FTD: NNA NG	Diesel CIDI HEV <sup>b</sup>	FTD	CIDI HEV
9	E85: herbaceous cellulose	E85 SI HEV <sup>b</sup>	HE85	SI HEV
10	Low-sulfur gasoline	Gasoline FP FCV	GASO	FP FCV
11	Crude naphtha	Gasoline FP FCV	NAP	FP FCV
12	FT naphtha: NNA NG	Gasoline FP FCV	FT NAP	FP FCV
13	Low-sulfur gasoline	Gasoline FP FC HEV	GASO	FP FC HEV
14	Crude naphtha	Gasoline FP FC HEV	NAP	FP FC HEV
15	FT naphtha: NNA NG	Gasoline FP FC HEV	FT NAP	FP FC HEV
16	MeOH: NNA NG	Methanol FP FCV	MEOH	FP FCV
17	MeOH: NNA NG	Methanol FP FC HEV	MEOH	FP FC HEV
18	E100: herbaceous cellulose	Ethanol FP FCV	HE100	FP FCV
19	E100: herbaceous cellulose	Ethanol FP FC HEV	HE100	FP FC HEV
20	GH <sub>2</sub> – stations: NNA NG	GH <sub>2</sub> FCV	GH <sub>2</sub> RS	FCV
21	GH <sub>2</sub> – stations: NNA NG	GH <sub>2</sub> FC HEV	GH <sub>2</sub> RS	FC HEV
22	GH <sub>2</sub> – central plants: NNA NG	GH <sub>2</sub> FCV	GH <sub>2</sub> CP	FCV
23	GH <sub>2</sub> – central plants: NNA NG	GH <sub>2</sub> FC HEV	GH <sub>2</sub> CP	FC HEV
24	LH <sub>2</sub> – central plants: NNA NG	LH <sub>2</sub> FCV	LH <sub>2</sub>	FCV
25	LH <sub>2</sub> – central plants: NNA NG	LH <sub>2</sub> FC HEV	LH <sub>2</sub>	FC HEV
26	GH <sub>2</sub> electrolysis: U.S. mix	GH <sub>2</sub> FCV	GH <sub>2</sub> EL	FCV
27	GH <sub>2</sub> electrolysis: U.S. mix	GH <sub>2</sub> FC HEV	GH <sub>2</sub> EL	FC HEV

<sup>a</sup> All HEVs are charge sustaining.

<sup>b</sup> Parallel.

### 3.3.1 Conventional and Hybrid Fuel/Vehicle Pathways

Figure 3.4 shows the total system energy use (in Btu/mi) for conventional and hybrid fuel/vehicle pathways powered by SI or CIDI engines.

The figure shows that:

- The diesel CIDI HEV uses the least amount of total energy.
- The diesel CIDI conventional vehicle and the gasoline SI HEV yield roughly the same total system energy use.
- The CNG SI conventional vehicles offer no energy use benefit over gasoline conventional vehicles.
- FTD, even in a comparable technology vehicle (CONV or HEV), is more energy-intensive than crude-based diesel.
- There is considerable opportunity for energy use improvement over the 50 percentile estimates for all pathways, including the baseline gasoline SI conventional vehicle.
- Hybridizing these vehicles reduces energy use by over 15% (see Table 3.8).

Figure 3.5 shows the percent energy loss split for these fuel/vehicle combinations (the calculation for the energy loss split is provided in Appendix 3B). The figure illustrates the impacts of the energy lost in delivering CNG and, particularly, FTD to the vehicle tank. Recall that much of the WTT energy loss for HE85 is from renewable sources (see Table 3.9).

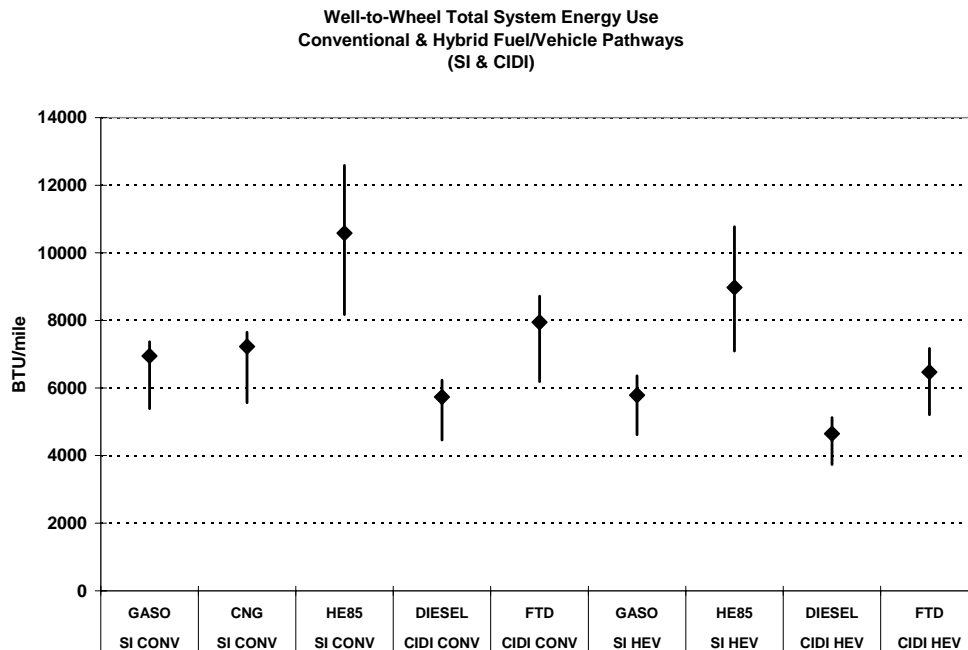


Figure 3.4 WTW Total System Energy Use: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI)

Table 3.8 Total WTW System Efficiency Improvements from Hybridization

Fuel	Conventional (Btu/mi) 50 percentile	HEV (Btu/mi) 50 percentile	Reduction (%)
Gasoline	6,950	5,790	17
Diesel	5,740	4,650	15
HE85	10,580	8,970	15
Average			16

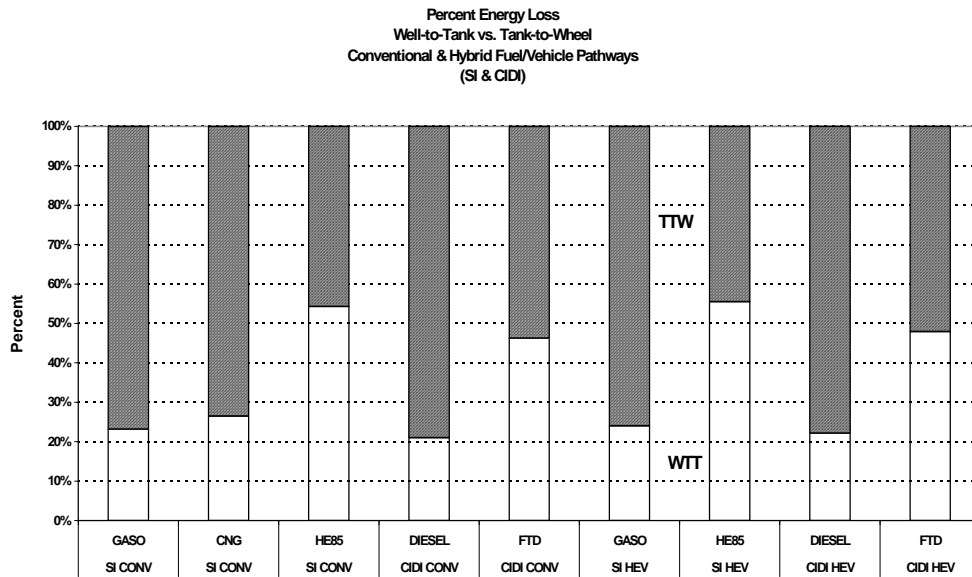


Figure 3.5 Percent Energy Loss, WTT vs. TTW: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI)

Table 3.9 Renewable Share of WTT Total Energy Use

Fuel	WTT % Renewable
Gasoline	1.7
Diesel	1.8
Crude naphtha	1.9
CNG	3.3
Methanol	0.2
FT naphtha	0.1
FTD	0.1
GH <sub>2</sub> – central plants	3.8
LH <sub>2</sub> – central plants	0.1
GH <sub>2</sub> – refueling stations	2.2
GH <sub>2</sub> – electrolysis	13.8
HE100	97.3
HE85	90.6

From the standpoint of GHG emissions, as shown in Figure 3.6:

- The herbaceous E85 (HE85)-fueled vehicles have by far the lowest GHG emissions.
- Among the other vehicles, the diesel CIDI HEV yields the largest potential GHG benefit.
- The CNG SI conventional vehicle generates somewhat higher GHG emissions than the diesel CIDI conventional vehicle.
- The FTD CIDI conventional vehicle and HEV have slightly higher GHG emissions than the crude oil-based diesel CIDI conventional vehicle and HEV.
- Once again, the asymmetric distributions indicate considerable opportunity for new-technology-based improvements in GHG emissions for all vehicles.

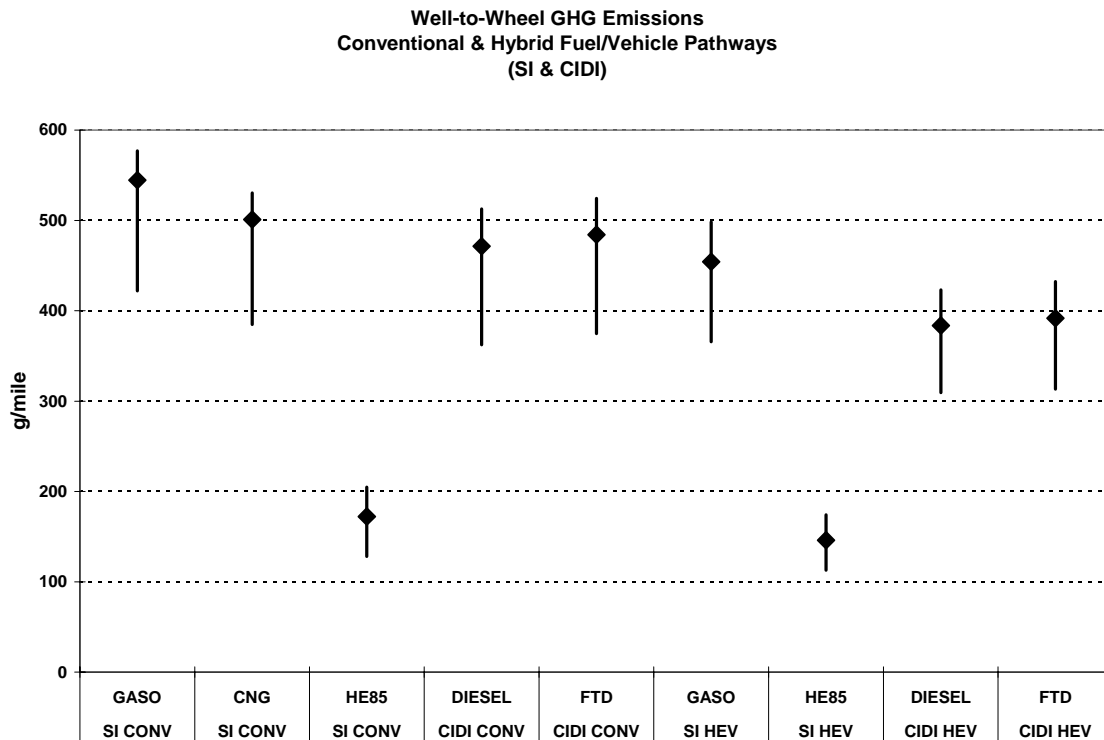


Figure 3.6 WTW GHG Emissions: Conventional and Hybrid Fuel/Vehicle Pathways (SI and CIDI)

### 3.3.2 Fuel/Hybrid and Non-Hybrid FCV Pathways

Nine different fuel/FCV combinations were analyzed in terms of their total system energy use and GHG emissions. Because the hybrid versions of these FCVs show an approximately 10% advantage (see Table 3.10) over their non-hybrid counterparts in terms of total systems energy use, their analysis results are discussed here.

Table 3.10 Total System Efficiency Improvements from Hybridization of FCVs

Fuel	Conventional (Btu/mi) 50 percentile	HEV (Btu/mi) 50 percentile	Reduction (%)
Gasoline	5,190	4,680	10
Crude naphtha	4,830	4,360	10
GH <sub>2</sub> – central plant	5,060	4,550	10
GH <sub>2</sub> – central plant	5,140	4,620	10
Methanol	5,920	5,220	12
LH <sub>2</sub>	6,350	5,720	10
FT naphtha	7,030	6,360	10
GH <sub>2</sub> electrolysis	11,870	10,660	10
HE100	8,830	7,980	10
Average			10

As illustrated in Figure 3.7:

- Gasoline and naphtha fuel processor-based FC HEVs, as well as H<sub>2</sub>-fueled FC HEVs for which the H<sub>2</sub> is produced centrally or at the retail site from non-North-American NG, all offer the best total system energy use.
- Hybridized FCVs fueled by LH<sub>2</sub> and FT naphtha involve higher energy consumption; MeOH use results in higher energy consumption, but is not statistically<sup>1</sup> different from, gasoline, crude naphtha, or GH<sub>2</sub>.
- The electrolysis-based H<sub>2</sub> FC HEV uses significantly more energy than the other pathways.
- The HE100-based pathway fares poorly on total system energy use, although a significant portion of the energy used is renewable (see Table 3.9).

Figure 3.8 reveals several interesting findings:

- While the total system energy use for gasoline and naphtha FP FC HEVs is roughly comparable to that of the H<sub>2</sub> FC HEV (as shown in Figure 3.7), their WTT energy loss split is entirely different: 18-26% for the FP FC HEVs compared to about 60% for the H<sub>2</sub> FCVs.
- The negative impact of WTT energy loss is clear for methanol, LH<sub>2</sub>, FT naphtha, and H<sub>2</sub> produced via electrolysis.

<sup>1</sup> Considering two pathways, if the 50-percentile (P<sub>50</sub>) point of one pathway lies outside the 20–80 percentile (P<sub>20</sub>–P<sub>80</sub>) range of a second pathway, the P<sub>50</sub> points of the two pathways are deemed to be statistically different.

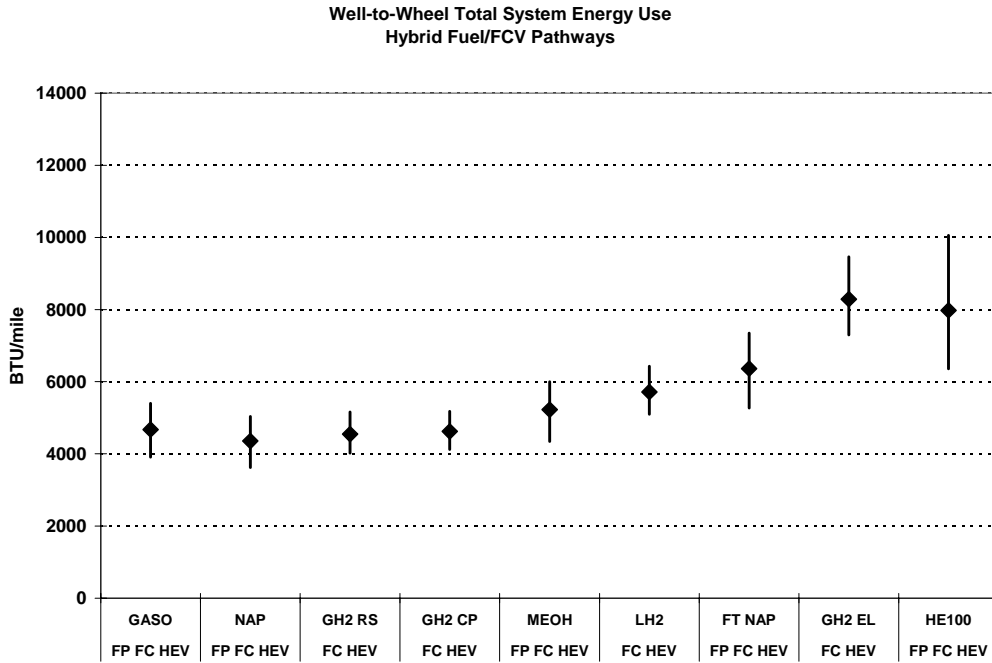


Figure 3.7 WTW Total System Energy Use: Hybrid Fuel/FCV Pathways

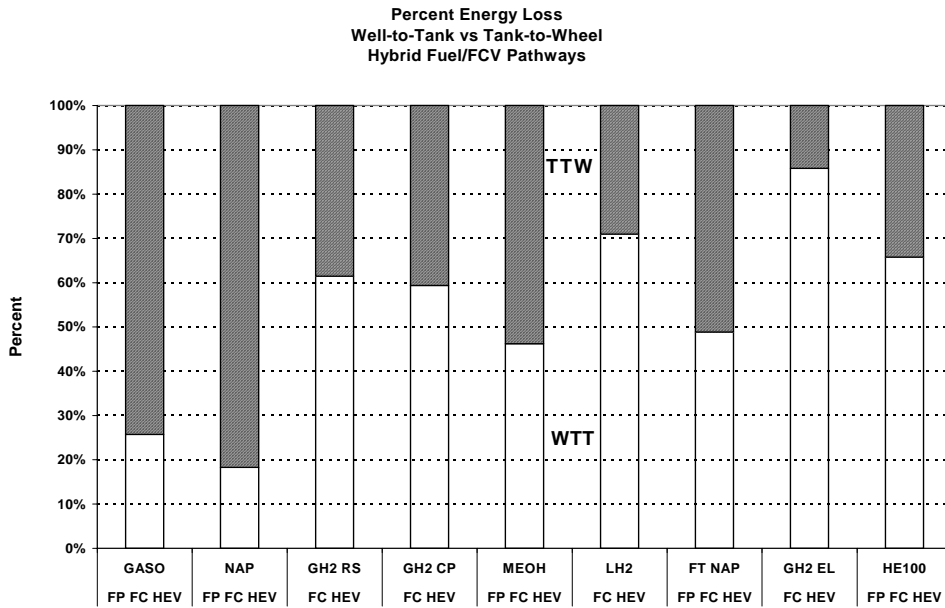


Figure 3.8 Percent Energy Loss, WTT vs. TTW: Hybrid Fuel/FCV Pathways

As shown in Figure 3.9, from a GHG standpoint, the analysis suggests:

- As expected, the HE100 FP FC HEV emits by far the lowest amount of GHGs.
- GHG emissions from the next lowest emitters, the two H<sub>2</sub> FC HEVs, are statistically the same.
- The naphtha and methanol FP FC HEVs are basically tied for third place.
- Gasoline FP FC HEVs and LH<sub>2</sub> FC HEVs are statistically tied for fourth place.
- The GH<sub>2</sub> electrolysis FC HEV pathways have the highest GHG emissions.

Figures 3.10 through 3.12 show non-hybridized versions of the pathways shown in Figures 3.7 through 3.9. In all cases, the energy use and GHG emissions are higher than for the corresponding hybridized FCVs. A quick review reveals that all of the rank order findings discussed above for the hybrid FCVs also apply to non-HEV versions.

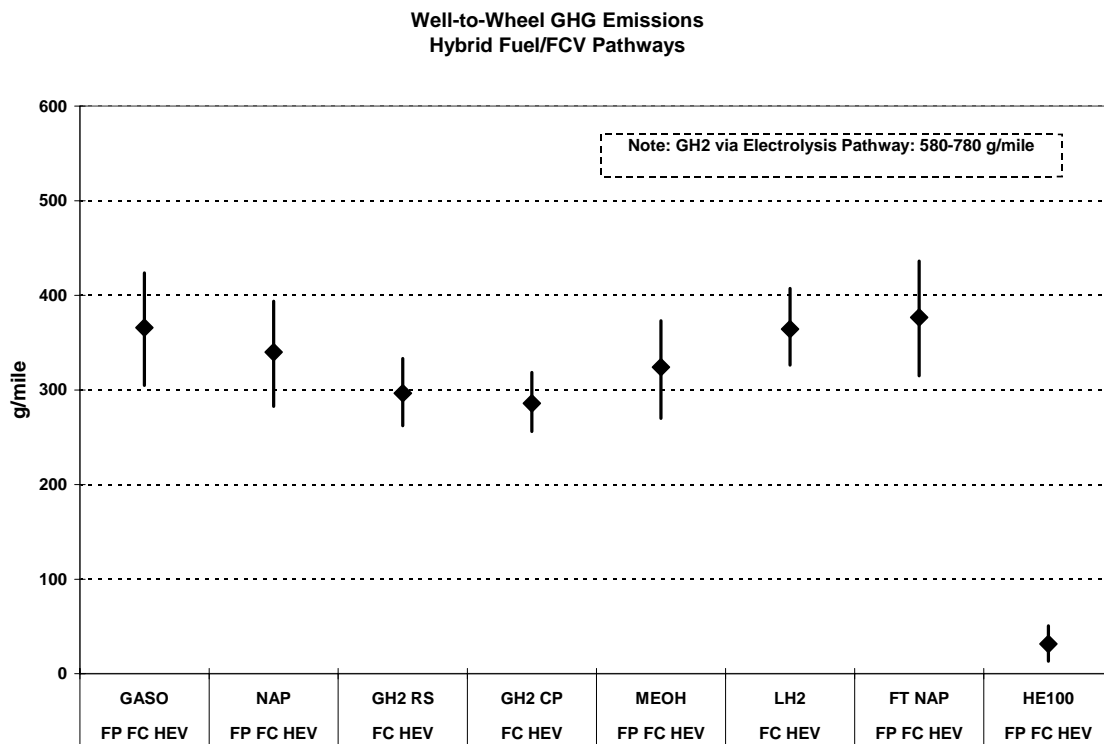


Figure 3.9 WTW GHG Emissions: Hybrid Fuel/FCV Pathways

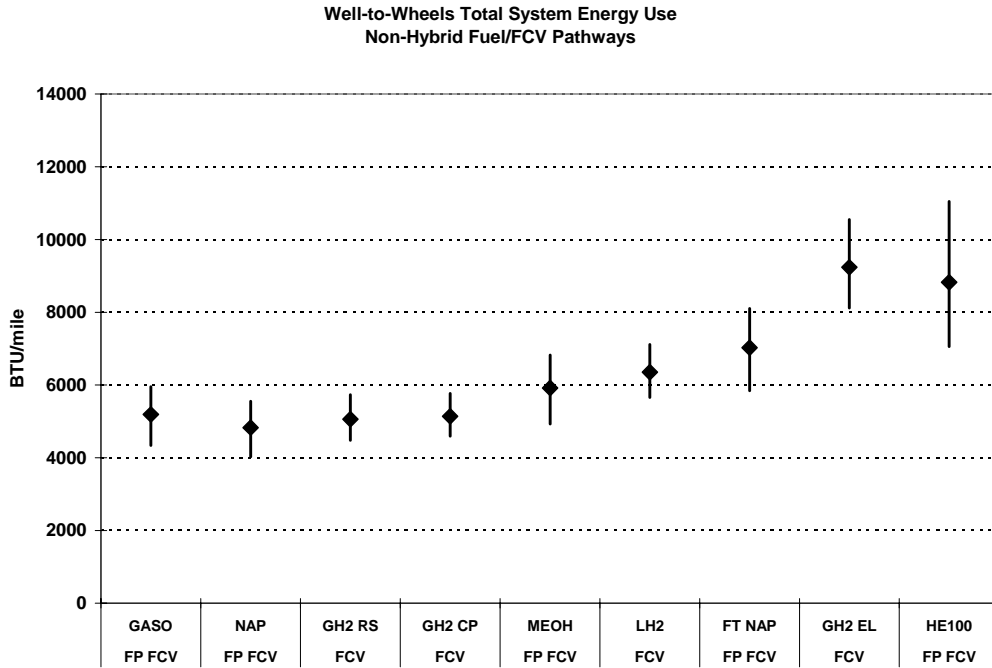


Figure 3.10 WTW Total System Energy Use: Non-Hybrid Fuel/FCV Pathways

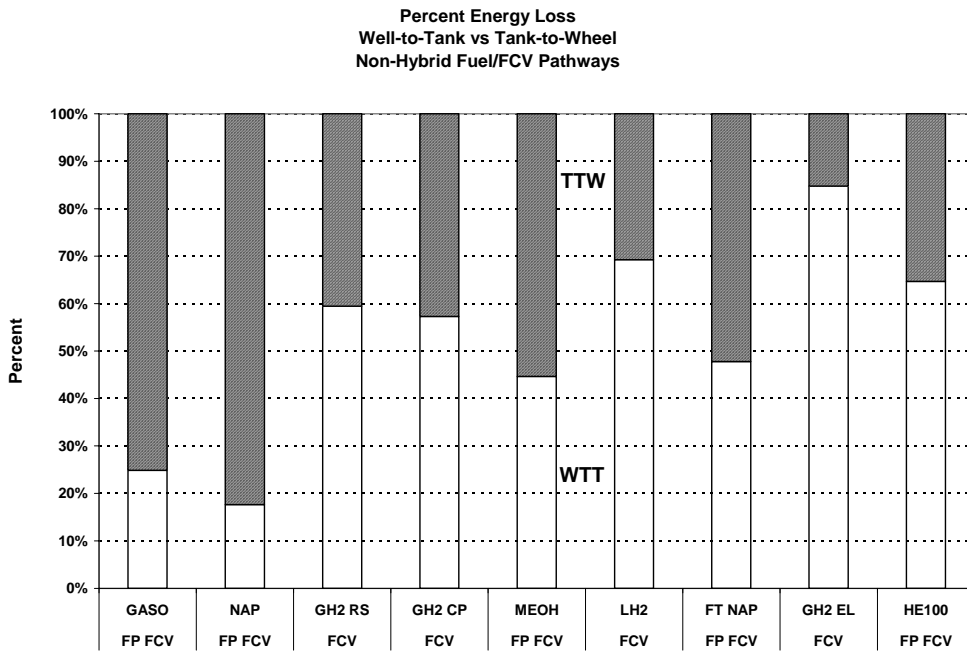


Figure 3.11 Percent Energy Loss, WTT vs. TTW: Non-Hybrid Fuel/FCV Pathways

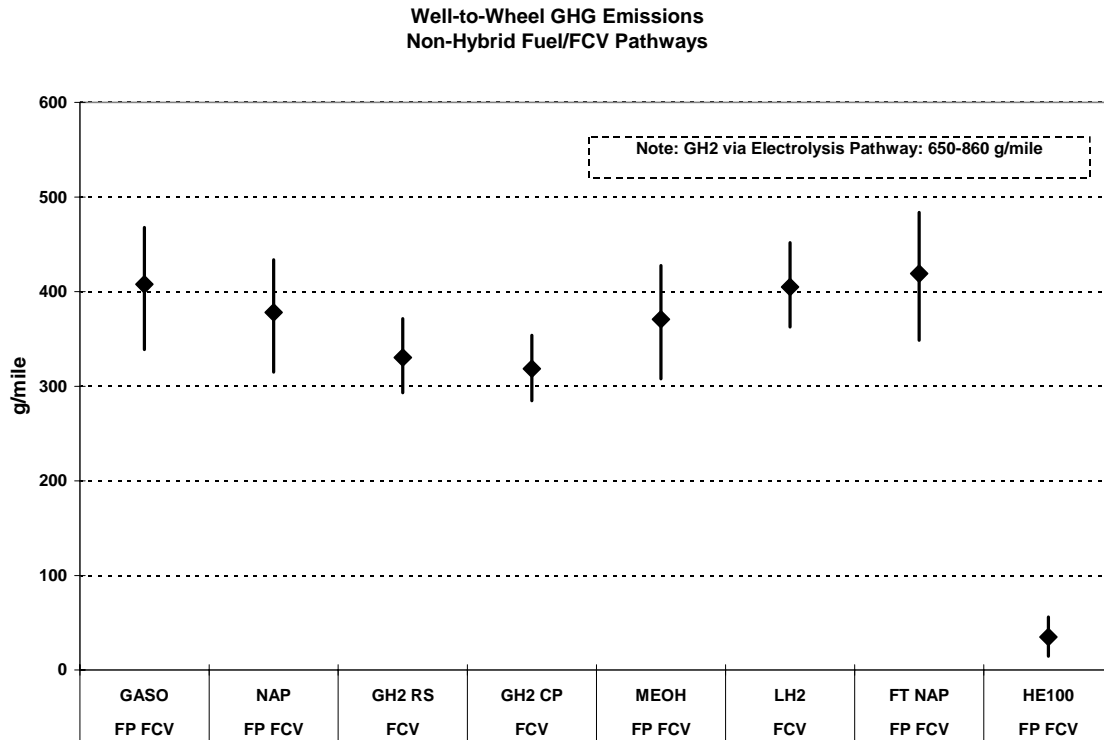


Figure 3.12 WTW GHG Emissions: Non-Hybrid Fuel/FCV Pathways

## 3.4 Conclusions

### 3.4.1 Energy Use

Key findings include the following:

- Figure 3.13 summarizes our results for total system energy use for selected pathways. From a statistical standpoint, the diesel CIDI HEV, gasoline and naphtha FP FC HEVs, as well as the two H<sub>2</sub> FC HEVs (represented by the GH<sub>2</sub> [refueling station] FC HEV only in the figures) are all the lowest energy-consuming pathways.
- Figure 3.14 illustrates an interesting finding: all of the crude oil-based selected pathways have WTT energy loss shares of roughly 25% or less. The H<sub>2</sub> FC HEV share is over 60%; the MeOH FP FC HEV share is about 50%. A significant fraction of the WTT energy use of ethanol is renewable — over 90% for HE100.

### 3.4.2 Greenhouse Gas Emissions

Key GHG findings are summarized in Figure 3.15 and include the following:

- The ethanol-fueled vehicles, as expected, yield the lowest GHG emissions per mile.
- The next lowest are the two H<sub>2</sub> FC HEVs (represented by the GH<sub>2</sub> [refueling station] FC HEV in the figure).

- The H<sub>2</sub> FC HEVs are followed by the MeOH, naphtha, and gasoline FP HEVs and the diesel CIDI HEV, in that order.
- The diesel CIDI HEV offers a significant reduction in GHG emissions (27%) relative to the gasoline conventional SI vehicle.

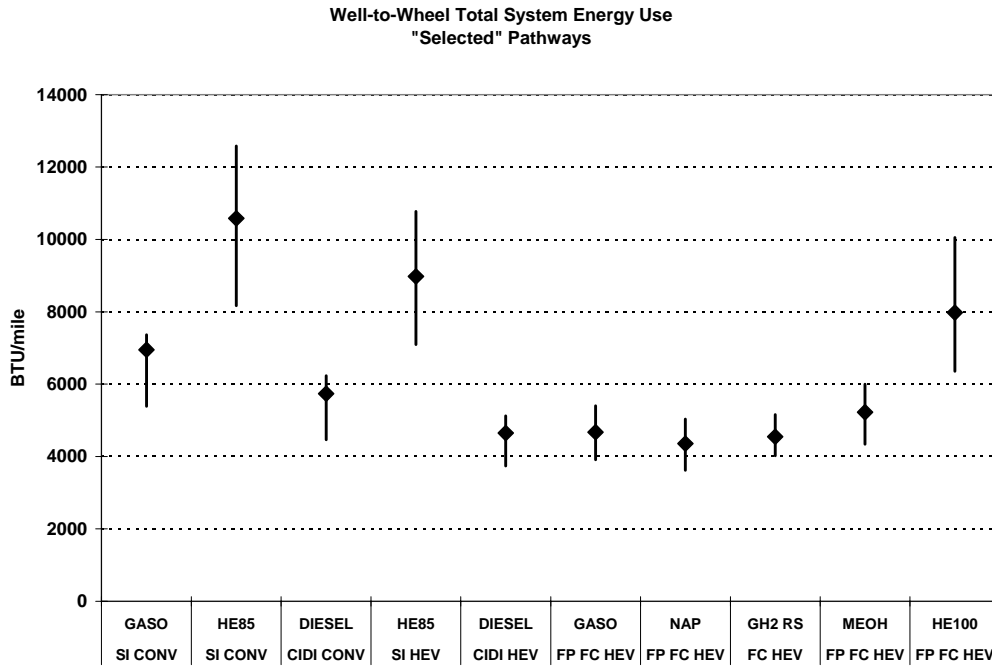


Figure 3.13 WTW Total System Energy Use: "Selected" Fuel/Vehicle Pathways

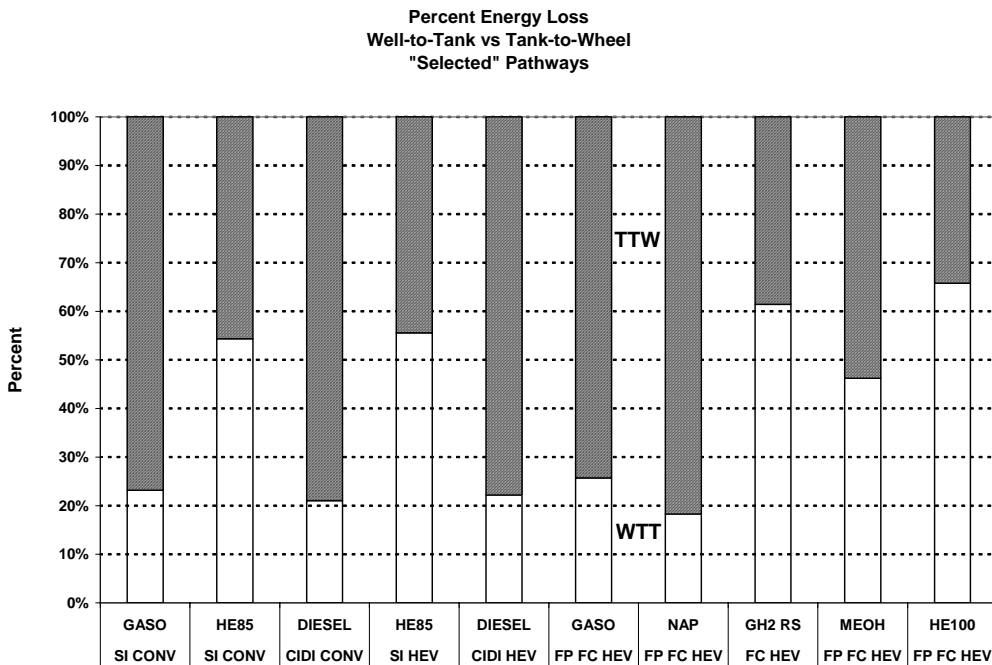


Figure 3.14 Percent Energy Loss, WTT vs. TTW: "Selected" Fuel/Vehicle Pathways

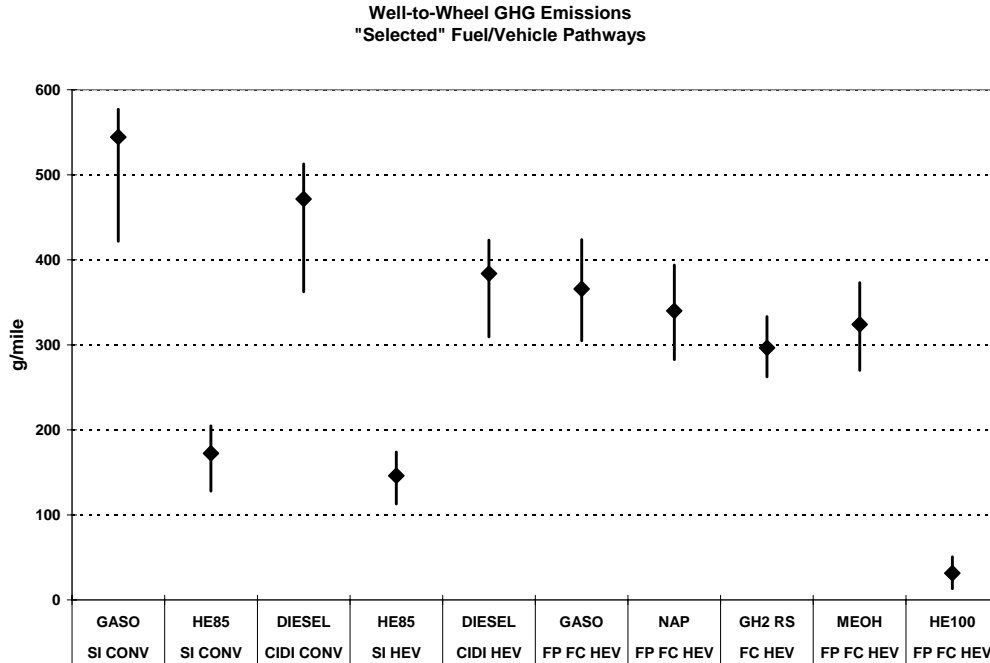


Figure 3.15 WTW GHG Emissions: "Selected" Fuel/Vehicle Pathways

### 3.4.3 Integrated Energy Use/GHG Emissions Results

Considering both total energy use and GHG emissions, the key findings are as follows:

- Among all of the crude oil- and NG-based pathways studied, the diesel CIDI HEV, gasoline and naphtha FP FC HEVs, and GH<sub>2</sub> FC HEVs, were nearly identical and best in terms of total system energy use (Btu/mi). Among these pathways, however, expected GHG emissions were lowest for the H<sub>2</sub> FC HEV and highest for the diesel CIDI HEV.
- Compared to the gasoline SI (conventional), the gasoline SI and diesel CIDI HEVs, as well as the diesel CIDI (conventional) yield significant total system energy use and GHG emission benefits.
- The MeOH FP FC HEV offers no significant energy use or emissions reduction advantages over the crude oil-based or other NG-based FC HEV pathways.
- Ethanol-based fuel/vehicle pathways have by far the lowest GHG emissions of the pathways studied and also do very well on WTT energy loss when only fossil fuel consumption is considered.
- It must be noted that for the HE100 FP FC HEV pathway to reach commercialization, major technology breakthroughs are required for both the fuel and the vehicle.
- On a total system basis, the energy use (Btu/mi) and GHG emissions of CNG conventional and gasoline SI conventional pathways are nearly identical.

- The crude oil-based diesel vehicle pathways offer slightly lower total system GHG emissions and considerably better total system energy use than the NG-based FTD CIDI vehicle pathways. (Note that criteria pollutants are not considered here.)
- LH<sub>2</sub>, FT naphtha, and electrolysis-based H<sub>2</sub> FC HEVs have significantly higher total system energy use and the same or higher levels of GHG emissions than the gasoline and crude naphtha FP FC HEVs and the GH<sub>2</sub> FC HEVs.

Appendix 3C provides the data used to prepare Figures 3.4 through 3.15.

### 3.5 References

EIA, 2000, *Annual Energy Outlook 2001*, U.S. Department of Energy, Energy Information Administration, Dec. ([www.eia.doe.gov/oiaf/aeo/](http://www.eia.doe.gov/oiaf/aeo/)).

GRI, 2000, *Pressbook – GRI Baseline Projection – 2000 Edition*, Gas Research Institute, Des Plaines, Ill.

Kheshgi, H., R. Prince, and G. Marland, 2000, “The Potential of Biomass Fuels in the Context of Global Climate Change: Focus on Transportation Fuels,” *Annual Review of Energy and Environment* 2000, 25:199–244.

NPC, 1999, *Natural Gas: Meeting the Challenges of the Nation’s Growing Natural Gas Demand*, National Petroleum Council, Dec.

*Oil & Gas Journal*, 2000, “Worldwide Look at Reserves and Production,” Volume 98, No. 51, pp. 122–123, Dec. 18.

Price, M., P. Westcott, P. Riley, and M. Graboski, 1998, *The Impact of Increased Corn Demand for Ethanol on Planted Cropland*, U.S. Department of Agriculture, Office of Energy Policy and New Uses, Washington, D.C., March.

USGS, 2000, *World Petroleum Assessment 2000 – Description and Results*, CD-ROM, U.S. Geological Survey.



## Appendix 3A: CO<sub>2</sub> Content of Fuels

Fuel	CO <sub>2</sub> Content (g/mmBtu)
GASO	76,477
DIESEL	81,245
FTD	78,155
CNG	60,185
HE85	76,289
NAP	76,108
FT NAP	73,959
MeOH	73,002
HE100	76,218
GH <sub>2</sub>	0
LH <sub>2</sub>	0



## Appendix 3B: Energy Loss Split Calculation

### Background

#### *Background*

Using the notation in Part 2, efficiency is defined as:

$$\text{Eff} = \frac{\text{EnergyOutput}}{\text{EnergyInput}} = \frac{E_o}{E_I}$$

where

$$E_o = \sum (\text{Roll Resist} + \text{Aero Resist} + \text{Ma}) * V * \Delta t \text{ over the drive cycle and}$$

$E_I$  = energy value of fuel consumed.

To illustrate the ramifications of the above definition, assume the mass is (roughly) constant over all vehicles being compared. Then,

$$E_o = \text{constant for all vehicles} \equiv \bar{E}_o.$$

We could say that all vehicles are required to provide the same amount of “useful work,”  $\bar{E}_o$ .

Then, the energy balance requires:

$$E_{iI} = \text{energy loss in propulsion system } i \text{ (PSL}_i\text{)} + \text{Energy loss with Auxiliaries } i \text{ (AuxL}_i\text{)} + \bar{E}_o,$$

where  $i$  = propulsion system designator.

Hence,

$$\text{Eff}_i = \frac{\bar{E}_o}{\bar{E}_o + \text{PSL}_i + \text{AuxL}_i}$$

where  $0 \leq \text{Eff} \leq 1$ .

Our study focuses on the fuels and propulsion systems and thus on differences in  $\text{PSL}_i$ . Improvement potentials in rolling resistance, aero resistance, and lighter weight materials are not part of this study.

For each of the fuel/vehicle pathways, total Btu consumed in permitting each of the vehicles the ability to transverse the same duty cycle “miles” plus the energy consumed to provide the Btu to the vehicle necessary to transverse that duty cycle mile is known. That is, the total Btu lost ( $E_L$ ) is known and is defined as:

$$E_L = E_F + E_V,$$

where

$E_V$  = Btu lost/consumed by the vehicle to provide the duty cycle miles of mobility ( $E_V = E_i$  above) and

$E_F$  = Btu lost/consumed in the fuel production process to provide to the vehicle's tank the fuel consumed by the vehicle.

### ***Problem***

Determine the allocation of the total Btu lost ( $E_L$ ) between the fuel production/delivery process ( $E_F$ ) and the vehicle ( $E_V$ ); that is, determine  $E_F/E_L$  and  $E_V/E_L$ , where the sum of the two allocations equals 1.

### ***Solution***

Let

$E$  = total energy (Btu) at the "wellhead,"

$e_F$  = efficiency of fuel production/distribution process so that

$E_F = (1 - e_F) E$ , and let

$e_V$  = efficiency of the vehicle over the duty cycle miles ( $e_V = \text{Eff}_i$  above) so that

$$(1 - e_V) = \frac{(\text{Btu lost / consumed by vehicle})}{(\text{Btu provided to the vehicle})} .$$

Hence, the total system energy loss,

$$E_L = (1 - e_F) E + (1 - e_V) e_F E ,$$

from which it follows that total system efficiency,

$$\eta = \frac{(E - E_L)}{E} = e_F * e_V ,$$

and the fuel production/distribution and vehicle allocations are as follows:

$$\text{Fuel loss fraction (FLF)} = E_F/E_L = \frac{(1 - e_F)}{(1 - e_F e_V)}$$

$$\text{Vehicle loss function (VLF)} = E_V/E_L = \frac{e_F(1 - e_V)}{(1 - e_F e_V)}$$

where  $\text{FLF} + \text{VLF} = 1$ .

**Note**

This result yields  $\eta$ , FLF, VLF to be independent of E. In fact, E would have to vary across pathways so that the vehicles associated with all pathways can traverse the same duty-cycle miles.

**Sample Calculations**

$e_F$	$e_V$	FLF	VLF
0.4	0.2	0.652	0.348
0.4	0.3	0.682	0.318
0.4	0.4	0.714	0.286
0.8	0.2	0.238	0.762
0.8	0.3	0.263	0.737
0.8	0.4	0.294	0.706



## Appendix 3C: Data Used to Prepare Figures 3.4 through 3.15

		WTW Energy Use			Energy Use Share		GHG Emissions		
		BTU/mile					g/mile		
		20%	50%	80%	WTT	TTW	20%	50%	80%
SI CONV	GASO	5388	6949	7365	23%	77%	422	544	577
CIDI CONV	DIESEL	4462	5735	6232	21%	79%	362	472	513
CIDI CONV	FTD	6191	7945	8718	46%	54%	375	484	524
SI CONV	CNG	5566	7224	7644	27%	73%	385	501	530
SI CONV	HE85	8170	10579	12582	54%	46%	128	172	205
SI HEV	GASO	4617	5788	6362	24%	76%	366	454	498
CIDI HEV	DIESEL	3741	4650	5126	22%	78%	309	384	423
CIDI HEV	FTD	5209	6471	7169	48%	52%	313	392	432
SI HEV	HE85	7097	8974	10771	56%	44%	113	146	174
FP FCV	GASO	4339	5192	5953	25%	75%	339	408	468
FP FCV	NAP	4025	4828	5549	18%	82%	315	378	434
FP FCV	FT NAP	5842	7026	8105	48%	52%	349	419	484
FP FC HEV	GASO	3912	4675	5398	26%	74%	305	366	424
FP FC HEV	NAP	3621	4357	5035	18%	82%	283	340	394
FP FC HEV	FT NAP	5272	6362	7346	49%	51%	315	377	436
FP FCV	MEOH	4927	5919	6827	45%	55%	308	371	428
FP FC HEV	MEOH	4341	5224	5997	46%	54%	270	324	373
FP FCV	HE100	7053	8827	11044	65%	35%	15	35	56
FP FC HEV	HE100	6358	7979	10052	66%	34%	13	31	51
FCV	GH2 RS	4476	5060	5729	59%	41%	293	330	371
FC HEV	GH2 RS	4022	4549	5159	61%	39%	262	296	333
FCV	GH2 CP	4595	5140	5765	57%	43%	285	318	354
FC HEV	GH2 CP	4122	4625	5178	59%	41%	256	286	319
FCV	LH2	5655	6351	7115	69%	31%	363	405	452
FC HEV	LH2	5101	5718	6427	71%	29%	326	364	407
FCV	GH2 EL	8117	9238	10549	85%	15%	651	750	863
FC HEV	GH2 EL	7294	8289	9463	86%	14%	584	675	777



VOLUME 3

*General Motors  
Corporation*

*Argonne National  
Laboratory*

*BP*

*ExxonMobil*

*and*

*Shell*

*Well-to-Tank Energy Use and  
Greenhouse Gas Emissions of  
Transportation Fuels  
– North American Analysis –*

June 2001

VOLUME 3

**General Motors  
Corporation**

**Argonne National  
Laboratory**

**BP**

**ExxonMobil**

**and**

**Shell**

**Well-to-Tank Energy Use and  
Greenhouse Gas Emissions of  
Transportation Fuels  
– North American Analysis –**

June 2001

# Contents

Notation.....	xi
1 Introduction.....	1
2 The GREET Model.....	3
3 Fuels and Fuel Production Pathways Included in This Study .....	5
3.1 Gasoline, Diesel, and Naphtha from Petroleum.....	5
3.1.1 Gasoline Requirements .....	5
3.1.2 Diesel Requirements .....	7
3.1.3 Crude Naphtha.....	7
3.1.4 Quality of Crude Oil.....	9
3.1.5 Energy Efficiency Assumptions for Production of Gasoline, Diesel, and Naphtha.....	10
3.2 Fuels Produced from Natural Gas .....	16
3.2.1 Natural-Gas-Based Fuel Pathways.....	16
3.2.2 Key NG Upstream Stages .....	22
3.3 Bio-Ethanol Production Options .....	29
3.3.1 Bio-Ethanol Pathways.....	30
3.3.2 Parametric Assumptions.....	31
3.4 Electricity Generation .....	32
3.4.1 Electricity Generation Pathways.....	32
3.4.2 Electricity Generation Efficiencies .....	33
3.5 Hydrogen Production via Electrolysis at Refueling Stations.....	34
3.5.1 Pathway Definitions .....	34
3.5.2 Efficiencies of Electrolysis.....	35
4 Development of Probability Distribution Functions for Key Parameters .....	37
4.1 Assignment of Uncertainty Levels.....	37
4.1.1 Petroleum-Based Fuel Pathways.....	37
4.1.2 Natural-Gas-Based Fuels.....	38
4.1.3 Bio-Ethanol Pathways.....	39
4.1.4 Electricity Generation .....	39
4.2 Electricity to Hydrogen via Electrolysis .....	40
4.3 Determination of Probability Distribution Functions.....	40
4.3.1 Petroleum-Based Fuel Pathways.....	40
4.3.2 Natural-Gas-Based Fuels.....	41
4.3.3 Bio-Ethanol Pathways .....	42
4.4 Electricity Generation .....	42
4.5 Electricity to Hydrogen via Electrolysis .....	44

## Contents (Cont.)

5	Transportation of Feedstocks and Fuels .....	45
5.1	Methodology .....	45
5.2	Assumptions .....	46
5.2.1	Crude Oil .....	46
5.2.2	Gasoline and Diesel.....	47
5.2.3	Methanol.....	47
5.2.4	Liquefied Natural Gas .....	49
5.2.5	Fischer-Tropsch Diesel and Naphtha .....	49
5.2.6	Liquid Hydrogen .....	50
5.2.7	Ethanol .....	50
5.2.8	Natural Gas and Gaseous Hydrogen .....	50
5.2.9	Electricity Transmission.....	51
5.2.10	Input Energy Efficiencies for Feedstock and Fuel Transportation .....	51
6	Results: Well-To-Tank Energy Use and Emissions .....	53
6.1	Total Energy Use.....	55
6.2	Well-to-Tank Energy Efficiencies .....	58
6.3	Fossil Energy Use.....	58
6.4	Petroleum Use .....	61
6.5	Greenhouse Gas Emissions .....	61
7	Conclusions.....	65
8	Acknowledgments .....	67
9	References.....	69
Appendix A: Probability Distribution Functions for Key Well-to-Tank Input Parameters .....		A-1
Appendix B: Complete Well-to-Tank Results .....		B-1

## Figures

1	Well-to-Tank Stages Covered in Argonne’s Study .....	1
2	Calculation Logic for Well-to-Tank Energy Use and Emissions of Transportation Fuels.....	4
3	Well-to-Tank Stages for Three Petroleum-Based Fuels.....	9
4	Pathways of CNG Production.....	17
5	Pathways of Methanol Production.....	18

## Figures (Cont.)

6	Pathways of Fischer-Tropsch Diesel and Naphtha Production .....	18
7	Pathways of Gaseous Hydrogen Production in Central Plants .....	19
8	Pathways of Gaseous Hydrogen Production at Refueling Stations .....	19
9	Pathways of Liquid Hydrogen Production in Central Plants .....	20
10	Pathways of Liquid Hydrogen Production at Refueling Stations .....	20
11	Pathways of Ethanol Production .....	30
12	Pathways of Electricity Generation .....	33
13	Pathways of Hydrogen Production via Electrolysis .....	34
14	Calculation Logic of Energy Use and Emissions Associated with Feedstock and Fuel Transportation .....	45
15	Crude Transportation from Oil Fields to U.S. Petroleum Refineries .....	46
16	Gasoline Transportation from Petroleum Refineries to Refueling Stations .....	47
17	Diesel Fuel Transportation from Petroleum Refineries to Refueling Stations .....	48
18	Methanol Transportation from Methanol Plants to Refueling Stations .....	48
19	Transportation of Fischer-Tropsch Diesel and Naphtha from Plants to Refueling Stations .....	49
20	Transportation of Liquid Hydrogen from Central Plants to Refueling Stations .....	50
21	Transportation of Ethanol from Plants to Refueling Stations .....	51
22	Well-to-Tank Total Energy Use .....	57
23	Well-to-Tank Energy Efficiencies .....	59
24	Well-to-Tank Fossil Energy Use .....	60
25	Well-to-Tank Petroleum Use .....	62
26	Well-to-Tank GHG Emissions .....	63
A1	Probability Distribution Functions for Energy Efficiencies of Petroleum Recovery and Refining .....	A-3

## Figures (Cont.)

A2	Probability Distribution Functions for Energy Efficiencies of Natural-Gas-Based Pathway Activities .....	A-8
A3	Probability Distribution Functions for Bio-Ethanol Pathway Activities .....	A-18
A4	Probability Distribution Functions for Energy Efficiencies of Electric Power Plants .....	A-28
A5	Probability Distribution Functions for Energy Efficiencies of Electrolysis H <sub>2</sub> Production.....	A-31

## Tables

1	Composition Requirements of CARFG2 and CARFG3.....	6
2	Typical Properties of CG and FRFG .....	7
3	Crude Quality and Product Yields from the Atmospheric Distillation Process .....	8
4	Typical Properties of Crude and Fischer-Tropsch Naphtha .....	8
5	Quality of Crude Oil Used in U.S. Refineries .....	10
6	Five Gasoline Options Included in This Study.....	11
7	Overall Energy Efficiencies of Petroleum Refineries Extracted from MathPro Studies.....	13
8	Energy Efficiencies of Producing Gasoline and Diesel Fuels .....	14
9	Natural Gas Reserves.....	16
10	Parametric Assumptions for Ethanol Production Pathways .....	32
11	Electrolysis Energy Efficiencies for Hydrogen Production.....	35
12	Uncertainty Levels for Energy Efficiencies of Petroleum Pathway Activities .....	38
13	Uncertainty Levels for Energy Efficiencies of Natural Gas Pathway Activities.....	38
14	Uncertainty Levels for Parameters of Ethanol Pathway Activities .....	39
15	Uncertainty Levels for Electricity Generation Efficiencies.....	40
16	Energy Efficiencies for Petroleum Pathway Activities .....	41
17	Energy Efficiencies for Natural-Gas-Based Pathway Activities .....	42

## Tables (Cont.)

18	Energy Efficiencies and Other Values for Bio-Ethanol Pathway Activities.....	43
19	Energy Conversion Efficiencies for Electric Power Plants.....	43
20	The U.S., California, and Northeast U.S. Electricity Generation Mix.....	44
21	Hydrogen Electrolysis Efficiencies.....	44
22	Energy Efficiencies for Transportation of Feedstocks and Fuels Calculated from GREET Outputs.....	52
23	Fuel Pathway Options Analyzed in This Study .....	54
B1	Conventional Gasoline .....	B-3
B2	150 ppm S FRFG with MTBE .....	B-3
B3	5–30 ppm S FRFG with MTBE .....	B-4
B4	5–30 ppm S FRFG with EtOH.....	B-4
B5	5–30 ppm S RFG with No Oxygenate .....	B-4
B6	Conventional Diesel .....	B-4
B7	Low-Sulfur Diesel.....	B-5
B8	1 ppm S Crude Naphtha.....	B-5
B9	CNG: NA NG.....	B-6
B10	CNG: NNA NG.....	B-6
B11	CNG: NNA FG.....	B-6
B12	Methanol: NA NG, No Steam or Electricity Co-Generation .....	B-6
B13	Methanol: NA NG, Steam Co-Generation .....	B-7
B14	Methanol: NA NG, Electricity Co-Generation .....	B-7
B15	Methanol: NNA NG, No Steam or Electricity Co-Generation .....	B-7
B16	Methanol: NNA NG, Electricity Co-Generation.....	B-7
B17	Methanol: NNA FG, No Steam or Electricity Co-Generation.....	B-8

## Tables (Cont.)

B18 FT Naphtha: NA NG, No Steam or Electricity Co-Generation .....	B-8
B19 FT Naphtha: NA NG, Steam Co-Generation .....	B-8
B20 FT Naphtha: NA NG, Electricity Co-Generation.....	B-8
B21 FT Naphtha: NNA NG, No Steam or Electricity Co-Generation .....	B-9
B22 FT Naphtha: NNA NG, Electricity Co-Generation.....	B-9
B23 FT Naphtha: NNA NG, No Steam or Electricity Co-Generation .....	B-9
B24 FT Diesel: NA NG, No Steam or Electricity Co-Generation.....	B-9
B25 FT Diesel: NA NG, Steam Co-Generation.....	B-10
B26 FT Diesel: NA NG, Electricity Co-Generation.....	B-10
B27 FT Diesel: NNA NG, No Steam or Electricity Co-Generation.....	B-10
B28 FT Diesel: NNA NG, Electricity Co-Generation.....	B-10
B29 FT Diesel: NNA FG, No Steam or Electricity Co-Generation .....	B-11
B30 Central G.H <sub>2</sub> : NA NG, No Steam or Electricity Co-Generation.....	B-11
B31 Central G.H <sub>2</sub> : NA NG, Steam Co-Generation.....	B-11
B32 Central G.H <sub>2</sub> : NA NG, Electricity Co-Generation.....	B-11
B33 Central G.H <sub>2</sub> : NNA NG, No Steam or Electricity Co-Generation.....	B-12
B34 Central G.H <sub>2</sub> : NNA NG, Electricity Co-Generation .....	B-12
B35 Central G.H <sub>2</sub> : NNA FG, No Steam or Electricity Co-Generation .....	B-12
B36 Central L.H <sub>2</sub> : NA NG, No Steam or Electricity Co-Generation .....	B-12
B37 Central L.H <sub>2</sub> : NA NG, Steam Co-Generation .....	B-13
B38 Central L.H <sub>2</sub> : NA NG, Electricity Co-Generation .....	B-13
B39 Central L.H <sub>2</sub> : NNA NG, No Steam or Electricity Co-Generation .....	B-13
B40 Central L.H <sub>2</sub> : NNA NG, Electricity Co-Generation .....	B-13
B41 Central L.H <sub>2</sub> : NNA FG, No Steam or Electricity Co-Generation.....	B-14

## Tables (Cont.)

B42 Station G.H <sub>2</sub> : NA NG.....	B-14
B43 Station G.H <sub>2</sub> : NNA NG.....	B-14
B44 Station G.H <sub>2</sub> : NNA FG.....	B-14
B45 Station L.H <sub>2</sub> : NA NG.....	B-15
B46 Station L.H <sub>2</sub> : NNA NG.....	B-15
B47 Station L.H <sub>2</sub> : NNA FG.....	B-15
B48 Electricity: U.S. Mix.....	B-15
B49 Electricity: CA Mix.....	B-16
B50 Electricity: NE U.S. Mix.....	B-16
B51 Electricity: NG CC Turbines.....	B-16
B52 Station G.H <sub>2</sub> : Electrolysis, U.S. Mix.....	B-16
B53 Station G.H <sub>2</sub> : Electrolysis, CA Mix.....	B-17
B54 Station G.H <sub>2</sub> : Electrolysis, N.E. U.S. Mix.....	B-17
B55 Station G.H <sub>2</sub> : Electrolysis, NG CC Turbines.....	B-17
B56 Station G.H <sub>2</sub> : Electrolysis, Nuclear Power.....	B-17
B57 Station G.H <sub>2</sub> : Electrolysis, Hydroelectric Power.....	B-18
B58 Station L.H <sub>2</sub> : Electrolysis, U.S. Mix.....	B-18
B59 Station L.H <sub>2</sub> : Electrolysis, CA Mix.....	B-18
B60 Station L.H <sub>2</sub> : Electrolysis, N.E. U.S. Mix.....	B-18
B61 Station L.H <sub>2</sub> : Electrolysis, NG CC Turbines.....	B-19
B62 Station L.H <sub>2</sub> : Electrolysis, Nuclear Power.....	B-19
B63 Station L.H <sub>2</sub> : Electrolysis, Hydroelectric Power.....	B-19
B64 Ethanol: Corn, Dry Mill, Displacement.....	B-19
B65 Ethanol: Corn, Dry Mill, Market Value.....	B-20

## Tables (Cont.)

B66	Ethanol: Corn, Wet Mill, Displacement.....	B-20
B67	Ethanol: Corn, Wet Mill, Market Value.....	B-20
B68	Ethanol: Woody Biomass.....	B-20
B69	Ethanol: Herbaceous Biomass.....	B-21
B70	E85: Corn, Dry Mill, Displacement.....	B-21
B71	E85: Corn, Dry Mill, Market Value.....	B-21
B72	E85: Corn, Wet Mill, Displacement.....	B-21
B73	E85: Corn, Wet Mill, Market Value.....	B-22
B74	E85: Woody Biomass.....	B-22
B75	E85: Herbaceous Biomass.....	B-22

## Notation

### Acronyms and Abbreviations

AMI	American Methanol Institute
ANL	Argonne National Laboratory
API	American Petroleum Institute
ATR	autothermal reforming
CAAA	Clean Air Act Amendments
CACD	California conventional diesel
CALSD	California low-sulfur diesel
CARB	California Air Resources Board
CARBOB	California reformulated blendstock for oxygenate blending
CARFG1	California Phase 1 reformulated gasoline
CARFG2	California Phase 2 reformulated gasoline
CARFG3	California Phase 3 reformulated gasoline
CC	combined-cycle
CG	conventional gasoline
CH <sub>4</sub>	methane
CNG	compressed natural gas
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CTR	Center for Transportation Research
DGS	distillers' grains and solubles
EC-D	emission control diesel
EPA	U.S. Environmental Protection Agency
EtOH	ethanol
EV	electric vehicles
FCD	federal conventional diesel
FCV	fuel-cell vehicle
FG	flared gas
FLSD	federal low-sulfur diesel
FRFG1	federal Phase 1 reformulated gasoline
FRFG2	federal Phase 2 reformulated gasoline
FT	Fischer-Tropsch
FTD	Fischer-Tropsch diesel
GAPC	Global Alternative Propulsion Center
GBS	gasoline blendstock
G.H <sub>2</sub>	gaseous hydrogen
GHG	greenhouse gas
GM	General Motors Corporation
REET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
GWP	global warming potential
HEV	hybrid electric vehicle
IPCC	Intergovernmental Panel on Climate Change
L.H <sub>2</sub>	liquid hydrogen

LNG	liquefied natural gas
LP	linear programming
LPG	liquefied petroleum gas
LS	low-sulfur
MeOH	methanol
MTBE	methyl tertiary butyl ether
NA	North American
NG	natural gas
NNA	non-North-American
NPC	National Petroleum Council
N <sub>2</sub> O	nitrous oxide
NO <sub>x</sub>	nitrogen oxides
NRC	National Research Council
P20	20% probability
P50	50% probability
P80	80% probability
PADD	Petroleum Administration Defense District
PM <sub>10</sub>	particulate matter with diameter of 10 μm or less
POX	partial oxidation
PSA	pressure swing adsorption
RFG	reformulated gasoline
RVP	Reid vapor pressure
S	sulfur
SMR	steam-methane reforming
SO <sub>x</sub>	sulfur oxides
U.S. DOC	U.S. Department of Commerce
U.S. DOT	U.S. Department of Transportation
EPA	U.S. Environmental Protection Agency
VOC	volatile organic compounds
WTT	well-to-tank

## Units of Measure

bbl	barrel(s)	kW	kilowatt(s)
Btu	British thermal unit(s)	mi	mile(s)
°C	degree(s) Celsius	min	minute(s)
°F	degree(s) Fahrenheit	mmBtu	million (10 <sup>6</sup> ) Btu
g	gram(s)	ppm	part(s) per million
gal	gallon(s)	psi	pound(s) per square inch
J	joule(s)	yr	year(s)
K	Kelvin	μm	micrometer(s)
kg	kilogram(s)		

# 1 Introduction

Various fuels are being proposed for use in fuel-cell vehicles (FCVs) and hybrid electric vehicles (HEVs). Some of these fuels will be able to power advanced internal combustion engine technologies as well. These fuels are made through different fuel production pathways, resulting in different energy efficiencies and emissions from feedstock recovery to vehicle operation. To fully analyze energy and emission impacts of vehicle/fuel systems, a full fuel-cycle analysis — from energy feedstock recovery (wells) to fuel use by vehicle (wheels) — needs to be conducted for fuel/vehicle systems. Figure 1 shows the well-to-tank stages included in Argonne’s study.

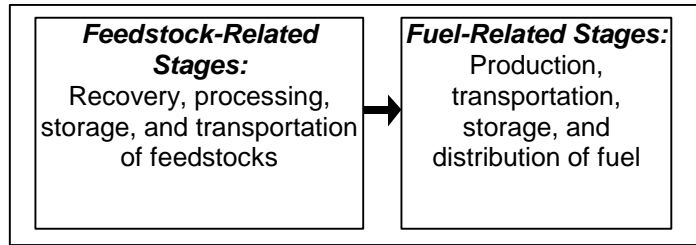


Figure 1 Well-to-Tank Stages Covered in Argonne’s Study

The Global Alternative Propulsion Center (GAPC) of General Motors Corporation (GM) commissioned the Center for Transportation Research (CTR) of Argonne National Laboratory (ANL) to conduct a study to evaluate energy and emission impacts of producing different transportation fuels from wells to fuels available in vehicle tanks (well-to-tank [WTT] analysis). Three energy companies — BP, ExxonMobil, and Shell — participated in the study by providing input and reviewing Argonne’s results. This report presents methodologies, assumptions, and results of Argonne’s study.



## 2 The GREET Model

In 1995, ANL began to develop a spreadsheet-based model for estimating the full fuel-cycle energy and emission impacts of alternative transportation fuels and advanced vehicle technologies. The intent was to provide an analytical tool to allow researchers to readily analyze various parametric assumptions that affect fuel-cycle energy use and emissions associated with fuels and vehicle technologies. The model, called GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation), calculates fuel-cycle energy use in British thermal units per mile (Btu/mi) and emissions in grams per mile (g/mi) for various transportation fuels and vehicle technologies. For energy use, GREET includes total energy use (all energy sources), fossil energy use (petroleum, natural gas, and coal), and petroleum use (each energy item is a part of the preceding energy item). For emissions, the model includes three major greenhouse gases (GHGs) (carbon dioxide [CO<sub>2</sub>], methane [CH<sub>4</sub>], and nitrous oxide [N<sub>2</sub>O]) and five criteria pollutants (volatile organic compounds [VOCs], carbon monoxide [CO], nitrogen oxides [NO<sub>x</sub>], particulate matter with diameters of 10 μm or less [PM<sub>10</sub>], and sulfur oxides [SO<sub>x</sub>]).

In the GREET model, the three GHGs are combined together with their global warming potentials (GWPs) to calculate CO<sub>2</sub>-equivalent GHG emissions. The default GWPs in GREET — 1 for CO<sub>2</sub>, 21 for CH<sub>4</sub>, and 310 for N<sub>2</sub>O — are recommended by the Intergovernmental Panel on Climate Change (IPCC) for the 100-year time horizon. On the other hand, emissions of the five criteria pollutants are further separated into total and urban emissions. Total emissions are emissions occurring everywhere. Urban emissions are those occurring within urban areas. The separation is conducted on the basis of information on facility locations and is intended to provide an approximation of population exposure of air pollution caused by the criteria pollutants.

For the GAPC project, Argonne estimated energy use for the three energy items and CO<sub>2</sub>-equivalent GHG emissions for the three GHGs. Because of data quality and time and resource constraints, emissions of criteria pollutants were not included in this study.

Development and use of the GREET model are documented in Wang (1999a and 1999b) and in Wang and Huang (1999). The current version of the model that is available to the general public is GREET1.5a, which was completed in January 2000. The model is in the public domain, and any party can use it free of charge. GREET1.5a and associated reports prepared by Argonne are posted on Argonne's transportation Web site at [www.transportation.anl.gov/ttrdc/greet](http://www.transportation.anl.gov/ttrdc/greet).

Figure 2 is a simplified diagram showing calculation logic for energy use and emissions associated with activities from wells to tanks. For a given stage, energy use by fuel type is estimated by using energy efficiency and fuel type shares. We then calculate emissions by using energy use by fuel type, emission factors by fuel type, and combustion technology shares. Finally, urban emissions are estimated from total emissions and split of facility locations between urban and non-urban locations. For CO<sub>2</sub> emissions, GREET takes a carbon-balance approach. That is, the carbon in CO<sub>2</sub> emissions is equal to the carbon contained in the fuel burned minus the carbon contained in combustion emissions of VOC, CO, and CH<sub>4</sub>. For details on calculation methodologies, see Wang (1999a and 1999b).

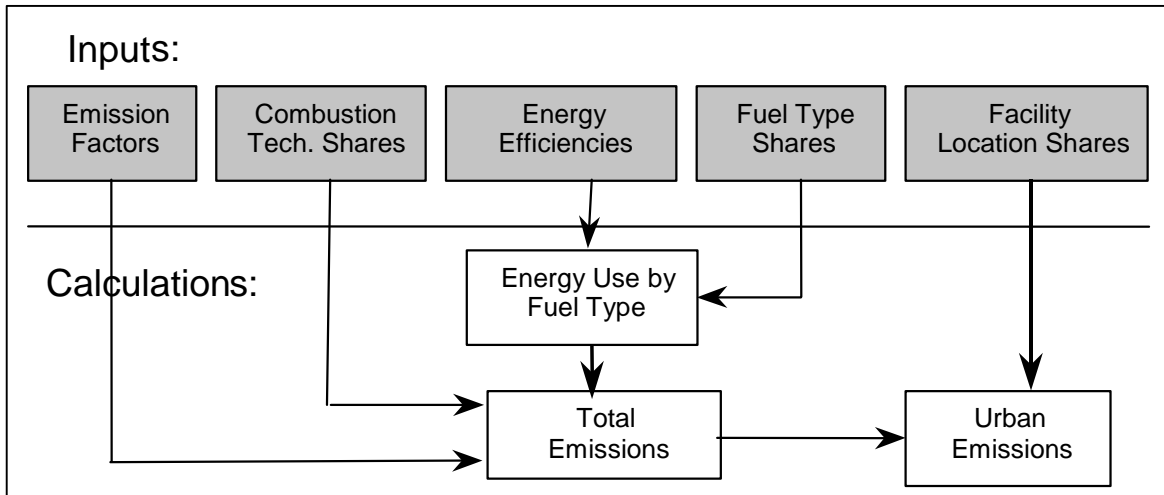


Figure 2 Calculation Logic for Well-to-Tank Energy Use and Emissions of Transportation Fuels

For this study, we used a new version of Argonne’s GREET model. Through a separate ANL effort, the GREET model was expanded to incorporate detailed information on transportation modes and their corresponding distances for different energy feedstocks and fuels. This version is in draft form and is not yet available to the general public. Details regarding the expansion of feedstock and fuel transportation in GREET are presented in a later section of this report.

Through the GAPC project, ANL began to formally address in the GREET model the uncertainties involved in key input parameters with subjective probability distribution functions. Previously, ANL addressed uncertainties with range estimates for key input assumptions. This time, ANL began to explore probability distribution functions for some of the key input parameters. In particular, based on published data for given fuel-cycle stages, ANL established subjective probability distribution functions for each stage. These distribution functions are incorporated into the GREET model. A commercial software, Crystal Ball™, is used in GREET to conduct Monte Carlo simulations. Instead of the point estimates included in previous GREET versions, the new version generates results with probability distributions. In order to use the new feature of Monte Carlo simulations in GREET, users need to have both Excel and Crystal Ball software. However, if Crystal Ball software is not available, users can still conduct point estimates with the new GREET version.

## **3 Fuels and Fuel Production Pathways Included in This Study**

### **3.1 Gasoline, Diesel, and Naphtha from Petroleum**

The petroleum-based pathways examined in this study include three fuels: gasoline, diesel, and naphtha. We further establish cases for gasoline and diesel to represent different fuel requirements. Currently available gasoline includes federal conventional gasoline (CG), federal Complex Model Phase 2 reformulated gasoline (FRFG2), and California Phase 2 reformulated gasoline (CARFG2). These gasoline options have an average sulfur content ranging from 30 parts per million (ppm) to over 500 ppm. Evaluation of future gasoline (to dominate gasoline market around 2010) includes California Phase 3 reformulated gasoline (CARFG3) and the gasoline requirements in the U.S. Environmental Protection Agency's (EPA's) Tier 2 vehicle emission standards. These gasoline options may have an average sulfur content of 10 ppm to 30 ppm and may contain methyl tertiary butyl ether (MTBE), ethanol (EtOH), or no oxygenates. Current diesel includes federal conventional diesel (FCD) and California low-sulfur diesel (CALSD) with a sulfur content ranging from 150 ppm to 350 ppm. Future diesel includes EPA's recently adopted federal low-sulfur diesel (FLSD) with a maximum sulfur content of 15 ppm. Virgin naphtha produced in petroleum refineries has a sulfur content of about 370 ppm. We assumed that it would be subject to desulfurization to reduce its sulfur content to about 1 ppm for FCV applications.

#### **3.1.1 Gasoline Requirements**

##### ***3.1.1.1 California Reformulated Gasoline***

In 1992, California began to require use of the so-called California Phase 1 reformulated gasoline (CARFG1). CARFG1 had the following composition requirements: a maximum aromatics content of 32% (by volume), a maximum sulfur content of 150 ppm, a maximum olefins content of 10% (by volume), and maximum 90% distillation temperature (T90) of 330°F (California Air Resources Board [CARB] 1991).

In 1996, California began to require the use of CARFG2. Table 1 presents the composition requirements of CARFG2. However, under the CARFG2 requirement, gasoline producers are allowed to certify gasoline either by meeting the specified composition requirements or by meeting an emission reduction requirement with an alternative gasoline formula. The emissions performance of a given alternative reformulated gasoline (RFG) formula was simulated by using CARB's Predictive Model.

In the spring of 1999, because of the concern about underground water contamination by MTBE, California Governor Grey Davis issued an executive order banning the use of MTBE in California's gasoline beginning in 2003. In December 1999, CARB adopted CARFG3; use of CARFG3 will be required beginning in 2003 (Table 1). Under the CARFG3 requirements, gasoline producers will be allowed to certify gasoline with a specified composition requirement or by meeting emission reductions requirements with an alternative composition formula. As Table 1 shows, one significant difference between CARFG2 and CARFG3 lies in the reduction of sulfur content from 30 ppm to 15 ppm.

Table 1 Composition Requirements of CARFG2 and CARFG3<sup>a</sup>

Requirement	Flat Limits		Averaging Limits		Cap Limits	
	CARFG2	CARFG3	CARFG2	CARFG3	CARFG2	CARFG3
RVP <sup>b</sup> (psi, summer only)	7.00	7.00	NA <sup>c</sup>	NA	7.00	6.40–7.20
Sulfur content (wt. ppm)	40	20	30	15	80	60 (30 after 2004)
Benzene content (vol. %)	1.0	0.8	0.8	0.7	1.2	1.1
Aromatics content (vol. %)	25.0	25.0	22.0	22.0	30.0	35.0
Olefins content (vol. %)	6.0	6.0	4.0	4.0	10.0	10.0
T50 (°F)	210	213	200	203	220	220
T90 (°F)	300	305	290	295	330	330
Oxygen content (wt. %)	1.8–2.2	1.8–2.2	NA	NA	1.8–3.5 (winter areas); 0–3.5	1.8–3.7 (winter areas); 0–3.7
Ban of MTBE	No	Yes	No	Yes	No	Yes

<sup>a</sup> From CARB 2000.

<sup>b</sup> RVP = Reid vapor pressure.

<sup>c</sup> NA = Not available.

### 3.1.1.2 Federal Reformulated Gasoline

The 1990 Clean Air Act Amendments (CAAA) require use of RFG in the nation's worst ozone nonattainment areas. The requirement for so-called federal Simple Model Phase 1 reformulated gasoline (FRFG1) took effect in January 1995, and Complex Model FRFG2 in June 2000. Gasoline producers could certify FRFG1 with a specified composition requirement or by making Complex Model Phase 1 RFG. FRFG1 composition requirements were a maximum benzene content of 1% (by volume), a per-gallon maximum aromatics content of 25% (by volume), and a minimum oxygen content of 2% (by weight). Under the emissions reduction requirements, producers were required to reduce VOC emissions in FRFG1 by 16% (northern regions) to 35% (southern regions) and air toxic emissions by about 15% relative to CG (EPA 1994). Note that the reduction for VOC emissions is the combined reduction of exhaust and evaporative emissions. FRFG2 is certified by meeting emission performance standards: a per-gallon VOC emissions reduction of 27.5% in southern regions and 25.9% in northern regions, an air toxic emissions reduction of 20%, and a NO<sub>x</sub> emissions reduction of 5.5%, all relative to CG. EPA's Complex Model is allowed for use in determining emissions of a given gasoline formula.

Although Complex Model FRFG2 was introduced into the market in 2000, some new requirements for gasoline will be in place in the next few years. In February 2000, EPA adopted the final rule of Tier 2 vehicle emission standards (EPA 2000a). Besides emission standards, the rule establishes a gasoline sulfur content requirement. While FRFG1 and FRFG2 have been required for use in ozone nonattainment areas only, the Tier 2 gasoline requirement will be applied to both CG and RFG nationwide, except in California, where CARFG3 will be in effect. We call this new requirement the Tier 2 FRFG requirement. Phase-in of the requirement will begin in 2004, and it will be fully implemented in 2006. The only new requirement for the FRFG is an average sulfur content of 30 ppm. This sulfur level is already accomplished in CARFG2. Also, BP began to introduce a 30-ppm sulfur premium gasoline in Chicago, Detroit, and some other cities in the spring of 2000.

Table 2 Typical Properties of CG and FRFG

Characteristic	CG <sup>a</sup>	FRFG2 <sup>b</sup>	Tier 2 FRFG <sup>c</sup>
RVP (psi, summer)	8.9	6.7	6.7
Sulfur content (wt. ppm)	339	150	30 (max. 80)
Benzene content (vol. %)	1.53	0.68	0.68
Aromatics content (vol. %)	32.0	25	25
Olefins content (vol. %)	9.2	11	11
200°F distillation (%)	41	49	49
300°F distillation (%)	83	87	87
Oxygen content (wt. %)	0.4	2.26	2.26

<sup>a</sup> From National Research Council (NRC 2000).

<sup>b</sup> Based on input parameters to EPA's Complex Model for simulating emissions performances of FRFG2.

<sup>c</sup> From EPA (2000a).

### 3.1.2 Diesel Requirements

In October 1993, EPA began to require use of a diesel fuel with a lower sulfur content in on-road motor vehicles. The maximum sulfur content for on-road diesel fuels was set at 500 ppm. As a result, the current average of diesel sulfur content in the nation (except California) is about 350 ppm (EPA 2000b). We call this diesel fuel FCD. Before October 1993, the sulfur content of diesel fuel was about 3,000 ppm (EPA 2000b). Recently, EPA has adopted a rule to lower the maximum sulfur content for on-road diesel fuel to 15 ppm: this rule will be effective in June 2006. EPA estimates that the average sulfur content of diesel fuel under this requirement will be 7–10 ppm (EPA 2000b). We call the newly proposed diesel fuel FLSD.

In October 1993, California began to require use of a low-sulfur diesel. California refiners and importers are allowed to adjust the diesel fuel properties in proprietary formulations as long as these formulations meet CARB emission requirements as proven by emission tests. California's low-sulfur diesel has a maximum sulfur content of 500 ppm and a maximum aromatics content of 10%. As a result, the current average sulfur content in California's diesel is probably 120 ppm (ARCO Products Company 1999). We call this diesel fuel California conventional diesel (CACD). Meanwhile, in March 1999, ARCO announced that it would produce a clean diesel called emission control diesel (EC-D) for the California market (ARCO Products Company 1999). The specifications of EC-D are a sulfur content of less than 10 wt. ppm (maximum 15 wt. ppm), an aromatics content of less than 10% (by volume) (maximum 12% by volume), and a cetane number of 60 (minimum of 57). EC-D is already being sold in the California market.

### 3.1.3 Crude Naphtha

At petroleum refineries, virgin naphtha is produced primarily from an atmospheric distillation process (although some naphtha is produced from visbreaking and other refining processes). Virgin naphtha contains normal paraffins, iso-paraffins, and cycloparaffins of C5–C10. The boiling point of this naphtha is higher than that of straight-run gasoline but lower than that of kerosene. Thus, naphtha is separated during the distillation process after straight-run gasoline. Petroleum naphtha can be further separated into light naphtha and heavy naphtha according to boiling point ranges. The former has a boiling point of 50–200°F, while the latter has a boiling point of 200–400°F (McKetta 1992). Light naphtha may go through a hydrotreating process to

reduce its sulfur (S) content and then an isomerization process to produce high-octane gasoline blendstocks. Heavy naphtha also requires additional refining processes, such as catalytic reforming. As Table 3 shows, crude with different qualities may produce different yields and qualities of naphtha. Usually, lighter crude can produce more naphtha than heavy crude.

Because virgin naphtha has a lower octane number (about 60), it is not an attractive neat gasoline blendstock. On the other hand, because naphtha contains more hydrogen than some other petroleum hydrocarbons, it could be a good candidate for FCV reformer fuels, so we include crude naphtha in this analysis (see Table 4).

Table 3 Crude Quality and Product Yields from the Atmospheric Distillation Process<sup>a</sup>

Crude	Crude Quality		Product Yield and Quality from the Atmospheric Distillation Process					
	API	S Content	Diesel		Gasoline		Naphtha	
	Gravity	(ppm)	Yield (%)	S Content (ppm)	Yield (%)	S Content (ppm)	Yield (%)	S Content (ppm)
<b>U.S. Crude</b>								
Alaska-North Slope	27.5	11,000	NA <sup>b</sup>	NA	0	NA	NA	NA
S. Louisiana Light	31.0	20,000	0	NA	6.9	200	17.0	700
CA-Hondo Blend	20.8	42,900	0	NA	0	NA	NA	NA
West Texas Intermediate	40.8	3,400	0	NA	0	NA	NA	NA
<b>Foreign Crude</b>								
U.K.-Brent	38.9	3,500	20.8	2,110	9.4	NA	17.7	30
Russia-Siberian Light	35.3	5,800	21.7	3,160	7.8	NA	15.1	NA
Saudi Light	32.9	19,000	20.9	12,470	6.8	NA	13.4	NA
Algeria-Saharan	45.7	700	21.3	485	11.8	NA	19.4	NA
Nigeria-Bonny Light	33.8	1,400	30.9	1,665	6.0	NA	14.4	20
Indonesia-Minas	36.0	810	20.6	480	3.5	NA	9.0	17
Venezuela-Tia Juana Light	31.6	10,800	20.0	5,670	6.0	NA	12.4	NA
Mexico-Isthmus	31.8	12,500	20.4	9,080	7.7	NA	14.1	NA

<sup>a</sup> From *Oil and Gas Journal* (1999).

<sup>b</sup> NA = no data are available.

Table 4 Typical Properties of Crude and Fischer-Tropsch (FT) Naphtha

Specification	Crude Naphtha <sup>a</sup>	FT Naphtha <sup>b</sup>
Density (g/gal)	2,861	2,651
Lower heating value (Btu/gal)	118,760	111,780
Higher heating value (Btu/gal)	127,330	120,020
Carbon (wt. %)	85.3	84.2
Sulfur content (wt. ppm)	367 <sup>c</sup>	0.2

<sup>a</sup> From Domalski and Jobe (1986).

<sup>b</sup> From Russell (2000).

<sup>c</sup> This is the sulfur content before desulfurization. Hydrotreating or other desulfurization measures will be needed to reduce crude naphtha sulfur content so that it can be used as a fuel-cell fuel. In our analysis, we assume that the sulfur content of crude naphtha will be reduced to about 1 ppm.

Figure 3 presents the pathways from crude to gasoline, diesel, and naphtha. In particular, Argonne’s analysis for petroleum-based fuels includes these activities: crude recovery; crude transportation; petroleum refining; and transportation, storage, and distribution of fuel products. Because virgin naphtha is produced from the atmospheric distillation process at refineries, production of virgin naphtha should be more energy efficient than production of gasoline and diesel, both of which go through more refining processes. Because the boiling point of naphtha is higher than that of liquefied petroleum gas (LPG), we expect that the efficiency for naphtha production is lower than that for LPG production. Transportation, storage, and distribution of naphtha could be similar to those of gasoline.

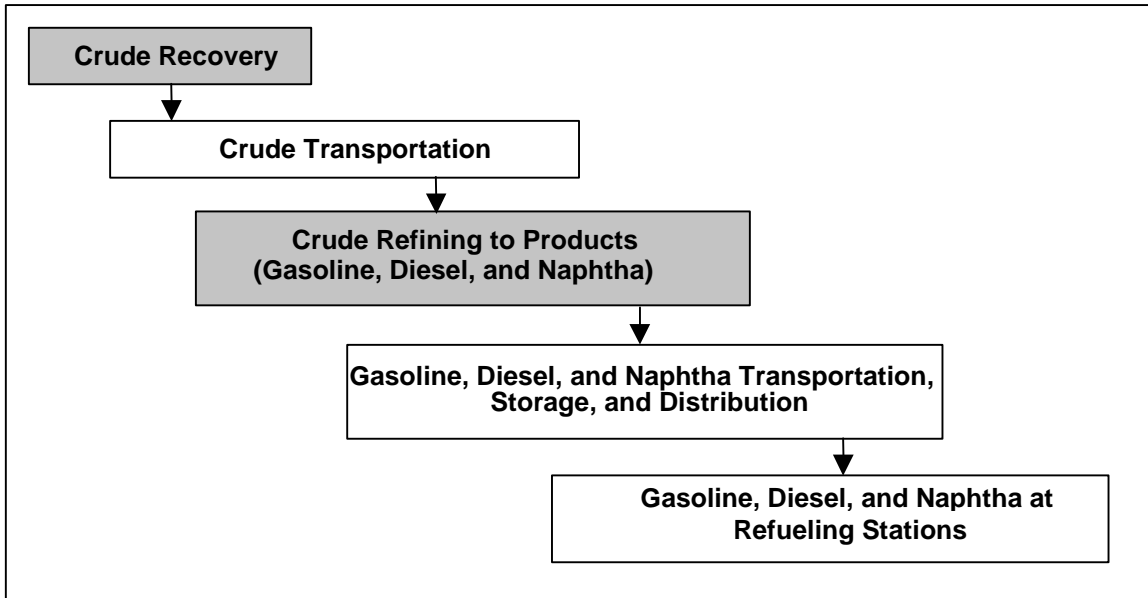


Figure 3 Well-to-Tank Stages for Three Petroleum-Based Fuels

### 3.1.4 Quality of Crude Oil

The quality of crude oil affects refinery product slates and energy use in refineries. Among the parameters measuring the quality of crude oil, two important ones are American Petroleum Institute (API) gravity and sulfur content. API gravity is one indicator of the amount of gasoline and other light fractions from crude distillation. Because of tightened sulfur requirements for gasoline and diesel, high-sulfur crude and its refined products will need to go through intensive desulfurization. Table 5 lists API gravities and sulfur contents of crude oils produced in different U.S. regions and in other countries that export crude oil to the United States. As the table shows, among the three U.S. crude production regions presented (the Gulf area, Alaska, and California), California crude contains more sulfur than does crude from the Gulf area and Alaska. Also, crude from California and Alaska is heavier than that from the Gulf area. This implies that petroleum refineries processing California and Alaska crude feeds need to employ more intensive refining processes than those with Gulf crude inputs.

Table 5 Quality of Crude Oil Used in U.S. Refineries

Country	API Gravity <sup>a</sup>		Sulfur Content (wt. %) <sup>a</sup>		Sources of U.S. Crude (1000 bbl/yr) <sup>b</sup>
	Range	Median	Range	Median	
United States					2,281,980
Gulf Area	31.0–40.8	35.9	0.34–2.00	1.17	638,880
Alaska	22.4–27.5	25.0	1.11–1.82	1.47	428,851
California	19.4–35.2	27.3	0.21–4.29	2.25	283,628
Saudi Arabia	27.4–38.7	33.1	1.19–2.80	2.00	517,072
Venezuela	10.1–31.8	21.0	1.10–5.50	3.30	499,580
Mexico	22.2–39.8	31.0	0.80–3.30	2.10	477,171
Canada	20.7–40.7	30.7	0.37–3.15	1.76	378,598
Nigeria	25.2–40.9	33.1	0.09–0.29	0.19	258,640
Angola	31.7–33.7	32.7	0.17–0.23	0.20	177,958
Colombia	30.8–36.4	33.6	0.25–0.47	0.36	130,364
Iraq	24.7–35.1	29.9	1.97–3.50	2.74	114,513
Kuwait	18.6–31.4	25.0	2.52–4.55	3.54	109,142
Norway	29.3–43.4	36.4	0.14–0.44	0.29	80,820
Gabon	31.8–39.5	35.7	0.05–0.11	0.08	75,543
The U.K.	33.6–41.7	37.7	0.05–1.01	0.53	66,002

<sup>a</sup> From *Oil and Gas Journal* (1999).

<sup>b</sup> From Energy Information Administration (1999).

Of the crudes imported to the United States, the crude from Kuwait, Venezuela, Iraq, and Saudi Arabia have a sulfur content of above 2% (sour crude). On the other hand, crudes from Gabon, Nigeria, Angola, Norway, and Colombia have a sulfur content of below 0.4% (sweet crude). As for API gravity, crudes from the U.K., Norway, Gabon, Colombia, Nigeria, Saudi Arabia, Mexico, and Canada have an API gravity above 30 (light crude). Crudes from Venezuela, Kuwait, and Iraq have an API gravity of below 30 (heavy crude). These crudes, with different sulfur contents and API gravity values, certainly have different impacts on refining energy intensities of U.S. refineries, and consequently, on petroleum refinery energy use and emissions.

The default energy efficiencies of U.S. petroleum refineries in the GREET model are based on studies for U.S. average refineries, which reflect the average quality of the crudes that U.S. refineries process. When marginal crude is used for a fuel-cycle analysis, it can have some impacts on energy use and emissions of petroleum refining. In this analysis, we implicitly assume the average quality of the crudes used in U.S. refineries.

### 3.1.5 Energy Efficiency Assumptions for Production of Gasoline, Diesel, and Naphtha

#### 3.1.5.1 Specifications of Fuel Options

For the three petroleum-based fuels, we include the following fuel options, depending on sulfur content and use of oxygenates (for gasoline) and sulfur content only (for diesel and naphtha). For gasoline, we include five options: CG, FRFG2, low-sulfur (LS) RFG with MTBE, LS RFG with ethanol, and LS RFG with no oxygenate (see Table 6). In GREET, we simulated each of the five options separately. In Appendix A, we present results for two aggregate options — current

Table 6 Five Gasoline Options Included in This Study

Item	Current Gasoline		Future Gasoline		
	CG <sup>a</sup>	FRFG2 with MTBE <sup>b</sup>	LS RFG with MTBE <sup>c</sup>	LS RFG with EtOH <sup>d</sup>	LS RFG with no Oxygenate <sup>e</sup>
RVP (psi, for summer)	8.9	6.7	6.7	6.7 <sup>f</sup>	6.7
Sulfur content (wt. ppm)	340	150	5-30	5-30	5-30
Benzene content (vol. %)	1.53	0.68	0.68	0.68	0.68
Aromatics content (vol. %)	32	25	25	25	25
Oxygen content (wt. %)	0.4	2.26	2.26	3.5	0
Oxygenate type	MTBE	MTBE	MTBE	EtOH	None

<sup>a</sup> CG is sold nationwide now except in the worst ozone nonattainment areas, where RFG is required. Nationwide, about 70% of gasoline sold now is CG.

<sup>b</sup> FRFG2 is currently required in the worst ozone nonattainment areas nationwide except in California.

<sup>c</sup> The RFG has significantly reduced sulfur content and uses MTBE to meet oxygen requirements.

<sup>d</sup> The RFG has significantly reduced sulfur content and uses ethanol to meet oxygen requirements.

<sup>e</sup> The RFG has significantly reduced sulfur content and uses no oxygenate.

<sup>f</sup> In order to meet the low RVP requirement, gasoline blendstock needs to have much lower RVP.

gasoline and future LS gasoline — and results for each of the five individual options. Current gasoline includes CG and FRFG2, and future gasoline includes LS RFG with MTBE, ethanol, and no oxygenate.

For on-road diesel fuels, we include two options: a current diesel and a future diesel. The current on-road diesel has a sulfur content of 120–350 ppm and includes the current federal diesel (350-ppm sulfur) and current California diesel (120-ppm sulfur). The future diesel reflects the new on-road diesel requirement adopted by EPA recently and will have sulfur content below 15 ppm.

Although virgin crude naphtha from petroleum refineries' distillation without desulfurization has a sulfur content of about 370 ppm, the sulfur content of naphtha will have to be reduced to an extremely low level in order for it to be used in FCVs. We assumed that the sulfur content of crude naphtha for fuel-cell application will be about 1 ppm. Thus, hydrotreating or some other desulfurization measures will be needed in refineries to reduce naphtha's sulfur content from the current level of about 370 ppm to 1 ppm.

### ***3.1.5.2 Energy Efficiencies of Key Stages***

#### ***Petroleum Recovery***

The petroleum recovery stage includes activities from removing oil from underground to oil treatment in oil fields. In oil fields, gas is usually produced in association with oil production. In some locations, the associated gas has no value. In this case, the gas is often flared or vented. In calculating the energy efficiency of petroleum recovery, the energy (in Btu) in the flared and/or vented gas is not accounted for because it is not an intended energy source. However, in calculating emissions associated with petroleum recovery, flaring and/or venting of gas is taken into account.

Past published data in the United States showed an energy efficiency of 97% to 99% for petroleum recovery (Wang 1999a). In some parts of the world, the efficiency could be as low as 96%. An efficiency range of 96% to 99% was assumed in this study.

### *Petroleum Refining*

Of the upstream and downstream activities from crude oil to gasoline and diesel fuels, crude refining is subject to the highest energy use, and consequently produces the largest amount of emissions. Thus, assumptions for the energy efficiency associated with refining crude into gasoline and diesel fuels are key factors in determining the upstream energy use and emissions of gasoline and diesel fuels.

Petroleum refinery operators have data on inputs of crude, other feedstocks, and process fuels (usually natural gas and electricity) and outputs of different petroleum products for their refineries. With input and output data for a given refinery, researchers can calculate the overall energy efficiency of the refinery. However, such data are usually not available to those outside of the individual companies. Thus, this approach may not be feasible for outside researchers.

Alternatively, a linear programming (LP) model may be run to simulate operations of a specified refinery (or a notional refinery) with certain crude quality and certain slate and quality of petroleum products. Results from refinery LP simulations can then be used to calculate the overall energy efficiency of the specified refinery. Admittedly, the energy efficiency of the notional refinery is different from that of individual refineries in operation, because the refinery configuration, advancement of refining technologies, crude quality, product slate, and gasoline quality (among many other factors) assumed in the notional refinery could be different those of actual refineries. Nonetheless, such LP simulations could provide information that is representative of petroleum refining. Ideally, LP simulations could be conducted for different sets of parameters regarding refinery input and output items to generate refining energy efficiencies for different refinery configurations. However, resource limitations have prevented almost all fuel-cycle studies, including Argonne's studies, from running LP models. Instead, these studies have relied on energy efficiencies generated from other detailed studies on petroleum refining modeling.

To complicate the matter further, the overall energy efficiency of a given refinery needs to be assigned to individual petroleum products so that a fuel-cycle analysis can be conducted for a given petroleum product (such as gasoline or diesel fuels). In other words, the total energy use in a refinery needs to be allocated to its different refinery products. The energy allocation can be done in the following steps. First, the energy use during each of the major refining processes (e.g., distillation, cracking, alkylation, isomeration, desulfurization) is estimated. Second, the estimated process-specific energy use is allocated into a product (or products), depending on the purpose of the process. Finally, the product-allocated energy use for all refinery processes is added together for a given product (e.g., gasoline) to represent the energy use for producing the product. Often, data at this level of detail are too scarce to take this approach.

Probably one of the most comprehensive refinery modeling studies that has been completed in the last ten years is the study conducted by the National Petroleum Council for production of various RFGs (NPC 1993). The NPC has recently completed a new study on the U.S. petroleum

refinery industry (NPC 2000). Energy efficiencies of producing various RFG types from the 1993 NPC study were summarized in Stork and Singh (1995). With data presented in Stork and Singh, we calculated an energy efficiency of 86.6–87.6% for CG, 86.3% for summer FRFG2 with MTBE, 88.2% for winter FRFG2 with MTBE, and 88.1% for winter RFG2 with ethanol (EtOH). It appears that efficiencies estimated with data from Stork and Singh are higher than those from other studies.

Three recently completed studies are available from MathPro, Inc. The first MathPro study was conducted for the Alliance of Automobile Manufacturers to simulate production of gasoline with 5-ppm sulfur in PADDs 1 to 3 (MathPro 1999a). The second study was conducted for the Engine Manufacturers Association to evaluate costs of diesel fuels with different sulfur contents (MathPro 1999b). The third study was conducted for California Energy Commission to evaluate the impacts of producing California’s newly adopted CARFG3 (MathPro 1999c).

The three MathPro studies simulated notional refineries for producing gasoline and diesel with different specifications. The studies present the amounts of various input feeds and the amounts of various output products with many individual LP simulation cases. By using the higher heating values for input feeds and output products that are provided in the MathPro studies, we calculated the overall energy efficiencies of refinery configurations that are simulated in the MathPro studies. The difference between lower and higher heating value for a given fuel lies in whether the heat associated with condensation of water vapor generated during combustion is taken into account. In transportation fuel-cycle analysis, some studies have used lower heating values, some use higher heating values, and others use the combination of lower and higher heating values. Use of higher heating values is based on the belief that energy contained in combustion vapor could be recovered for use. Use of lower heating values is based on the fact that energy in combustion vapor from vehicles is impractical to recover. The GREET model is based on lower heating values.

Our estimated overall efficiencies for different refinery configurations are summarized in Table 7. The low and high efficiencies in Table 7 represent the range of the results for different refinery configurations to produce gasoline with the same specifications. Note that Table 7 shows that the high-end efficiency for producing RFG with MTBE or ethanol could be higher than that for producing CG, based on MathPro simulations. One reason could be the octane enhancement effect of adding MTBE and ethanol to gasoline, which makes production of gasoline blendstock (GBS) of RFG efficient.

Table 7 Overall Energy Efficiencies of Petroleum Refineries Extracted from MathPro Studies

Refinery	Refinery Overall Energy Efficiency (%)		Source
	Low	High	
Producing federal CG with 340 ppm S	88.4	88.4	MathPro (1999b)
Producing 150 ppm S FRFG2 with MTBE	87.7	87.9	MathPro (1999b)
Producing 5–30 ppm S RFG with MTBE	87.7	89.5	MathPro (1999a, 1999c)
Producing 5–30 ppm S RFG with EtOH	87.4	88.9	MathPro (1999a, 1999c)
Producing 5–30 ppm S RFG without oxygenate	87.6	87.8	MathPro (1999c)

The overall refinery efficiencies, as presented in Table 7, need to be converted into product-specific refinery efficiencies. We took the following steps for the conversion. As a rule of thumb in the petroleum industry, we allocated 60–65% of total refining process fuel use to gasoline production, 18–22% to diesel production, and the remaining 13–22% to other petroleum products. In 1999, of the total production volume of all petroleum products from U.S. refineries, motor gasoline accounts for 46.7% vol., diesel fuels for 20% vol., and other products for the remaining 33.3% vol. (EIA 2000). With the assumed allocations of total refinery fuel use and the product splits, we calculated a relative energy intensity of 1.28–1.39 for gasoline production, 0.90–1.10 for diesel production, and 0.39–0.66 for other products together, all relative to the energy intensity for production of all petroleum products combined.

With the above information, we estimated the energy efficiency of producing gasoline or diesel fuels. Table 8 presents our estimated energy efficiencies associated with producing various types of gasoline and diesel fuels.

From MathPro (1999a), we estimated that the amount of refining process fuels used (natural gas and electricity) is increased by 1.6% from 330-ppm diesel to 10-ppm diesel, and by 2.4% from 330-ppm diesel to 2-ppm diesel. By allocating all the increase to LS diesel production, we estimated the energy efficiencies for 10-ppm sulfur diesel and 5-ppm sulfur diesel (see Table 8).

Table 8 also shows that there might be an energy penalty for production of CARFG3 containing no oxygenates, relative to production of FRFG and CARFG containing oxygenates. We believe that the decreased efficiency for CARFG3 with no oxygenate is attributable to increased energy requirement for replacement octane (MathPro simulation results showed increased amounts of inputs of isobutene, isomerate, and CARBOB [California reformulated blendstock for oxygenate blending]) and decreased CARFG3 output, as shown in MathPro’s simulations. Note that MathPro’s simulations for national RFG and diesel production were conducted for PADDs I, II, and III, while the simulations for California RFG production were conducted for California (about 90% of PADD V). For comparison purpose, Unnasch estimated refinery efficiencies of 83.6% for CG production and 88.6% for CD production in California (Unnasch 2000).

Table 8 Energy Efficiencies of Producing Gasoline and Diesel Fuels

Fuel	Results from MathPro Simulations (%)		Values Adopted in This Study (%)	
	Low Efficiency <sup>a</sup>	High Efficiency <sup>a</sup>	Low Efficiency <sup>a</sup>	High Efficiency <sup>a</sup>
340 ppm S CG	84.5	85.5	85	86
150 ppm S RFG with MTBE	83.7 (84.7)	84.9 (85.9)	84 (85)	86 (87)
5–30 ppm S RFG with MTBE	83.6 (84.6)	86.9 (87.9)	83 (84)	86 (87)
5–30 ppm S RFG with EtOH	83.3 (84.4)	86.2 (87.2)	83 (84)	86 (87)
5–30 ppm S RFG3 without oxygenate	83.5	84.8	83	86
120–350 ppm S diesel	87.0	89.2	88	90
5–30 ppm S diesel	86.8	89.0	85	89
5–30 ppm S crude naphtha	89.0	93.0	89	93

<sup>a</sup> Numbers in parentheses are efficiencies for production of gasoline blendstocks for RFG. The increased efficiencies for gasoline blendstock production reflect the octane enhancement effect of adding oxygenates into RFG.

Table 8 shows that with the decrease in diesel fuel's sulfur content from 330 ppm to 10 ppm and then to 5 ppm, the energy penalty is minimal, based on MathPro's simulation results. Shell and BP suggest that MathPro's LP simulations may underestimate energy penalty of gasoline and diesel desulfurization. Based on its own experience, Shell believes a 1% point penalty for sulfur reduction from 350 ppm to 50 ppm, and another 1% point penalty from 50 ppm to 5 ppm, for both gasoline and diesel. We adjusted the efficiencies derived from MathPro's simulations with Shell's suggestion. In particular, we assumed the same efficiencies for the high-efficiency case between current gasoline and future gasoline and but lower efficiencies for future diesel than for current diesel. For gasoline, we reduced the efficiency for the low-efficiency case by 1% point from CG to 150-ppm S RFG and by another 1% point from 150-ppm S RFG to 5-30 ppm S RFG. For diesel fuels, we reduced the efficiency for the low-efficiency case by 2% points from current diesel to future diesel.

Historically, naphtha has been a gasoline upgrading process blendstock, not a major final product from petroleum refineries. Because of this, we have not seen any studies to evaluating energy efficiencies of producing naphtha in petroleum refineries. As stated in a previous section, virgin pipestill naphtha is produced from the atmospheric distillation process in refineries. The process is relatively energy efficient. However, as Tables 3 and 4 show, naphtha from the distillation process contains a high level of sulfur. FCVs will certainly require much lower sulfur content in naphtha.

LPG, straight-run gasoline, naphtha, and middle distillates rank from low to high in terms of their boiling points. We do not have energy efficiencies for naphtha production, but we do have energy efficiencies for production of LPG, gasoline, and diesel. However, gasoline energy efficiencies presented in existing studies are not for straight-run gasoline from the atmospheric distillation process. To approximate efficiencies for naphtha production, we used the efficiencies for LPG and diesel production. Based on how these three fuels are produced in refineries, we assumed that the efficiency for naphtha production is below that for LPG production but above that for diesel production.

Wang (1999a), showed LPG refining efficiencies of 90–94.6%, with a mean value of 93.5%. As the above table presents, refining efficiency for current diesel is 87–89% (with a mean value of 88%). Based on these data, we assumed refining efficiencies of 91–93% (with a mean value of 92%) for producing naphtha with a sulfur level of about 370 ppm. As stated above, there may be an energy efficiency penalty of 2 percentage points to reduce diesel sulfur level from 350 ppm to 1 ppm. Based on this, we assumed a 2% point reduction in refining efficiencies for the low-efficiency case of crude naphtha with sulfur level reduced from 370 ppm to 1 ppm. Thus, we assumed refining efficiencies of 89–93% (with a mean value of 91%) for producing 1-ppm S naphtha from crude.

Table 8 presents efficiencies of producing RFG that contains gasoline blendstocks (GBSs) and oxygenates (MTBE or ethanol). In GREET, energy efficiencies of RFG are further separated for gasoline blendstocks and oxygenates in order to conduct detailed simulations. For this purpose, we need energy efficiencies of producing gasoline blendstocks that are to be used for blending with oxygenates for different RFG types. Because of the octane enhancement effect of adding oxygenates to RFG, production of gasoline blendstocks for RFG could be more efficient than production of RFG without oxygenates. We allow some energy benefits of oxygenates' octane

enhancements in our analysis. The efficiencies with oxygenates' octane enhancement effect, as presented in parentheses of Table 8, are used in our simulations.

MTBE, ethanol, or no oxygenate is assumed for use in RFG (see Table 6). MTBE is allowed for use in RFG to meet its oxygen requirement until 2003 after which either ethanol could be used to meet oxygen requirements, or there may not be an oxygen requirement at all. Energy use and emissions of producing MTBE and ethanol are simulated separately in the GREET model. GREET assumes that MTBE is produced from methanol, which is, in turn, produced from natural gas. Ethanol is currently produced from corn. For details of energy use and emission simulations of MTBE and ethanol production, see Wang (1999a).

### 3.2 Fuels Produced from Natural Gas

This study includes these fuels that are produced from natural gas: compressed natural gas (CNG), methanol, Fischer-Tropsch diesel (FTD), gaseous hydrogen (G.H<sub>2</sub>) produced in central plants, G.H<sub>2</sub> produced in refueling stations, liquid hydrogen (L.H<sub>2</sub>) in central plants, L.H<sub>2</sub> in refueling stations, and naphtha via the Fischer-Tropsch process (FT naphtha).

All the fuels included here can be produced in North America. However, since abundant and inexpensive gas is available outside of North America, we include pathways of producing these fuels from non-North-American (NNA) gas as well. Furthermore, since there is a large amount of gas that is being flared each year in some parts of the world, for NNA gas-based pathways, we include both commercial gas and flared gas for production of the fuels included in this study. Details of production pathways are presented in sections below.

#### 3.2.1 Natural-Gas-Based Fuel Pathways

Three sources of NG feed are included in this analysis: North American natural gas (NA NG, including natural gas from the U.S., Canada, and Mexico), non-North-American natural gas (NNA NG), and non-North-American flared gas (NNA FG). As Table 9 shows, NA NG accounts for only 5.8% of total world gas reserves. Because of the large amount of inexpensive NNA NG, it is conceivable that the U.S. transportation sector may tap into NNA NG in the future.

Table 9 Natural Gas Reserves<sup>a</sup>

Location	Natural Gas Reserve	
	10 <sup>12</sup> cubic feet (ft <sup>3</sup> )	10 <sup>9</sup> oil-equivalent barrels
North America	297.2	51.2
United States	167.2	28.8
Central and South America	221.9	38.3
Western Europe	166.5	28.7
Eastern Europe and Former USSR	1952.0	336.6
Middle East	1723.4	297.1
Africa	351.9	60.7
Far East and Oceania	378.5	65.3
World Total	5091.2	877.8
OPEC	2213.0	381.6

<sup>a</sup> From Wang and Huang (1999).

Worldwide, about 3.8 trillion ft<sup>3</sup> of gas (equivalent to about 655 million barrels of oil) is flared each year (EIA 1998). This is about 5% of the total NG produced each year. Some researchers suspect that the actual amount of gas flared is far greater than reported. As some countries started to impose economic penalties for gas flaring in an effort to reduce CO<sub>2</sub> emissions, energy companies began to look for other alternatives to dispose or use associated gas from oil fields. One option is to build production and transportation facilities near oil fields to produce liquid fuels from flared gas. We include NNA FG for fuel production in our analysis.

Among the fuels included in this study, while liquid fuels (i.e., methanol, L.H<sub>2</sub>, FTD, and FT naphtha) can be produced outside of North America from either NG or FG and then transported to the U.S., gaseous fuels (CNG, G.H<sub>2</sub>, and L.H<sub>2</sub> produced in refueling stations) must be produced in the U.S. in order to avoid expensive cross-ocean transportation of gaseous fuels. For these cases, we assumed that liquefied natural gas (LNG) is produced from NNA NG and FG first. LNG is then transported to U.S. ports and gasified there. Finally, gasified NG is transmitted via pipelines to refueling stations where gaseous fuels are produced in the way similar to their production from NA NG. Figures 4–10 present production pathways for each of the fuels included in this study. The stages that are highlighted in shade in these figures are to be subject to probability distribution functions for their energy efficiencies (see a later section).

The fuel production pathways presented in the seven figures represent possible pathways. The economics of some of the pathways will certainly rule them out from further consideration. However, economics is not part of the scope of this study, so we present technologically possible pathways.

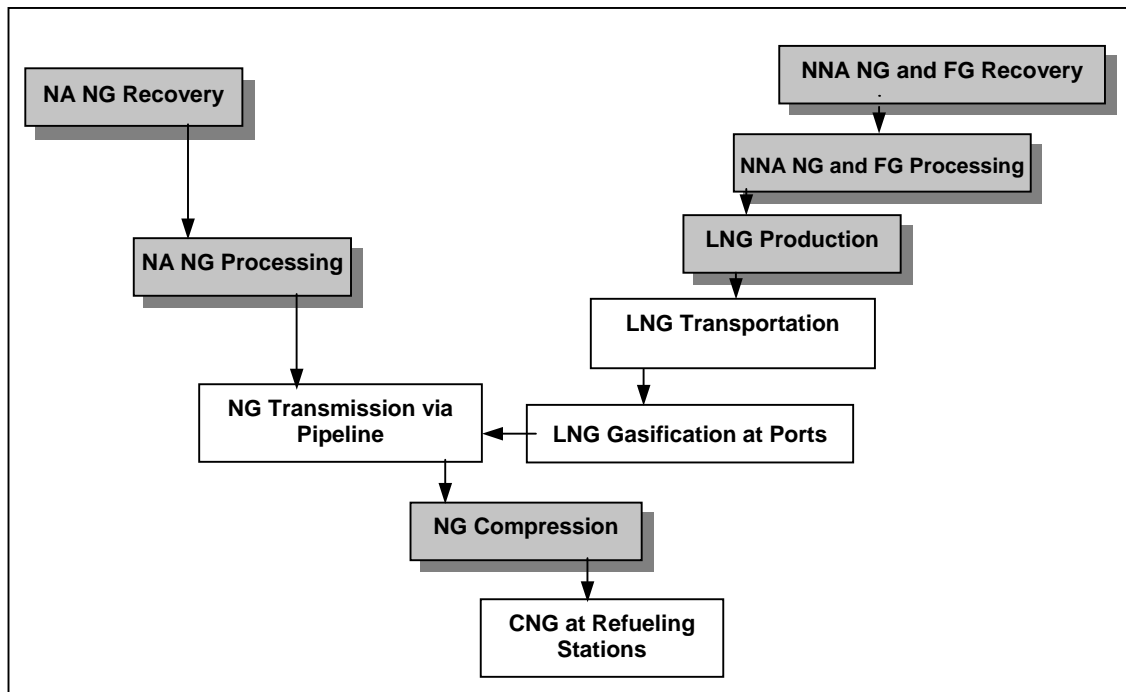


Figure 4 Pathways of CNG Production

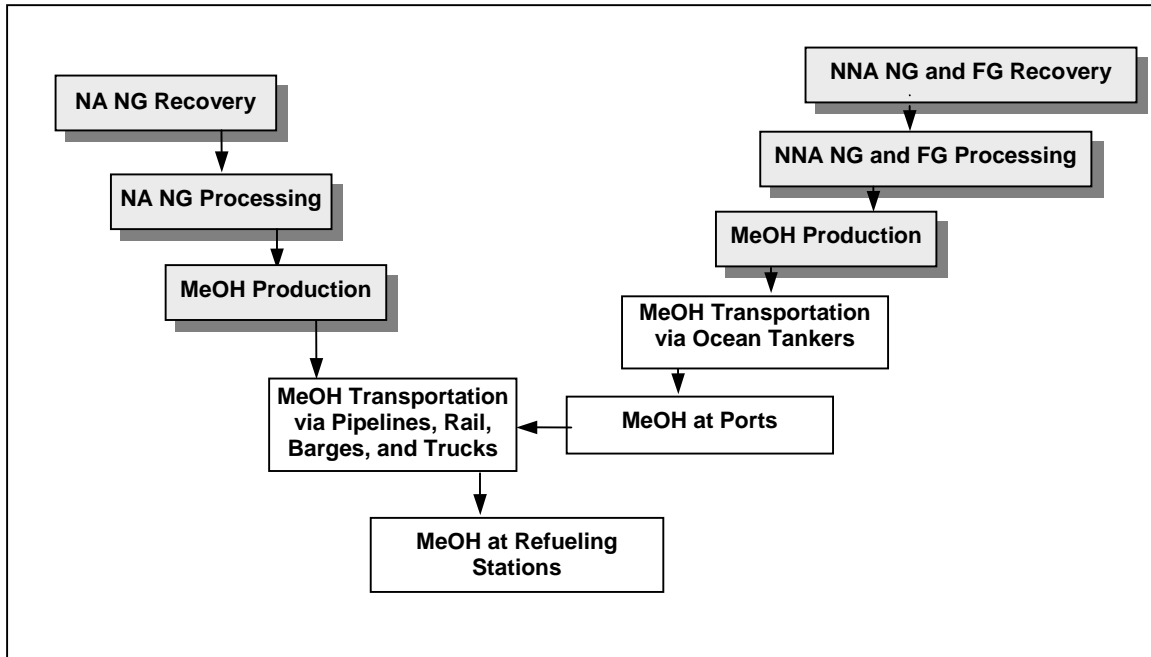


Figure 5 Pathways of Methanol Production

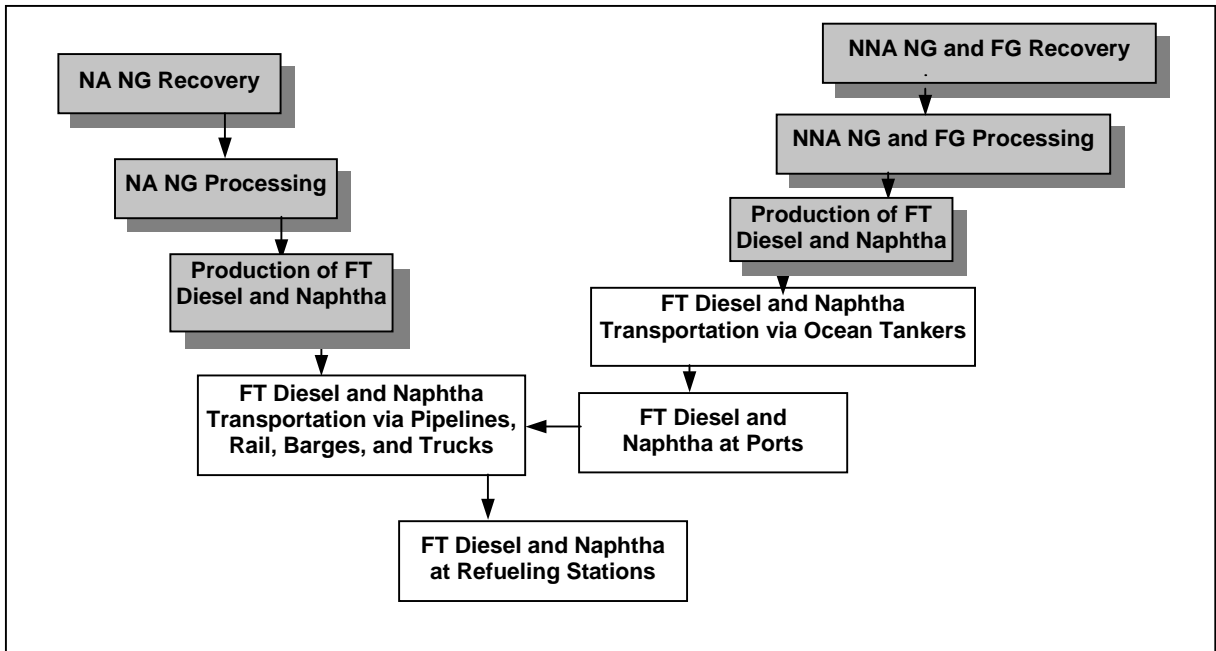


Figure 6 Pathways of Fischer-Tropsch Diesel and Naphtha Production

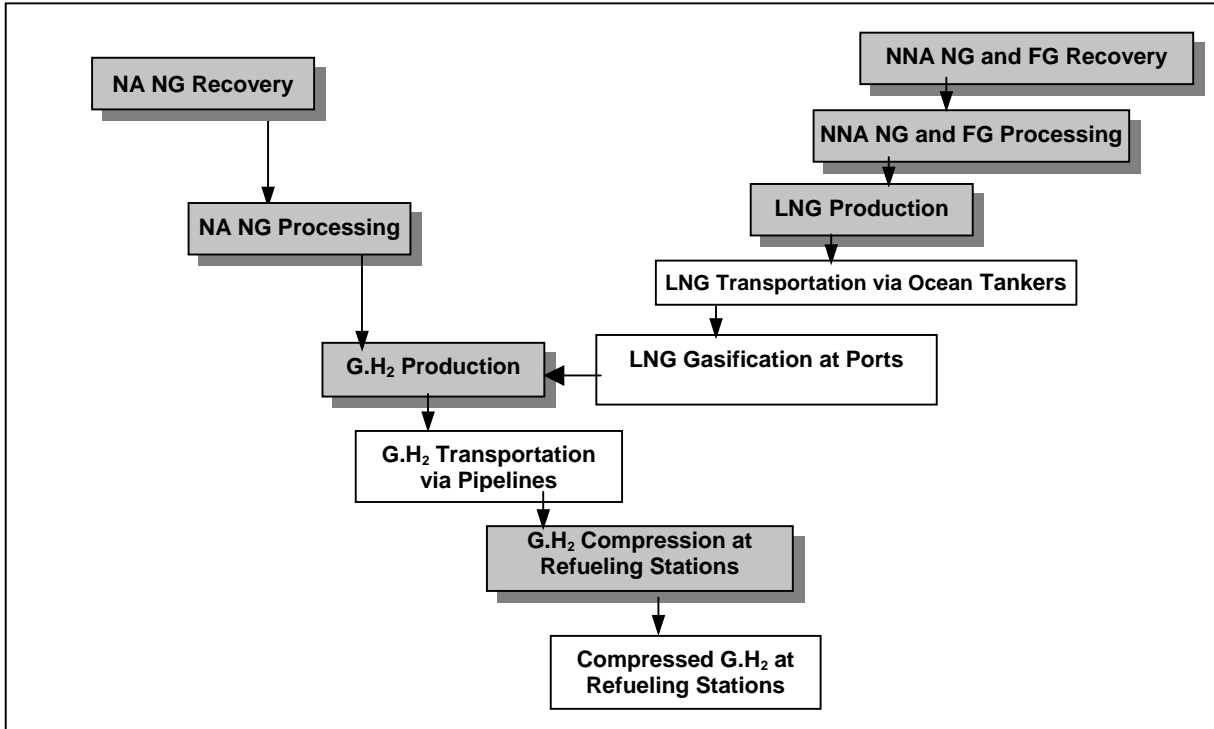


Figure 7 Pathways of Gaseous Hydrogen Production in Central Plants

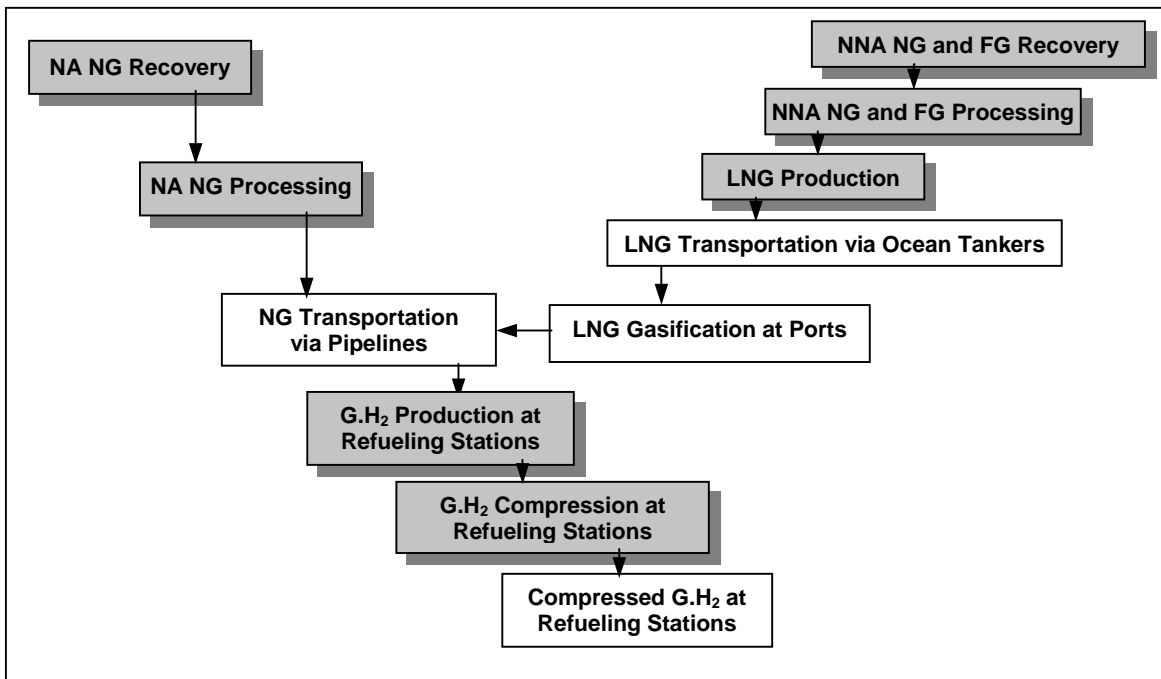


Figure 8 Pathways of Gaseous Hydrogen Production at Refueling Stations

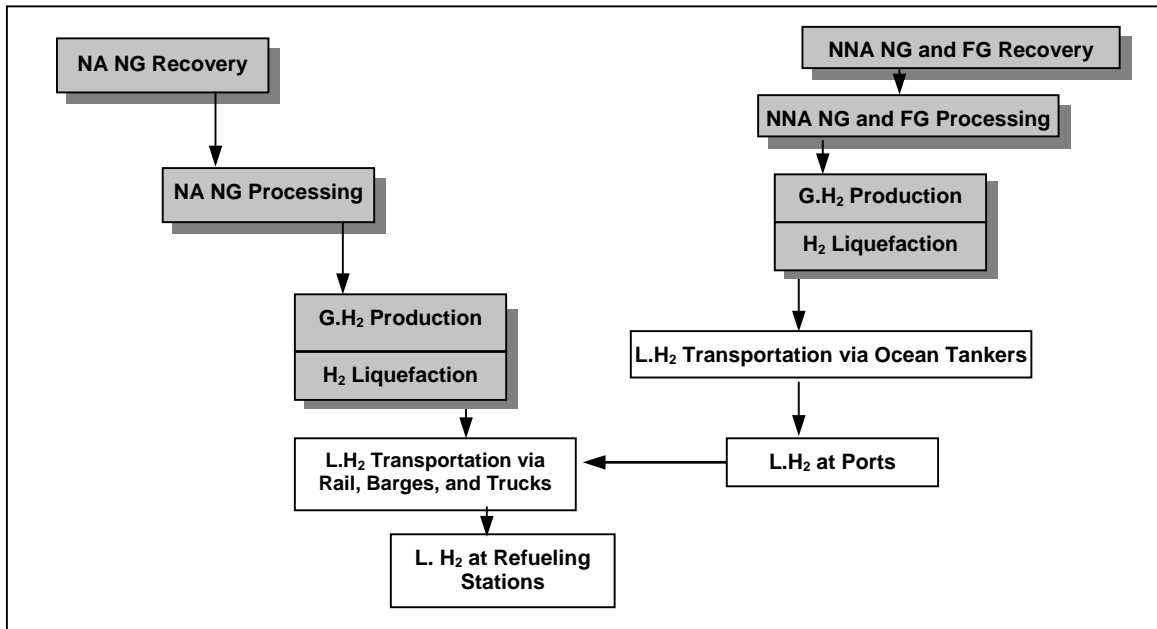


Figure 9 Pathways of Liquid Hydrogen Production in Central Plants

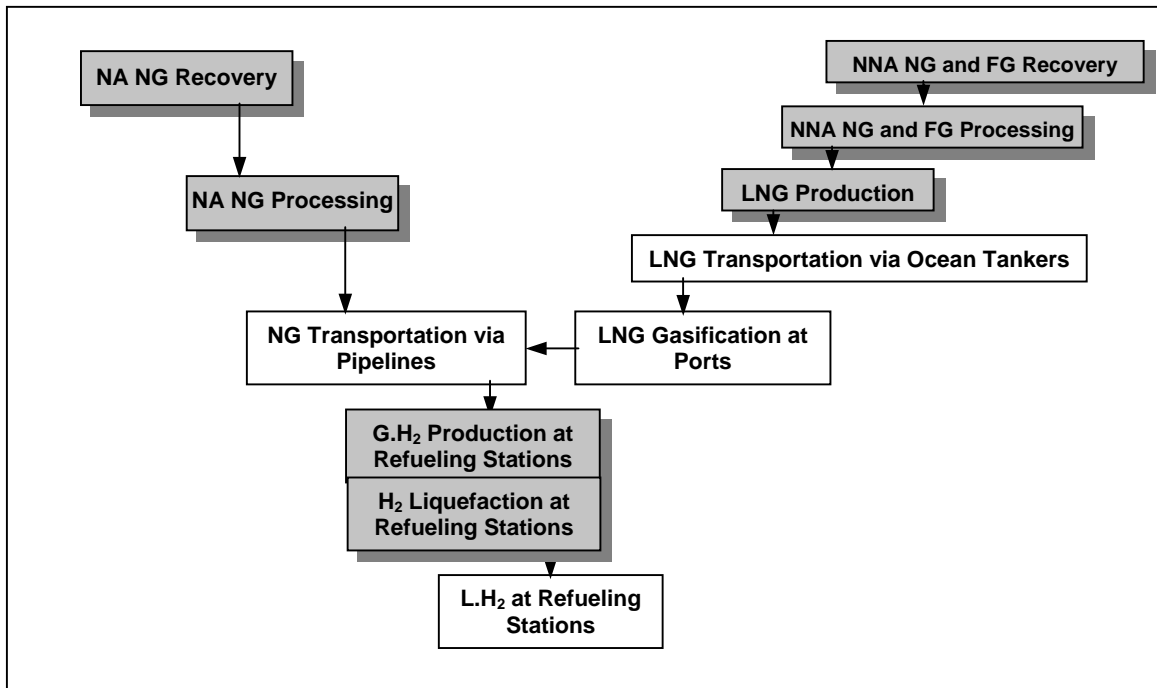


Figure 10 Pathways of Liquid Hydrogen Production at Refueling Stations

Figure 4 presents three pathways of producing CNG for motor vehicle applications: CNG from NA NG, NNA NG, and NNA FG. We assumed that CNG is stored onboard vehicles at a pressure of about 3,600 pounds per square inch (psi). In order to achieve this onboard pressure, natural gas in storage tanks at CNG refueling stations probably needs to be maintained at around 4,000 psi. We assumed that both electric and NG compressors will be used to compress NG. For the two NNA pathways, NG is liquefied and LNG is transported to the U.S. via ocean tankers. LNG is then gasified in LNG terminals. Because of production of LNG involved in these two pathways, these pathways suffer additional efficiency losses.

Figure 5 shows the three pathways for methanol production from NA NG, NNA NG, and NNA FG. At present, it is reported that worldwide there is at least 33% excess methanol production capacity. Most of the excess capacity is located where NG feed cost is high. If MTBE is eventually phased out in U.S. gasoline, there will be more excess capacity that can produce methanol for other applications such as powering FCVs. In our analysis, we take into account the potential use of the excess methanol production capacity for FCV applications. Among all the stages involved in the methanol pathways, methanol production suffers the largest efficiency losses.

Interest in Fischer-Tropsch diesel (FTD) that is produced from NG has been heightened in recent years mainly because of demand for cleaner diesel fuels for diesel engines to reduce emissions of  $\text{NO}_x$  and particulate matter. FT plants usually produce three groups of hydrocarbons: FT naphtha (C5–C9), FT middle distillates (C10–C20), and FT wax (>C20). In some FT plant designs, wax is further cracked into middle distillates. FT middle distillates (commonly called FT diesel) are a premium diesel engine fuel with virtually zero sulfur content and high cetane number but poor cold flow properties. FT naphtha, with virtually no sulfur, could be a reformer feedstock for fuel-cell vehicles. Typical properties of FT naphtha are presented in Table 4. Figure 6 presents the pathways from NG to FTD and FT naphtha. For each fuel, there are three production pathways (from NA NG, NNA NG, and NNA FG). The largest efficiency loss during these pathways occurs in FT plants. Wang and Huang (1999) discussed FT plant designs, production efficiencies, and other co-products in detail. In our analysis, we allocated energy use between FTD and FT naphtha according to the share of energy content in produced FTD and FT naphtha in FT plants. As the figure shows, FT naphtha is to be transported to refueling stations from FT plants. Although pipelines and tankers, which are used now to transport gasoline, could be used to transport FT naphtha, potential contamination of zero-sulfur FT naphtha by residual gasoline in transportation facilities needs to be avoided. FTD can be transported to refueling stations with the existing diesel transportation and distribution infrastructure.

Figure 7 shows the three pathways for producing the  $\text{G.H}_2$  in central plants from NA NG, NNA NG, and NNA FG. To avoid expensive transportation of  $\text{G.H}_2$  across oceans for NNA NG and NNA FG to  $\text{G.H}_2$ , we assumed that NNA NG and FG are liquefied first. LNG is then transported via ocean tankers to U.S. LNG terminals where LNG is gasified. Gasified NG is transported to central  $\text{H}_2$  plants via pipelines. Depending on economics, centralized  $\text{H}_2$  plants can be built near LNG terminals or city gates. In the former case, NG transportation is avoided. In the latter case, long-distance transportation of  $\text{G.H}_2$  is avoided.

For the three central  $\text{G.H}_2$  pathways, the  $\text{G.H}_2$  production stage suffers the largest efficiency losses among all of the activities associated with these pathways.  $\text{G.H}_2$  is assumed to be stored

on FCVs at about 5,000 psi. To achieve this, G.H<sub>2</sub> may need to be compressed to 6000 psi at refueling stations. We assumed that electric compressors are used to compress H<sub>2</sub> at H<sub>2</sub> refueling stations. Compression of G.H<sub>2</sub> incurs a substantial efficiency penalty. For the two NNA pathways, production of LNG suffers additional large efficiency losses.

While H<sub>2</sub> production in central plants can have high-energy efficiencies and take the advantage of economy of scale in costs, centralized H<sub>2</sub> production requires pipelines for H<sub>2</sub> transportation, which can be very expensive to build. On the other hand, H<sub>2</sub> production at refueling stations avoids expensive H<sub>2</sub> pipelines. Figure 8 shows G.H<sub>2</sub> production pathways at refueling stations (sometimes called decentralized or distributed H<sub>2</sub> production). In this case, NG is transported to refueling stations where small-scale reformers will be used to produce G.H<sub>2</sub>. But refueling station H<sub>2</sub> production suffers from low efficiency and high cost.

L.H<sub>2</sub> may be produced so that H<sub>2</sub> can be stored cryogenically on FCVs. Figures 9 and 10 show L.H<sub>2</sub> production pathways in central plants and at refueling stations. With these pathways, produced G.H<sub>2</sub> needs to be liquefied, which is very energy inefficient. Note that for production of L.H<sub>2</sub> from NNA NG and FG in central plants, L.H<sub>2</sub> is assumed to be produced offshore and then transported to the U.S. via ocean tankers. Although there is no L.H<sub>2</sub> ocean tanker now, the technological and economical feasibility has been studied in Japan. On the other hand, production of L.H<sub>2</sub> at refueling stations with NNA NG and FG requires production of LNG and transportation of it to U.S. LNG terminals.

As stated above, use of NNA NG and NNA FG for production of CNG, G.H<sub>2</sub>, and L.H<sub>2</sub> production at refueling stations requires production of LNG outside of North America and transportation of LNG to North America, causing considerable energy losses. We estimate and include energy use and emissions of LNG production and transportation for these fuel options.

In general, production of liquid fuels (methanol, FTD, FT naphtha, and L.H<sub>2</sub>) in North America can be more efficient than production outside of North America, since North American gas is more expensive than NNA gas, providing incentives for efficient plants. For this reason and for the reason that the transportation distance is very different between NA pathways and NNA pathways, the GREET model separates production pathways between NA gas and NNA gas so that individual reserachers can simulate these pathways separately.

### **3.2.2 Key NG Upstream Stages**

#### ***3.2.2.1 Natural Gas Recovery and Processing***

In gas fields, natural gas is lifted from underground and transmitted to processing plants via small distribution pipelines. At processing plants, natural gas liquids and impurities are removed from gas to produce pipeline-quality gas. The gas recovery stage includes lifting gas from underground and transportation of gas to processing plant gates. During this stage, gas may leak during lifting and transmission. Because gas is the intended energy source, the leaked gas should be taken into account in estimating gas recovery efficiency. On the other hand, the gas processing stage includes all the activities in gas processing plants to making gas available at the beginning of gas distribution pipelines. On the basis of published data and comments from the three energy companies, we assumed the same energy efficiencies for gas recovery and processing.

This study includes three NG supply sources for U.S. fuel production: NA NG, NNA NG, and NNA FG. Because of high gas demand, NA NG has high market value. Because of this, one might expect that efforts would be made to reduce gas leaks during gas recovery and processing, resulting in high energy efficiencies. However, there are no data to differentiate energy efficiencies among NA NG, NNA NG, and NNA FG. Consequently, we assumed the same efficiencies for the three NG supply sources.

### 3.2.2.2 Fuel Production

#### Compression of Natural Gas

CNG vehicles can store NG onboard vehicles at a pressure of 3000–3600 psi. We assumed 3600 psi of NG pressure for NG stored onboard. To achieve this storage pressure, NG needs to be compressed to about 4000 psi and stored at that pressure in CNG refueling stations. We used the following formula to calculate the energy efficiency of NG compression.

$$W_{\min} = N \times \frac{k}{k-1} \times M \times R \times T \times Z \times \left( \left( \frac{P_2}{P_1} \right)^{\frac{k-1}{Nk}} - 1 \right) \quad (1)$$

$$\text{Compression Efficiency} = \frac{FD}{\frac{W_{\min}}{CE \times EE} + FD} \quad (2)$$

where

- $W_{\min}$  = minimum work required for gas compression (W),
- $N$  = number of compression stages (4 for NG and 3 for G.H<sub>2</sub>),
- $k$  = ratio of specific heats (1.32 for NG and 1.41 for H<sub>2</sub>),
- $M$  = mass flow (kg/s),
- $R$  = universal gas constant (J/kg K, 518 for NG and 4,124 for H<sub>2</sub>),
- $T$  = temperature (K),
- $Z$  = compressibility factor (0.95 for NG and 1.2 for H<sub>2</sub>),
- $P_2$  = final pressure (bar),
- $P_1$  = initial pressure (bar),
- Compression efficiency = overall efficiency for compression,
- $FD$  = fuel delivered (kW),
- $CE$  = work efficiency of compressors (70% assumed here),
- $EE$  = engine efficiency (30–50% for NG-powered reciprocating engines and 90–92% for electric motors).

As the above formula shows, compression efficiency here is defined as the heating value of the compressed gas divided by the sum of energy used during NG compression and the heating value of the compressed gas. Several key factors determine the compression efficiency. They are initial pressure of NG, final pressure of NG, and the type of compressors. We assumed an initial pressure of 15 psi and a final pressure of 4000 psi for NG. We calculated compression

efficiencies for NG and electric compressors separately. For NG compressors, we assumed an energy efficiency range of 35% to 50% for reciprocating engines fueled with NG and an energy efficiency range of 90% to 93% for electric motors. Although it appears that electric compressors are much more efficient than gas compressors, there is a large efficiency loss during electricity generation. For example, conventional fossil fuel power plants have energy efficiencies of 32% to 38%. When electric power plant efficiencies are taken into account, the overall efficiency of gas compressors can be higher than that of electric compressors. The GREET model takes into account electric power plant efficiencies in estimating overall energy requirements of gas compression.

Using the above assumptions, we estimated the following compression efficiencies for CNG: 93% (with a range of 92% to 94%) for gas compressors and 97% (with a range of 96% to 98%) for electric compressors.

### *Natural Gas Liquefaction*

As described in some previous sections, we assumed NG liquefaction for some of the fuel production pathways in order to bring NNA NG and FG to the U.S. for producing transportation fuels. In fact, at the current gas price in the U.S., some have maintained that LNG could be competitive against NA gas for use in the U.S. (*Oil and Gas Journal* 2000).

In LNG plants, substances such as water, CO<sub>2</sub>, sulfur, and heavier hydrocarbons that freeze during NG liquefaction must be removed before liquefaction. Some of the substances are removed in NG processing plants. But usually pipeline-quality NG still has some remaining impurities that need to be removed before liquefaction. If LNG plants are built next to NG processing plants, or if two are integrated together, efficiencies of NG processing and NG liquefaction may be difficult to separate. In a fuel-cycle analysis, it is important that energy losses are not left out or double-counted.

The purified NG is cooled to about -260°F (at atmospheric pressure), the temperature at which NG becomes liquid. This is accomplished by heat exchange between NG feed and vaporization of refrigerants. NG can also be liquefied using an expansion cycle in which the gas (under high pressure) is expanded rapidly, thereby cooling it to its boiling point. Produced LNG is stored as a cryogenic liquid in insulated storage vessels at pressures of 50–150 psi. LNG stored this way can be transported by ocean tankers, trucks, rail, or barges.

The largest amount of energy in LNG plants is consumed in powering the refrigeration compressors. Energy required by the compressors can be provided by steam boilers, steam turbines, gas turbines, or electric motors. In old LNG plants, steam boilers or steam turbines, with low thermal efficiencies, were used. New plants are equipped with more efficient gas turbines, especially combined-cycle gas turbines (either providing shaft power directly or generating electricity for use in electric motors) (Kikkawa and Nozawa 1999; Vink and Nagelvoort 1998). We assumed that new centralized LNG plants employ combined-cycle turbines that provide shaft power directly to the compressors. Based on data in published studies, we assumed an energy efficiency range of 87–93% for NG liquefaction.

As the temperature in LNG tanks rises over time, some LNG evaporates and becomes NG. Pressure within an LNG tank can build up; this buildup is called a “boil-off effect” and the gas generated is called “boil-off gas.” The boil-off effect can cause major losses of LNG during transportation and storage. Boil-off gas in LNG plants, ocean tankers, and bulk terminals is usually collected as a fuel for combustion. We accounted for the collected boil-off gas in our simulation.

### ***Methanol Production***

Methanol is produced through synthesis of a gaseous mixture of H<sub>2</sub>, CO, and CO<sub>2</sub> (called syngas) into methanol via the steam-methane reforming (SMR) technology. This process requires a large amount of steam, and consequently consumes a large amount of energy. Syngas is then converted into methanol via the following reactions:  $\text{CO}_2 + 2\text{H}_2 \rightarrow \text{CH}_3\text{OH}$  and  $\text{CO}_2 + 3\text{H}_2 \rightarrow \text{CH}_3\text{OH} + \text{H}_2\text{O}$ . Both reactions are exothermic, and efficient plants are designed to use the waste heat from the two reactions. However, most of the waste heat in a methanol plant is recovered when hot syngas from SR or ATR is cooled to lower the temperatures of the methanol synthesis reactor. This waste heat can be used to preheat reformer feed, generate steam for export, generate electricity for export, or purify product.

Another technology for methanol production is autothermal reforming (ATR). With ATR, the heat requirement for steam reforming is provided by combustion of a portion of the gas feed with pure oxygen inside a reforming reactor. One recent technology development for producing syngas to achieve the desired molar ratio is to integrate a partial oxidation (POX) process using pure oxygen with the SMR process. The integrated design, sometimes referred to as “two-step reforming,” requires production of O<sub>2</sub> in methanol plants. The two-step reforming design is suitable for mega-size (3,000–5,000 ton/day capacity) methanol plants (Berggren 1997; Gronemann 1998; Islam and Brown 1997).

Wang and Huang (1999) summarized energy efficiencies of methanol plants with different designs. Recently, a study by (S&T)<sup>2</sup> Consultants (2000) prepared for Methanex adopted the following energy efficiencies: 63% for existing SMR methanol plants and 73–75% for POX plants. The Methanex-commissioned study used an energy efficiency of 71% for year 2000 methanol plants and 73% for year 2010 methanol plants. Note that all efficiencies in that study are based on higher heating values, while all efficiencies used in Argonne’s study are based on lower heating values.

As stated in an above section, at present, there is about 33% excess methanol production capacity. Furthermore, of the total amount of methanol used worldwide, about 26% is used for MTBE production. Several states in the U.S. already decided to ban use of MTBE in gasoline because of groundwater contamination by MTBE. There seems to be a trend that MTBE use in gasoline will decline significantly in the near future. We assume that MTBE use will be reduced by 50% worldwide in the next 10–15 years. This will result in additional methanol excess capacity. With these assumptions, we estimate that excess methanol capacity could reach 11 million metric tons a year (assuming no significant increase in methanol consumptions by other uses). This could fuel about 5 million methanol FCVs a year. Assuming 15 million methanol FCVs on road around 2015, we estimate that 1/3 of methanol for FCVs could be provided by idled existing methanol plants and 2/3 by new methanol plants. With an efficiency

of 63% for existing plants and 70% for new plants (based on lower heating values), we estimate an average efficiency of 67.5% for methanol production for FCV applications. This is for the plant design without steam generation.

As stated above, methanol plants are capable of producing steam for export or for electricity generation. We included three types of methanol plant designs: without steam generation, with steam generation for export, and with electricity generation for export. For the plant design with steam generation, we assumed an energy efficiency of 64% (without considering energy in co-generated steam) together with 78,130 Btu of steam per mmBtu of methanol produced. For the plants with electricity generation, we assumed the co-generated steam in methanol plants is used in steam boilers to generate electricity. Since the co-generated steam is low-quality steam (i.e., low-pressure steam), we assumed a low electricity generation efficiency of 30% with the low-quality steam.

In estimating energy and emission credits of the generated steam in methanol plants (and in FT diesel plants and hydrogen plants to be presented in sections below), we assumed that the co-generated steam will displace steam generation by conventional steam boilers fueled with natural gas, which have an energy efficiency of about 80% (Btu contained in steam divided by Btu contained in burned natural gas). In estimating energy and emission credits of the generated electricity in methanol plants (and in FT diesel plants and hydrogen plants to be presented in sections below), we assumed that the generated electricity would displace electricity generation by natural gas-fueled combined-cycle turbines.

### ***Fischer-Tropsch Diesel and Naphtha Production***

Production of FT diesel and naphtha consists of three steps: (1) production of syngas, (2) synthesis of middle distillates, and (3) upgrading of products. At the syngas production stage, NG feed is converted into syngas (a mixture of CO and H<sub>2</sub>). Although SMR, POX, ATR technologies can all be used to generate syngas, POX and ATR reformers are preferred technologies for syngas production in FTD plants.

The next stage in FTD plants is the Fischer-Tropsch synthesis. The reaction, with the help of catalysts, produces a variety of hydrocarbon liquids including middle distillates and naphtha. The product mix from the process depends on the catalyst used and the operating temperature of the reactor. For example, an operating temperature of 180–250°C helps produce predominately middle distillates and wax; an operating temperature of 330–350°C helps produce gasoline and olefins.

Because the Fischer-Tropsch reaction is exothermic, some excess amount of steam is generated from the process. The generated steam can be exported to nearby facilities or used to generate electricity for export.

We included three types of FTD plant designs: with no steam generation, with steam generation, and with electricity generation. Both diesel fuels and naphtha can be produced from FTD plants. We assumed that they go through same processes in FTD plants and allocated energy and emissions according to their energy output shares.

The largest efficiency loss during FT pathways occurs in FT plants. Wang and Huang (1999) discussed FT plant designs, production efficiencies, and other co-products in details. In our analysis, we allocated energy use between FTD and FT naphtha according to the share of energy content in produced FTD and FT naphtha in FT plants. Based on published data and inputs from the three energy companies, we made the following assumptions. For the FTD plant design with no steam generation, we assumed energy efficiencies of 61% to 65%. For the design with steam generation, we assume energy efficiencies of 53% to 57% (without considering Btu in the generated steam) together with 189,000 to 210,500 Btu of steam per mmBtu of fuel products produced. For the design with electricity co-generation, we assumed the co-generated steam would be used in steam boilers to generate electricity for export.

It is important to notice that when comparing FTD with refinery diesel, the methodology used in this study and in many other transportation fuel-cycle studies does not give FTD any credit for the following: (1) an FT plant does not produce any less desirable co-products such as those from petroleum refineries (e.g., heavy residual oil and coke); and (2) FTD produced at a large scale could begin to allow diesel cars fueled with FTD to displace gasoline passenger cars in countries such as the United States, where, in some areas, tight emission regulations have recently restricted the penetration of diesel cars into the passenger car market.

Carbon efficiency of FT plants is defined as carbon in all products divided by carbon in NG feed. It is used to calculate net CO<sub>2</sub> emissions from FT plants. It is reported that the carbon efficiency of FTD plants can be 75% to 85% (see Table 3.3 of Wang and Huang [1999]). We used carbon efficiencies of 75% to 85%.

### ***Gaseous Hydrogen Production in Central Plants***

The majority of existing large-scale H<sub>2</sub> plants use SMR technology. Steam is added to NG feed, and the mixture of NG and steam is preheated before entering the reformer, where CH<sub>4</sub> is converted into the syngas (H<sub>2</sub>, CO, and CO<sub>2</sub>) in the presence of catalysts. The produced hot syngas, at a temperature of 900–930°C, exits the SMR reformer and is cooled before entering the shift converter, where shift catalysts convert CO and steam to CO<sub>2</sub> and additional H<sub>2</sub>. The gas from the shift converter is further cooled to ambient temperature before entering a pressure swing adsorption (PSA) unit, where high-purity H<sub>2</sub> is produced; the remaining gas mixture, the so-called tail gas, is used in the SMR reformer as supplemental fuel for the burners. Besides conventional SMR technology, other technologies such as POX and ATR can be applied in H<sub>2</sub> plants.

A H<sub>2</sub> plant can generate a significant amount of steam. Some of the steam can be used for processes within the plant, while the remainder can be exported to nearby facilities or to generate electricity for export. In our analysis, we assumed three types of H<sub>2</sub> plants: with no steam co-generation, with steam co-generation, and with electricity co-generation.

Based on published data and comments from the three energy companies, we assumed the following efficiency assumptions for the three plant types. For the H<sub>2</sub> plant design with no steam co-generation, we assumed energy efficiencies of 68% to 75%. For the H<sub>2</sub> plant design with steam co-generation, we assumed energy efficiencies of 66% to 73% (without considering the energy contained in the co-generated steam) together with 120,000–170,000 Btu of steam per

mmBtu of H<sub>2</sub> produced. For the plant design with electricity export, we assumed that co-generated steam is used in steam boilers to generate electricity for export.

In H<sub>2</sub> plants, all the carbon in CH<sub>4</sub> eventually ends up as CO<sub>2</sub>. The produced CO<sub>2</sub> could be sequestered into depleted oil and gas wells to limit CO<sub>2</sub> emissions from H<sub>2</sub> plants or to enhance oil or gas recovery in oil or gas fields. Some researchers maintain that injection of CO<sub>2</sub> into oil and gas wells helps increase oil and gas production, which could make CO<sub>2</sub> injection an economical way to increase oil and gas production (Williams and Wells 1997; Blok et al. 1997). However, without economic incentives or regulations, it is uncertain whether CO<sub>2</sub> from H<sub>2</sub> plants will be sequestered. In our analysis, we did not assume CO<sub>2</sub> sequestration in H<sub>2</sub> plants.

### *Liquid Hydrogen Production in Central Plants*

For this L.H<sub>2</sub> production option, we assumed that G.H<sub>2</sub> is produced in central plants first and then liquefied at the same facility. Thus, G.H<sub>2</sub> production efficiencies assumed in the previous section are applied to this pathway. In addition, H<sub>2</sub> liquefaction efficiencies are applied to the pathway.

Power requirements for refrigeration compressors during liquefaction consume a large amount of energy. Although energy for the compressors can be provided by steam boilers, steam turbines, gas turbines, or electric motors, most studies assumed that electricity is to be used for H<sub>2</sub> liquefaction. Because the boiling point of L.H<sub>2</sub> is much lower than that of LNG (-253°C vs. -163°C), the amount of energy required for H<sub>2</sub> liquefaction is much higher than that required for NG liquefaction. In our study, we assumed liquefaction efficiencies of 65% to 77% for central H<sub>2</sub> plant liquefaction (see Wang and Huang 1999).

We assumed three types of L.H<sub>2</sub> plants: without steam co-generation, with steam co-generation, and with electricity co-generation. Since L.H<sub>2</sub> plants require a large amount of electricity for liquefaction, we assumed the co-generated electricity is used in the plants for liquefactions. On the other hand, for plants with steam co-generation, we assumed that the co-generated steam is exported. In practice, the low-quality, low-pressure steam generated in H<sub>2</sub> plants could be upgraded and used to drive compressors for the liquefaction process.

Because of cryogenic storage of L.H<sub>2</sub> during L.H<sub>2</sub> transportation and storage, L.H<sub>2</sub> is subject to the boil-off effect. Because of this, L.H<sub>2</sub> is subject to some losses. The extent of L.H<sub>2</sub> loss during the boil-off effect depends on the duration of L.H<sub>2</sub> in a storage vessel. The duration of L.H<sub>2</sub> in L.H<sub>2</sub> tankers depends on transportation distance. For example, transportation of L.H<sub>2</sub> from NNA locations to U.S. ports may require about 13 days. Also, we assume an average storage time of 5 days on L.H<sub>2</sub> production plants, L.H<sub>2</sub> bulk terminals, and L.H<sub>2</sub> refueling stations each. We assume a boil-off rate of 0.3% per day for L.H<sub>2</sub> (see Wang and Huang 1999). The gaseous H<sub>2</sub> from boil-off of L.H<sub>2</sub> can be recovered as a process fuel. We assume a recovery rate of 50% for the generated gaseous H<sub>2</sub>. Similarly, LNG is subject to the boil-off effect. Because the boil-off temperature for LNG is 98 °C higher than that for L.H<sub>2</sub> (-161°C vs. 259°C), the boil-off rate for LNG is smaller than that for L.H<sub>2</sub>. We assume a boil-off rate of 0.1% per day for LNG.

### *Gaseous Hydrogen Production in Refueling Stations*

To avoid long-distance transportation and storage of G.H<sub>2</sub> and L.H<sub>2</sub>, which can be very expensive, G.H<sub>2</sub> may be produced from NG in refueling stations with small-scale SMR systems. For this production option, we did not assume that steam is co-generated with H<sub>2</sub> in stations. Because operating conditions may not be optimized with small-scale SMRs, and operators may not be able to maintain a constant H<sub>2</sub> output, we expect that H<sub>2</sub> production efficiency at refueling stations is lower than that in central plants. We assumed energy efficiencies of 62–72%.

### *Gaseous Hydrogen Compression in Refueling Stations*

G.H<sub>2</sub> may need to be stored onboard FCVs at pressures above 5,000 psi. So G.H<sub>2</sub> may need to be compressed to 6,000 psi or greater at refueling stations. For G.H<sub>2</sub> produced in central plants and transported to stations via pipelines, we assumed that electric compressors would be used to compress H<sub>2</sub> at the refueling stations. We assumed an initial pressure of 250 psi for G.H<sub>2</sub> coming out of H<sub>2</sub> pipelines at refueling stations. By using the formula presented in a previous section with specific parameters for H<sub>2</sub> compression, we estimated H<sub>2</sub> compression efficiencies of 90% to 95% for electric compressors (and 82.5% to 87.5% for corresponding NG compressors). In our analysis, compression efficiency is defined as the energy contained in the compressed H<sub>2</sub> divided by the sum of energy in electricity or NG used for compression and the energy in the compressed H<sub>2</sub>. Energy loss during electricity generation is taken into account in a different part of the GREET model.

For G.H<sub>2</sub> produced at refueling stations, we assumed that both NG and electric compressors would be used to compress H<sub>2</sub>. We assumed an initial pressure of 500 psi for G.H<sub>2</sub> produced at refueling stations. By using the formula that we presented previously, we estimated G.H<sub>2</sub> compression efficiencies of 91.5–96.5% for electric compressors and 83.5–88.5% for NG compressors.

To validate the compression formula presented in Section 3.2.2.2, we ran the ASPEN model at Argonne National Laboratory to generate G.H<sub>2</sub> compression efficiencies using similar assumptions. We calibrated our compression formula to make our estimated compression efficiencies close to the ASPEN-generated compression efficiencies.

### *Liquid Hydrogen Production in Refueling Stations*

For this fuel production option, we assumed G.H<sub>2</sub> is produced at refueling stations first and H<sub>2</sub> is liquefied there. We assumed H<sub>2</sub> liquefaction efficiencies of 60–72%, which are lower than the liquefaction efficiencies in central plants.

## **3.3 Bio-Ethanol Production Options**

Currently, the United States has an annual ethanol production capacity of 1.8 billion gallons, virtually all of which use corn as the feedstock. The transportation sector consumes about 1.5 billion gallons of ethanol a year, most of which is consumed in E10 (10% ethanol and 90% gasoline by volume). Meanwhile, the U.S. Department of Energy has been funding R&D efforts on cellulosic ethanol with emphasis on farming of trees and grasses and ethanol production from

cellulosic biomass. In this study, we included three ethanol production pathways: ethanol from corn, woody biomass (trees), and herbaceous biomass (grasses).

### 3.3.1 Bio-Ethanol Pathways

Figure 11 presents the three pathways of ethanol production from corn, woody biomass, and herbaceous biomass. These pathways begin with production of fertilizers and pesticides that are applied to corn and biomass farms. For corn-based ethanol, ethanol plants are the largest fossil energy-consuming source for the entire fuel cycle. Corn-based ethanol plants can be wet milling or dry milling. Wet milling plants employ more processes, require more capital investments to build, and are usually larger in size than dry milling plants. At present, a larger amount of ethanol is produced from wet milling plants than from dry milling plants in the U.S., even though recent additions of ethanol plants in the United States have virtually all been dry milling plants (primarily because smaller capital investment is required for dry milling plants and relatively large tax advantages are available for small ethanol plants in some states). We analyzed energy and emission impacts for both wet and dry milling plants.

Corn-based ethanol plants produce other products besides ethanol. These so-called co-products include distillers' grains and solubles (DGS) in dry milling plants, and corn gluten feed, corn gluten meal, corn oil, and other products in wet milling plants. Energy use and emissions need to be allocated between ethanol and its co-products. Several ways have been employed by researchers to allocate energy use and emissions (see Wang 1999a). We used the displacement

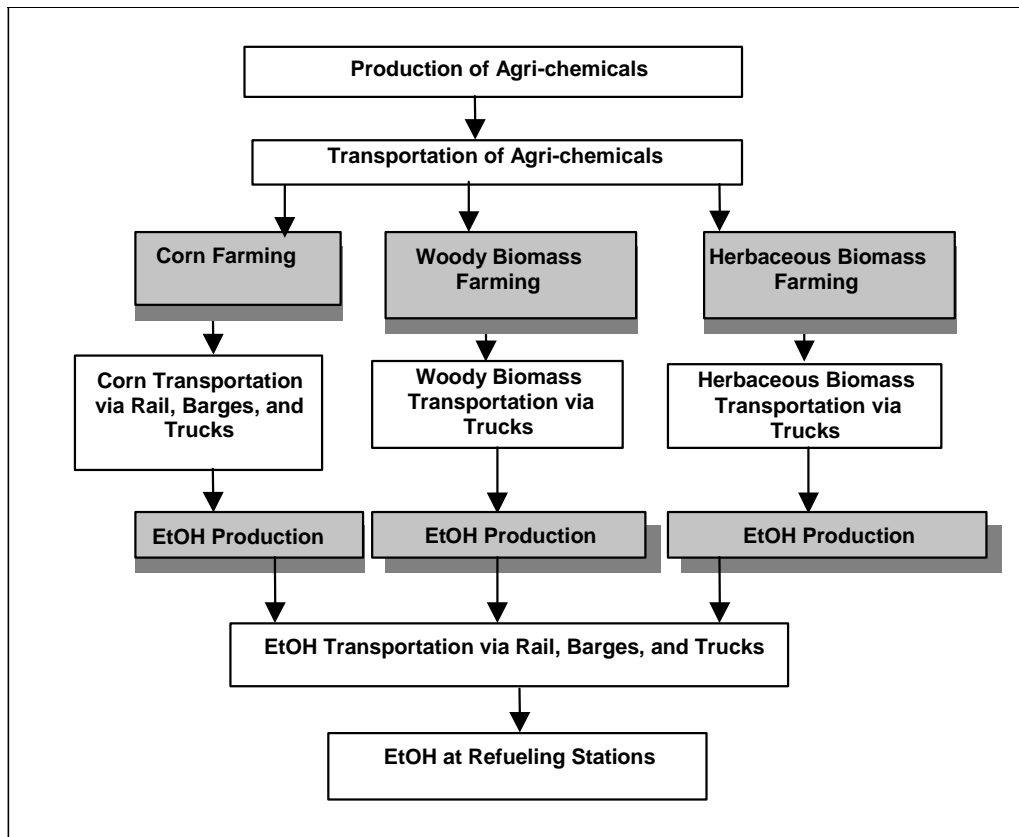


Figure 11 Pathways of Ethanol Production

method and market value method in this study. With the displacement method, first, the amount of co-products produced in an ethanol plant is estimated. Second, the products to be displaced by these co-products in marketplace are identified. Third, the displacement ratios between co-products and the displaced products are determined. Finally, energy use and emissions of producing the amount of displaced products are estimated. The estimated amount of energy and emissions, which represent energy and emission credits of ethanol co-products, are subtracted from total energy and emissions of ethanol pathways.

On the other hand, the market value method allocates energy and emissions among products on the basis of the market values of different products from corn ethanol plants. The method provides higher energy and emission credits than the displacement method does for corn ethanol. In our analysis, we used both the displacement and market value methods to cover the range of potential energy and emission credits of ethanol co-products.

In cellulosic ethanol plants, cellulose in biomass is converted into ethanol through enzymatic processes. The lignin portion of biomass can be burned in ethanol plants to provide needed steam. Co-generation systems can be employed to generate both steam and electricity from lignin. In this case, some amount of extra electricity can be generated in cellulosic ethanol plants. The co-generated electricity can be exported to the electric grid to displace electricity generation in some conventional electric power plants. We took electricity credit into account in calculating energy use and emissions of cellulosic ethanol production. In estimating energy and emission credits of cellulosic ethanol electricity, we used electricity generation with the U.S. average electric generation mix.

### **3.3.2 Parametric Assumptions**

For corn-to-ethanol pathways, key input parameters determining ethanol's energy and GHG emissions impacts include: (1) energy use of corn farming (Btu per bushel of corn harvested), (2) nitrogen fertilizer use of corn farming (grams per bushel of corn harvested), (3) N<sub>2</sub>O emissions from nitrification and denitrification of nitrogen fertilizer in cornfields (grams of nitrogen in N<sub>2</sub>O per gram of nitrogen in nitrogen fertilizer applied to cornfields; N<sub>2</sub>O is 310 times as potent as CO<sub>2</sub> in terms of potential global warming effects), (4) energy use in ethanol plants (Btu per gallon of ethanol produced), (5) ethanol yield per bushel of corn, and (6) ways of dealing with ethanol co-products. For the first five parameters, we established probability distribution functions. For co-product credits, since selection of allocation methods of dealing with co-product credits is more important than parametric values used for each allocation method, we used two methods to cover the potential range. The first method is the displacement method, which is the GREET-default method. The second method is the market value-based method. The market value-based method gives higher credits to co-products than the displacement method does.

For biomass-to-ethanol pathways, key input parameters include: (1) energy use for farming of trees and grasses, (2) fertilizer use for farming of trees and grasses, (3) N<sub>2</sub>O emissions from nitrification and denitrification of nitrogen fertilizer in biomass farms, (4) ethanol yield per ton of biomass, and (5) electricity credit from cellulosic ethanol plants.

Table 10 lists parametric assumptions used in the GREET model.

Table 10 Parametric Assumptions for Ethanol Production Pathways<sup>a</sup>

Item	Pessimistic Assumption	Optimistic Assumption
Corn farming energy use (Btu/bushel of corn harvested)	18,990	17,090
Corn farming N fertilizer use (g/bushel of corn harvested)	440	396
N <sub>2</sub> O emissions in cornfields (N in N <sub>2</sub> O as % of N in N fertilizer)	1.5	1.5
Soil CO <sub>2</sub> emissions (g/bushel of corn harvested)	390	0
Energy use for tree farming (Btu/dry ton of trees harvested)	234,770	211,290
Energy use for grass farming (Btu/dry ton of grass harvested)	217,230	195,510
N fertilizer use for tree farming (g/dry ton of trees harvested)	709	638
N fertilizer use for grass farming (g/dry ton of grass harvested)	10,633	9,570
N <sub>2</sub> O emissions in biomass farms (N in N <sub>2</sub> O as % of N in N fertilizer)	1.3	1.3
Soil CO <sub>2</sub> sequestration in tree farms (g/dry ton of trees harvested)	0	-225,000
Soil CO <sub>2</sub> sequestration in grass farms (g/dry ton of grasses harvested)	0	-97,000
EtOH yield of dry milling plants (gal/bushel)	2.6	2.8
EtOH yield of wet milling plants (gal/bushel)	2.5	2.7
Energy use in dry milling plants (Btu/gal)	41,400	36,900
Energy use in wet milling plants (Btu/gal)	40,300	34,000
EtOH yield of woody biomass plants (gal/dry ton)	76	98
EtOH yield of herbaceous biomass plants (gal/dry ton)	80	103
Electricity credit in woody biomass plants (kWh/gal)	-1.730	-1.730
Electricity credit in herbaceous biomass plants (kWh/gal)	-0.865	-0.865

<sup>a</sup> From Wang (1999a).

### 3.4 Electricity Generation

Electricity can be used in battery-powered electric vehicles (EVs) and grid-connected hybrid electric vehicles (HEVs). Although use of electricity by these vehicles does not produce emissions, electricity generation does. In this study, we estimated energy use and emissions of electricity generation for these vehicle types. One of the key factors determining energy use and emissions of electricity generation is electric generation mix (the mix of the power plants fired with different fuels). Electric generation mix varies with regions. We included three generation mixes: the U.S., the California, and the Northeast U.S. electric generation mixes to cover a broad range of generation mixes. Some studies have concluded that NG-fired CC turbines will provide marginal electricity in the U.S. To approximate marginal electricity supply for EVs and HEVs, we included electricity generation with NG-fired CC turbines.

#### 3.4.1 Electricity Generation Pathways

Figure 12 shows pathways for electricity generation. In GREET, four types of electric power plants are included for energy and emissions estimations: oil-fired, NG-fired, coal-fired, and nuclear power plants. Other power plants, such as hydroelectric power plants and windmill plants, have virtually zero operation emissions. Emissions from nuclear power plants are due to uranium recovery, enrichment, and transportation. As the figure shows, to estimate emissions associated with electricity generation, GREET includes fuel production stages as well as

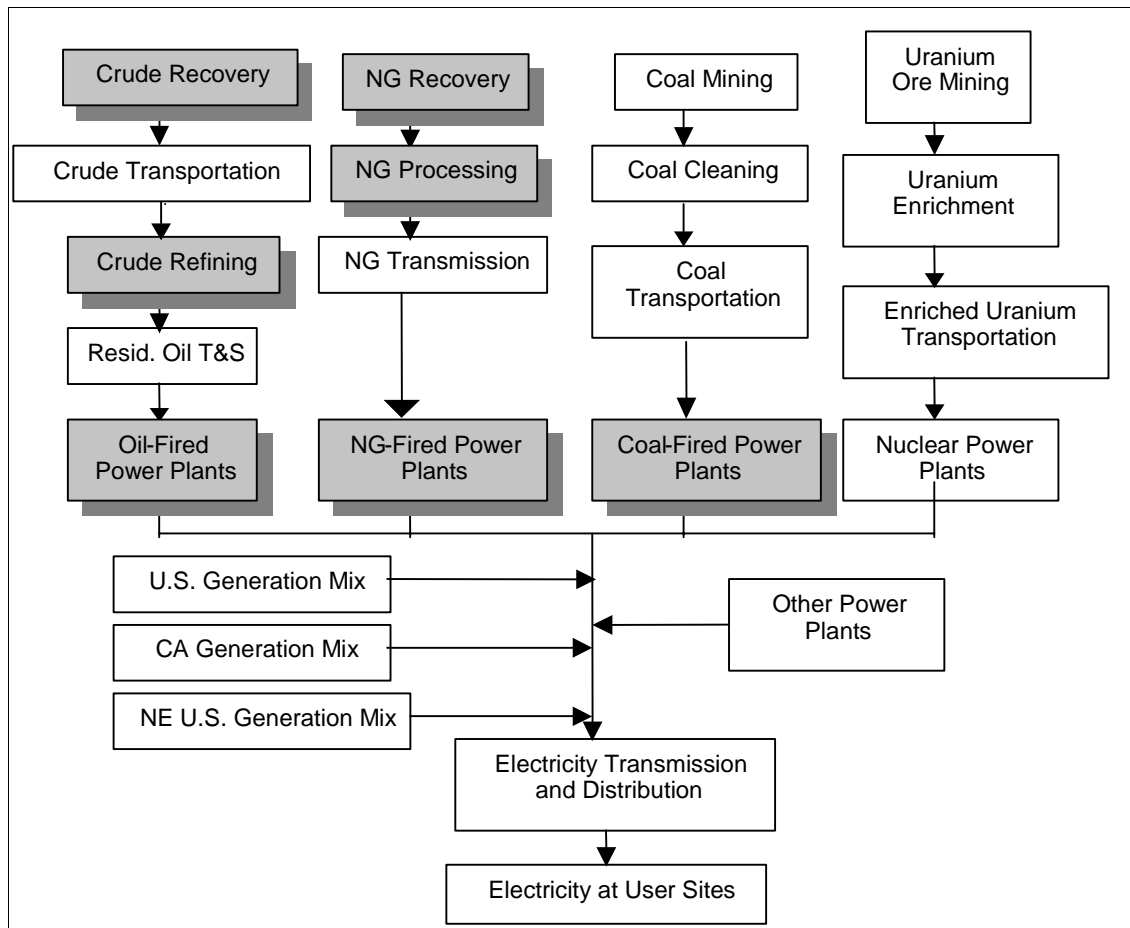


Figure 12 Pathways of Electricity Generation

electricity generation. In this study, the four types of power plants are eventually combined together with U.S., California, or Northeast U.S. electric generation mix to generate utility system energy use and emissions results.

### 3.4.2 Electricity Generation Efficiencies

The most important factor determining energy and emissions of electricity generation pathways is power plant energy conversion efficiencies. Based on published data, we assessed the following conversion efficiencies: 32–35% for steam boilers fired by oil, NG, and coal, 50–60% for NG-fired combined-cycle turbines, and 38–44% for advanced coal-fired power plants such as integrated gasification combined-cycle turbines.

There is an energy loss during transmission of electricity from power plants to user sites. The average electricity transmission loss is about 8% in the U.S. We included this loss in our calculation.

### 3.5 Hydrogen Production via Electrolysis at Refueling Stations

#### 3.5.1 Pathway Definitions

Hydrogen can be produced from electricity via electrolysis of water in refueling stations. Since the electric transmission and distribution system is already extensive, electricity can readily be transmitted to refueling stations. Thus, this pathway helps avoid long-distance transportation and storage of H<sub>2</sub>. In particular, if H<sub>2</sub> will eventually become a fuel-cell fuel, this pathway could help overcome inadequate H<sub>2</sub> distribution infrastructure in the early stage of FCV introduction and in areas outside of major metropolitan areas. Urban H<sub>2</sub> distribution infrastructure will be probably established first and will be more extensive than non-urban areas.

To generate H<sub>2</sub> with clean electricity, some have proposed production of H<sub>2</sub> from hydroelectric power and nuclear power. In Canada, CO<sub>2</sub>-free H<sub>2</sub> is currently produced from hydroelectricity (though the quantity is limited). In this analysis, we evaluated H<sub>2</sub> production with electricity that is generated from hydroelectric power, nuclear power, the U.S. generation mix, the California generation mix, the Northeast U.S. generation mix, and electricity generation with NG-fired combined-cycle turbines. The last case represents the most efficient electricity generation with fossil fuels.

Figure 13 shows the pathways of producing H<sub>2</sub> from electricity via electrolysis of water. Although H<sub>2</sub> can be produced via electrolysis in central plants, the central plant production pathway requires long-distance transportation of gaseous or liquid H<sub>2</sub>, which can be very expensive. To avoid this, we did not include central plant H<sub>2</sub> production from electricity.

In refueling stations, H<sub>2</sub> production via electrolysis requires a large amount of electricity. Electric distribution lines and local electric transmitters may need to be upgraded to deliver the large amount of electricity. The cost of upgrading electric distribution and transmission system is beyond the scope of this project. We included production of both G.H<sub>2</sub> and L.H<sub>2</sub> via electrolysis.

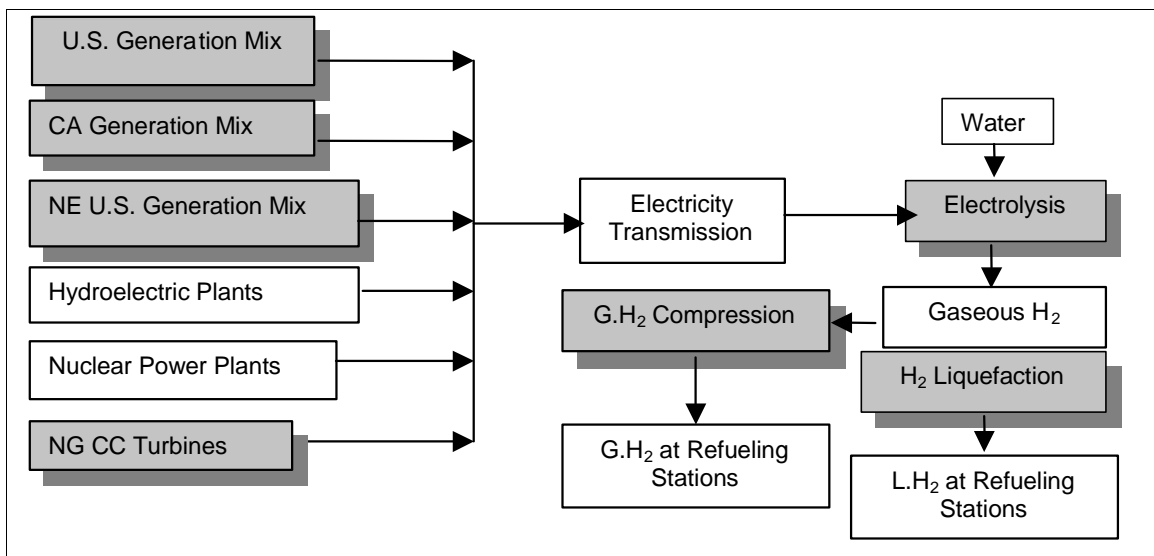


Figure 13 Pathways of Hydrogen Production via Electrolysis

We assumed that G.H<sub>2</sub> would be stored onboard vehicles at a pressure of about 5,000 psi. To achieve this onboard pressure, G.H<sub>2</sub> probably needs to be compressed to 6,000 psi at refueling stations. We assumed this pressure in order to estimate efficiencies for H<sub>2</sub> compression (with an initial pressure of 500 psi). Liquefaction of H<sub>2</sub> consumes a large amount of energy. We assumed the required energy would be electricity. L.H<sub>2</sub> will be cryogenically stored onboard vehicles.

In GREET, five types of electric power plants are included for energy and emissions estimations – oil-fired, NG-fired, coal-fired, nuclear power plants, and other power plants. Other power plants include such plants as hydroelectric power plants and windmill plants. They have virtually zero emissions. As Figure 13 shows, to estimate emissions associated with electricity generation, GREET includes fuel production activities as well as electricity generation. In this analysis, we evaluated six pathways for electricity generation: the U.S. electric generation mix, the California electric generation mix, the Northeast U.S. electric generation mix, nuclear power plants, hydroelectric power plants, and NG-fired CC gas turbines. The first three pathways show the importance of the electric generation mix in determining energy and emissions effects of electricity-to-hydrogen pathways. The next two pathways show the effects of potentially clean sources for electricity generation (radiation effects of nuclear power plants and ecological effects of hydroelectric power plants are not considered in this analysis). The last pathway shows the effect of the most efficient fossil fuel power plants. As for nuclear power to H<sub>2</sub> production, DOE is funding some research efforts at Argonne National Laboratory for potential H<sub>2</sub> production from nuclear power.

### 3.5.2 Efficiencies of Electrolysis

For the pathways of producing G.H<sub>2</sub> and L.H<sub>2</sub> from electricity, energy efficiencies for electricity generation for coal-fired, NG-fired, oil-fired, and nuclear power plants were presented in a section above. Energy efficiencies for G.H<sub>2</sub> compression and liquefaction were presented in a separate section above. We used those data for the electrolysis pathways here.

The additional step for electrolysis pathways is H<sub>2</sub> production via electrolysis. There are large efficiency losses during this stage. Table 11 summarizes electrolysis efficiencies of H<sub>2</sub> production presented in different studies. The table shows a wide range of 60% to 80% for electrolysis efficiencies. When the two outliers are taken out (60% and 80%), the energy efficiency range appears to be within the range of 67% to 76%.

Table 11 Electrolysis Energy Efficiencies for Hydrogen Production

Source	Energy Efficiency: Based on Lower Heating Value of H <sub>2</sub> (%)	Remarks
Thomas et al. (1997)	66.7–68.0	Home electrolyzers
	68.0–73.0	Station electrolyzers
Amstutz and Guzzella (1998)	76.0	
Berry et al. (1996)	68.0	
Ogden (1999)	70.0	Current technology
	80.0	Year 2020 technology
Adamson and Pearson (2000)	60.0	
Pembina Institute (2000)	68.0	
Unnasch and Browning (2000)	68.0	Near-term technology
	72.0	Long-term technology



## **4 Development of Probability Distribution Functions for Key Parameters**

In this project, we began to formally address uncertainties in fuel-cycle analysis with the GREET model. Using the Crystal Ball software, we conducted Monte Carlo simulations for the pathways included in this study. To do so, we needed to develop probability distribution functions for key parameters, which can be developed with two approaches. One approach is to generate enough data from tests, surveys, or other methods so that objective distribution functions can be developed from the collected data. The other approach is to develop subjective distribution functions based on one's understanding of uncertainty levels and parametric ranges for given parameters.

In our analysis, we used our professional judgments to establish subjective distribution functions. We first developed ranking of the uncertainty level involved in a given input parameter. Then, based on the range of values for the parameter from published results and the developed uncertainty level, we determined the values for the input parameter at probability of 20% and 80%. Furthermore, we assumed that the input parameter (except as noted) follows the normal distribution curve in order to establish the probability distribution function for the parameter.

### **4.1 Assignment of Uncertainty Levels**

Energy efficiencies of key upstream stages in a fuel-cycle pathway are determined by many factors. Because of this, efficiencies are subject to uncertainties. Key upstream stages mainly include fuel production, compression, and liquefaction. We developed a rating system to assign uncertainty levels to key parameters. With our rating system, we assigned more dots to the parameters with greater uncertainties. In determining the number of dots for input parameters, we considered the following factors that affect energy efficiencies of fuel production facilities: (1) status of technology development; (2) variability in existing operations/resources; (3) by-product uncertainties (steam, electricity, etc.); (4) uncertainty in business decision of promoting certain technologies, and (5) the regulatory uncertainty in developing and operating certain facilities. Needless to say, our uncertainty rating is qualitative and crude, and involves significant professional judgments.

#### **4.1.1 Petroleum-Based Fuel Pathways**

Because crude quality, crude production locations, petroleum refinery configurations, and many other factors are different for different cases of producing gasoline, diesel fuels, and naphtha, estimated energy efficiencies for upstream activities of petroleum-based fuels are subject to great uncertainties. Two key stages for petroleum pathways are petroleum recovery and petroleum refining. Table 12 presents our ranking of uncertainty levels in energy efficiencies for upstream activities of petroleum-based fuels. Energy efficiencies of crude recovery may be subject to moderate degree of uncertainties since crude quality and production locations for U.S. refinery crude can vary (Table 5). For petroleum refining, production of currently available fuels is subject to moderate uncertainties, but production of new gasoline and diesel fuel may be subject to great uncertainties. Our assignment of the degree of uncertainties in Table 12 reflects these situations.

Table 12 Uncertainty Levels for Energy Efficiencies of Petroleum Pathway Activities<sup>a</sup>

Pathway	Petroleum Recovery	Fuel Production
340 ppm sulfur CG	••	••
150 ppm sulfur RFG with MTBE	••	••
5–30 ppm sulfur RFG with MTBE	••	•••
5–30 ppm sulfur RFG with EtOH	••	•••
5–30 ppm sulfur RFG with no oxygenate	••	•••
120–350 ppm sulfur diesel	••	••
5–30 ppm sulfur diesel	••	•••
5–30 ppm sulfur naphtha	••	•••

<sup>a</sup> • – least uncertain; •••• – most uncertain.

#### 4.1.2 Natural-Gas-Based Fuels

Key well-to-tank stages for natural-gas-based pathways are highlighted in Figures 4 through 10. Energy efficiencies of these key stages are subject to great uncertainties. Table 13 presents our ranking of uncertainty levels in energy efficiencies for NG pathway upstream activities. Energy efficiencies of NG recovery may be subject to moderate degrees of uncertainties because production location can impact efficiencies. Liquefaction of NG may be subject to a moderate degree of uncertainty. Production of liquid fuels from NG and FG are subject to the greatest degree of uncertainty. Compression of NG and G.H<sub>2</sub> may be subject to a large degree of uncertainty. Our assignment of the degrees of uncertainty listed in Table 13 reflects these situations.

Table 13 Uncertainty Levels for Energy Efficiencies of Natural Gas Pathway Activities<sup>a</sup>

Pathway	NG Recovery	NG Processing	NG Liquefaction	Fuel Production	Fuel Liquefaction	Gaseous Fuel Compression
CNG	•	•	NA	NA	NA	•••
G.H <sub>2</sub> in central plants	•	•	NA	•••••	NA	••••
G.H <sub>2</sub> in stations	•	•	NA	••••••	NA	••••
L.H <sub>2</sub> in stations	•	•	NA	••••••	••••	NA
Methanol	•	•	NA	••••	NA	NA
FTD	•	•	NA	•••••	NA	NA
Naphtha w/no sulfur	•	•	NA	•••••	NA	NA
CNG	•	•	•••	NA	NA	•••
G.H <sub>2</sub> in central plants	•	•	•••	•••••	NA	••••
G.H <sub>2</sub> in stations	•	•	•••	••••••	NA	••••
L.H <sub>2</sub> in central plants	•	•	NA	•••••	•••••	NA
L.H <sub>2</sub> in stations	•	•	•••	••••••	••••	NA
Methanol	•	•	NA	••••	NA	NA
FTD	•	•	NA	•••••	NA	NA
Naphtha w/no sulfur	•	•	NA	•••••	NA	NA

<sup>a</sup> • – least uncertain; •••••• – most uncertain; NA – not applicable.

### 4.1.3 Bio-Ethanol Pathways

Table 14 presents our ranking of uncertainty levels in key upstream parameters for bio-ethanol pathways. Energy and fertilizer use for farming of corn and biomass may be subject to moderate degree of uncertainties since farming regions, climate, soil conditions, and many other factors can affect application rates for each unit of corn or biomass harvested. N<sub>2</sub>O emissions from soil in cornfields may be subject to a greater degree of uncertainty than those in biomass farms because cornfield soil is more disturbed than biomass farm soil. Fossil energy use in cellulosic ethanol plants may be subject to less uncertainty than that in corn ethanol plants, since the former uses much less fossil fuels than the latter (steam is generated by burning of biomass lignin, whose uncertainty level is determined by ethanol yield per dry ton of cellulosic biomass). Ethanol yield per unit of corn or biomass can vary, depending on plant designs and technologies employed. Co-product credits can vary, depending on technologies employed in ethanol plants and market conditions for co-products (animal feeds for corn ethanol plants and electricity for cellulosic ethanol plants).

Table 14 Uncertainty Levels for Parameters of Ethanol Pathway Activities

Pathway	Energy Use of Feedstock Farming	Fertilizer Use of Feedstock Farming	N <sub>2</sub> O Emissions from Farms	Soil CO <sub>2</sub> Sequestration	Energy Use in Ethanol Plants	Ethanol Yield	Co-Product Credits
Corn to EtOH: dry mill	•••••	•••••	•••	•	•••	••	NA <sup>b</sup>
Corn to EtOH: wet mill	•••••	•••••	•••	•	•••	••	NA <sup>b</sup>
W. cellulosic EtOH	••	••	••	•••••	NA <sup>a</sup>	•••	•••••
H. Cellulosic EtOH	••	••	••	•••••	NA <sup>a</sup>	•••	•••••

<sup>a</sup> • – least uncertain; ••••• – most uncertain; NA – not applicable.

<sup>b</sup> The amount of fossil fuels used in cellulosic plants is very small. Virtually all the energy needed in these plants is provided by burning of lignin. The uncertainty of the amount lignin burned is addressed by ethanol yield per dry ton of cellulosic biomass.

<sup>c</sup> Though uncertainties are associated with the amount of co-products produced per gallon of ethanol and the displacement ratios between ethanol co-products and the displaced products, the most significant factor determining co-product energy and emission credits is whether the displacement method or the market value-based method is considered for estimating co-product credits (see Wang [1999a] for details of the two methods). We conducted analyses with the two methods rather than conducting probability-based analysis for the displacement method.

### 4.1.4 Electricity Generation

Of all the upstream stages involved in electricity generation, production of petroleum and natural gas is already covered in previous sections. Upstream stages for coal and uranium production and processing are usually efficient. We did not establish probability distribution functions for these stages. Electricity generation suffers the largest efficiency losses for the complete electricity cycle. In this section, we address uncertainties in electricity generation in fossil fuel power plants.

Table 15 presents our ranking of uncertainty levels in power plant conversion efficiencies. Energy conversion efficiencies of oil-fired plants may be subject to a moderate degree of uncertainties. On the other hand, efficiencies of NG- and coal-fired power plants may be subject to a large degree of uncertainties, since advanced technologies such as combined-cycle turbines, which may be employed in these two types of power plants, can increase efficiencies significantly, and deployment of these technologies is affected by many factors.

Table 15 Uncertainty Levels for Electricity Generation Efficiencies<sup>a</sup>

Power Plants	Conversion Efficiency
Oil-fired plants	••
NG-fired plants	••••
Coal-fired plants	••••

<sup>a</sup> • – least uncertain; •••• – most uncertain.

## 4.2 Electricity to Hydrogen via Electrolysis

As discussed in an above section, the pathway of electricity to H<sub>2</sub> via electrolysis includes production of primary energy (petroleum, natural gas, coal, etc.), electricity generation, electricity transmission, H<sub>2</sub> production, H<sub>2</sub> compression (in the case of G.H<sub>2</sub>), and H<sub>2</sub> liquefaction (in the case of L.H<sub>2</sub>). All these stages, except H<sub>2</sub> production via electrolysis, have been covered in other sections of this report. This section covers electrolysis efficiencies only.

As a previous section showed, our survey of studies on electrolysis efficiencies shows a wide range of electrolysis efficiencies. Because current electrolysis systems are less mature and small in scale, there is a large potential for improved efficiencies. We assigned six dots, the highest level of uncertainties, to electrolysis efficiencies.

## 4.3 Determination of Probability Distribution Functions

We determined probability distribution functions with the following steps. We presented the ranges of efficiencies for key stages that we obtained from open literature and communications with experts. In the above section, we assigned uncertainty levels to these stages with number of dots (the more dots, the more uncertain). For a given stage, we determined the range of efficiency for probability of 20% and 80% (P20 and P80) by considering the range we obtained and the number of dots we assigned for the uncertainty level of the stage. If a stage has more dots assigned, we increased our original range for the stage. If a stage has less dots assigned, we reduced our original range. For most stages, we assumed the normal distribution curve for probability distribution of efficiencies.

### 4.3.1 Petroleum-Based Fuel Pathways

We developed efficiencies for upstream activities of petroleum-based fuel pathways under probabilities of 20%, 50%, and 80% (P20, P50, and P80, respectively). Since we assumed the normal distribution curve for most parameters, the value for P50 is usually the average of the values for P20 and P80. Table 16 presents our estimated values.

Table 16 Energy Efficiencies for Petroleum Pathway Activities

Activity	Energy Efficiency (%)		
	P20	P50	P80
Petroleum recovery <sup>a</sup>	96.0	98.0	99.0
Petroleum refining: 340 ppm S CG	85.0	85.5	86.0
Petroleum refining: 150 ppm S RFG with MTBE: GBS <sup>b</sup>	85.0	86.0	87.0
Petroleum refining: 5–30 ppm S RFG with MTBE: GBS <sup>b</sup>	84.0	85.5	87.0
Petroleum refining: 5–30 ppm S RFG with EtOH: GBS <sup>b</sup>	84.0	85.5	87.0
Petroleum refining: 5–30 ppm S RFG with no oxygenate	83.0	84.5	86.0
Petroleum refining: 120–350 ppm S diesel	88.0	89.0	90.0
Petroleum refining: 5–30 ppm S diesel	85.0	87.0	89.0
Petroleum refining: 5 ppm naphtha	89.0	91.0	93.0

<sup>a</sup> A triangle distribution curve was assumed for petroleum recovery.

<sup>b</sup> GBS – gasoline blendstock.

Figure A1 of Appendix A shows the probability distribution functions for crude recovery and refining, as developed with the Crystal Ball software with the assumptions made in Table 16. As the figures show, we assumed the normal distribution curve for all the parameters except petroleum recovery efficiency.

#### 4.3.2 Natural-Gas-Based Fuels

With the assigned uncertainty levels in Table 13 and energy efficiency ranges that we obtained from open literature and communication with experts, we established values under P20, P50, and P80 for efficiencies of natural-gas-based pathway activities. Table 17 presents the estimated values. (Note that compression of NG or G.H<sub>2</sub> has smaller efficiency ranges for each compressor type presented than the ranges implied in a previous section. This is because, in the previous section, we discussed compression efficiencies for both NG and electric compressors together. If one combines the compression efficiencies of both types listed in Table 17, the range of compression efficiencies is much larger than the range for each type.)

In FT plants, if naphtha is produced as a fuel-cell fuel, together with FT diesel as a diesel engine fuel, it is likely that both FT naphtha and diesel will be subject to similar intensive production and refining processes. This implies that production of one unit of energy in FT naphtha and FT diesel could require about the same amount of energy. Thus, we assumed same energy efficiencies between FT naphtha and FT diesel. In other words, we allocated energy use and emissions in FT plants between naphtha and diesel based on their energy output shares. On the energy basis, FT plants may produce 60–70% of its output products as diesel, 20–30% as naphtha, and remainings as other products such as waxes.

Figure A2 of Appendix A graphically shows probability distribution functions for the parameters presented in Table 17. These distribution charts are developed with the Crystal Ball software. We assumed triangle distribution functions for NG liquefaction, electric compressors for NG compression, and steam credits from methanol plants, H<sub>2</sub> liquefaction in central plants, NG compressors for G.H<sub>2</sub> compression, and electric compressors for G.H<sub>2</sub> compressors. These triangle distribution functions were assumed to ensure that Crystal Ball simulations did not yield unrealistic efficiency ranges (i.e., values exceeding 100%).

Table 17 Energy Efficiencies for Natural-Gas-Based Pathway Activities

Activity	P20	P50	P80
NG recovery: NA NG, NNA NG, NNA FG	96.0%	97.5%	99.0%
NG processing: NA NG, NNA NG, NNA FG	96.0%	97.5%	99.0%
LNG production from NG and FG <sup>a</sup>	87.0%	91.0%	93.0%
NG compression: NG compressor	92.0%	93.0%	94.0%
NG compression: electric compressor <sup>a</sup>	96.0%	97.0%	98.0%
MeOH production: with no steam production <sup>a</sup>	65.0%	67.5%	71.0%
MeOH production: with steam production <sup>a</sup>	62.0%	64.0%	66.0%
MeOH production, with steam production, steam credit (Btu/mmBtu) <sup>a</sup>	64,520	78,130	90,910
FT diesel and naphtha production: with no steam production	61.0%	63.0%	65.0%
FT diesel and naphtha production: with steam production	53.0%	55.0%	57.0%
FT diesel and naphtha production: with stream production, steam credit (Btu/mmBtu)	189,000	200,000	210,500
G.H <sub>2</sub> production in central plant: with no steam production	68.0%	71.5%	75.0%
G.H <sub>2</sub> production in central plant, with steam production	66.0%	69.5%	73.0%
G.H <sub>2</sub> production in central plant, with steam production, steam credit (Btu/mmBtu)	120,000	145,000	170,000
H <sub>2</sub> liquefaction in central plants <sup>a</sup>	65.0%	71.0%	77.0%
G.H <sub>2</sub> production in stations	62.0%	67.0%	72.0%
G.H <sub>2</sub> compression for central G.H <sub>2</sub> : NG compressor <sup>a</sup>	82.5%	85.0%	87.5%
G.H <sub>2</sub> compression for central G.H <sub>2</sub> : electric compressor <sup>a</sup>	90.0%	92.5%	95.0%
G.H <sub>2</sub> compression for station G.H <sub>2</sub> : NG compressor <sup>a</sup>	83.5%	86.0%	88.5%
G.H <sub>2</sub> compression for station G.H <sub>2</sub> : electric compressor <sup>a</sup>	91.5%	94.0%	96.5%
H <sub>2</sub> liquefaction in stations	60.0%	66.0%	72.0%

<sup>a</sup> Triangle distribution functions were assumed for these parameters.

### 4.3.3 Bio-Ethanol Pathways

With the assigned uncertainty levels in Table 14 and parametric value ranges that we obtained from published literature, we developed values for P20, P50, and P80 for key bio-ethanol upstream parameters. Table 18 presents the estimated values.

Figure A3 of Appendix A graphically shows probability distribution functions for the bio-ethanol activities that we developed with the Crystal Ball software. To ensure that Crystal Ball simulations do not go beyond reasonable efficiency ranges, we assumed triangle distribution functions for the following parameters: corn farming energy use, N<sub>2</sub>O emissions in corn farms, soil CO<sub>2</sub> emissions from corn farms, ethanol yield of dry milling ethanol plants, ethanol yield of wet milling ethanol plants, N<sub>2</sub>O emissions in biomass farms, soil CO<sub>2</sub> sequestration in biomass farms, and electricity credits of cellulosic ethanol plants.

### 4.4 Electricity Generation

With the assigned uncertainty levels in Table 15 and the range of parametric values that we obtained from published literature, we developed values for P20, P50, and P80 for power plant conversion efficiencies (Table 19).

Table 18 Energy Efficiencies and Other Values for Bio-Ethanol Pathway Activities

Activity	P20	P50	P80
<i>Corn-to-Ethanol Pathways</i>			
Corn farming energy use (Btu/bushel of corn) <sup>a</sup>	12,600	26,150	39,700
N fertilizer use in corn farms (g/bushel of corn)	370	475	580
N <sub>2</sub> O emissions in corn farms (N in N <sub>2</sub> O as % of N in N fertilizer) <sup>a</sup>	1.0	1.5	2.0
Soil CO <sub>2</sub> emissions in corn farms (g/bushel of corn) <sup>a</sup>	0	195	390
Ethanol yield, dry mill plants (gal/bushel of corn) <sup>a</sup>	2.5	2.65	2.8
Ethanol yield, wet mill plants (gal/bushel of corn) <sup>a</sup>	2.4	2.55	2.7
Energy use in dry mill plants (Btu/gal of ethanol)	36,900	39,150	41,400
Energy use in wet mill plants (Btu/gal of ethanol)	34,000	37,150	40,300
<i>Cellulosic Biomass-to-Ethanol Pathways</i>			
Energy use for tree farming (Btu/ton of trees)	176,080	234,770	293,460
Energy use for grass farming (Btu/ton of grasses)	162,920	190,080	271,540
N fertilizer use for tree farming (g/ton of trees)	532	709	886
N fertilizer use for grass farming (g/ton of grasses)	7,980	10,630	13,290
N <sub>2</sub> O emissions in biomass farms (N in N <sub>2</sub> O as % of N in N fertilizer) <sup>a</sup>	0.8	1.15	1.5
Soil CO <sub>2</sub> sequestration in tree farms (g/ton of trees) <sup>a</sup>	-225,000	-112,500	0
Soil CO <sub>2</sub> sequestration in grass farms (g/ton of grasses) <sup>a</sup>	-97,000	-48,500	0
Ethanol yield, woody biomass plants (gal/ton of trees)	76	87	98
Ethanol yield, herbaceous biomass plants (gal/ton of grasses)	80	92	103
Electricity credit of woody biomass plants (kWh/gal of ethanol) <sup>a</sup>	-1.73	-1.15	-0.56
Electricity credit of herbaceous biomass plants (kWh/gal of ethanol) <sup>a</sup>	-0.865	-0.57	-0.28

<sup>a</sup> Triangle distribution functions are assumed for these parameters.

Table 19 Energy Conversion Efficiencies for Electric Power Plants

Power Plant Type	Efficiency (%)		
	P20	P50	P80
Oil-fired power plants: steam boiler	32.0	35.0	38.0
NG-fired power plants: steam boiler	32.0	35.0	38.0
NG-fired power plants: combined-cycle turbines <sup>a</sup>	50.0	55.0	60.0
Coal-fired power plants: steam boiler	33.0	35.5	38.0
Coal-fired power plants: advanced technologies	38.0	41.5	45.0

<sup>a</sup> A triangle distribution function is assumed for NG-fired CC gas turbines.

Figure A4 of Appendix A graphically shows probability distribution functions for electric power plant conversion efficiencies. We assumed normal distribution functions for conversion efficiencies except for that of NG-fired CC gas turbines, for which as assumed a triangle distribution function.

Table 20 presents the U.S., California, and Northeast U.S. electricity generation mix. About 54% of U.S. electricity is generated from coal. In California and Northeast U.S., over 30% of electricity is generated from natural gas. In addition, about 33% of California's electricity is generated from hydro, geothermal, organic waste, wind and other energy sources.

Table 20 The U.S., California, and Northeast U.S. Electricity Generation Mix

Generation Mix	Coal	Oil	Natural Gas	Nuclear	Others <sup>a</sup>
U.S. Mix <sup>b</sup>	53.8%	1.0%	14.9%	18.0%	12.3%
CA Mix <sup>c</sup>	21.3%	0.0%	32.9%	14.7%	31.3%
NE U.S. Mix <sup>b</sup>	28.2%	2.5%	31.6%	26.3%	11.4%

<sup>a</sup> Including hydro, geothermal, organic waste, solar, wind, and other electric power plants.

<sup>b</sup> From Wang (1999a).

<sup>c</sup> From Kelly (2000).

Table 20 presents the average generation mixes for the U.S., California, and Northeast, which we used to simulate electricity generation under the three generation mixes. To precisely simulate energy and emission effects of electricity use by EVs and HEVs, marginal electric generation mix — the mix for providing electricity for these vehicles — should be estimated and used for analyses. Some have maintained marginal electricity will be probability generated with NG-fired CC gas turbines. In our analysis, we included this technology to approximate the U.S. marginal electricity supply.

Some analyses conducted in California took a different approach in estimating energy and emissions effects of EVs and HEVs. These analyses excluded emissions of power plants located outside of California on the ground that emissions from those plants occur outside of the state. For power plants located within an air basin (such as the South Coast Air Basin), the analyses sometimes assumed zero emissions from the in-basin plants for EV electricity demand on belief that the emissions from increased electric generation from in-basin electric plants to meet EV and HEV electricity demand must be offset by other sources because the emission cap regulation, as adopted in some air basins, must be met. These steps are extremely in favor of EVs and HEVs, which we did not take in our analysis. Although this discussion is more relevant to emissions of criteria pollutants, which we did not include in this analysis, use of one approach over the other affects calculations of energy use and GHG emissions significantly.

#### 4.5 Electricity to Hydrogen via Electrolysis

We developed values for P20, P50, and P80 for hydrogen electrolysis efficiencies (Table 21). Figure A5 of Appendix A graphically shows the probability distribution function for electrolysis efficiencies.

As we stated in an above section, we simulated electricity-to-hydrogen pathways with three electricity generation mixes — the U.S., the California, and the Northeast U.S. mixes — as well as electricity generation in nuclear power plants, hydroelectric power plants, and NG-fired combined-cycle turbine plants. The six options cover wide ranges of potential energy and emission impacts of hydrogen production via electrolysis.

Table 21 Hydrogen Electrolysis Efficiencies

Activity	Efficiency (%)		
	P20	P50	P80
Electrolysis	67.0	71.5	76.0

## 5 Transportation of Feedstocks and Fuels

Through a separate Argonne project, we have expanded the simulations of transportation of energy feedstocks and fuels. In previous GREET versions, transportation of feedstocks and fuels was simulated with aggregate energy efficiencies for transportation of various feedstocks and fuels. In the new GREET version, for a given feedstock or fuel, its transportation is simulated with transportation mode split, transportation distance for each mode, and energy intensity of each mode. Development of transportation simulations is documented in He and Wang (2000). Eventually, we could establish probability distribution functions for transportation distance and energy intensity of each transportation mode. Because of time and funding constraints, we did not establish such distribution functions this time.

### 5.1 Methodology

We employed the following approach to estimate energy use and emissions for transportation of feedstocks and fuels. First, we determined the types and shares of transportation modes (i.e., ocean tankers, pipelines, barges, rail, and trucks) to be used for transporting a given feedstock or fuel. Second, we identified the types and shares of process fuels (residual oil, diesel fuels, natural gas, electricity, etc.) to be used for powering a given transportation mode. Third, we calculated the energy intensity and emissions associated with a given transportation mode fueled with a given process fuel. Finally, we added together the energy use and emissions of all transportation to be used for transporting the given feedstock or fuel. Figure 14 shows the way in which the new GREET version simulates transportation of feedstocks and fuels.

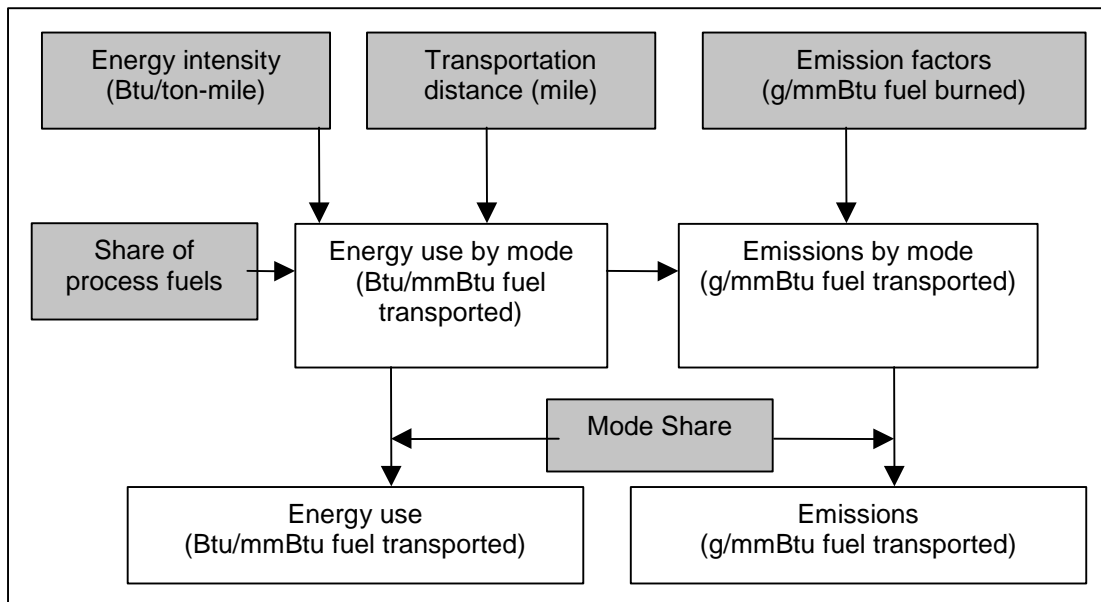


Figure 14 Calculation Logic of Energy Use and Emissions Associated with Feedstock and Fuel Transportation

## 5.2 Assumptions

### 5.2.1 Crude Oil

Figure 15 shows our specifications of transportation of crude from wells to U.S. refineries. In 1998, 58% of crude oil consumed in the United States was imported (EIA 1999). We assumed that ocean tankers are used to ship imported crude oil from Alaska and countries outside of North America, and pipelines are used for shipping crude from Canada and Mexico. Four transportation modes may be used for in-land transportation: pipelines, barge, and rail. The U.S. Department of Transportation (U.S. DOT 1996) estimated that, in 1993, 52.6% of crude oil was shipped by pipeline, 47.3% by water carriers, and 0.1% by rail. These mode splits were incorporated into the new GREET version to represent U.S. average mode splits. A GREET user can specify a different set of mode splits according to the specific case in simulation.

We calculated the average distance associated with ocean tanker transportation according to port-to-port distances (from [www.distance.com](http://www.distance.com)) and the amount of imported oil transported from different countries to the United States. Crude oil from Southeast Asia (across the Pacific Ocean) was assumed to reach Los Angeles; crude from Europe, the Middle East, and Africa was assumed to reach Houston and New York across the Atlantic Ocean. For in-land transportation, the travel distance for each mode was obtained from the Commodity Flow Survey (U.S. DOT and U.S. Department of Commerce [DOC], 1997). Round trips were considered for ocean tankers, barges, and tanker trucks because no other goods could be hauled for the back haul.

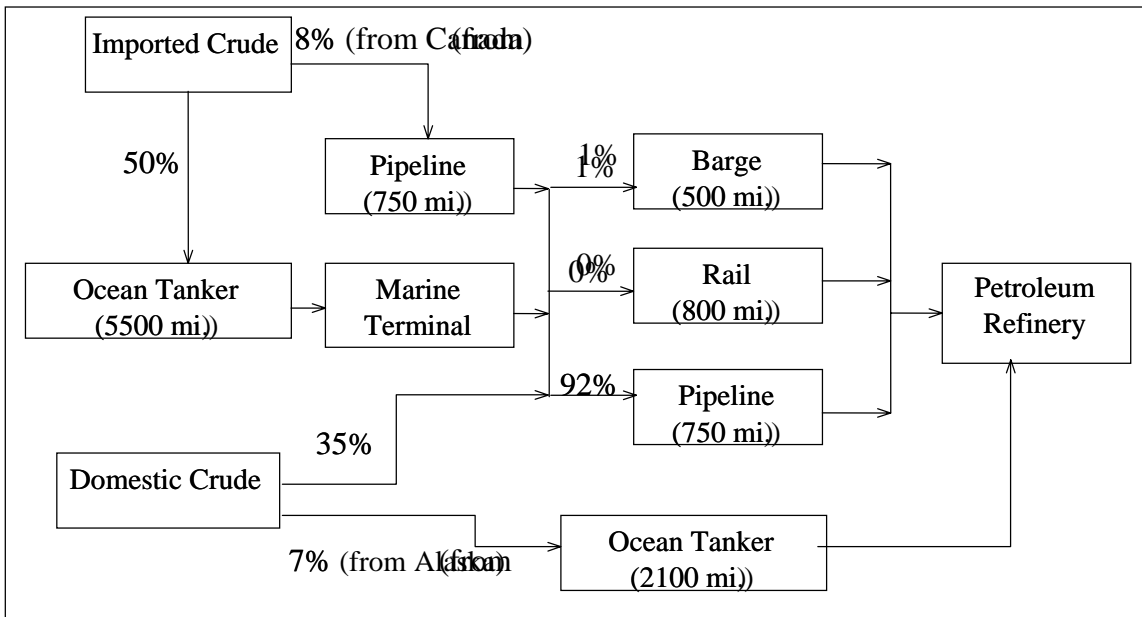


Figure 15 Crude Transportation from Oil Fields to U.S. Petroleum Refineries

### 5.2.2 Gasoline and Diesel

Although both domestic and imported gasoline and diesel supply the U.S. market, imported gasoline and diesel are small, relative to domestic production. EIA (1999) estimated that in 1998, less than 5% of U.S. motor gasoline and diesel fuels was imported. Except for Canadian gasoline and diesel, we assumed imported gasoline and diesel to be shipped by ocean tankers. For in-land transportation, we assumed that 59% of gasoline and diesel is moved from refineries/marine terminals to bulk terminals by pipeline, 32.7% by water carriers, and the rest by railroads (U.S. DOT 1996). We assumed that delivery trucks move gasoline and diesel from bulk terminals to service stations. The average transportation distance of ocean tankers was calculated according to the amount of imported petroleum products and the port-to-port distance from a country of origin to major U.S. ports. The distances for in-land transportation modes were based on the Commodity Flow Survey (U.S. DOT and U.S. DOC 1997). Figures 16 and 17 present our specifications of gasoline and diesel transportation.

### 5.2.3 Methanol

The United States produces almost one-quarter of the world's methanol. In 1995, methanol production capacity from 17 U.S. plants in 8 states totaled 2,205 million gallons. These plants meet three quarters of the U.S. methanol demand. The remaining demand is met by import, of which Canada supplies over one half. In 1995, 90% of methanol consumed in the United States was produced in North America; 8% in Trinidad, Venezuela, and Chile; and the remaining 2% in and the rest by pipeline. Trucks were assumed for transportation from bulk terminals to refueling stations. Figure 18 shows our specifications for methanol transportation. As the figure shows, we used question marks for the shares of pipeline, rail, and ocean tanker for imported methanol. This is because that we simulated three cases: methanol from NA NG, NNA NG, and NNA FG. Each

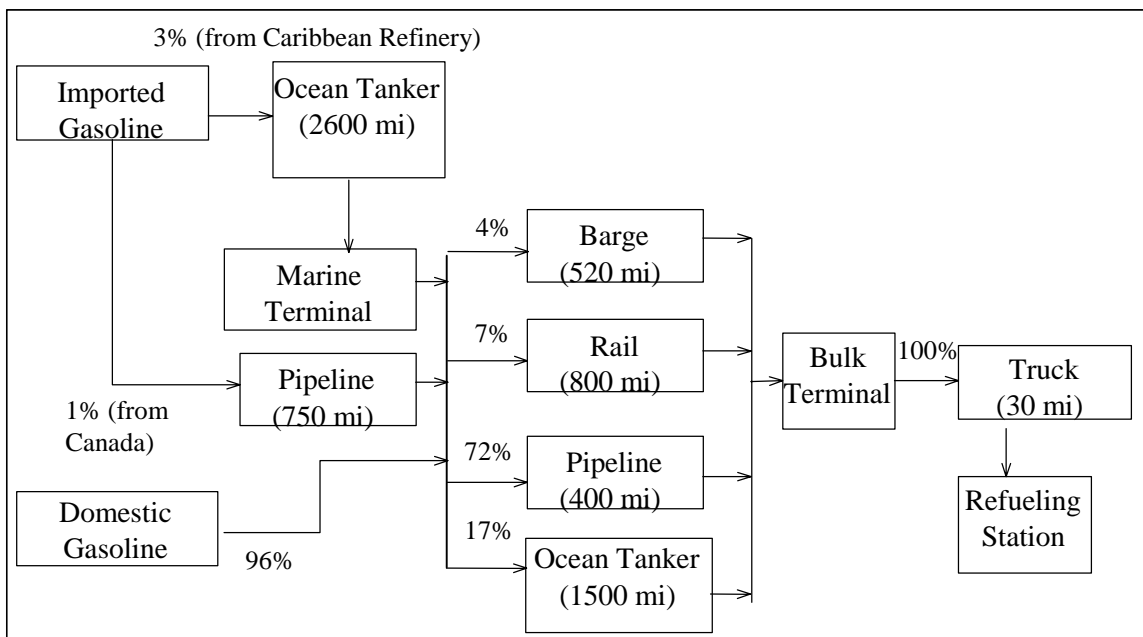


Figure 16 Gasoline Transportation from Petroleum Refineries to Refueling Stations

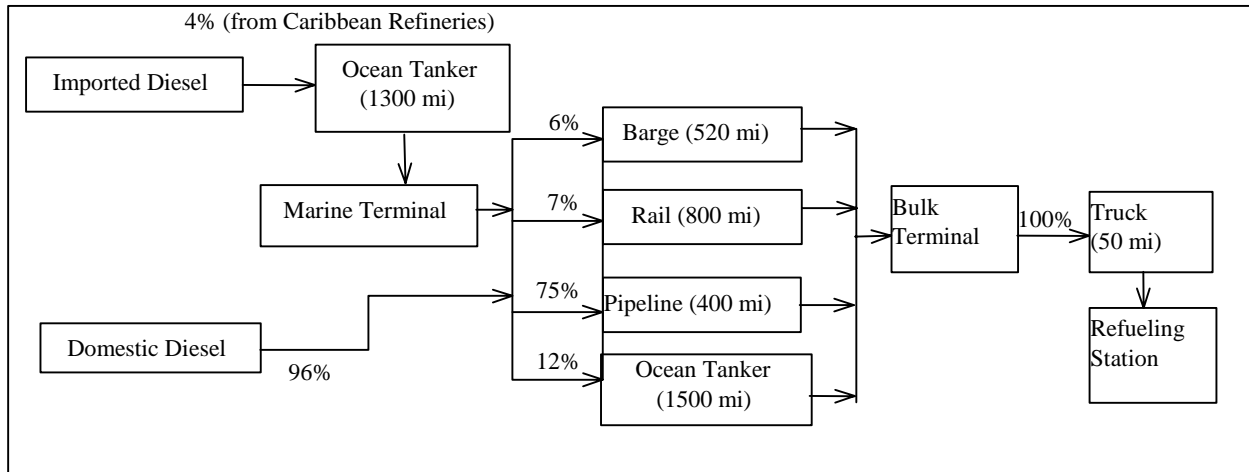


Figure 17 Diesel Fuel Transportation from Petroleum Refineries to Refueling Stations

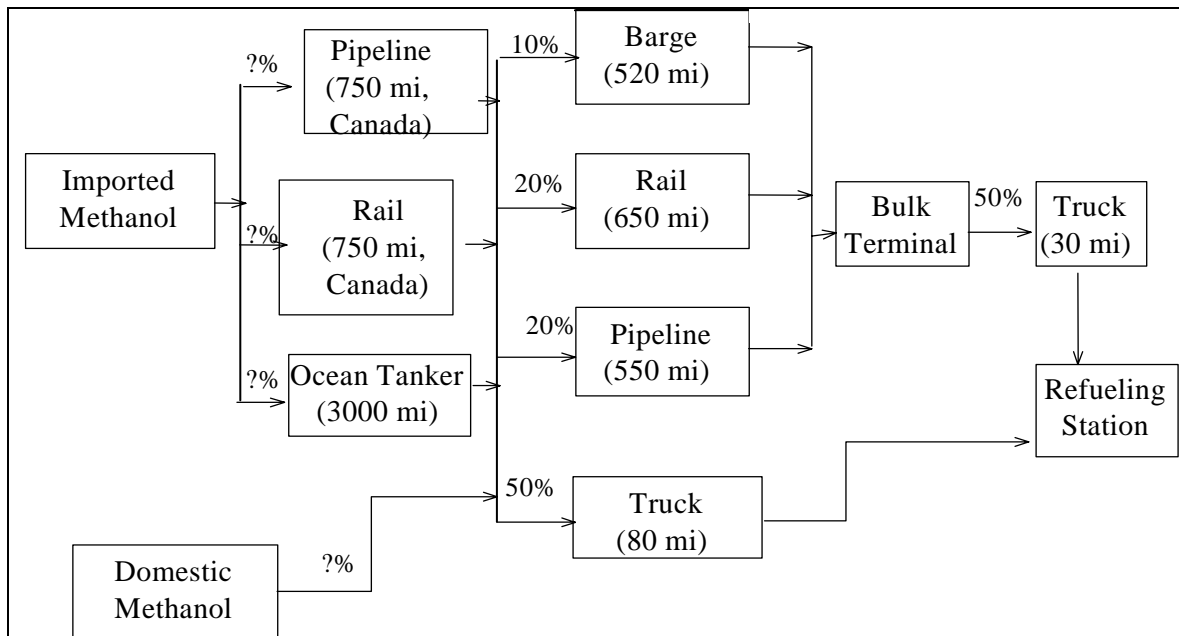


Figure 18 Methanol Transportation from Methanol Plants to Refueling Stations

Europe, Southeast Asia, and the Middle East (American Methanol Institute [AMI] 1996). On the basis of this information, we estimated that the average marine travel distance for methanol is about 2,000 miles. For in-land transportation, we assumed that half of methanol is moved by truck from methanol plants or marine terminals to bulk terminals, 10% by barge, 20% by rail, case has different shares. Furthermore, for ocean tanker transportation distance of methanol from NNA NG and NNA FG, we assumed a distance of 5,900 miles (which were based on our assumptions of 1/3 offshore methanol will come from the Persian Gulf area with a transportation distance of 10,000 miles, 1/3 from North and West Africa with a transportation distance of 5,200 miles, and 1/3 from South America with a transportation distance of 2,300 miles).

## 5.2.4 Liquefied Natural Gas

In this study, LNG itself is not a motor vehicle fuel for evaluation. Instead, it is an intermediate fuel that we assumed in order to bring NNA NG and FG to the U.S. for production of other motor fuels (CNG, G.H<sub>2</sub>, and production of L.H<sub>2</sub> at refueling stations). That is, LNG is produced offshore and transported to U.S. LNG terminals where LNG is gasified and transported via pipelines to fuel production sites.

1998, the amount of LNG imported by the United States reached 85 billion cubic feet (relative to more than 20 trillion cubic feet of natural gas consumption in the U.S.). Algeria supplied 80%, and Australia and the United Arab Emirates supplied the remaining 20% (EIA 1998). We assumed an average LNG transportation distance of 5,900 miles from offshore production sites to U.S. LNG terminals (see discussion in the methanol section).

## 5.2.5 Fischer-Tropsch Diesel and Naphtha

FT diesel and naphtha may be transported with existing diesel and gasoline transportation infrastructure. FT diesel and naphtha from offshore production can be transported to the U.S. via ocean tankers. FT diesel and naphtha produced in the U.S. and Canada can be transported to refueling stations via pipelines, rail, barges, and trucks. FT diesel and naphtha produced in Alaska can be transported to the continental U.S. via ocean tankers. Figure 19 shows our specifications of transportation of FT diesel and naphtha. As the figure shows, we used question marks for the shares of pipeline, ocean tanker, and domestic production for FT diesel and naphtha. This is because we simulated three cases: FT diesel and naphtha from NA NG, NNA NG, and NNA FG. Each case has different mode shares. Furthermore, for ocean tanker transportation distance of FT diesel and naphtha from NNA NG and NNA FG, we assumed a distance of 5,900 miles (see discussion in the methanol section).

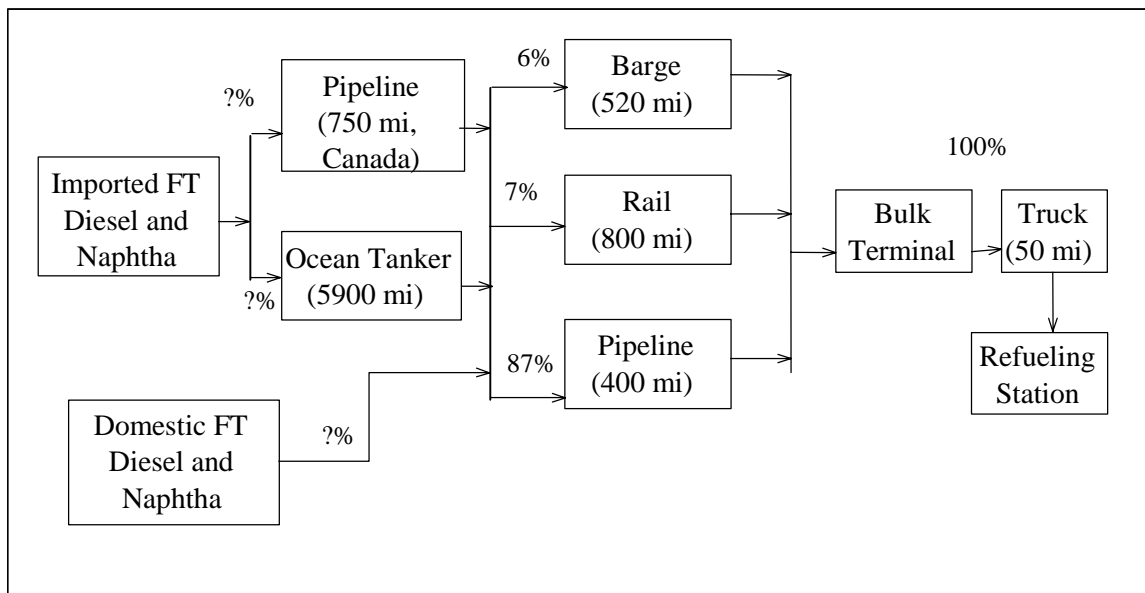


Figure 19 Transportation of Fischer-Tropsch Diesel and Naphtha from Plants to Refueling Stations

### 5.2.6 Liquid Hydrogen

L.H<sub>2</sub> for U.S. use could be produced in North America or in other offshore countries. Because the transportation system for large volumes of LH<sub>2</sub> is not in place yet, we assumed transportation distances and mode shares for L.H<sub>2</sub> based on our understanding of LNG transportation. Figure 20 shows our specifications of L.H<sub>2</sub> transportation. For NNA L.H<sub>2</sub>, an ocean tanker transportation distance of 5,900 miles is assumed (see discussion in the methanol section).

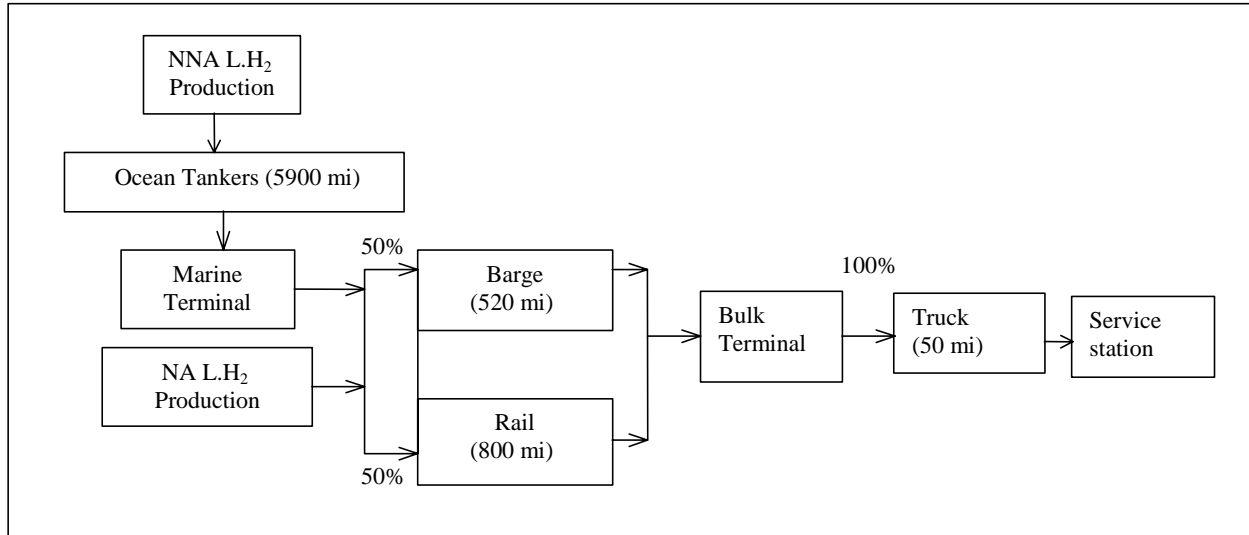


Figure 20 Transportation of Liquid Hydrogen from Central Plants to Refueling Stations

### 5.2.7 Ethanol

We assumed that fuel ethanol is produced in the United States and moved through the same transportation modes as gasoline. However, no pipeline is currently used for ethanol transportation. We further assumed that ethanol is transported from ethanol plants to bulk terminals by barge (40%), rail (40%), and truck (20%) and that only trucks are used for transportation from bulk terminals to refueling stations. Figure 21 presents our specifications of ethanol transportation.

### 5.2.8 Natural Gas and Gaseous Hydrogen

For NG and G.H<sub>2</sub> produced in central plants, pipelines were assumed to be the only transportation mode. For natural gas, we assumed a pipeline transportation distance of 750 miles, which was based on the U.S. average transportation distance for natural gas. For G.H<sub>2</sub> production in central plants, we assumed a pipeline transportation distance of 750 miles from plants to refueling stations. For G.H<sub>2</sub> production at refueling stations, we assumed zero transportation distance.

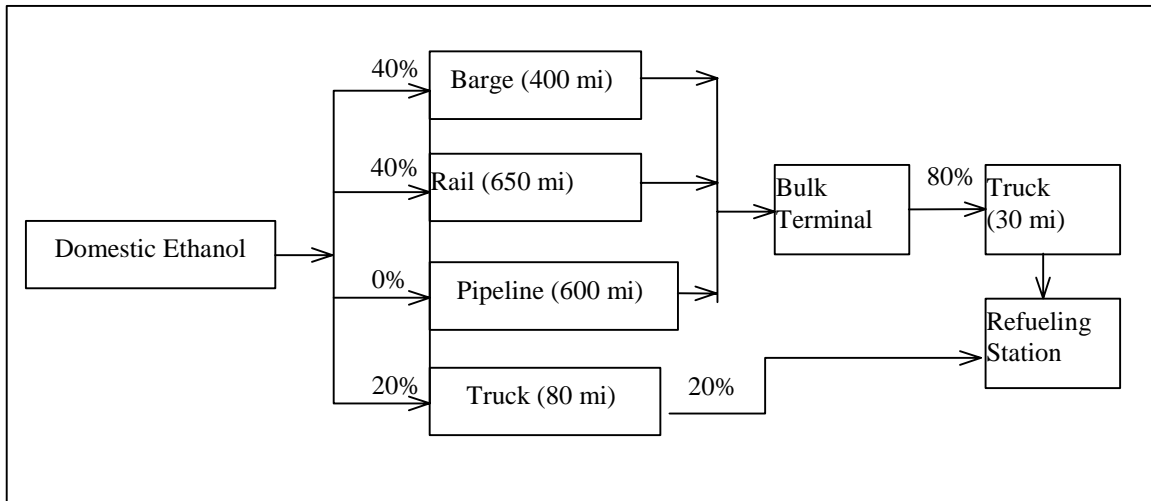


Figure 21 Transportation of Ethanol from Plants to Refueling Stations

### 5.2.9 Electricity Transmission

When electricity is transmitted from electric power plants to user sites, some electricity is lost. The U.S. average electricity loss during transmission and distribution is about 8%. The GREET model takes this loss into account.

Besides the feedstocks and fuels presented above, the GREET model also simulates some other feedstocks such as coal and uranium for electricity generation, agricultural chemicals (fertilizers, pesticides, and herbicides) for agricultural farming, and corn and biomass for ethanol production. Assumptions regarding transportation of these feedstocks are presented in He and Wang (2000).

### 5.2.10 Input Energy Efficiencies for Feedstock and Fuel Transportation

Many previous studies, including previous GREET studies, inputted energy efficiencies for transportation of feedstocks and fuels into fuel-cycle energy and emission calculations. With detailed assumptions regarding transportation modes, distance, and energy intensities, this study simulated energy use and emissions of transportation activities in a more transparent way than previous studies did. To put the results from detailed simulations of feedstock and fuel transportation conducted in this study into comparison with other previous studies, we imputed energy efficiencies of feedstock and fuel transportation with the GREET-calculated energy use for feedstock and fuel transportation with the detailed assumptions listed in above sections.

Table 22 presents our imputed energy efficiencies for transportation of various feedstocks and fuels. For most of the feedstocks and fuels, transportation energy efficiencies are above 99%. Transportation of NNA-produced fuels has lower energy efficiencies because of longer distances involved. Transportation of methanol has low energy efficiencies since a large portion of methanol is assumed to be transported via trucks within the U.S. (see Figure 18). Pipeline transportation of  $G.H_2$  has low efficiencies since a large quantity of  $G.H_2$  needs to be compressed and moved due to the low volumetric energy content  $G.H_2$  at the atmospheric pressure.

Transportation of L.H<sub>2</sub> from NNA locations has low efficiencies because of the low volumetric energy content of L.H<sub>2</sub> and the boil-off loss of L.H<sub>2</sub> during transportation. Ethanol's low transportation efficiency is due to use of trucks to transport a large quantity of it (Figure 21).

Table 22 Energy Efficiencies for Transportation of Feedstocks and Fuels  
Calculated from GREET Outputs

Feedstock/Fuel	Energy Efficiency (%)
Crude oil from oil fields to U.S. refineries	99.0
Gasoline from U.S. refineries to refueling stations	99.4
CA gasoline from CA refineries to refueling stations	99.7
Diesel from U.S. refineries to refueling stations	99.2
Petroleum naphtha from U.S. refineries to refueling stations	99.0
NG from NA fields to refueling stations	99.3
LNG from NNA plants to U.S. LNG terminals	98.5
Methanol from NA plants to refueling stations	98.0
Methanol from NNA plants to refueling stations	96.8
FT naphtha and diesel from NA plants to refueling stations	99.2
FT naphtha and diesel from NNA plants to refueling stations	98.2
Central G.H <sub>2</sub> from NA plants to refueling stations	96.3
L.H <sub>2</sub> from NA plants to refueling stations	98.9
L.H <sub>2</sub> from NNA plants to refueling stations	95.8
Ethanol from U.S. plants to refueling stations	98.5

## 6 Results: Well-To-Tank Energy Use and Emissions

With the assumptions presented in above sections and other default assumptions already in GREET, we estimated energy use and emissions of producing and delivering one million Btu of each fuel to vehicle tanks. Table 23 shows all the fuel pathways options analyzed in this study. We analyzed 75 fuel pathways options. For the main text of this report, we graphically present the results for 30 pathway options. Results of all pathway options are presented in Appendix B of this report. The 30 selected fuel pathway options are highlighted in bold in Table 23.

As the table shows, in determining pathway options for methanol, FT diesel, FT naphtha, central plant G.H<sub>2</sub>, and central plant L.H<sub>2</sub>, we assumed that plants to be built in North America could be designed to co-produce steam or electricity, since these plants can be built next to other chemical plants where co-generated steam can be exported. If these plants are to be built outside of North America, we assumed that they may be designed to co-generate electricity. Plants outside of North America may not be built next to other chemical plants. Thus, export of co-generated steam may not be feasible. If NNA FG is the feed for plants, the plants will probably be built in remote areas. Export of either steam or electricity may not be feasible. We did not assume co-generation of steam or electricity for FG-based plants.

For electricity generation, we included the U.S., the California, and the northeast U.S. generation mixes in order to show the importance of electric generation mixes. In addition, we included NG-fired CC turbines, which are very efficient and are considered probably to supply U.S. marginal electricity. Also for H<sub>2</sub> production via electrolysis, we included electricity generation from nuclear power and hydroelectric power in order to show the effect of air-pollution-clean electricity generation on H<sub>2</sub> production.

Four pathway options were analyzed for corn-based options, depending on milling technology (dry or wet) and the way of dealing with ethanol co-products (the displacement method or the market value method). Besides E100 (pure ethanol) for FCV applications, we included E85 (85% ethanol and 15% gasoline) for ICE applications. There is about 5% of gasoline in ethanol serving as denaturant for ICE application. Thus, in our analysis, E85 actually has 80% ethanol and 20% gasoline.

In selecting the 30 pathway options for presentation in this section, we dropped all the FG-based pathways, since the amount of FG available worldwide could be limited (though their efficiency and emission benefits are huge, see Appendix B). Also, we dropped all the NG-based pathways with co-generation of steam or electricity. Plant designs with co-generation of steam or electricity achieve additional efficiency and emission benefits (again, see Appendix B). We combined CG and the 150-ppm S RFG together to represent current gasoline. We combined the three RFGs with 5-30 ppm S together to represent future gasoline. We combined the four corn-ethanol pathways. The results for the combined pathways are presented in Appendix B.

Table 23 Fuel Pathway Options Analyzed in This Study<sup>a</sup>

Feedstock	Fuel
Petroleum	<p><b>(1) Conventional gasoline (CG)<sup>b</sup></b>                      (2) 150 ppm S RFG with MTBE (current federal RFG)<sup>b</sup>                      (3) 5-30 ppm S RFG with MTBE<sup>c</sup>                      (4) 5-30 ppm S RFG with EtOH<sup>c</sup>  <b>(5) 5-30 ppm S RFG without oxygenate<sup>c</sup></b>  <b>(6) Conventional diesel (CD)</b>  <b>(7) Low-sulfur (LS) diesel</b>  <b>(8) Crude naphtha</b></p>
Natural gas to compressed natural gas (CNG)	<p><b>(9) CNG from North American (NA) natural gas (NG)</b>  <b>(10) CNG from non-North American (NNA) NG</b>                      (11) CNG from NNA flared gas (FG)</p>
Natural gas to methanol	<p><b>(12) Methanol from NA NG without steam or electricity co-generation</b>                      (13) Methanol from NA NG with steam co-generation                      (14) Methanol from NA NG with electricity co-generation  <b>(15) Methanol from NNA NG without steam or electricity co-generation</b>                      (16) Methanol from NNA NG with electricity co-generation                      (17) Methanol from NNA FG without steam or electricity co-generation</p>
Natural gas to Fischer-Tropsch diesel	<p><b>(18) FT diesel from NA NG without steam or electricity co-generation</b>                      (19) FT diesel from NA NG with steam co-generation                      (20) FT diesel from NA NG with electricity co-generation  <b>(21) FT diesel from NNA NG without steam or electricity co-generation</b>                      (22) FT diesel from NNA NG with electricity co-generation                      (23) FT diesel from NNA FG without steam or electricity co-generation</p>
Natural gas to Fischer-Tropsch naphtha	<p><b>(24) FT naphtha from NA NG without steam or electricity co-generation</b>                      (25) FT naphtha from NA NG with steam co-generation                      (26) FT naphtha from NA NG with electricity co-generation  <b>(27) FT naphtha from NNA NG without steam or electricity co-generation</b>                      (28) FT naphtha from NNA NG with electricity co-generation                      (29) FT naphtha from NNA FG without steam or electricity co-generation</p>
Natural gas to G.H <sub>2</sub> in central plants	<p><b>(30) G.H<sub>2</sub> from NA NG without steam or electricity co-generation</b>                      (31) G.H<sub>2</sub> from NA NG with steam co-generation                      (32) G.H<sub>2</sub> from NA NG with electricity co-generation  <b>(33) G.H<sub>2</sub> from NNA NG without steam or electricity co-generation</b>                      (34) G.H<sub>2</sub> from NNA NG with electricity co-generation                      (35) G.H<sub>2</sub> from NNA FG without steam or electricity co-generation</p>
Natural gas to L.H <sub>2</sub> in central plants	<p><b>(36) L.H<sub>2</sub> from NA NG without steam or electricity co-generation</b>                      (37) L.H<sub>2</sub> from NA NG with steam co-generation                      (38) L.H<sub>2</sub> from NA NG with electricity co-generation  <b>(39) L.H<sub>2</sub> from NNA NG without steam or electricity co-generation</b>                      (40) L.H<sub>2</sub> from NNA NG with electricity co-generation                      (41) L.H<sub>2</sub> from NNA FG without steam or electricity co-generation</p>

Table 23 Fuel Pathway Options Analyzed in This Study (Cont.)

Feedstock	Fuel
Natural gas to G.H <sub>2</sub> in refueling stations	<b>(42) G.H<sub>2</sub> from NA NG without steam or electricity co-generation</b> <b>(43) G.H<sub>2</sub> from NNA NG without steam or electricity co-generation</b> (44) G.H <sub>2</sub> from NNA FG without steam or electricity co-generation
Natural gas to L.H <sub>2</sub> in refueling stations	<b>(45) L.H<sub>2</sub> from NA NG without steam or electricity co-generation</b> <b>(46) L.H<sub>2</sub> from NNA NG without steam or electricity co-generation</b> (47) L.H <sub>2</sub> from NNA FG without steam or electricity co-generation
<b>(48) U.S. mix</b> (49) CA mix (50) NE U.S. mix <b>(51) NA NG CC turbines</b>	Electricity
G.H <sub>2</sub> via electrolysis in refueling stations	<b>(52) Electricity with U.S. generation mix</b> (53) Electricity with CA generation mix (54) Electricity with Northeast U.S. generation mix <b>(55) Electricity with NA NG-fired combined-cycle turbines</b> (56) Electricity with nuclear power (57) Electricity with hydroelectric power
L.H <sub>2</sub> via electrolysis in refueling stations	<b>(58) Electricity with U.S. generation mix</b> (59) Electricity with CA generation mix (60) Electricity with Northeast U.S. generation mix <b>(61) Electricity with NA NG-fired combined-cycle turbines</b> (62) Electricity with nuclear power (63) Electricity with hydroelectric power
(64) Dry mill, displacement <sup>d</sup> (65) Dry mill, market value <sup>d</sup> (66) Wet mill, displacement <sup>d</sup> <b>(67) Wet mill, market value<sup>c</sup></b> <b>(68) Woody cellulose</b> <b>(69) Herbaceous cellulose</b>	Ethanol (E100, pure ethanol)
(70) Dry mill, displacement <sup>d</sup> (71) Dry mill, market value <sup>d</sup> (72) Wet mill, displacement <sup>d</sup> (73) Wet mill, market value <sup>d</sup> (74) Woody cellulose (75) Herbaceous cellulose	E85 (85% ethanol and 15% gasoline by volume. Ethanol contains 5% gasoline as denaturant. Gasoline is assumed to be RFG without oxygenate)

<sup>a</sup> Results for the options highlighted in bold are presented in this section. All options are presented in Appendix B.

<sup>b</sup> Conventional gas and 150-ppm sulfur RFG are combined together to represent current gasoline.

<sup>c</sup> These three RFG options are combined together to represent future gasoline.

<sup>d</sup> These four corn-based ethanol options are combined together to represent corn-based ethanol.

In the following sections, we graphically present the results for the 30 selected pathways. With Crystal Ball simulations, we were able to estimate energy use and emissions with probability distribution. Appendix B presents energy and emission results at probability of 0% to 100% for each 10% interval. The charts in the following sections show the range results from P20 (20% probability) to P80 (80% probability).

## 6.1 Total Energy Use

Total energy use from wells to tanks includes use of all energy sources (non-renewables and renewables). To calculate total energy use, the GREET model traces energy use back to energy

content of the primary energy feedstocks for most of transportation fuels. For example, GREET considers energy contained in crude oil in oil fields to calculate energy use for gasoline. However, there are exceptions for fuels based on biomass, solar energy, hydroelectric power, and nuclear power. For ethanol, one could estimate the amount of solar energy used for a unit of energy in ethanol produced. In this case, the energy efficiency of the photosynthesis process during plant growth would be taken into account. However, since solar energy is never a constraint for plant growth, tracing back to solar energy for ethanol does not have much meaning. We traced back the energy use for ethanol production to the energy in grown plants in our calculations.

For solar H<sub>2</sub> production via solar photovoltaic panels, one could trace the energy use for H<sub>2</sub> production all the way back to solar energy received by photovoltaic panels. In this case, the efficiency of photovoltaic panels would be taken into account. However, since solar energy is so abundant, we traced energy use for H<sub>2</sub> production back only to the energy contained in electricity generated by photovoltaic panels.

One could trace energy use for hydroelectric power generation back to energy contained in water behind dams. However, we traced energy back only to energy contained in the electricity generated in hydroelectric power plants.

For nuclear power, one could trace energy use for nuclear power generation all the way back to energy contained in uranium. However, we traced energy back only to energy contained in the electricity generated in nuclear power plants.

As Figure 22 shows, petroleum-based fuels have the lowest total energy use for each unit of energy delivered to vehicle tanks. NG-based fuels generally have high total energy use (except for CNG). The fuels with the highest energy use are: L.H<sub>2</sub> (production in both central plants and refueling stations), G.H<sub>2</sub> and L.H<sub>2</sub> production via electrolysis, and electricity generation. L.H<sub>2</sub> suffers large efficiency losses during H<sub>2</sub> liquefaction. H<sub>2</sub> production via electrolysis suffers two large efficiency losses – electricity generation and H<sub>2</sub> production.

Use of NNA NG for NG-based fuel production results in slightly higher total energy use than use of NA NG does. This is because transportation of liquid fuels produced outside of North America consumes an additional amount of energy. In the case of CNG, G.H<sub>2</sub>, and station L.H<sub>2</sub>, NG liquefaction, which has additional energy efficiency losses, is involved in order to bring NNA NG to the U.S.

There is a large reduction in total energy use from the U.S. electric generation mix to NG-fired CC turbines for electricity generation and consequently for H<sub>2</sub> production via electrolysis with the latter. This is because while the average conversion efficiency of existing U.S. fossil fuel plants is 32-35%, NG-fired CC turbine conversion efficiency is over 50%. Thus, use of electricity generated with CC turbines results in reduced total energy use.

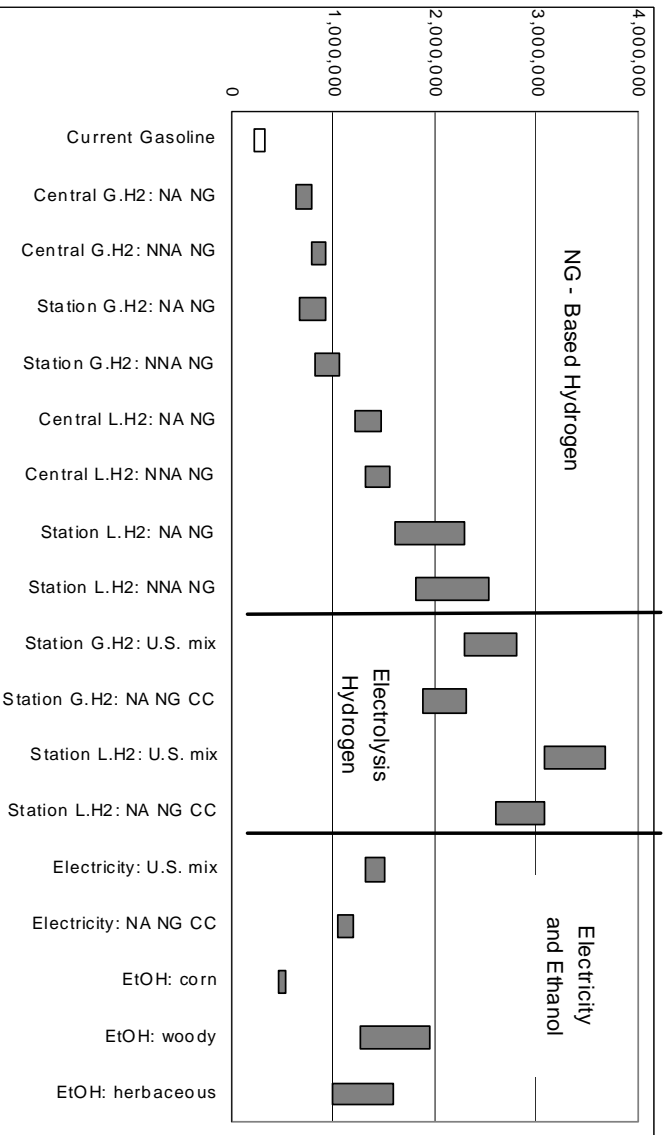
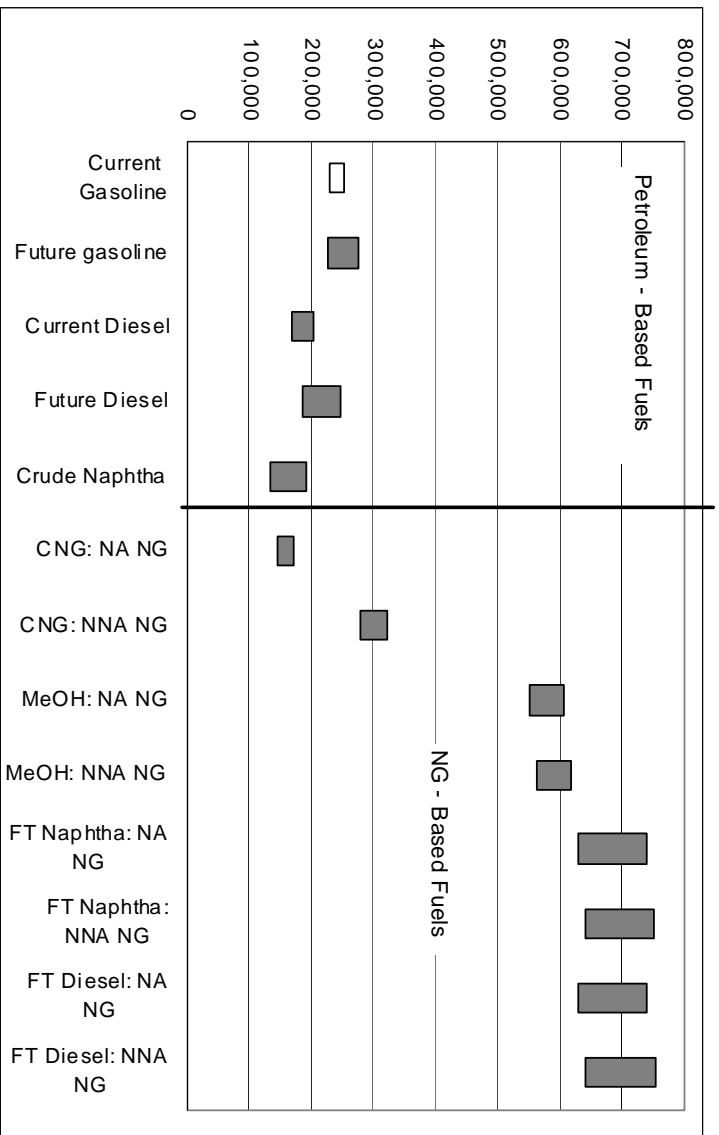


Figure 22 Well-to-Tank Total Energy Use (Btu/mBtu of fuel delivered to vehicle tanks)

## 6.2 Well-to-Tank Energy Efficiencies

Energy efficiencies are calculated here with total energy use, as presented in Figure 22. In particular, the following formula was used to calculate energy efficiency:

$$\text{Efficiency} = 1,000,000 / (1,000,000 + \text{total energy use}) ,$$

where

1,000,000 = 1 mmBtu of a given fuel available in vehicle tanks and

total energy use = WTT total energy use to produce and deliver 1 mmBtu to vehicle tanks (in Btu per mmBtu of fuel available in vehicle tanks, as presented in the above section).

Figure 23 shows energy efficiencies of the 30 fuel pathways. While gasoline, diesel, crude naphtha, and CNG have efficiencies near or above 80%, energy efficiencies of station L.H<sub>2</sub>, G.H<sub>2</sub> and L.H<sub>2</sub> via electrolysis, and electricity generation with the U.S. mix are below 40%. This means that vehicles using these fuels must achieve doubled vehicle efficiencies in order for these vehicles to achieve well-to-wheel efficiencies comparable to gasoline vehicle overall efficiencies.

As the above efficiency formula shows, the efficiency calculated this way takes into account both energy used for producing a fuel and its energy content. The efficiency treats different energy sources the same. For example, energy use for and energy contained in petroleum- and natural gas-based fuels are primarily petroleum and natural gas, both of which are with finite amounts on the earth. On the other hand, energy use for and energy contained in cellulosic ethanol are primarily energy in biomass, which is eventually from solar energy and is renewable. If resources for converting renewable energy sources into ethanol are not a constraint, use of renewable energy sources should have a much less concern than use of non-renewable energy sources. The efficiency based on total energy use is less meaningful for renewable energy-based fuels than for non-renewable energy-based fuels. A better indicator for renewable energy-based fuels could be a ratio between the energy produced in renewable fuels and the non-renewable energy used for the production. Such ratio provides some indication of the enhancement effect of renewable fuel production on prolonging use of finite amounts of non-renewable resources. The results on fossil energy use by each fuel presented in the next section are intended to serve this purpose.

## 6.3 Fossil Energy Use

Figure 24 presents well-to-tank fossil fuel use for the 30 pathway options. Fossil fuels include petroleum, NG, and coal – the three major non-renewable energy sources. Except for ethanol pathway options, fossil fuel use patterns are similar to those of total energy use. A large amount of lignin is burned in cellulosic ethanol plants. While the energy in lignin is accounted in calculating total energy use, it is not accounted in calculating fossil fuel use. Consequently, fossil fuel use by the two cellulosic ethanol pathways is much lower than total energy use by the two pathways.

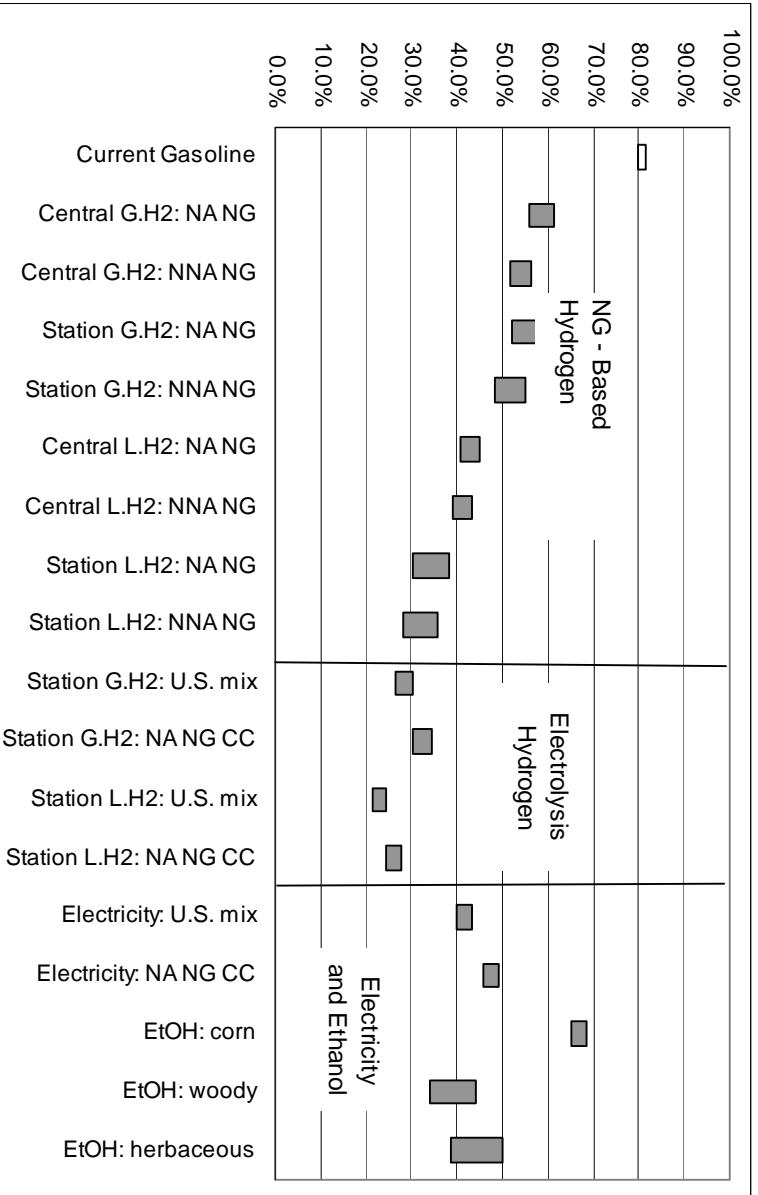
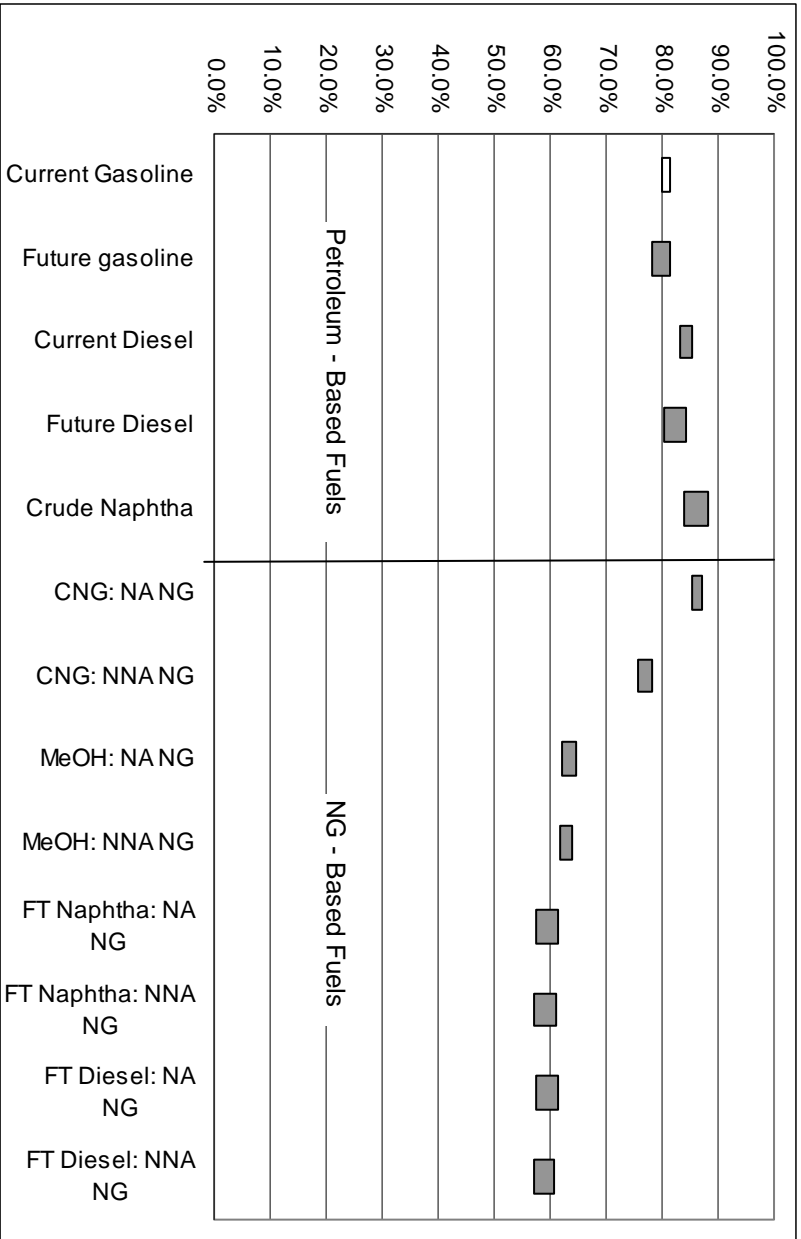


Figure 23 Well-to-Tank Energy Efficiencies

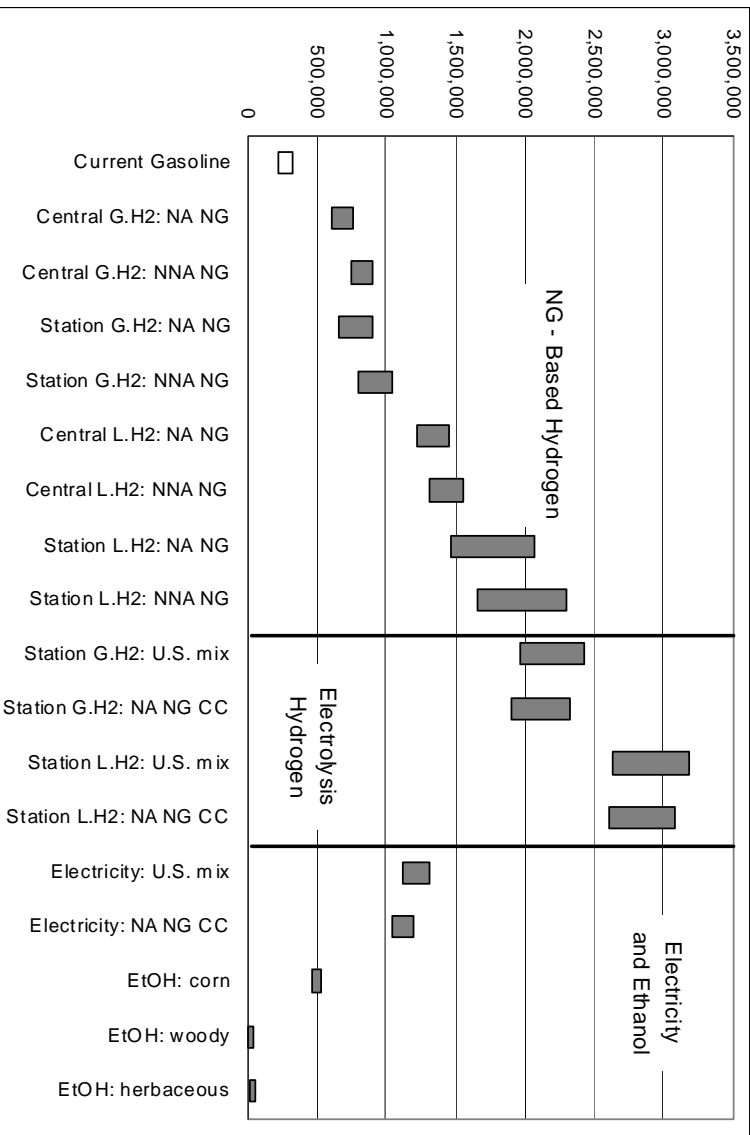
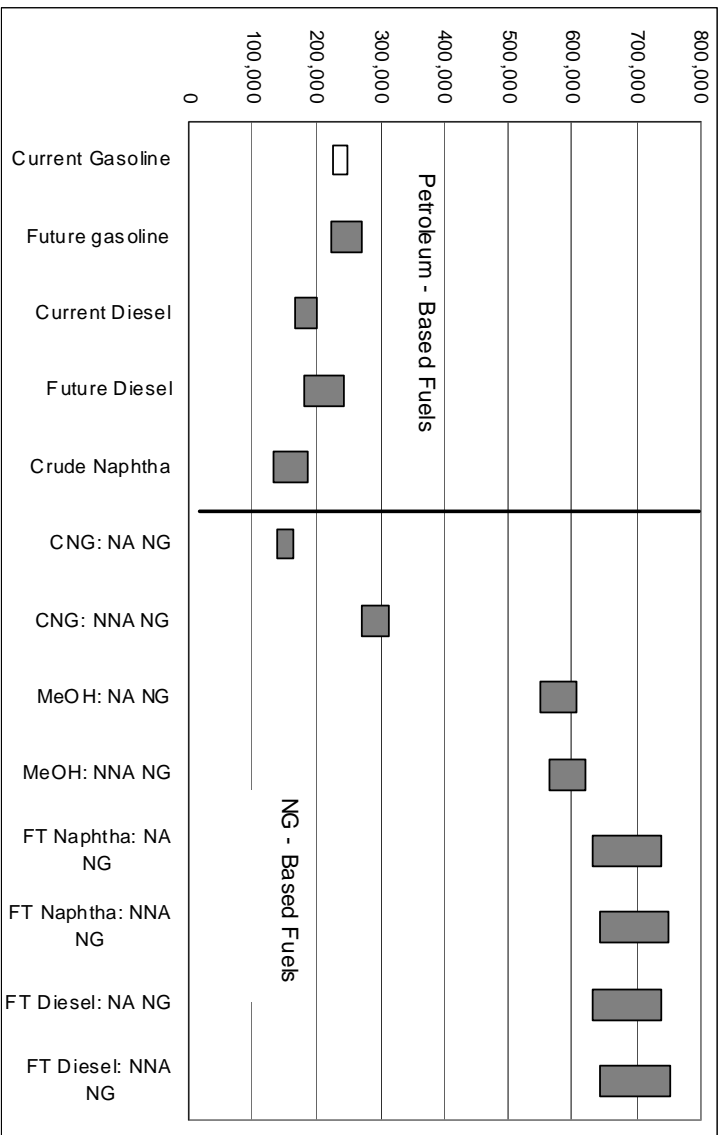


Figure 24 Well-to-Tank Fossil Energy Use (Btu/mBtu of fuel delivered to vehicle tanks)

With electricity generation and H<sub>2</sub> production via electrolysis, fossil fuel use between the U.S. generation mix and NG-fired CC turbines is very similar. This is because while the U.S. generation mix has an overall conversion efficiency lower than that of CC turbines, under the U.S. average mix, there are some non-fossil fuel power plants (such as nuclear and hydroelectric power plants), which are not accounted in calculating fossil fuel use.

## 6.4 Petroleum Use

We estimated petroleum use for each pathway to provide information on potential petroleum displacement by a given pathway, relative to conventional gasoline.

Figure 25 shows that all the petroleum-based fuel pathways have expectedly high petroleum use. Methanol pathways have relatively high petroleum use because trucks and rails were assumed to transport a large quantity of methanol. The high petroleum use for central G.H<sub>2</sub> relative to station G.H<sub>2</sub> is due to our assumption that central G.H<sub>2</sub> is compressed in refueling stations with electric compressors, but station G.H<sub>2</sub> is compressed in refueling stations by both electric and NG compressors. Electricity pathways consume some amount of petroleum.

With electricity generation and H<sub>2</sub> production via electrolysis, there is a large reduction in petroleum use from the U.S. average generation mix to NG-fired CC turbines. This is because with the U.S. generation mix, a small amount of electricity is generated with residual oil. Also, mining and transportation of coal consume a significant amount of oil. The three ethanol pathways consume the amount of oil similar to that by the petroleum gasoline pathways. This is caused by the large amount of petroleum diesel that is consumed during farming and transportation of corn and cellulosic biomass. Also note that herbaceous cellulosic ethanol has petroleum use less than that by corn ethanol and woody cellulosic ethanol. This is because corn ethanol consumes a relatively large amount of diesel and because of transportation of woody biomass, which has high moisture content, consumes more energy than transportation herbaceous biomass.

## 6.5 Greenhouse Gas Emissions

GHG emissions here include emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O, the three major GHGs specified in the Kyoto protocol. In our analysis, these three gases were combined together with their global warming potentials (1 for CO<sub>2</sub>, 21 for CH<sub>4</sub>, and 310 for N<sub>2</sub>O) to derive CO<sub>2</sub>-equivalent GHG emissions. Figure 26 shows well-to-tank GHG emissions.

Petroleum-based fuels and CNG from NA NG have low GHG emissions. CNG from NNA NG has relatively high GHG emissions because of CH<sub>4</sub> emissions from boil-off effect and LNG leakage during LNG transportation from offshore to U.S. LNG terminals. Methanol and FT fuels have high GHG emissions because of CO<sub>2</sub> emissions during fuel production.

All H<sub>2</sub> pathways have very high GHG emissions because all the carbon in feedstocks for H<sub>2</sub> production ends up as CO<sub>2</sub> emissions. As stated in a previous section, we did not assume carbon sequestration during H<sub>2</sub> production. Note that L.H<sub>2</sub> production, electrolysis H<sub>2</sub>, and electricity generation have the highest GHG emissions. There is a large reduction in GHG emissions from

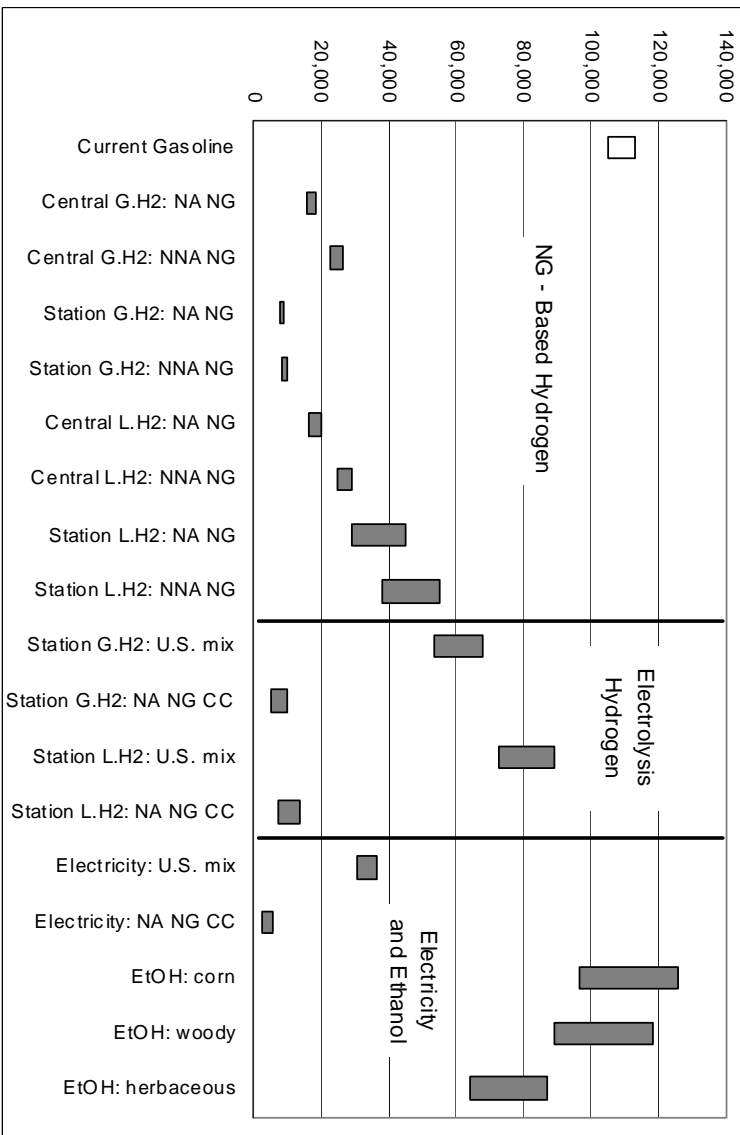
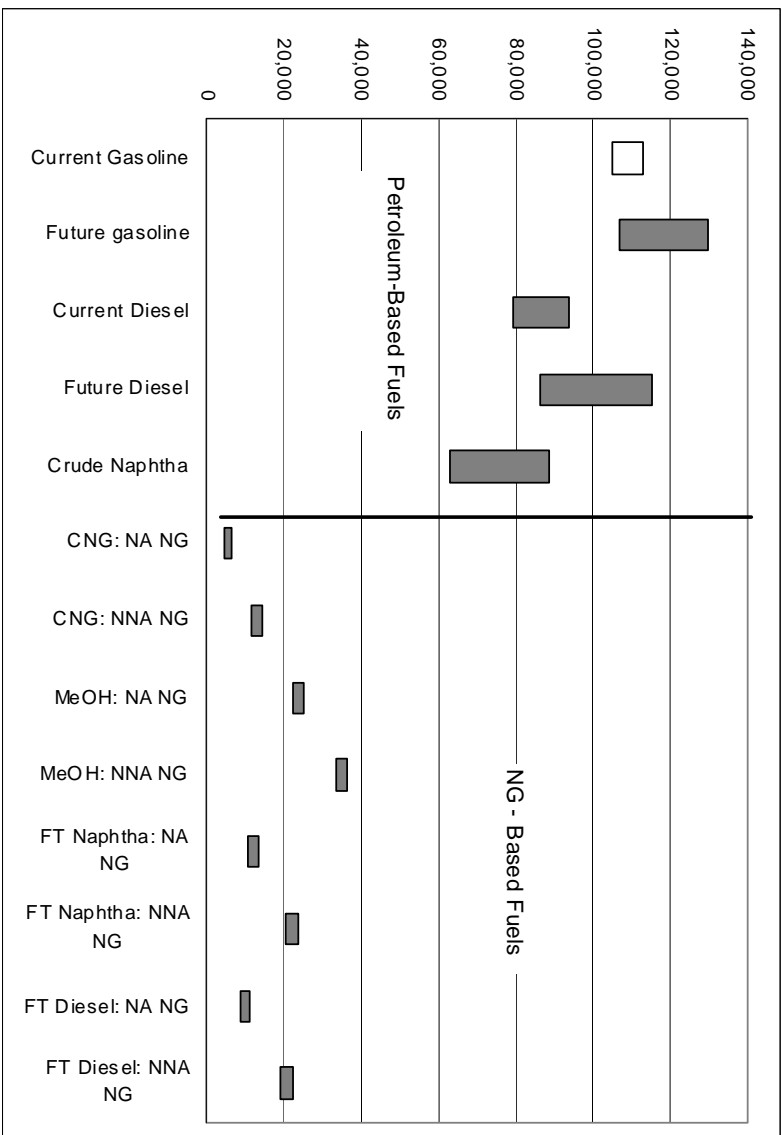


Figure 25 Well-to-Tank Petroleum Use (Btu/mBtu of fuel delivered to vehicle tanks)

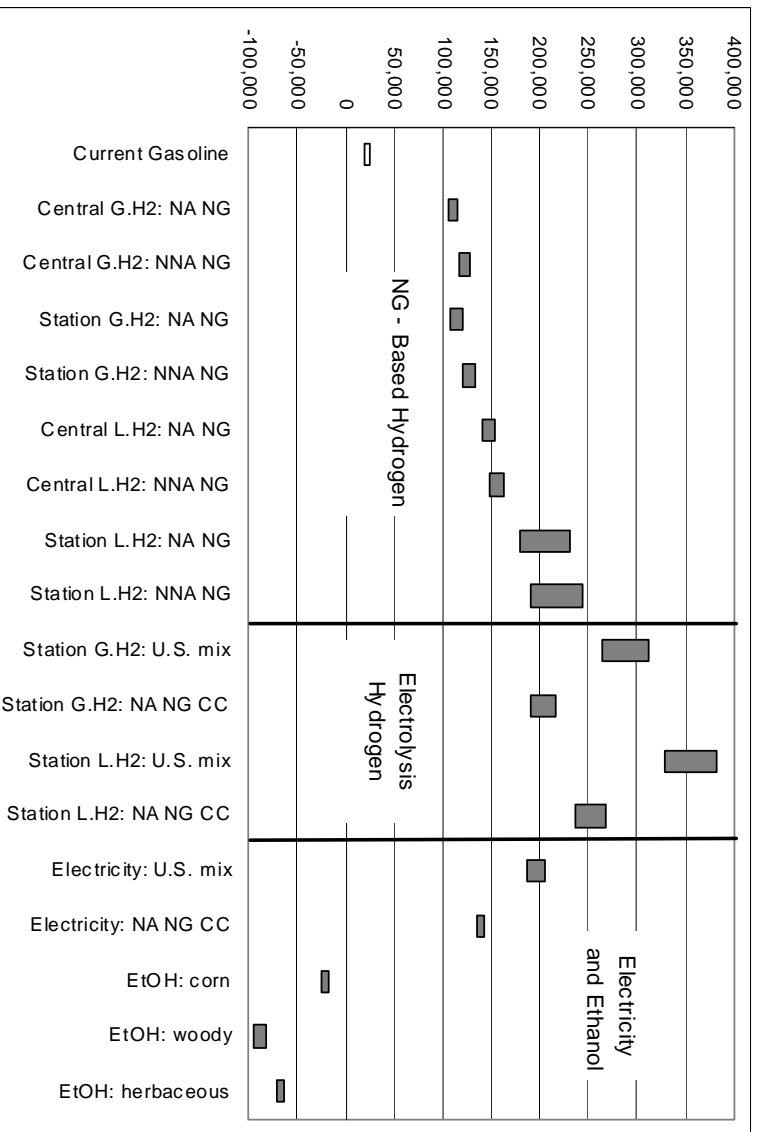
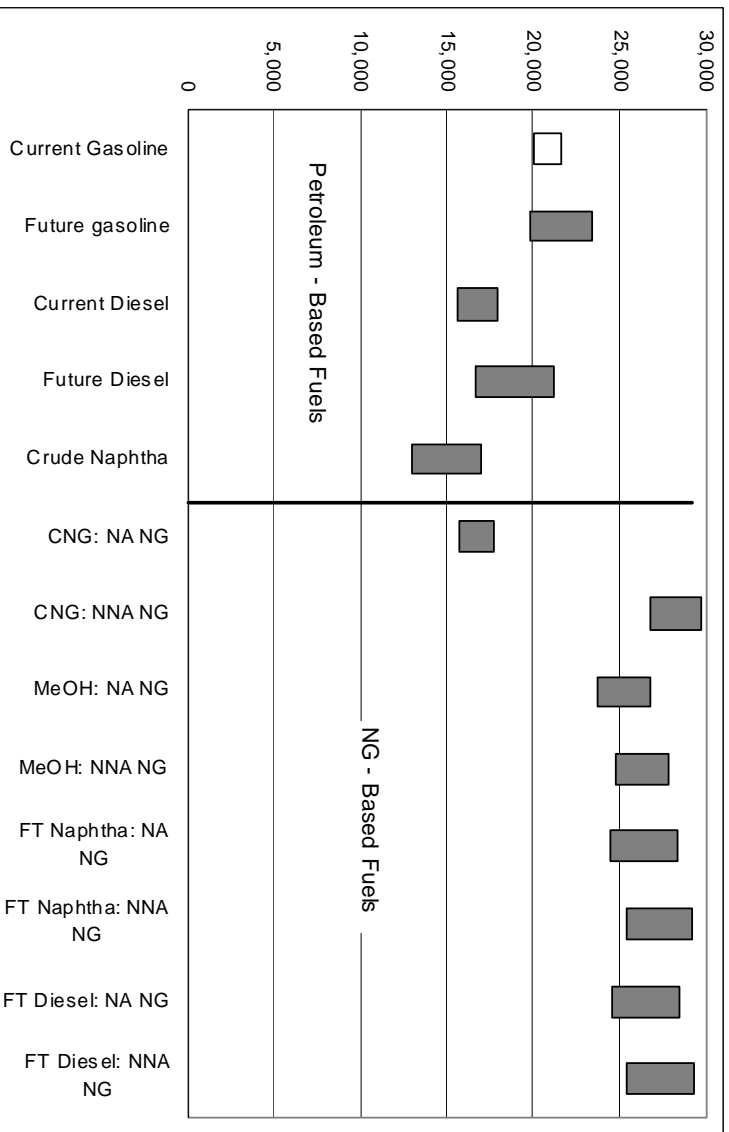


Figure 26 Well-to-Tank GHG Emissions (g/mBtu of fuel delivered to vehicle tanks)

the U.S. average electric generation mix to NG-fired CC turbines. This is primarily caused by high GHG emissions from coal- and oil-fired electric power plants, relative to those from NG-fired CC turbine plants.

The three ethanol pathways have negative GHG emissions. This is because of carbon sequestration during growth of corn plants, trees, and grass. The carbon sequestered during biomass growth will emit to the air during combustion of ethanol on vehicles.

The very high GHG emissions for H<sub>2</sub> and electricity and negative GHG values for ethanol on the well-to-tank basis, as shown in Figure 26, demonstrates incomplete, sometimes misleading, conclusions for comparison of GHG emissions of fuel/vehicle technologies on the well-to-tank basis. This is because during the tank-to-wheels stage, all the hydrocarbon fuels will emit a large amount of carbon, while H<sub>2</sub> and electricity will have zero carbon emissions. For ethanol, while there is carbon sequestration during biomass growth (resulting in negative WTT GHG emissions), most of the carbon sequestered during biomass growth will be emitted back to the air. At net, ethanol fuels may have close to zero GHG emissions, not a large negative GHG value. In this regard, the results presented in this report is partial results. Readers should read a separate report that is prepared by GM on well-to-wheels GHG emission results.

## 7 Conclusions

Our WTT analysis resulted in the conclusions stated below. It is important to remember that WTT results are incomplete in evaluating fuel/propulsion systems. The systems must be evaluated on a WTW basis; this analysis is presented in Part 3 of Volume 2.

- *Total Energy Use.* For the same amount of energy delivered to the vehicle tank for each of the fuels evaluated in our study, petroleum-based fuels and CNG are subject to the lowest WTT energy losses. Methanol, FT naphtha, FTD, and G.H<sub>2</sub> from NG and corn-based ethanol are subject to moderate WTT energy losses. Liquid H<sub>2</sub> from NG, electrolysis H<sub>2</sub> (gaseous and liquid), electricity generation, and cellulosic ethanol are subject to large WTT energy losses.
- *Fossil Energy Use.* Fossil energy use — including petroleum, NG, and coal — follows patterns similar to those for total energy use, except for cellulosic ethanol. Although WTT total energy use of cellulosic ethanol production is high, its fossil energy use is small because cellulosic ethanol plants would burn lignin, a non-fossil energy source, for needed heat.
- *Petroleum Use.* Production of all petroleum-based fuels requires a large amount of petroleum. Electrolysis H<sub>2</sub> (with the U.S. average electricity) and the three ethanol pathways consume an amount of petroleum about equal to that consumed by petroleum-based fuels. NG-based fuel pathways require only small amounts of petroleum.
- *Greenhouse Gas Emissions.* Production of petroleum-based fuels and NG-based methanol, FT naphtha, and FTD results in a smaller amount of WTT GHG emissions than production of H<sub>2</sub> (gaseous and liquid) and electricity generation. WTT GHG emission values of the three ethanol pathways are negative because of carbon sequestration during growth of corn plants, trees, and grass.

Overall, our WTT analysis reveals that petroleum-based fuels have lower WTT total energy use than do non-petroleum-based fuels. L.H<sub>2</sub> production (in both central plants and refueling stations) and production of G.H<sub>2</sub> and L.H<sub>2</sub> via electrolysis can be energy-inefficient and can generate a large amount of WTT GHG emissions. Cellulosic ethanol, on the other hand, because it is produced from renewable sources, offers significant reductions in GHG emissions. The other fuels options examined here have moderate WTT energy and GHG emissions effects.



## **8 Acknowledgments**

This work was funded by the Global Alternative Propulsion Center of GM. Argonne would like to acknowledge guidance and input from the GM project managers, Dr. Tony Finizza, Dr. Jim Wallace, and Greg Ruselowski. We are grateful to Dr. James Simnick and Andrew Armstrong of BP, Gilbert Jersey and Dr. John Robbins of ExxonMobil, Norman Brinkman of GM Research and Development Center, and Jean Cadu of Shell for their input to and review of this report. We would also like to thank our colleagues Marianne Mintz, Dan Santini, and Chris Saricks for their input.

Finally, the study participants would like to thank Tien Nguyen, Dr. Phillip Patterson, and David Rodgers of the U.S. Department of Energy's Office of Transportation Technologies; without their support of previous versions of the GREET model, this study would not have been possible. We would also like to acknowledge the excellent editorial support provided by Mary Fitzpatrick of Argonne.



## 9 References

Adamson, K.A., and P. Pearson, 2000, "Hydrogen and Methanol: a Comparison of Safety, Economics, Efficiencies, and Emissions," *Journal of Power Sources* 86:548–555.

AMI, 1996, *Methanol: North America's Clean Fuel and Chemical Building Block*, American Methanol Institute (<http://www.methanol.org/methanol/fact/methanol.html>).

Amstutz, A., and L. Guzzella, 1998, "Fuel Cells for Transportation — an Assessment of Its Potential for CO<sub>2</sub> Reduction," *Proceedings of the Fourth International Conference on Greenhouse Gas Control Technologies*, Aug. 30–Sept. 2, Interlaken, Switzerland.

ARCO Products Company, 1999, "Emission Control Diesel," presentation material, Los Angeles, Calif., March.

Berggren, M.A., 1997, "Mega-Methanol — Methane Madness vs. Money Maker," presented at the 1997 World Methanol Conference, Tampa, Fla., Dec. 8–10.

Berry, J.R., A.L. Pasternak, G.D. Rambach, J.R. Smith, and T.N. Schock, 1996, "Hydrogen as a Future Transportation Fuel," *Energy* 21:289–303.

Blok, K., et al., 1997, "Hydrogen Production from Natural Gas, Sequestration of Recovered CO<sub>2</sub> in Depleted Gas Wells and Enhanced Natural Gas Recovery," *Energy* 22(2-3):161–168.

California Air Resources Board, 1991, *California Phase 2 Reformulated Gasoline Specifications, Volume 1, Proposed Regulations for California Phase 2 Reformulated Gasoline*, Sacramento, Calif., Jan. 28.

California Air Resources Board, 2000, *Updated Informative Digest of California Reformulated Gasoline*, Sacramento, Calif.

CARB: see California Air Resources Board.

Domalski, E.S., and T.L. Jobe, 1986, *Thermodynamics Data for Biomass Conversion and Waste Incineration*, SERI/SP-271-2839, prepared by National Institute of Standards and Technology, Washington, D.C., for Solar Energy Research Institute, Golden, Colo.

EIA: see Energy Information Administration.

Energy Information Administration, 1998, *International Energy Annual 1996*, DOE/EIA-0219(96), Washington, D.C., Dec.

Energy Information Administration, 1999, *Petroleum Supply Annual, 1998*, Washington, D.C.

Energy Information Administration, 2000, *Petroleum Supply Annual, 1999, Volume 1*, Washington, D.C., June.

EPA: see U.S. Environmental Protection Agency.

Gronemann, V., 1998, "Methanol Process Developments; Mega Methanol Synthesis," presented at the 1998 IMPCA Latin American Methanol Conference, San Juan, Puerto Rico, May 4–6.

He, D., and M.Q. Wang, 2000, *Contribution of Feedstock and Fuel Transportation to Total Fuel-Cycle Energy Use and Emissions*, SAE paper 2000-01-2976, Society of Automotive Engineers.

Islam, M.N., and K.J. Brown, 1997, "Building Large Methanol Plants for Reliability and Economy," presented at the 1997 World Methanol Conference, Tampa, Fla., Dec. 8–10.

Kelly, L., 2000, personal communication, California Energy Commission, Sacramento, Calif., Aug. 24.

Kikkawa, Y., and N. Nozawa, 1999, "Optimizing Liquefied Natural Gas Power Chain," presented at the 1999 Spring Meeting of the American Institute of Chemical Engineers, Houston, Texas, March 14–18.

MathPro, 1999a, *Refining Economics of 5 PPM Sulfur Standards for Gasoline in PADDs 1-3*, prepared for the Alliance of Automobile Manufacturers, West Bethesda, Md., Oct. 18.

MathPro, 1999b, *Refining Economics of Diesel Fuel Sulfur Standards*, prepared for Engine Manufacturers Association, West Bethesda, Md., Oct. 5.

MathPro, 1999c, *Analysis of California Phase 3 RFG Standards*, submitted to California Energy Commission, West Bethesda, Md., Dec. 7.

McKetta, J.L., 1992, *Petroleum Processing Handbook*, Macel Dekker, Inc., New York, N.Y.

National Petroleum Council, 1993, *U.S. Petroleum Refining, Meeting Requirements for Cleaner Fuels and Refineries, Volume II — General Information Appendices*, Washington, D.C., Aug.

National Petroleum Council, 2000, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels*, Washington, D.C., June.

National Research Council, 2000, *Ozone-Forming Potential of Reformulated Gasoline*, National Academy Press, Washington, D.C.

NPC: see National Petroleum Council.

Ogden, J.M., 1999, "Developing an Infrastructure for Hydrogen Vehicles: A Southern California Case Study," *International Journal of Hydrogen Energy* 24:709–730.

*Oil and Gas Journal*, 1999, *Oil and Gas Journal Databook, 1999 Edition*, PennWell Publisher, Tulsa, Okla.

*Oil and Gas Journal*, 2000, "LNG Imports Needed to Meet Growing U.S. Gas Supply Deficit," Oct. 2.

Pembina Institute, *Climate-Friendly Hydrogen Fuel: a Comparison of the Life-Cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems*, Drayton, Alberta, Canada, March.

Russell, B., 2000, personal communication, Syntroleum Corporation, Tulsa, Okla., Sept., 15.

(S&T)<sup>2</sup> Consultants, Inc., 2000, *Assessment of Emissions of Greenhouse Gases from Fuel Cell Vehicles*, prepared for Methanex Corporation, Delta, British Columbia, Canada, June 5.

Stork, K., and M. Singh, 1995, *Impacts of the Renewable Oxygenate Standard for Reformulated Gasoline Ethanol Demand, Energy Use, and Greenhouse Gas Emissions*, ANL/ESD-28, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., April.

Thomas, C.E., B.D. James, I.F. Kuhn, F.L. Lomax, and G.N. Baum, 1997, *Direct-Hydrogen-Fueled Proton-Exchange-Membrane Fuel Cell System for Transportation Applications: Hydrogen Infrastructure Report*, DOE/CE/50389-504, prepared for the U.S. Department of Energy, Office of Transportation Technologies, Washington, D.C., July.

Unnasch, S., 2000, *Refinement of Selected Fuel-Cycle Emission Analyses*, draft final report, prepared by Arthur D. Little, Mountain View, Calif., for California Air Resources Board, Feb. 9.

Unnasch, S., and L. Browning, 2000, *Fuel-Cycle Energy Efficiency Analysis*, prepared for California Energy Commission, Sacramento, Calif., May.

U.S. DOT, 1996, *National Transportation Statistics 1996*, Bureau of Transportation Statistics, U.S. Department of Transportation, Washington, D.C.

U.S. DOT and U.S. DOC, *1997 Commodity Flow Survey*, Bureau of Transportation Statistics, U.S. Department of Transportation, and Economics and Statistics Administration, U.S. Department of Commerce, Washington, D.C.

U.S. Environmental Protection Agency, 1994, *Regulation of Fuels and Fuel Additives; Standards for Reformulated and Conventional Gasoline, Final Rule*, Federal Register, Vol. 59, Feb. 16.

U.S. Environmental Protection Agency, 2000a, *Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, Final Rule*, Federal Register, Vol. 65, No. 28, Feb. 10.

U.S. Environmental Protection Agency, 2000b, *Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, Final Rule*, Dec. 21.

Vink, K.J., and R.K. Nagelvoort, 1998, "Comparison of Baseload Liquefaction Processes," presented at the 12th International Conference and Exhibition on Liquefied Natural Gas, May.

Wang, M.Q., 1999a, *GREET 1.5 — Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results*, ANL/ESD-39, Vol. 1, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., Aug.

Wang, M.Q., 1999b, *GREET 1.5 — Transportation Fuel-Cycle Model, Volume 2: Appendices of Data and Results*, ANL/ESD-39, Vol. 2, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., Aug.

Wang, M.Q., and H.S. Huang, 1999, *A Full Fuel-Cycle Analysis of Energy and Emissions Impacts of Transportation Fuels Produced from Natural Gas*, ANL/ESD-40, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., Dec.

Williams, R., and B. Wells, 1997, “Solar-Assisted Hydrogen Production from Natural Gas with Low CO<sub>2</sub> Emissions,” presented at the International Conference on Technologies for Activities Implemented Jointly of the IEA Greenhouse Gas R&D Programme, Vancouver, British Columbia, Canada.